1996 WHOLESALE POWER AND TRANSMISSION RATE PROPOSAL

ADMINISTRATOR'S RECORD OF DECISION

BONNEVILLE POWER ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

JUNE 1996

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ATTACHMENTS:

1. TRANSMISSION RATES AND TERMS AND CONDITIONS SETTLEMENT AGREEMENT

2. POWER AND TRANSMISSION PARTIAL SETTLEMENT AGREEMENT

APPENDIX:

WHOLESALE POWER AND TRANSMISSION RATE SCHEDULES

COMMONLY USED ACRONYMS

AC	Alternating Current or Southern Intertie Annual Costs (rate)
ACME	Accelerated California Market Estimator (computer program)
AER	Actual Energy Regulation
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	Average Megawatt
AOP	Assured Operating Plan
APS	Ancillary Products and Services
ASC	Average System Cost
ASM	Aluminum Smelter Model
BASC	BPA's Average System Cost
BPA	Bonneville Power Administration
BTU	British Thermal Unit
CE	Emergency Capacity (rate)
cfs	Cubic feet per second
CO-OP	Co-operative Electric Utility
COB	California-Oregon Border
COE	United States Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRC	Critical Rule Curves
CRFA	Columbia River flow augmentation
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CWIP	Construction Work In Progress
CY	Calendar Year (Jan - Dec)
DC	Direct Current
DOE	Department of Energy
DSIs	Direct Service Industrial Customers
DSM	Demand-Side Management
EA	Environmental Assessment
ECC	Energy Content Curve
EIS	Environmental Impact Statement
EPA '92	Energy Policy Act of 1992
ESA	Endangered Species Act
ET	Energy Transmission (rate)
ETCA	Exchange Transmission Credit Agreement
F & O	Financial and Operating Reports
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
FLCC	Firm Load Carrying Capability
FPSs	Firm Power Products and Services
FPT	Formula Power Transmission (rate)
FRE	Firm Resource Exhibit
FSEA	Federal Secondary Energy Analysis
FY	Fiscal Year (Oct - Sep)
GCPs	General Contract Provisions
GPU	Generating Public Utilities
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GTRSPs	General Transmission Rate Schedule Provisions
IE	Eastern Intertie Transmission (rate)
IN	Northern Intertie Transmission (rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (rate)
IR	Integration of Resources (rate)
IRE	Industrial Replacement Energy
IS	Southern Intertie Transmission (rate)
ISC	Investment Service Coverage
ksfd	thousand second foot days
KV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LOLP	Loss of Load Probability
LTIAP	Long-Term Intertie Access Policy
Maf	Million Acre Feet
M/kWh	Mills per kilowatthour
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
MW	Megawatt (1 million watts)
MW-miles	Megawatt-miles
MWh	Megawatthour
MT	Market Transmission (rate)
NEPA	National Environmental Policy Act
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (computer program)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOB	Nevada-Oregon Border
NR	New Resource Firm Power (rate)
NRF	Northwest Regional Forecast

NSGPU	non- and small-generating public utilities
NSR	Named Set of FBS Resources
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OY	Operating Year (August-July)
PA	Public Agency
PIP	Programs in Perspective
PF	Priority Firm Power (rate)
PMDAM	Power Market Decision Analysis Model (computer model)
PNCA	Pacific Northwest Coordination Agreement
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Interconnection
PS	Power Shortage (rate)
PSW	Pacific Southwest
PTP	Point-to-Point
PURPA	Public Utilities Regulatory Policies Act
PUD	Public or Peoples' Utility District
RAM	Rate Analysis Model (computer model)
REM	Regional Economic Model (computer model)
REVEST	Revenue Estimate (computer program)
ROD	Record of Decision
RP	Reserve Power (rate)
RPSA	Residential Purchase and Sale Agreement
RPSM	BPA’s Resource Policy Screening Model
SDD	Short Distance Discount
SI	Special Industrial Power (rate)
SMEA	Shaped Monthly Energy Amounts
SP	Surplus Firm Power (rate)
SPM	Supply Pricing Model (computer program)
SPOM	Surplus Power-Open Market
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Risk Evaluation and Analysis Model
TGT	Townsend-Garrison Transmission (rate)
TRDS	Transmission Rate Design Study
UFT	Use of Facilities Transmission (rate)
USBR	United States Bureau of Reclamation
USFWS	United States Fish and Wildlife Service
VI	Variable Industrial Power (rate)
VOR	Value of Reserves

WNP	Washington Public Power Supply System (Nuclear) Project
WPPSS	Washington Public Power Supply System
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WSCC	Western Systems Coordinating Council

1.0 INTRODUCTION

1.1 Procedural History of This Rate Proceeding

1.1.1 Other Proceedings

1.1.1.1 Issue Workshops

From the preliminary rate proposal through development of this Record of Decision, BPA sponsored workshops on a variety of issues related to its ratemaking. The workshops covered topics ranging from transmission rates and terms and conditions to workshops on revenue requirements, marginal cost, rate design and rate complexity. These noticed workshops were held between BPA and interested parties to develop a common understanding of the issues and to generate ideas and proposed, alternative solutions to issues in specific areas, if possible. Solutions and ideas arising from the workshops were incorporated into BPA's initial and supplemental rate proposals and, thus, into the final rate case studies and this Record of Decision, where appropriate.

1.1.1.2 Environmental Analysis

BPA must evaluate its proposed rates for wholesale power and transmission services in a formal rate proceeding pursuant to section 7(i) of the Northwest Power Act. In addition, BPA must evaluate the potential environmental effects of the proposed rates and alternatives thereto, as required by the National Environmental Policy Act (NEPA). BPA's final 1996 rate proposal is consistent with BPA's Business Plan, the Business Plan Final Environmental Impact Statement (BP FEIS) (DOE/EIS-0183, June 1995), and the Business Plan Record of Decision (ROD) (August 15, 1995). The BP FEIS and ROD were intended to guide BPA in a series of related decisions on various issues and actions, including a range of rate levels and designs. Consistent with the Business Plan ROD, the Administrator reviewed the BP FEIS to determine whether the actions embodied in proposing the 1996 rates were adequately covered within the scope of the BP FEIS. BPA's 1996 rate proposal includes some of the issues and actions contemplated by the BP FEIS and has been determined by the Administrator not to have significant environmental effects, as summarized in this ROD.

1.1.1.3 Terms and Conditions Proceeding

Concurrently with the rate proceeding described in this Record of Decision, BPA conducted a hearing to establish terms and conditions of general applicability for transmission access. As described below in section 1.3.1, the Federal Energy Regulatory Commission (FERC) has authority to order transmission service on the Federal Columbia River Transmission System (FCRTS). The Energy Policy Act of 1992 (EPA'92), Pub. L. No. 102-486, 106 Stat. 2776 (1992) describes the circumstances under which FERC can order access and prescribes additional standards for the rates applicable to such transmission access. The sections of the Energy Policy Act of 1992 applicable to the

FCRTS permit the Administrator to conduct a separate, regional process to determine terms and conditions of general applicability for FERC-ordered access to the FCRTS.

In addition, Bonneville is a member to two regional transmission associations (RTAs), the Western Regional Transmission Association (WRTA) and Northwest Regional Transmission Association (NRTA). As a condition of approval of the RTAs, FERC has required that members offer comparable open transmission access, at least to other members. *See Southwest Regional Transmission Association* , 69 FERC ¶ 61,100, at 61,398 (1994)(SWRTA), *order on compliance filing*, 73 FERC ¶ 61,147 (1995); *PacifiCorp, the California Municipal Utilities Association, and the Independent Energy Producers (on behalf of Western Regional Transmission Association)*, 69 FERC ¶ 61,099, *order on reh'g* 69 FERC ¶ 61,352 (1994), *order on compliance filing,* 71 FERC ¶ 61,158 (1995)(WRTA), and *Northwest Regional Transmission Association*, 71 FERC ¶ 61,397 (1995)(NRTA); *see also Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 Fed. Reg. 21,540, at 21,548 (1996), III FERC Stats. & Regs. ¶ 31,036 (1996) [hereinafter Order 888]. The proposed open access transmission tariffs will meet the RTA requirement and be FERC approved tariffs available for requests under FPA sections 211 and 213.

The tariffs have been the subject of a separate public process, held concurrently with the rates proceeding. On February 14, 1995, Bonneville filed a Federal Register Notice of "Hearing and Opportunity for Public Comment; Regarding Proposed Comparable Transmission Terms and Conditions." The notice stated:

> BPA will be proposing terms and conditions applicable to three transmission services over the network transmission system of the Federal Columbia River Transmission System (FCRTS) which BPA considers to be comparable to the uses BPA itself makes of such system for its own power transactions. The Federal Power Act, as amended by the Energy Policy Act of 1992, provides that BPA may institute a regional hearing process on proposed transmission terms and conditions of general applicability. By this notice, BPA is announcing such a proceeding and the dates on which the proposed transmission terms and conditions will be available.

60 Fed. Reg. 8511 (1995). EPA'92 provides for the Hearing Officer in the Terms and Conditions proceeding to make a recommended decision to the Administrator. At the end of the proceeding, the Administrator will make the final decision on the transmission terms and conditions. Bonneville intends to file the terms and conditions tariffs, along with the rates that apply to those tariffs, for approval by FERC.

1.1.2 Explanation of Distinction Between Power and Transmission Rates and Transmission Terms and Conditions Proceedings

In this proceeding, Bonneville has proposed transmission rates of general applicability and rates to be used with transmission tariffs described in section 1.1.1.3. All of the transmission rate proposals have been included the WP-96/TR-96 dockets, which were conducted concurrently with the terms and conditions proceeding described above (TC-96) and pursuant to section 7(i). As described in section 1.3.2, EPA'92 distinguished terms and conditions from rates both procedurally and substantively, and BPA has conducted these proceedings to preserve the distinction between transmission terms and conditions and rates.

For ease of administration, BPA has conducted the proceedings concurrently. Federal Register Notices were filed for both proceedings at the same time, and the same schedule was adopted for both proceedings. In addition, much of the testimony submitted in the rate case was concurrently submitted in the terms and conditions proceeding. In fact, at the end of cross examination, the hearings officers combined the records of the two proceedings into a single record. Tr. 2236. This meant that all evidence elicited in the record is available to support both rates and terms and conditions decisions.

The proceedings were conducted with two hearings officers: one for the rates proceedings and one for the terms and conditions proceedings. The Hearing Officer for TC-96 submitted a recommended decision to the Administrator on May 14, 1996. TC-96-RD-01. The Administrator will make the final decision in both proceedings..

1.1.3 Explanation of Settlement Discussions and Agreements

1.1.3.1 Settlement Discussions

Subsequent to cross examination, BPA held several workshops with customers, noticed pursuant to the ex parte rule, to address various issues that had arisen during the pendency of the rate proceeding. Workshops and settlement conferences relating to transmission terms and conditions or transmission rates issues were held on February 12, March 7, March 14, March 20, March 25-29, April 1-2,1996. The notices for these meetings clearly stated that they were being held with a view to settlement of outstanding issues.

At a hearing held March 29, 1996, BPA reported to the Hearings Officers that BPA and the parties were making progress on settlement of issues in the rates and terms and conditions proceedings, and the parties requested an additional day of hearings to be held on April 4, 1996, to memorialize the settlement agreement reached by the parties, if any. Tr. 2294. The request was granted. On April 4, 1996, the parties reported substantial progress, and, indeed, BPA submitted two proposed settlement agreements to the record, subject to the condition that a sufficient number of BPA's customers agreed to the settlement. Tr. 2316-2341. BPA undertook to notify all parties as soon as practicable after April 11, 1996, if it decided not to proceed with the settlement agreements. BPA has decided to proceed with the settlement agreements.

As a result of the settlement discussions, the parties produced two settlement documents: the "Transmission Rates and Terms and Conditions Settlement Agreement,"*see* Attachment 1 [hereinafterTransmission Settlement Agreement] and the "Power and

Transmission Partial Settlement Agreement," *see* Attachment 2 [hereinafter Power Settlement Agreement] (jointly Agreements or Settlement Agreements). The Transmission Settlement Agreement is intended by the parties to settle all issues relating to transmission rates, terms and conditions for the five year settlement period from October 1, 1996 through September 30, 2001. The Power Settlement Agreement settles some issues, including the level of the Priority Firm Rate, as described below. The settlement agreements were amended by joint motion of the parties. *See* WP-96-M-81, Or. Tr. 2371.

The vast majority of Bonneville's customers signed the Settlement Agreements, either on their own behalf or through action by their representative in the rate case. The number of parties signing the Agreements has been characterized as "some of the litigants" by APAC, which does not support the settlement, TC-96-B-PA-01 at 2, and "substantially all of the parties to these proceedings" by PGP, which does, WP-96-B-PG-01/TC-96-B-PG-01at 3. The number of parties signing and the diversity of their interests in the proceedings, from full requirements customers to wheeling-only customers, is testament to the strength of the consensus on the Settlements. These Agreements represent substantial regional consensus on the issues addressed in them, including transmission rates and the form of the open-access tariffs to be adopted by BPA.

1.1.3.2 Content of Agreements

It should first be noted that the Agreements represent agreed-upon proposals for resolution of issues raised in Bonneville's 1996 Wholesale Power and Transmission Rates proceeding and the Terms and Conditions proceeding, as litigated in BPA Dockets WP/TR-96 and TC-96. That is, the proposals are subject to review by the Administrator for compliance with applicable statutes, including the requirement that the Administrator's decision be made based on substantial evidence in the rule-making record. Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839f(e)(2)(1982) [hereinafter Northwest Power Act]. As will be demonstrated below, the proposals meet the statutory tests.

Common Provisions

The Agreements contain several common substantive provisions. For example, both agreements contain a paragraph, labeled "Proposal, " that specifically declares that the Agreement "represents an agreed-upon proposal" (or "agreed-upon partial proposal" in the case of the Power Settlement) and that the Administrator's final decision on the issues must be supported and made based on the record of the proceeding. Attachment 1, p. 1; Attachment 2, p. 1. See discussion at section 2.6, below. Both agreements provide that no precedent, either substantive or procedural, is created by the adoption of the settlement proposal. Attachment 1, pp. 1-2; Attachment 2, pp. 1-2. Both agreements contain a "Right to Contest" provision that defines the ability of a signing party to contest issues settled by the agreements in subsequent proceedings. Attachment 1, p.2 Attachment 2, p. 2. Finally, both agreements contain language that specifies that the settlement agreements do not amend contracts or limit remedies available under contracts. Attachment 1, p. 6; Attachment 2, p. 3.

Provisions of the Transmission Settlement

The Transmission Settlement was intended by the parties to settle all issues in the transmission terms and conditions proceeding and the transmission rates proceeding. It provides that the Administrator should, with certain listed exceptions, adopt Bonneville's supplemental proposal for transmission terms and conditions. Attachment 1, p. 3.

With regard to transmission rates, the Transmission Settlement provides for specific rate level increases for transmission rates, proposes a plan for the recovery of BPA's delivery facilities costs and includes a proposal for the adoption of a policy by BPA for the purchase and sale of such facilities to the user of those facilities. *Id.* at 3. It specifically provides that the Delivery Charge should be established at $9.00 per kW-yr, and establishes the billing determinant for the charge. *Id.* at 4. It also provides that the costs of certain facilities formerly proposed to be included in the delivery segment, instead be included in the Network segment, and that utilities that take delivery at that level not be subject to the Delivery Charge. *Id.* It provides for allocation of the costs of general transfer agreements (GTAs) to the power rates and delivery segments, *id.*, and proposes to treat the Northern Intertie segment as part of Bonneville's network segment and terminate the Northern Intertie rate schedule for the settlement period. *Id.* at 5. The Transmission Settlement also includes sections relating to specific rate design and cost allocation proposals for the PTP, NTP and NT rate schedules including a proposal for the determination of Billing Demand under the PTP-96 rate schedule. *Id.* at 5-6.

The Transmission Settlement also contains provisions proposing changes to the transmission terms and conditions tariffs relating to the treatment of Bonneville as an eligible customer under the NT tariff and redispatch provisions. *Id.* at 4-5.

Provisions of the Power Settlement

The Power Settlement provides that the parties agreeing to it also agree to the Transmission Settlement. Attachment 2, p. 3. The Power Settlement also provides that the Priority Firm Power (PF) rate should be established at "less that 24.4 mills per kWh as shown on line 21 of Table RDS 50 of the 1996 Final Documentation to the Wholesale Power Rate Development Study." *Id.* at 2. It contains a specific proposal for assumptions relating to any underrecovery of Utility Delivery facilities' cost due to the limit on the Delivery Charge, a proposal for the adoption of the Availability Charge, and proposals relating to the computed maximum requirement waiver and Partial Load Shaping. *Id.* at 3.

1.1.4 **<u>Procedural History of This Rate Proceeding</u>**

Section 7(i) of the Northwest Power Act,16 U.S.C. §839e(i), requires that BPA's wholesale power and transmission rates be established according to certain procedures. These procedures include, among other things, issuance of a Federal Register Notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. As noted above, this rate proceeding to adjust wholesale power rates has been combined with the proceeding for BPA's proposal to adjust transmission rates. This proceeding is governed by BPA's rule for general rate proceedings, §1010.9 of the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986) (hereinafter Procedures). These Procedures implement the statutory section 7(i) requirements.

On December 28, 1994, BPA published a Notice of Intent to Revise Transmission Rates, 59 Fed. Reg. 66946 (1994), and Notice of Intent to Revise Wholesale Power Rates, 59 Fed. Reg. 66947 (1994). Subsequently, BPA published Federal Register Notices of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496 (1995), Proposed Transmission Rate Adjustment, 60 Fed. Reg. 8505 (1995), and Hearing and Opportunity for Public Comment Regarding Proposed Comparable Transmission Terms and Conditions, 60 Fed. Reg. 8511 (1995).

BPA's 1995 wholesale power and transmission rate proceeding, and the terms and conditions proceeding, began with a Prehearing Conference on February 13, 1995. The proceedings, originally in two dockets, WP-95/TR-95 (wholesale power and transmission rates) and TC-95 (transmission services terms and conditions), subsequently were separated into three different dockets as described below.

At the direction of the Hearing Officers at the February 13, 1995, prehearing conference, an additional prehearing conference was scheduled for March 15, 1995, and additional time was allowed for petitions to intervene. A Federal Register Notice for Additional Prehearing/Settlement Conference for March 15, 1995, was published on March 3, 1995. 60 Fed. Reg. 11962 (1995).

On February 14, 1995, BPA published a preliminary rate proposal in the Federal Register. 60 Fed. Reg. 8496 (1995). In that proposal, BPA noted that competitive forces are causing a fundamental and significant change in the Pacific Northwest wholesale power market. In light of these competitive forces, BPA determined that its initial proposal should include a 5-year rate as well as a 2-year rate. BPA anticipated that the work necessary to develop such a proposal would take until July 1995.

At the March 15, 1995, prehearing conference the parties notified the hearing officers that they had been involved in negotiations for a settlement of issues that might affect the hearing schedule and requested additional time to complete the negotiations. The Hearing

Officers acted on petitions to intervene received to that date and set a scheduling conference for March 22, 1995.

On March 17, 1995, most parties to the rate case signed a Settlement Agreement agreeing that BPA would propose to surcharge BPA's current rates for a 1-year period, October 1, 1995, through September 30, 1996, and to extend the Variable Industrial Power (VI) rate which was scheduled to expire on June 30, 1996, through September 30, 1996. The parties also agreed to conduct a separate subsequent process to establish a 2-year and a 5-year rate proposal, and a proposal for transmission services terms and conditions. The Settlement Agreement was an attempt to balance a number of interests, including concerns expressed by customer representatives to BPA's Power Sale Contract renegotiations, which were conducted during the same period as the rate proceeding.

As a result of the March 22, 1995, scheduling conference, the Hearing Officers issued an Order that divided the proceedings previously designated as WP-95, TR-95, and TC-95 into three separate dockets:

A. The 1995 Wholesale Power and Transmission Rate Proceeding was designated WP-95/TR-95, and this 90-day expedited rate proceeding would be conducted pursuant to Section 1010.10 of the Procedures. On May 1, 1995, BPA issued its initial rate proposal and published it in the Federal Register. 60 Fed. Reg. 21132 (1995).

B. A 1996 Wholesale Power Proceeding was designated WP-96 and the Transmission Rate Proceeding was designated TR-96, both to be general rate proceedings conducted pursuant to Section 1010.9 of the Procedures. The March 22, 1996, Order established a hearing schedule beginning July 10, 1995, to establish BPA's power and transmission rates for the period beginning October 1, 1996, and new transmission services terms and conditions. The schedules adopted by the Hearing Officers for WP/TR-96 and TC-96 were intended to afford the parties a hearing process that encompasses a period of 8 months for establishment of BPA's new rate designs including new 2- and 5-year rates, and for establishment of transmission services terms and conditions.

C. The 1996 Transmission Services Terms and Conditions Proceeding was designated TC-96, and was scheduled to be conducted pursuant to Section 1010.9 of the Procedures concurrently with and on the same schedule as WP-96/TR-96.

In separate orders issued March 22, 1995, the Hearing Officers: (1) adopted a service list for BPA's 1995 Wholesale Power and Transmission Rate Adjustment Proceeding, 1996 Wholesale Power and Transmission Rate Adjustment Proceeding, and 1996 Transmission Terms and Conditions Proceeding; and (2) ruled on other procedural matters concerning these proceedings, ruled that intervenors who intervened in the dockets designated WP-95/TR-95 and TC-95 on or before March 15, 1995, were admitted as parties for all proceedings noted above.

BPA's 1995 initial rate proposal was filed on May 1, 1995. Direct testimony was filed by the parties on May 30, 1995. Cross examination took place on June 30, 1995. The Parties submitted briefs on July 10, 1995. Because the proceeding was held pursuant to the rule for expedited proceedings, BPA did not prepare a draft Record of Decision and there were no briefs on exceptions. BPA made the 1995 Final Rate Proposal available on July 31, 1995.

On August 1, 1995, BPA filed with FERC for both interim and final approval of the proposed 1995 rates for power sales and transmission services, including rates for nonfirm sales outside the Pacific northwest region. BPA requested approval of its wholesale power and transmission rates and Variable Industrial Power Rate and an extension of its Impact Aid Methodology for the period October 1, 1995 through September 30, 1996. Also requested were approval of BPA's proposed Southern Intertie Annual Cost Rate, for the period from October 1, 1995, through the remaining life of the facilities and approval of rates under the Pacific Northwest Coordination Agreement effective August 4, 1995. On September 11, 1995, these rates were approved on an interim basis, effective October 1, 1995. Final approval of these rates was granted by FERC on April 4, 1996. *U.S. Dept. of Energy--Bonneville Power Admin.*, 75 FERC ¶ 62,010 (1996).

On July 17, 1995, BPA filed notice in the Federal Register that it was proposing new wholesale power rates and transmission rates to be effective on October 1, 1996, including new 2- and 5-year rates for requirements service. 60 Fed. Reg. 36464 (1995). On July 6, 1995, BPA also published a separate notice in the Federal Register on its proposed new transmission services terms and conditions tariffs. 60 Fed. Reg. 35185 (1995).

BPA's 1996 initial rate proposal was filed on July 10, 1995, and was supported by prefiled written testimony and studies sponsored by approximately 74 witnesses. Clarification on BPA's initial rate proposal began on July 18, 1995. On August 21, 1995, and October 4, 1995, respectively, the Hearing Officers issued an Order Amending the Schedule at the request of BPA and the Parties in order to allow BPA time to revise portions of its initial proposal. On September 8, 1995, BPA filed a revised Segmentation Study and TRDS tables, and a revised Rates Analysis Model (RAM) using Gross Exchange Cost Materials. The parties filed their direct testimony on September 8, 1995.

On December 8, 1995, litigants to the proceeding filed rebuttal to the Parties' direct case. BPA also filed a supplemental rate proposal on December 8, 1995, which consisted of written testimony and studies. On this date the parties filed their direct case on BPA's Revised Segmentation Study and Revised RAM. Clarification on BPA's supplemental rate proposal began on December 12 , 1995.

The parties filed their direct case in response to BPA's supplemental rate proposal on January 26, 1996, and the litigants responded to the Parties' Direct Case on the Revised Segmentation Study and Revised RAM. BPA also filed a Revised Repayment Study on

January 26, 1996. Testimony responding to the parties' supplemental case was filed on February 12, 1996. Surrebuttal testimony was filed by all parties on February 14, 1996. BPA responded to 1554 data requests concerning the initial and supplemental rate proposals and rebuttal testimony. The parties filed their prehearing briefs on February 12, 1996. Cross-examination began on February 20 and ended on March 11, 1996. Testimony, exhibits, errata thereto and transcript cross examination elicited during the wholesale power and transmission rate proceeding (WP-96/TR-96) was admitted into the Terms and Conditions (TC-96) docket on March 12, 1996.

At a March 29, 1996, hearing the parties notified the hearing officers that they had been involved in negotiations for a settlement of issues that might affect the hearing schedule and requested additional time to complete the negotiations. The Hearing Officers set another hearing for April 4, 1996, at which time certain motions to admit additional evidence into the record would be heard. On March 29, the Hearing Officers approved a motion that was proposed by the parties to amend the rate case schedule.

On April 4, 1996, BPA and a majority of the parties jointly proposed a five-year settlement of BPA transmission rates and terms and conditions. Agreement also was reached on a proposed settlement for the level of five-year wholesale power rates for BPA's public utility customers. The Settlement Agreements were admitted to the record as exhibits WP-96-E-BPA-128 and WP-96-E-BPA-129. On April 11, 1996, BPA and some of the rate case parties filed a motion to revise language to the proposed transmission settlement agreement which was approved on April 30, 1996. The Settlement Agreements are discussed in Section 1.1.3.2, above.

For interested persons who did not wish to become parties to the formal evidentiary hearings, BPA conducted transcribed field hearings between September 14 and September 28, 1995, in eight locations: Burley and Idaho Falls, Idaho; Kalispell, Montana; Springfield and Portland, Oregon; and Everett, Spokane and Pasco, Washington. BPA received and considered 609 written comments and comments recorded from telephone calls during the comment period, which officially ended on October 2, 1995. BPA also received and 198 written comments from the end of the official comment period through the issuance of this Record of Decision. The transcribed field hearings and the comments from rate case participants are part of the record on which the Administrator bases his decisions.

Parties submitted briefs on April 22, 1996. Oral argument before the Administrator and Deputy Administrator was held on April 30, 1996.

The Draft Record of Decision (ROD) was published and distributed to parties on May 14, 1996. The parties filed their Briefs on Exceptions on May 30, 1996. On May 21 and June 3 respectively, BPA released draft priority firm (PF), new resources (NR), and industrial firm (IP) power rate schedules, draft transmission rate schedules and draft Transmission Rate Design Study (TRDS) tables as a courtesy to the rate case parties. Normally, BPA does not publish actual rates with the Draft Record of Decision. The draft wholesale power rate schedules reflected a reformatting of the rate schedules and the rates that would have been adopted if decisions documented in the Draft Record on Decision were adopted without change. The draft transmission rate schedules and draft TRDS tables reflected the Transmission Settlement Agreement provisions. It was noted that the draft wholesale power and transmission rate schedules and TRDS tables were subject to change based on the result of the final rate case studies and decisions of the Administrator documented in the Final Record of Decision.

This ROD is based on the Administrator's consideration of the entire rate case record, including written comments discussed in section 14.4.

This ROD was made available on June 17, 1996.

This ROD, which includes the proposed rates, will be filed with FERC. FERC will review the proposed rates for conformance with statutorily-designated review standards and, upon issuance of interim approval, the rates will go into effect on October 1, 1996.

1.2 Legal Guidelines Governing Establishment Of Rates

1.2.1 Statutory Guidelines

Section 6 of the Bonneville Project Act (Project Act), 16 U.S.C. § 832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Under the Project Act, rate schedules become effective upon confirmation and approval by the Federal Power Commission (succeeded by FERC). Section 6 of the Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 of the 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 amortization of the capital investment over a reasonable period of years.

The Federal Columbia River Transmission System Act 16 U.S.C. § 838 (Transmission System Act), contains requirements similar to those of the Project Act. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, provides that rates shall be established: (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 amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that 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 System Act. Section 10 of the Transmission System 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 (Flood Control Act) contains ratemaking requirements similar to the Project Act and the Transmission System Act. Section 5 of the Flood Control Act directs that rate schedules should 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 electric energy, including the amortization of the Federal investment over a reasonable number of years.

In addition to the Bonneville Project Act, the Transmission System Act, and the Flood Control Act, the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839 (Northwest Power Act), provides numerous rate directives. Section 7 of the Northwest Power Act 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, 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) over a reasonable period of years. 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 of the Northwest Power Act 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 comments, and an opportunity to refute or rebut other material submitted for 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 Fed. Reg. 7611 (1986). The Energy Policy Act of 1992 (EPA'92) sets forth additional ratemaking requirements for transmission rates to be applied in connection with transmission access ordered by the Federal Energy Regulatory Commission.

1.2.2 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 (D.C. Or. 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 Admin.*, 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) ("[b]ecause BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA's statutory interpretation"); *PacifiCorp v. F.E.R.C.*, 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 Admin.*, 818 F.2d 701, 705 (9th Cir. 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"); *Dep't of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 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").

1.3 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. *United States Dep't of Energy--Bonneville Power Admin.*, 13 F.E.R.C. ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator, but may only confirm, reject or remand them. *United States Dep't of Energy--Bonneville Power Admin.*, 23 F.E.R.C. ¶ 61,378, 61,801 (1983). EPA'92 did not in any way alter this process for BPA's transmission rates for FERC-ordered transmission access. H.R. Conf. Rep. No. 102-1018, 102nd Cong., 2d Sess., 389 (1992), *reprinted in* 1992 U.S.C.C.A.N 2480.

1.3.1 Firm and Surplus Firm Power Rates and Transmission Rates

With respect to all rates other than those for sales of nonfirm power outside the Pacific Northwest and rates for transmission access ordered by FERC, FERC determines whether: (1) rates are sufficient to assure repayment of the Federal investment in the FCRPS 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 Dep't of Energy--Bonneville Power Admin.*, 39 F.E.R.C. ¶ 61,078, 61,206 (1987). The limited FERC review of all but nonregional nonfirm rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which are subject to FERC jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

Sections 721 and 722 of the Energy Policy Act of 1992 include new authority for FERC to order access to utility transmission systems, including the authority to order access to the Federal Columbia River Transmission System (FCRTS). The new authorities are codified at 16 U.S.C. §§ 824i, 824j, 824k and 824l. In general, EPA'92 authorizes FERC to issue an access order, after notice and an opportunity for hearing, to any applying entity that generates electricity for sale or for resale. 16 U.S.C. § 824j(a). EPA'92 contains provisions specifically applicable to the FCRTS:

> (1) The Commission shall have authority pursuant to section 824i of this title, section 824j of this title, this section, and section 824l of this title to (A) order the Administrator of the Bonneville Power Administration to provide transmission service and (B) establish the terms and conditions of such service. In applying such sections to the Federal Columbia River Transmission System, the Commission shall assure that —
>
> (i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and
>
> (ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, or section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(1)(ii) (1985 & Supp. 1993) (emphasis added).

EPA’92 also contained language providing for the determination of terms and conditions for transmission access. 16 U.S.C. § 824k(i)(2)(A

EPA'92 further provides that if the Administrator denies an application, or a party seeks access under "terms and conditions different than those offered by the Administrator" and the application is "filed within 60 days of the Administrator's final determination and in accordance with Commission procedure," FERC may determine whether to grant or deny access and determine the terms and conditions of the access. An important qualification on FERC's determination, however, is that if the Administrator has conducted a hearing, the Administrator's hearing record is, with very limited exceptions, the basis for Commission review. 16 U.S.C. § 824k(2)(B). It is only when the Administrator has not conducted a hearing pursuant to section 824k(2)(B), that the provisions of section 824j apply. 16 U.S.C. § 824k(i)(2)(B)(ii).

The Administrator's discretion to set rates was preserved by EPA'92, with the addition of the new standard. Thus, the Administrator, and FERC, must determine that BPA's rates are sufficient to repay the Federal investment in the FCRPS, are based upon the Administrator's total system costs, and for transmission rates, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the system. See section 1.2.1 *supra*; 16 U.S.C. § 839(a)(2). The Administrator must also establish the rates to meet the widespread use and lowest possible rates standards discussed in section 1.2.1 *supra*. In addition, the transmission rates for wheeling ordered by FERC pursuant to its new authorities must not be unjust and unreasonable or unduly discriminatory or preferential.

The Joint Explanatory Statement of the Committee of Conference is instructive with regard to the additional ratemaking standard. The statement of the conferees reinforces congressional intent to leave prior law governing BPA intact. The Conference Report makes clear that, except for adding a new standard for FERC ordered transmission, EPA'92 did not change rate review authority:

> Rates for transmission services provided by BPA under an order issued under section 211 are to be established by BPA and reviewed by FERC through the same process and using the same statutory requirements as are applicable to all other transmission rates established by BPA, with the additional requirement that such rates for transmission services must also be just and reasonable and not unduly discriminatory or preferential as determined by the FERC, taking into account BPA's other statutory authorities and responsibilities.

H.R. Conf. Rep. No. 1021018, 102d Cong., 2d Sess., 381 (1992) reprinted in 1992 U.S.C.C.A.N. 2472, 2480 (Conference Report). Thus, the Administrator's rate decisions remain entitled to substantial deference by FERC, as previously established by law. In addition, this language was intended to ensure that the new standard be developed in light of BPA's unique character and particular circumstances rather than as previously developed under the Federal Power Act. *Id.*

1.3.2 Nonfirm Energy Rates

Although both regional and nonregional rates are established by the Administrator under common statutory standards, FERC review of nonregional rates for sales of nonfirm energy is undertaken pursuant to section7(k) of the Northwest PowerAct. 16 U.S.C § 839e(k). FERC reviews nonregional nonfirm energy rates to ascertain that BPA has designed the 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 that protects the interest of the United States in amortizing its investments in the projects within a reasonable number of years. *United States Dep't of Energy--Bonneville Power Admin.*, 36 F.E.R.C. ¶ 61,335, 61,798 (1986); *United States Dep't of Energy--Bonneville Power Admin.*, 54 F.E.R.C. ¶ 61,235, 61,294 (1991).

FERC review of BPA's nonregional nonfirm energy rates is based upon the evidentiary record developed by BPA pursuant to section7(i) of the Northwest Power Act, 16U.S.C. § 839e(i). *Aluminum Company of America v. Bonneville Power Admin.*, 903 F.2d 585, 592 (9th Cir. 1990). This review is consistent with FERC authority to confirm, reject, or remand BPA's rates. *United States Dep't of Energy--Bonneville Power Admin.*, 23 F.E.R.C. ¶ 61,378, 61,801 (1983); *Central Lincoln Peoples' Utility District v. Johnson,* 735 F.2d 1101, 1113 n.6 (9th Cir. 1984).

The Northwest Power Act provides no specific guidance to BPA in how to apply the section 7(k) statutory standards while designing nonfirm energy rates. *Aluminum Company of America v. Bonneville Power Admin.*, 903 F.2d 585, 598 (9th Cir. 1990). In *Aluminum Company*, the court noted that BPA has three conflicting obligations in conforming its rates to the section7(k) statutory standards. BPA must ensure that nonfirm energy is sold at the lowest possible rates consistent with sound business principles, but must also ensure cost recovery and Treasury repayment, while encouraging the most widespread use of electricity. *Id.* As concerns the requirements of lowest possible rates and widespread use, the court determined that these requirements afford BPA wide latitude in nonfirm energy rate design, providing BPA with so much discretion that there is no law to apply. *Id.* However, BPA is constrained in its discretion by the other directives in section 7(k), since nonfirm energy rates must be designed with regard to cost recovery and amortization of the investment of the U.S. Treasury over a reasonable period of years. Pursuant to section 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. Part 300 (1993).

2.0 BPA'S BUSINESS CONSTRUCT

2.1 Introduction

Throughout this rate proceeding BPA has been mindful of the rapid changes taking place in the energy business, not only in the Northwest region, but also in the national arena. This section reviews issues related to BPA's business relationships and need to remain competitive while meeting its statutory objectives in the changing energy environment. This section includes not only a discussion of competitiveness and Bonneville's business relationships, but also a discussion of comparability and how the Settlement Agreements aid in securing the region's energy future.

2.2 BPA's Competitive Challenge

As described in its first piece of testimony in this proceeding, the era of BPA's dominance as the unchallenged low-cost wholesale power supplier in the Pacific Northwest is over. Moorman, Evans, WP-96-E-BPA-09, at 2. For the first time in BPA's existence, a significant number of competitive alternatives to Federal power now are available to BPA's customers at prices equal to or lower than BPA's proposed firm power rates. *Id*. The West Coast wholesale electricity market has become highly competitive over the last decade due to a combination of legislative, economic, and technological developments. Traditional utility wholesalers now are vying against each other for sales to other utilities and to large industrial customers. Norman, Oliver, WP-96-E-BPA-10. Independent resource developers, energy marketers, and brokers that facilitate the consummation of long- and short-term power deals are aggressively seeking and achieving entry into this market. *Id*. BPA's customers, and the large industrial customers that many of them serve, all are searching actively for new lower cost suppliers. Moorman, Evans, E-BPA-65, at 4-5. Parties representing every segment of BPA's customer base, investor-owned utility, direct-service industry, and public utility, have acknowledged the fact that BPA is faced with an increasingly competitive market. *See e.g.*, Brattebo, E-GE/PL/PS-03, at 2; Schoenbeck, Bliven, WP-96-E-DS-01, 3; Drummond, WP-96-E-RC-01; Piper, WP-96-E-RC-05; Eldridge, *et al*., WP-96-E-PP-01, at 1-3.; Beck, *et al*., WP-96 -E-WA-01, at 6-11; Carr, *et al*., WP-96-E-PP/PA-03, at 4. Most have urged BPA to take the actions, consistent with its statutory obligations, that are necessary to become more competitive. *See e.g.*, PPC Brief, WP-96/TR-96-B-PP-01, at 9-11; WPAG Brief, WP-96-B-WA-01, at 2-5; RCC Brief, WP-96-B-RC-01, at 2-5; DSI Brief, WP-96-B-DS-01, *passim*. These same parties have acknowledged that BPA must compete in this market if it is to stay in business and collect sufficient revenues to meet its statutory obligations. *See e.g.*, Piper, WP-96-E-RC-05; WP-96-B-RC-01, at 1-5; Eldridge, *et al*., WP-96-E-PP-01, at 1-3.

New market entrants, low gas prices, and surplus supplies of short-term capacity and energy in California and the Inland Southwest have led to steadily falling electricity prices. Moorman, Evans, E-BPA-09, at 12. Natural gas deregulation has led to a more abundant supply of natural gas at lower prices, making the cost of generating electricity from surplus gas-fired units, such as gas turbines, competitive. *Id*. In addition, advances in combustion turbine (CT) technology have reduced the cost of new CTs by an additional 25 percent, so that these new units can produce electricity at low costs. *Id*. Existing West Coast power surpluses are projected to last beyond the year 2000, and absent an extremely rapid and unexpected run-up in gas prices, this fundamental market situation implies that wholesale market prices will not increase significantly, if at all, over the 1997-2001 period. *Id*. at 9. In fact, BPA's long-term gas price forecast for the West Coast market dropped by 10 percent between the initial and supplemental proposals. *See* Supplemental Marginal Cost Analysis Study Documentation, WP-96-E-BPA-60A, Section II, and has dropped even further.

Since passage of the Energy Policy Act of 1992 (EPA'92), more and more independent power producers (IPPs) and other non-utility energy wholesalers are soliciting BPA's customers. Passage of EPA'92 has allowed both utility and non-utility wholesalers to broaden their markets. *Id*. The open transmission access provisions of EPA'92, which the Federal Energy Regulatory Commission (FERC) is in the process of implementing, have facilitated the growth of a vigorously competitive wholesale power market. *Id*. This transmission access, combined with the low cost of producing power from both old and new gas combustion turbines or other resources, means these new market entrants and other power suppliers are very capable competitors. *Id*. BPA also faces serious competition from other established utilities on the West Coast, such as PacifiCorp and Washington Water Power. *Id*.

With all of the new market entrants on the West Coast, with the continued low market prices, and with the advent of competition in the wholesale market, nearly all of BPA's current sales are at risk from competition because all of BPA's sales are in the wholesale power market. Moorman, Evans, E-BPA-65, at 11. As a strictly wholesale marketer of electricity, BPA and its customers have been a focal point of this enhanced competition in the Pacific Northwest. Hill, *et al*., WP-96-E-BPA-51, at 3. Consequently, in order to retain existing load and capture new load where appropriate, BPA is under tremendous pressure to offer products, services and prices that are competitive in the market. Moorman, Evans, E-BPA-09, at 26. BPA must position itself to be successful in the short-term and the long-term, so it must think in terms of short-term and long-term consequences. The Public Power Council (PPC), a group representing many of BPA's public utility customers, drew the conclusion succinctly in its testimony:

> Simply put, in order for BPA to continue to thrive in this competitive environment, it must provide power and transmission products and services at prices that its customers are willing to pay over an extended period of time.

Eldridge, *et al*., WP-96-E-PP-01, at 2. A legion of examples demonstrate the competition BPA faces in retaining existing sales and making new sales. *See generally* Norman, Oliver, E-BPA-10; Moorman, Evans, E-BPA-09, at 13-14, and E-BPA-65, at 3-6; Hill, *et al*., E-BPA-51, at 3-5. In fact, BPA has continued to lose sales during the course of this rate proceeding, notwithstanding the fact that its proposed rates generally represent a significant reduction compared to existing rate levels for most customers. Since BPA filed its initial proposal in July 1995, it has lost approximately 700 aMW of direct-service industry (DSI) sales to alternative suppliers. Moorman, Evans, E-BPA-65, at 6. Likewise, projections of public utility purchases from BPA have been reduced to account for utilities that are seeking actively other suppliers. Supplemental Loads and Resources Study, WP-96-E-BPA-57, at 13; Supplemental Loads and Resources Study Documentation, Vol. 1, WP-96-E-BPA-57A, at 229.

Even so, customers represented by the Western Public Agencies Group (WPAG) argue that BPA has misjudged its position in the wholesale market, and has grossly underestimated the desire of its preference customers to diversify their power supply. Beck, *et al.*, WP-96-E-WA-13, at 6, 10-11. They note that, at the time their testimony was submitted in November 1995, preference customers had made submissions to BPA pursuant to their power sales contracts to reduce their load on BPA by over 780 aMW, and that they expected to see this number increase. *Id*. Since that time, some of these customers have sued BPA in an attempt to access alternative power suppliers.

In fact, there is evidence that BPA's proposed rates remain above the market price of power, in spite of the significant reduction from their current levels. The PPC and Association of Public Agency Customers (APAC) assert in testimony that it is finding prices for electric power in the upper teens and the low-twenty mill range. Carr, *et al.*, WP-96-E-PP/PA-03, at 4. They add that, even after transmission costs are added to certain offers in that range, BPA's priority firm rate still is above the market price for power. *Id*. This comparison is confirmed by BPA's Marginal Cost Analysis Study. WP-96-E-BPA-60. Competitors have lowered the prices offered to BPA customers in reaction to BPA's proposal in this rate proceeding. Moorman, Evans, E-BPA-65, at 9. For example, shortly after BPA announced its initial proposal rates in July 1995, WPAG asked bidders to its earlier request for proposals to make new price offers. *Id*. Most responded with new prices that were 10 to 20 percent lower than their original bids. *Id*. Consequently, for some customers in active discussions with suppliers, any increase in BPA's proposed rates will put BPA rates above the prices of alternative offers, and will be perceived as confirmation of competitors' assertions that BPA is not reliable and cannot or will not sustain its proposed rates. *Id*.; *see also* Beck, *et al.*, E-BPA-13, at 8.

BPA's DSI customers likewise are evaluating alternative energy supply options. DSI Pr. Brief, WP-96-P-DS-01, at 2. They state in testimony that they can purchase power on the open market at delivered prices in the range of 20 mills/kWh. Schoenbeck, Bliven, WP-96-E-DS-01, at 2. Faced with the sudden changes in the market and the resulting high likelihood that the DSIs would exercise their contractual right to remove their load from BPA on nine months notice, BPA acted to protect its overall revenues and ability to recover its costs by negotiating block sale contracts, committing the DSIs to place a substantial amount of load on BPA for five years. Kitchen, Moorman, WP-96-E-BPA-98, at 11. The new 1996 "block sale" contracts specify a rate test such that if the rate developed in this proceeding is equal to or lower than the rate limit, then each DSI will be required to purchase its load commitment from BPA. *Id*. at 6. If BPA does not establish rates to the DSIs that meet the negotiated rate test, then the DSIs will be under no obligation to purchase power from BPA. DSI Pr. Brief, P-DS-01, at 2. In addition, by developing competitive rates and products for the DSIs, BPA has opportunities to serve the remaining DSI load not already contracted for under the block sale contracts. *Id*.

Setting Rates for Sustainable Revenues in a Competitive Market

In the newly competitive West Coast electricity markets, BPA must set rates that are low enough to be competitive, but high enough to create, or sustain, a stream of revenues over time that covers BPA's costs. The Requirements Customer Coalition (RCC), a group representing full-requirements customers, acknowledged the necessity for BPA "to walk a very fine line between recovering its cost of doing business, and driving itself out of business." RCC Brief, B-RC-01, at 1; *see also* RCC Brief, WP-96-B-RC-01, at 5; Piper, WP-96-E-RC-05; Moorman, Evans, E-BPA-09. RCC defines this balance between pricing to compete and pricing to cover costs as "sustainable revenues," a concept introduced in this rate case by BPA in the testimony of Moorman and Evans, E-BPA-09, at 14-25.

Analysis presented in BPA testimony shows that, if BPA were to charge higher than market prices, it would lose customers and lose revenues, thus damaging its ability to sustain sufficient revenues to cover costs. *Id*. at 14-25, *and see* Moorman, Evans, E-BPA-65, at 2-11. Statements in the testimony and briefs of several customer groups corroborate this conclusion. For example, RCC states in its brief that "(r)aising rates further will drive more load from BPA, actually reducing total revenue." RCC Brief, B-RC-01, at 4. PPC stated that "[i]f BPA's wholesale prices remain above those of its competitors . . . it will continue to lose load which will spread fixed costs over the remaining customer base adding further rate increase pressure." Eldridge, *et al*., E-PP-01, at 3. Other parties share this conclusion. Schoenbeck, Bliven, E-DS-01, at 3-4; Beck, *et al*., E-WA-01, at 9; Piper, E-RC-05, at 1, 7.

BPA's analysis estimates the likely effects of competition on BPA sales and revenues if higher PF or IP rates were charged than those presented in BPA's supplemental case, as a means to recover either increased program costs or planned net revenues to achieve a higher probability of Treasury payment. Moorman, Evans, E-BPA-09, at 14-25, and E-BPA-65, at 2-11. Two price scenarios were considered that represent medium and high relative rate levels. The base case is the proposed PF rate. For each of these price scenarios, estimates of potential sales were made based on known and projected customer decisions regarding their suppliers of electricity. Estimates of potential DSI sales losses were based on BPA's knowledge of how each DSI would respond to higher prices as well as the results of the DSI block sale. Sales losses during the rate period, relative to a base case total of about 7,000 aMW, were estimated to be about 3,700 aMW for the medium scenario and about 4,700 aMW for the high scenario. Moorman, Evans, E-BPA-09, at 16-19, and E-BPA-65, at 6-7.

Total BPA revenues for each scenario then were calculated and compared to revenues under the base case sales to result in estimates of net revenue losses. Higher rates did not offset the effect of reduced sales, resulting in a net revenue loss to BPA. Losses were nearly $400 million per year in the medium scenario, and about $600 million per year in the high price scenario. Moorman, Evans, E-BPA-09, at 22-23, and E-BPA-65, at 8-9. In a competitive market, BPA's sales no longer are guaranteed, but rather must be earned through competitive prices and quality, reliable service. RCC states that if BPA cannot deliver competitive rates it will "virtually assure that it would lose some or all of the load from many of [its members], which historically have been BPA's strongest supporters." Piper, E-RC-05, at 7; *see also* Eldridge, *et al*, E-PP-01, at 3.

Other testimony from parties representing BPA's customers corroborates the sobering conclusion of BPA's "sustainable revenues" analysis. Drummond, WP-96-E-RC-01, at 3-4; Piper, E-RC-05, at 1-6. BPA and its customers agree: "BPA's best and only chance for meeting its spending obligations is to deliver rates for products and services which allow us, its customers, to continue to do business with it." *Id*. at 7.

<u>Consequences of Uncompetitive BPA Rates</u>

Failure to meet the competitive challenge described in the previous sections will make it increasingly difficult, and ultimately impossible, for BPA to meet its statutory mission, including its cost recovery and Treasury repayment obligations. Moorman, Evans, E-BPA-09, at 26. While BPA's mission was expanded greatly by passage in 1980 of the Pacific Northwest Power Planning and Conservation Act, 16 U.S.C. §§ 839 - 839h (1988) (Northwest Power Act), many core elements have remained the same, and have been reiterated in all of BPA's organic legislation enacted since the BPA Project Act of 1937. These core objectives include: to encourage the widest possible diversified use of Federal power at the lowest cost consistent with sound business principles, to insure preference and priority to public and cooperative systems, to secure the full repayment of the reimbursable portion of the Federal investment in the FCRPS, and to establish its rates to recover its costs from ratepayers. *See generally* Bonneville Project Act, 16 U.S.C. §§ 832 - 832l (1988); Flood Control Act of 1944, 16 U.S.C. § 825s (1988); Regional Preference Act, 16 U.S.C. §§ 837 - 837h (1988); Pacific Northwest Federal Transmission System Act, 16 U.S.C. §§ 838 - 838k (1988) (Transmission System Act); Northwest Power Act, 16 U.S.C. §§ 839 - 839h (1988). In 1980, Congress added to BPA's mission the obligations to mitigate, protect, and enhance fish and wildlife, to give the highest priority to cost-effective conservation in acquiring resources to meet its customers needs, and to meet the load growth of its customers when it was requested to do so. Northwest Power Act, 16 U.S.C. § 839(6), § 839c(b)(1), §839d(a)(1).

BPA's ability to accomplish each of the objectives that constitute its mission, however, is in jeopardy. Moorman, Evans, E-BPA-09, at 26. At the time the Northwest Power Act was passed in 1980, BPA's potential competitors had power costs several times greater than those of BPA. Moorman, Evans, E-BPA-09, at 3. Since that time, the average preference rate established by BPA has risen approximately 600 percent. *Id*. at 5. The products, rate structures, cost management practices, and contracts that served the purpose of encouraging the widest possible diversified use of Federal power at the lowest cost will no longer suffice. *Id.* at 26. Meeting these mandates now requires BPA to conduct its affairs with a view toward market considerations. Absent the reforms needed to meet its competitive challenge, BPA increasingly will be hard put to recover its costs, contribute its part to the restoration of endangered fish stocks, make its payments to the Federal Treasury on time, and deliver competitive, responsive products to its customers. *Id.*

BPA Actions to Ensure Competitiveness

BPA is taking four principal actions to ensure that it recovers its costs while maintaining competitive rates: 1) cutting costs aggressively; 2) implementing fish-mitigation cost stabilization and funding arrangements that have been forged with the Clinton Administration; 3) redesigning the basic products it offers; and 4) proposing redesigned rates. Moorman, Evans, E-BPA-09, at 27. During the course of this rate proceeding BPA's customers have urged BPA to redouble its cost cutting efforts. Carr, Wolverton, WP-96-E-PP/DS/PA/PG/RC/WA-01, at 4; Piper, 96-E-RC-05, at 3; Beck, *et al.*, E-WA-13, at 12; Carr, *et al.*, E-PP/PA-03, at 5. Prior to the supplemental proposal, BPA targeted overall cuts that averaged $298 million per year over the course of the rate period, and all but an average of $14 million per year in these expense reductions were specifically identified prior to, and were included in, the Supplemental Revenue Requirement Study. De Wolf, *et al.*, WP-96-E-BPA-69, at section 3. In March and April of 1996, additional cuts were made, and are reflected in the final proposal revenue requirements.

The costs cut prior to and after the supplemental proposal both were in addition to earlier reductions amounting to about $240 million a year on average from the operating expenses that BPA planned for FYs 1996-2000 when rates were set in 1993. Moorman, Evans, E-BPA-09, at 27. In addition, BPA and the Clinton Administration have agreed to share the costs of BPA's increasing fish mitigation costs. This cost sharing arrangement includes three components: (1)BPA cost cuts of a minimum of $30 to $40 million per year beginning in FY 1996; (2) credits against BPA's cash transfers to Treasury under section 4(h)(10)(c) of the Northwest Power Act; and, (3) to the extent required, reductions in BPA's accumulation of cash reserves and its probability of meeting its annual payments to Treasury. *Id.* *See also* sections 4.1 and 10.4.

By proposing redesigned rates and products BPA is attempting to reposition itself in the market to be more competitive. Buchanan, *et al.*, E-BPA-11, at 3. This fundamental repositioning includes: unbundling BPA's power products so that customers pay for only the products and services they want; designing products that meet specific customer needs, including offering longer-term products; and redesigning rates to result in competitive prices for products and services , and that send appropriate price signals to customers. *Id.* at 3-4. Because of recent restrictions in hydro system flexibility, the amount of water available at certain times and, therefore, the generating capability of the system, no longer matches system loads as in the past. *Id*. at 5. BPA has less water available to generate power in the winter when loads are high and it has excess generating capability in the spring when loads are lower. *Id*. By redesigning its rates, BPA hopes to match its loads more closely to its generation capability and its costs, thereby encouraging a more efficient use of the system.

BPA also is moving to become more competitive by unbundling its products. Unbundled products are those that are defined, priced and offered individually, to be combined with other products as the customer chooses. Buchanan, *et al*., E-BPA-11, at 8. Unbundling is being proposed because the traditional bundled product delivered by BPA was resulting in certain undesirable outcomes, including: 1) BPA providing products and services that customers did not need to serve their loads or to operate their resources; 2) BPA providing products and services that may be provided more efficiently or cost-effectively acquired from another supplier; 3) BPA providing products and services for which it was not being reimbursed directly by the customer responsible for the costs associated with that product or service; and 4) customers using products and services inefficiently because they did not have a price that they can track to each product or service they used. *Id*. Customers are receiving offers that allow them to match more closely their needs to particular products and services, and BPA's proposals to unbundle its products and services will permit it to compete at its lowest price with an equivalent product or service to its competition. *Id*.

Unbundling also will improve BPA's competitive position by helping to keep costs down. *Id*. at 10. In combination with sending correct price signals through its rate redesign proposals, unbundling will encourage more efficient operation of BPA's resources. This will result because specific uses of the system will be priced separately, so customers will face the cost impacts of their decisions. *Id*. The resulting increase in BPA's operational efficiency will lead to either lower costs for the same output or greater output for the same costs, or both. *Id*. In addition, as the system is operated more efficiently, BPA will avoid investments in new resources that otherwise would be needed to meet loads at different times of the year or week, and it will be able to sell more products and services from existing resources. Some customers, however, have expressed concerns about potential adverse operational and financial impacts BPA's rate redesign and unbundling proposals may have on them. These issues are discussed in the following section.

2.3 BPA's Business Relationship

In this proceeding, parties have explained how BPA's long-term success is dependent upon developing strong business relationships with its customers. PGP Brief, WP-96-B-PG-01, at 7; WPAG Brief, WP-96-B-WA-01, at 3. They also have raised arguments that this relationship is dependent on BPA recognizing the interdependence of BPA's operations with customer resources and their operations. *Id*. They urge the Administrator to work with computed requirements customers to develop contractual arrangements which "address the situations in which the utilities could face penalties despite operating efficiently and appropriately under the 1981 contracts." *Id*. at 8. PGP "urges the Administrator to engage in discussions with the computed requirements customers with an eye toward making the contracts more consistent with the rate proposal without requiring the customers to give up rights they deem valuable." *Id.* at 9. PGP sums up this section of their brief by stating that "[i]f BPA wants these customers to make significant load commitments on BPA, the contractual arrangements must recognize the operational and business needs of the customers, not just the needs and desires of BPA. PGP urges the Administrator to keep that critical fact in mind in implementing and finalizing the rate structure." *Id.*

WPAG stated that since BPA "no longer" has a price advantage, it must make up for that by providing "quality of service," which they argued has been poor based on BPA's track record, as "exemplified by the load commitment and amendatory agreement process." WPAG Brief, WP-96-B-WA-01, at 3. They also imply that BPA is not a reliable business partner, because BPA "re-interpret[s] contracts and commitments in light of changed circumstances," and that customer confidence is enhanced when BPA "sticks to a commitment even when circumstances have change[d]." *Id.*

BPA agrees that its long-term business relationship with its customers is important, and is repositioning its products to make them more attractive to customers. Buchanan, *et al.*, E-BPA-11, at 3. BPA is attempting to offer products that are as flexible and attractive as possible so as to be the provider of choice. *Id.* at 9. BPA does not desire an adversarial relationship with PGP or other customers. BPA is attempting to position itself to provide PGP members (and other customers) service packages which are tailored to the needs of each individual customer, and which provide that service at the lowest possible price. *Id.*

BPA also recognizes that in order to have a "partial requirements business relationship that works for the customer and Bonneville" (Beck, *et al.*, WP-96-E-WA-13, at 60), BPA must be compensated fairly for the products it provides. In this rate case, BPA has attempted to price fairly the different products various types of customers currently are receiving from BPA. As documented extensively in this rate case record, the competitive pressures on BPA are enormous. BPA has responded in numerous ways, including by making very significant cost cuts where lawfully possible. Given a level of remaining costs that must be recovered, BPA will be better positioned to compete by avoiding cross-subsidies and by recovering the costs of services from those customers who are provided the services. Kitchen, Moorman, WP-96-E-BPA-98, at 8.

BPA has taken many steps to achieve a long-term business relationship with its customers that works for both sides. These have included significant cost reductions, as well as changes in rate design in response to customers' concerns. These include changes to the availability of load shaping options and industrial exemption under 1981 contracts, revising the seasonality of our energy rates (particularly August), increasing the demand charge while lowering the energy charges, changing the demand billing determinants for computed requirements customers under the 1981 contracts and, obviously, the compromises reached in the Settlement Agreement. *See generally* sections 11, 13, 1.13 and 2.5. We also have indicated a willingness to negotiate changes to existing power sales contracts, in order to allow customers to take advantage of rate options. These all have been done to give customers good reasons for doing business with BPA. We are greatly encouraged by comments made by counsel for WPAG about our long-term business relationship during oral argument before the Administrator. *See generally* Or. Tr. 2427-2430.

However, BPA is in the midst of contract negotiations with most of our customers. The issues raised by PGP and WPAG in their briefs, cited above, are issues to be dealt with in contract negotiations, not in this rate case. In addition, several parties raised arguments in their testimony to the effect that certain BPA product and rate design proposals adversely affected some of their rights under the 1981 contract. *See e.g.*, Smith, *et al.*, WP-96-E-PG-01, and WP-96-E-PG-05; Leone-Woods, *et al.*, WP-96-E-PA/PG-03. These parties did not, however, raise these issues or provide any argument in support of their positions in their initial briefs. Therefore, no issue has been presented for the Administrator's decision regarding the consistency between BPA's product and rate design proposals and these customers' 1981 contracts. Bonneville Power Administration, Rules of Procedure Governing Rate Hearings, § 1010.13(c). Nevertheless, BPA wishes to clarify in the Record of Decision the business and policy reasoning behind these proposals.

<u>BPA's Rate Proposal is Consistent with 1981 Contracts</u>

In testimony, WPAG argued that Bonneville is proposing to fundamentally alter the relationship between BPA and its partial requirements customers under the 1981 contracts by imposing separate charges, and in some cases penalties, on numerous separate products. Beck, *et al.*, E-WA-13, at 20. They also argued that product unbundling has become a tool with which to force contract amendments, reduce operating flexibility, limit power supply choices, and extract additional revenues from the existing customer base. *Id.* at 23. In particular they disagree about the appropriateness of "standing ready to serve" type charges. These are specifically discussed in Sections 11.2.1 (Load Shaping), 11.3.2 (Power Demand Reservation Charge) and 11.3.3 (Availability Charge). WPAG also stated that the supplemental rate proposal makes doing business with BPA "extremely" difficult, imposes restrictive operating requirements, charges for services not requested or rendered, and assesses penalties that exceed costs incurred by Bonneville. Beck, *et al.*, E-WA-13, at 24.

In testimony, PGP argued that BPA's proposed rate structure will increase the charges assessed under the 1981 contracts, allow less flexibility in utility operations, and limit the rights of the utilities under the 1981 contracts. Smith, *et al.*, E-PA/PG-05, at 7. They assert that "[b]y virtue of the terms, conditions, and new definitions instituted through this rate proceeding, [their] 1981 contract is implicitly modified." Smith, *et al.*, E-PG-01, at 1. They argue that BPA is "unilaterally modifying" the contract, *Id.* at 7, and that BPA seeks to unbundle and price separately services it "allegedly" provides with no recognition of the collaborative relationship [that exists]. PGP Pr. Brief, P-PG-01, at 7. PGP reiterates these positions in its brief on exceptions. PGP Ex. Brief, WP/TC-96-R-PG-01, 4.

BPA does not intend for generating utility customers to relinquish their existing contractual rights, and BPA's rate proposal will not require them to do so. Kitchen, Moorman, WP-96-E-BPA-41, at 8. BPA designed a rate structure intended to send price signals regarding the costs of providing various products and services. BPA's proposed rate design and product unbundling were an attempt to encourage more efficient operation of the resources BPA uses to provide products. This efficiency would result when customers faced the cost impacts of their decisions when the specific uses of the system were priced separately. Buchanan, *et al.*, E-BPA-11, at 11.

PGP argues that this rate proposal modifies their 1981 contract such that it "no longer will have the value it did when it was negotiated." Smith, *et al.*, E-PG-01, at 8. BPA's rate proposal does not modify the 1981 contracts. Any change in "value" of the contract is limited to the change in the value of those products and services in the marketplace or to changes in the cost to BPA of providing those services, as reflected in BPA's rates. BPA is pricing the different service options available to customers, including those under the 1981 contracts. The rate proposal does not modify those contracts, nor eliminate any service options that customers have. Kitchen, Moorman, E-BPA-41, at 3.

In BPA's initial proposal, BPA priced the specific product packages customers currently purchase under their 1981 contracts. *Id.* at 9. If customers wanted different purchase relationships, they could use their contractual rights within their 1981 contracts to change their customer designation. Kitchen, Moorman, E-BPA-41, at 6. The 1996 rate proposal represented one piece of BPA's marketing strategy. *Id.* at 1. In addition to the rate case, BPA was implementing its marketing strategy through new power sales contract offers. *Id.* at 3. Beyond the options in the 1981 contracts, BPA assumed customers would primarily exercise their choice options through new power sales contractual relationships. *Infra* section 10.3.

PGP raised several issues in testimony related to operations under their 1981 contracts. They state that the PGP utilities worked effectively with BPA under the 1981 contracts, operated their resources to minimize adverse economic impacts on the Federal system, and added resources to cover load growth as the contract requires. They then argued that the proposed rate design changes will penalize these utilities for doing so. Smith, *et al.*, E-PG-01, at 8; *see also* PGP Ex. Brief, R-PG-01, 4. They also stated that the 1981 contracts were negotiated and operated as a collaborative approach to operation of BPA's and the generating public's system to benefit both the customers and BPA. They indicated that the "PGP utilities have operated their resources within the parameters of the contracts and have received PF service from BPA, all to the Region's benefit." Smith, *et al.*, E-PG-05, at 2. Because they feel these contracts have "worked well for all concerned" they see "no significant reason to change that arrangement." *Id.* WPAG, PGP and APAC all argued in testimony that BPA's supplemental rate proposal will reduce operating flexibility or operational parameters, (Beck, *et al.*, E-WA-13, at 23, and Smith, *et al.*, E-PG-05, at 3), or will reduce operating efficiency. *Id.* at 6.

BPA disagrees with this assessment. Nothing in this rate case is intended to modify existing contractual rights or to change operational flexibility. BPA is simply attempting to price that flexibility appropriately through rate design changes. Kitchen, Moorman, E-BPA-98, at 6. BPA does not believe its rate proposal penalizes customers for adding or operating resources. BPA has not changed any of the terms of the 1981 contracts in its rate proposal. Kitchen, Moorman, E-BPA-41, at 7. Customers have prudently operated in a way consistent with the price signals BPA has previously sent, so as to minimize their operational costs. However, as is documented throughout the record, BPA's current price signals no longer match the costs of providing the various products and services our customers purchase from BPA. The operational flexibility reflected in the 1981 contracts carries a cost. In this rate case, BPA has attempted to more accurately assess those costs to the customers that cause BPA to incur those costs. Kitchen, Moorman, E-BPA-98, at 6-7. The significant reason to change the rate design that applies to the 1981 contracts is that BPA's existing rate design no longer sends price signals consistent with its costs. *See generally* Buchanan, *et al.*, E-BPA-11. PGP confuses BPA's contractual right to change rate design with unilaterally modifying the 1981 contract. There is no contractual entitlement to the old rate design. Section 8 of the General Contract Provisions (Exhibit B), provides that BPA may periodically review and revise rates. BPA previously has changed its rate design under this contract to reflect changing conditions in the electric utility industry. The 1981 contract provides for such changes in rate design. Kitchen, Moorman, E-BPA-41, at 4.

WPAG asserted in testimony that BPA is imposing "punitive rate conditions" (Beck, *et al.*, E-WA-13, at 9) that "punish utilities which seek power supply diversity" (*id.* at 12), and that BPA must "quit trying to control the operational and power supply activities of its preference customers." *Id*. BPA disagrees that this is the case. As WPAG recognizes in its testimony, BPA must make significant changes to the products and pricing it offers to its customers in order to remain viable in current competitive wholesale power markets and carry out its statutory obligations to recover the Federal investment in the FCRPS. These changes are not punitive, they merely increase BPA's ability to pass on to those customers the costs imposed on the Federal system by their actions, so that those costs do not have to be borne by other customers. Nor do the changes represent an attempt to control the operational and power supply activities of customers. Rather, BPA's proposed product and pricing changes are intended to increase the operational and power supply choices available to customers, but to do that in a way that ensures customers face the full costs associated with planning and executing those activities. Even though BPA previously developed bundled rates that included some of the stand-ready services provided to customers, it is not correct to characterize as "punitive" the changes to BPA product and rate designs intended to pass on those costs to customers causing them. BPA is not trying to punish utilities for taking actions that impose costs on BPA, or to control their activities through unbundled charges. That is neither the intent, nor the result, of BPA's rate proposal. Kitchen, Moorman, E-BPA-98, at 5.

Bundled Rate Design

As evidence that BPA is modifying the 1981 contract, PGP states in testimony that the contract anticipated power as a bundled product to be sold under the PF rates. Smith, *et al.*, E-PG-05, at 5. They argue that BPA's efforts to unbundle will mean that the PGP utilities under the 1981 contracts will pay "PF plus" for their power and will be limited in their transmission service choices. They argue that "[i]n total, this results in a different treatment for those utilities who choose to retain their 1981 contracts, both in the provisions of federal power and for access to the transmission system. In short, BPA's application of the tariffs to the 1981 contracts has dramatically diminished the value of these contracts." Smith, *et al.*, E-PG-01, at 7.

BPA does not agree with PGP that the 1981 contract describes PF as a bundled product. Neither the language, nor the intent, of the 1981 contracts either locks in bundled pricing or precludes the product pricing proposed by BPA in this rate case. Kitchen, Moorman, E-BPA-98, at 5. Historically, BPA's rates were designed to recover most of its costs through an energy charge and a demand charge. Included in these charges were products that BPA now proposes to unbundle. *See generally* Buchanan, *et al.*, E-BPA-11; Kitchen, Moorman, E-BPA-41; and Kitchen, Moorman, E-BPA-98. Also included in those energy and demand charges were charges that compensate BPA for being prepared to meet its service obligations under its power sales contracts. As stated above, BPA is now proposing to unbundle charges for certain products provided under the 1981 contracts. In addition, the way BPA is setting its rates, by definition, means a utility does not pay "PF plus." In this rate proposal, BPA has changed the way it classifies costs. It now classifies costs to capacity, energy and rights to energy. *See* Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, section 2.2.2. Rights to energy include unbundled products, such as Load Shaping. The expected revenues from unbundled products are credited to generation costs, which make up BPA's power rates. This credit results in a PF energy rate lower than it would have been without the unbundled products credit. Therefore, customers are not paying "PF plus" for their power. Kitchen, Moorman, E-BPA-41, at 40-41.

Customers Have Sufficient Choices To Respond To Price Signals

In testimony, PGP, WPAG, and APAC (in joint testimony with PGP) generally argued that BPA is not offering its customers choices, either in the package of products that they purchase from BPA, or to access markets to obtain services from others. They also argued that BPA's rate proposal, coupled with their lack of supply choices, is forcing a dramatic increase in their rates. PGP Pr. Brief, P-PG-01, at 6; PGP Brief, WP-96-B-PG-01, at 9; Beck, *et al.*, E-WA-13, at 22-23; Smith, *et al.*, E-PG-05, at 3; Leone-Woods, *et al.*, WP-96-E-PG/AP-02, 23. They also argued that the rate proposal is a tool to unilaterally force contract amendments on the customers. Smith, *et al.*, WP-96-E-PG-05, at 3; Beck, *et al.*, E-WA-13, at 23.

PGP argued in their testimony that "BPA gives every indication that it intends to make the 1981 contracts as unattractive as possible to push customers into signing new contracts prior to the termination of the 1981 contracts." Smith, *et al.*, E-PG-05, at 3. They further stated that "BPA has increased the costs under the 1981 contract and changed the operational parameters. Yet, the partial requirements 1981 contract holders are prevented from accessing the very market upon which these costs are allegedly based." *Id.* PGP also indicates that "the traditional 'PF service' has been repriced in a way apparently intended to make it an uneconomical choice." *Id.* at 5. PGP uses as an example of the lack of choice that customers have, the fact that to take advantage of purchasing Partial Load Shaping under the 1981 contracts, the customer must become a planned computed requirements customer. They indicate that this requires the customer to "substantially change the way it operates, plans, and schedules" power. *Id.* at 9. They stated that customers who may not want to change their purchase arrangement for "sound business reasons" face additional charges and potential penalties. *Id.*

BPA does not intend to eliminate any service options that customers have under their 1981 contracts. Kitchen, Moorman, E-BPA-41, at 3. Nothing in this rate proposal changes the provisions of the contract governing customers' ability to access, or not access, power markets. Kitchen, Moorman, E-BPA-98, at 6. In fact, during oral argument counsel for PGP told the Administrator that in the upcoming contract negotiations the Administrator should consider the PGP utilities as "high load factor customers with choices." Or. Tr. 2446 and 2449. BPA developed a product and pricing strategy in this rate case to make its products <u>more</u> attractive to customers by designing different products that meet individual customers' needs so that customers pay for only the products and services they want. Buchanan, *et al.*, E-BPA-11, at 3.

BPA's goal is to provide customers with more choices in their purchase relationship with BPA, not less. Kitchen, Moorman, E-BPA-41, at 8. In rebuttal testimony, BPA indicated that it is not BPA's intention to push customers into the 1996 Contracts:

> Our intent is to price the package of services that customers are receiving under the 1981 contract. Our intent is to price various products similarly, whether a customer purchases them under the 1981 contract or the 1996 Contract. The 1996 Contract will be available for customers who want to purchase a different set of products than they currently purchase.

Kitchen, Moorman, E-BPA-98, at 8. In fact, this final rate proposal offers customers even more purchase options under their 1981 contracts than originally included in the initial proposal. These include, for example, various load shaping options; ability to amend 1981 contracts to avoid the power demand reservation charge; different billing determinants for different purchase arrangements; and the flexible PF and NR rate options. *See generally infra* section 11.

The one choice computed requirements customers do not have is the ability to purchase exactly the same way they always have, and not face a different set of charges. This is because BPA is using its contractual right to change rate design to reflect the different costs to BPA and/or value of various products in the market place. *See supra* section 2.2. Customers do have the contractual ability to respond to those price signals, which is BPA's intent. In testimony, and in a line of cross-examination questions by their attorney, WPAG created a hypothetical example to illustrate how they do not have choices as to when various charges or penalties apply. However, WPAG confuses customers having choices about what services they will get with having to pay for those services. They have a choice of what services they take. If they take those services, they do not have a choice about paying for them. *See generally* Tr. 410; Kitchen, Moorman, E-BPA-41, at 5-6, 8. PGP argues that the way BPA has unbundled its PF service has resulted in a dramatic increase in the overall rates charged by BPA to the PGP utilities. PGP Pr. Brief, P-PG-01, at 5-6. PGP provided no evidence to substantiate this claim. However, assuming it is true, a dramatic increase in overall rates would occur only if the PGP utilities did not respond to our new rate design. It is possible, that if a utility operated exactly the way it used to operate, its bill from BPA would increase. However, as we have said, that would reflect the change in the costs to BPA of providing those services. Kitchen, Moorman, E-BPA-41, at 3. However, our customers have extremely flexible contracts, and we have provided many options for customers to choose to purchase different packages of products. We fully expect these customers to use those tools to respond to the price signals BPA is trying to send through these rates. In this way, customers' rational actions to lower their purchase power costs will also result in lower costs to BPA and the Region, rather than shifting costs to other customers. Tr. 443. We expect this to be true for metered requirements customers as well, who purchase all, or nearly all, of their power from BPA. Tr. 442.

RCC stated that customers must have "[e]qually viable and unbiased options for full or partial requirements service." RCC Brief, WP-96-B-RC-01, at 2. This concern is a contract issue. However, as stated above, BPA has priced both the full and partial requirements service packages. Whether an individual customer sees those packages as equal will depend on the unique circumstances of the customer.

WPAG equates choices to respond to price signals for unbundled products with wanting to take load off of BPA. In testimony they state

> [f]or unbundled products to provide customers freedom of choice, the customers must have the freedom to decide whether they will or will not purchase the product. Bonneville has combined its unbundling proposal with a policy determination that preference customers must continue to purchase at or near current Bonneville load levels for the rate period.

Beck, *et al.*, E-WA-13, at 22-23. Within existing contracts, customers have sufficient flexibility to respond to the price signals BPA is sending through these proposed rates, by selecting different product packages. As noted above, nothing in this rate case modifies existing contractual rights.

2.4 Comparability

2.4.1 Introduction

With enactment of the Energy Policy Act of 1992 (EPA'92), Congress declared its policy choice to encourage the development of competitive power markets through the availability of open transmission access. EPA'92 amended sections 211 and 212 of the Federal Power Act to allow FERC to order utilities to wheel power over their systems. The definition of transmitting utility includes a Federal Power Marketing Administration, such as Bonneville. EPA'92 contains provisions specifically applicable to the FCRTS. 16 U.S.C. § 824k(i)(1).

Since passage of EPA'92, FERC has actively declared its policy to remove barriers to competition in the electric energy industry by promoting open transmission access, both through rulings on a case by case basis and through rulemaking:

> Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition. Transmitting utilities own the transportation system over which bulk power competition occurs and transmission service continues to be a natural monopoly. Denials of access (whether they are blatant or subtle), and the potential for future denials of access, require the Commission to revisit and reform its regulation of transmission in interstate commerce.

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540, 21,550, FERC Stats. & Regs. ¶31,036 (1996) [hereinafter Order 888].

The construct that has emerged relies on the concept of "comparability." In March 1995, FERC issued a Notice of Proposed Rulemaking (NOPR) to adopt terms and conditions for open transmission access. *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 70 FERC ¶ 61,357. On April 24, 1996, FERC announced its final rule, Order 888. As FERC stated:

> The Commission found that a voluntarily offered, new open access transmission tariff that did not provide for services comparable to those that the transmission owner provided itself was unduly discriminatory and anticompetitive. In reaching that conclusion, the Commission broadened its undue discrimination analysis . . . to include a focus on the rates, terms and conditions of a utility's own uses of the transmission system.

Order 888, at 21,548.

The Commission further stated that "[A]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of the system. *Id.*, *citing American Electric Power Service Corporation*, 69 FERC ¶ 61,035 at 61,490, *reh'g denied*, 72 FERC ¶ 61,071 (1995)(*AEP*); *see also Southwest Regional Transmission Association*, 69 FERC ¶ 61,100, at 61,398 (1994), *order on compliance filing*, 73 FERC ¶ 61,147 (1995) (SWRTA). FERC has applied the comparability standard to "all transmitting utility members of an RTG." Order 888, at 21,548, 21,549-50. Bonneville is a member of two RTGs. FERC has also promulgated pricing guidelines that adopt the*AEP* comparability standard. Order 888, at 21,549. *See also Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 59 Fed. Reg. 55,031 (1994) [hereinafter Pricing Guidelines]. In addition FERC has required that certain ancillary services that are needed to provide basic transmission service be provided to transmission customers. Order 888, at 21,578. FERC has also required that jurisdictional utilities must functionally unbundle transmission from generation. *Id.* at 21,552.

While Order 888 by its terms does not apply directly to Bonneville, FERC has declared its intention to apply the policies it announces as broadly as it can through sections 211 and 212 of the Federal Power Act, to promote a national policy of open transmission access. *Id.* at 21,572-73. Thus, Bonneville and its customers have been guided throughout the rate proceeding (and the terms and conditions proceeding) by a desire to arrive at rates, terms and conditions for access to the FCRTS that would conform to the policies announced in the Pricing Guidelines, the NOPR, and ultimately, the Final Rule adopted in Order 888. *See, e.g.*, Metcalf *et al.*, WP-96-E-BPA-27; Metcalf, *et al*., TC-96-E-BPA-03.

A number of parties have stated that the rates, terms and conditions embodied in the Transmission Settlement Agreement meet the comparability standard. Portland General Electric, Puget Sound Power & Light, and PacifiCorp stated in their joint brief:

> [A]ssuming Bonneville adopts the proposal agreed to by parties to the Transmission Settlement Agreement dated April 4, 1996 ("Transmission Settlement Agreement"), FERC should find that Bonneville's proposed PTP and NT tariffs are comparable to the Commission's stage-1 pro forma tariffs. Bonneville's tariffs should satisfy FERC's threshold requirement that a power marketer have transmission open access tariffs that provide comparable services.

PGE, Puget, PacifiCorp Brief, WP-96-B-GE/PL/PS-02, at 4-5. Similarly, the Public Generating Pool (PGP) stated

> Comparability is a critical issue for all BPA customers who purchase transmission services from BPA. Much of the transmission terms and conditions testimony by PGP and others has focused on whether BPA's proposal meets comparability

> requirements. . . . The proposed NT and PTP tariffs, as modified by the settlement, are a realistic approach to the needs of BPA in operating the Federal Transmission System while maximizing the customers' ability to use the system. PGP believes that the proposed tariffs contain terms and conditions which are generally consistent with FERC's pro forma tariffs. They appropriately balance the obligation to substantially conform to the pro forma tariffs with the specific needs of BPA's customers in the Northwest. PGP believes that NT and PTP tariffs under the Settlement Agreements are equal to or better than the FERC pro forma tariffs when considered in light of the particularities of the Northwest hydro system and the historical usage of the Federal Transmission System.

PGP Brief, WP-96-B-PG-01/TC-96-B-PG-01, at 5-6.

2.4.2 Comparable Treatment of Transmission for BPA Power Sales

Implementing comparability posed some unique challenges for Bonneville. For example, unlike many transmission providers, Bonneville sells its power at wholesale only. In testimony, BPA identified two general alternatives for implementing comparability as it applied to BPA power sales. Metcalf, *et al.*, E-BPA-27, at 5-6. One alternative would be to treat the power business as a large wheeling customer. This would allow BPA to combine all its business under a single PTP contract or put its requirement sales under single NT arrangement and the remainder of its business under a single PTP agreement.

The other general alternative would be to apply the tariffs individually to each sale. In this way each customer could choose whether to be a PTP or NT customer. The major advantage of this alternative is that it is more consistent with principle of transparency. Each customer would face the same transmission rates, terms and conditions buying from BPA than if they requested wheeling for an alternative resource or purchase. Metcalf, *et al.*, E-BPA-27, at 6, A-1, A-2. This alternative also has the advantage of allowing the customers the ability to combine the transmission for BPA power purchases and wheeling under a single umbrella arrangement. Metcalf, *et al.*, WP-96-E-BPA-84, at 2.

However, it also could have the impact of putting the BPA Power Business at a disadvantage relative to its competitors. The PTP tariff allows transmission service to be provided to both power purchasers and power sellers. Thus, the power business' competitors can purchase transmission from BPA and make fixed price offers for delivered power. The seller may take the risk that the transmission rates may be different than assumed, and the seller may be able to utilize their PTP rights to complete a number of arrangements with varying seasonality and diurnality but that, in total, fit underneath a single contract demand. Metcalf, *et al.*, WP-96-E-BPA-84, at 3.

In supplemental testimony, BPA proposed a compromise. For its PF, IP, and NR sales BPA would apply the tariffs individually to each sale. However, for other business, BPA will have the same options as other sellers to purchase firm transmission rights and utilize them in a flexible manner. *Id.* at 4.

As proposed in its Supplemental proposal, BPA will apply the rates and tariffs individually to each PF, IP, and NR power sale. This insures compliance with the principle of transparency for these sales. For BPA's remaining business, the power business will have the option of purchasing PTP service under the same rates terms and conditions as other wheeling customers and bundle that transmission with power products in a flexible manner. This will allow BPA to compete on an equal footing with other power marketers. This outcome is consistent with the Settlement Agreement.

2.4.3 Functional Unbundling

Issue

Whether Bonneville can provide open and comparable transmission service without functionally separating its power and transmission businesses. Clark Brief, WP-96-B-CP-01, at 23.

Parties' Position

Clark claims in its brief that BPA excluded from dockets any substantive discussion of how and when BPA will functionally separate, and argued that functional separation is a necessary and integral part of the NT and PTP rate schedules and that a proposal that does not include functional separation is substantively deficient. Clark Brief, WP-96-B-CP-01, at 23-24. Clark does not cite any testimony to support its position.

Evaluation of Positions

Clark's assertions regarding functional unbundling are based on an incorrect assumption: that Bonneville will not functionally unbundle its power and transmission businesses. Clark implies that Bonneville should be held to a high standard of proof regarding functional unbundling. Clark Brief, B-CP-01, at 23. Clark's position is founded upon an incorrect reading of FERC's rules. FERC does not require utilities with voluntary open access tariffs to provide proof of functional separation or include functional separation in pro forma tariffs. FERC has articulated three tests for functional unbundling:

> (1) a public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others;
>
> (2) a public utility must state separate rates for wholesale generation, transmission, and ancillary services;

(3) a public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.

Order 888, at 21,552.

Clark's assertion that BPA did not present evidence regarding plans for functional separation is incorrect. Metcalf *et al.*, E-BPA-27, at 3. In fact BPA stated in testimony that it would meet each of these tests. During this rate proceeding, Bonneville has consistently recognized and agreed that it would use the tariffs of general applicability for its own use of the system. *Id.* at 3. No one challenged the assertion. Bonneville has also consistently proposed and supported separate rates for wholesale generation, transmission and ancillary services. *Id.* at 4, 11; *see also* Rehman, *et al.*, TC-96-E-BPA-04. Bonneville's rates for ancillary services are discussed in Chapter 13. Finally, Bonneville has consistently recognized the importance of the real time information network (now OASIS) in implementing comparability and has taken steps to comply with the OASIS requirement. Metcalf, *et al.*, E-BPA-27, at 4, *see also* Arnold, TC-96-E-BPA-05. Bonneville made the following comments in the Real-Time Information Networks and Standards of Conduct Docket, RM95-9-000 that led to the adoption of the OASIS final rule, Order No. 889. In those comments, BPA stated that it was

> separating its wholesale power marketing function from its transmission system operations and reliability function to the extent possible under law, and is establishing a Real-Time Information Network. Finally, BPA will conduct its future operations consistent with the standards of conduct to the extent possible under law. However, BPA's ability to isolate the Administrator from decisions made by either the power marketing or transmission functions or to accomplish total unbundling or divestiture, should that become FERC's policy, is constrained by Acts of Congress that established a single agency conducting both transmission and power marketing functions, and a single Administrator with all agency powers and responsibilities. In addition, total unbundling or divestiture would be substantially complicated by BPA's status as a singular financial entity whose total debt is retired without regard to the source of the revenues.

In addition, Bonneville plans to file its procedures for compliance with the FERC Standards of Conduct of Order 889, *Open Access Same-Time Information System (Formerly Real Time Information Networks) and Standards of Conduct*, 61 Fed. Reg. 21,737 (1996), under the reciprocity provisions of FERC's order.

No further proof of compliance is required as a prerequisite to adopting the proposed comparable transmission rates, terms and conditions.

Decision

Although Bonneville is not required to prove in a rate case that it will comply with FERC requirements for functional unbundling, nevertheless there is sufficient uncontroverted evidence in the record to demonstrate that Bonneville intends to comply with the FERC requirements for functional unbundling.

2.4.4 Customer Service Policy

Issue

Whether the retention of Bonneville's Customer Service Policy (CSP) violates the comparability standard. Clark Brief, B-CP-01, at 26.

Parties' Positions

Clark claims that "[t]he proposed NT and PTP Rate Schedules are deficient because they fail to include any disposition, whether by revision or elimination, of Bonneville's current Customer Service Policy." Id. Clark further states that "[t]his Customer service policy is inconsistent with the provision of transmission access and service on a uniform and comparable basis." Id.

Evaluation of Positions

Clark does not cite any record evidence to support its position. Clark did not offer any evidence during the proceeding to support its position. The Customer Service Policy was raised as an issue by several parties. *See e.g.*, Huntsinger, *et al.*, WP-96-E-GE/IP/MP/PL/PS/WP-01/TC-96-E-GE/IP/MP/PL/PS/WP-01, at 8-9; Black, *et al.*, WP-96-E-PG-04/TC-96-E-PG-04, at 18. No party claimed that the *rate schedules* were deficient because they "fail to include any disposition . . . of Bonneville's current Customer Service Policy." In fact, the issue was whether Bonneville's proposed terms and conditions *tariffs* should contain references to the CSP.

In its supplemental/rebuttal testimony, Bonneville testified that it would "apply FERC standards to determine cost responsibility for construction of new transmission facilities" rather than utilize the CSP to make these determinations. Metcalf, *et al.*, WP-96-E-BPA-96, 29-30. References to the CSP have been removed from the transmission tariffs. This position was reiterated at oral argument. Or. Tr. 2467, 2494.

Decision

Consistent with the settlement agreement and testimony in the record, BPA will apply FERC standards to determine cost responsibility for construction of new transmission facilities rather than utilize the CSP for making these determinations.

2.5 Settlement

2.5.1 Introduction

As described above, the Settlement Agreements were signed by most of Bonneville's customers. However, two parties to the rate proceeding, Clark Public Utility District and Association of Public Customers (APAC)("non-signing parties") have raised issues relating to the settlement and have argued that the Administrator should not adopt the proposals contained in them. *See* section 2.5.3, below. They have objected on both substantive and procedural grounds, and have raised issues related to individual provisions of the Settlement Agreements. Individual issues will be discussed in the appropriate section of this ROD. The Administrator can adopt the proposals embodied in the Settlements if they are consistent with sound business principles, supported by substantial evidence in the hearing record, and otherwise comport with all applicable statutory requirements.

2.5.2 Consistency of Settlement Agreements with Sound Business Principles

Clark urges the Administrator to reject the Agreements for a host of reasons, including the proposition that the rates and terms and conditions proposed by the Agreements are not consistent with Bonneville's statutory directives. *See, e.g.*, Clark Ex. Brief, WP-96-R-CP-01, at 8. Parties who signed the Agreements, on the other hand, have urged the Administrator to adopt the Settlements. *See, e.g.*, NIU Brief, WP-96-B-NI-01, at 1; PPC Brief, WP-96-B-PP-01, at 9; Powerex Brief, WP-96-B-BC-01, at 1; PacifiCorp Brief, WP-96-B-PL-01, at 2-3; RCC Brief, WP-96-B-RC-01/TC-96-B-RC-01, at 8-9; PGP Brief, WP-96-B-PG-01/TC-96-B-PG-01, at 5. *See also* Or. Tr. 2376, 2388, 2401, 2413, 2422, 2446, 2455. The signing parties who either briefed or argued the issue urged the Administrator to adopt the settlements in their entirety *Id.*

Clark does not specifically raise the issue of sound business principles. Clark makes many arguments by assertion with little supporting documentation or record support. In addition, legal arguments are made on bare assertion without explanation. Clark asserts that statutory directives are violated, and while Clark recites some statutory standards that apply, it does not explain how directives are violated. Nevertheless, this section will analyze the underlying claim that adopting the settlement would violate statutory directives.

As described in section 1.2 above, Bonneville's rates are to be set to "recover, *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) over a reasonable period of years." 16 U.S.C. § 839e(a)(1). FERC reviews Bonneville's rates to assure that the repayment, cost recovery and equitable allocation tests are met. 16U.S.C. § 839e(a)(2). During oral argument in this proceeding, the PPC argued that the acceptance of the settlement goes right to the heart of the concept of sound business principles:

> I would suggest to you that the sound business principle language found in [the] Northwest Power Act[,] found in section 7(a)(1)[,] is a tried and true mechanism with new relevance today. I would suggest that sound business principles allow Bonneville to make the necessary decisions to remain competitive in this case.

Or. Tr. 2392-94 (PPC). Section 2.1 of this Record of Decision contains a discussion of Bonneville's need to be competitive and will not be repeated here. Bonneville agrees however, that settlement of this rate proceeding is consistent with sound business principles.

Bonneville has routinely faced the issue of "sound business principles" in its rate proceedings. For example, in 1993, parties argued that Bonneville should keep its rate increase at 14 percent or less in order to be competitive. Bonneville took the position in that case, as it does in this, that program level issues were not properly part of the rate proceeding. Administrator's Record of Decision, 1993 Final Rate Proposal, WP-93-A-02, at 11 (1993 ROD). In the evaluation of the position, however, the Administrator stated:

> If, viewed as a whole, all reasonable rates actions have been taken to establish the rates as low as possible consistent with sound business principles--and here it must be understood that decisions on many issues trade off and factor into decisions on other issues--the consequence is that the rates are the lowest consistent with sound business principles. If those rates, however, are not competitive--meaning for rate determination purposes that BPA cannot recover its costs--the consequence is that BPA must change some aspect of its business to attain competitive rates.

1993 ROD, WP-93-A-02, at 14. In this proceeding the parties have reached agreement regarding both some rate levels and some cost allocation issues, all with a view to achieving rates that allow Bonneville to remain competitive (*i.e.*, remain in the market), which is surely consistent with sound business principles, while at the same time recovering its costs.

Bonneville recognizes that it cannot continue to do business and expect to recover its costs unless it pays attention to the effect its rate increases have on its competitiveness. As the Administrator stated in the 1993 ROD:

> The conclusion that the "lowest possible rates" standard is a not an operational standard, but a ratemaking standard, in *no way detracts from the fact that BPA must be concerned with operating in a sound and businesslike fashion and conducting its business so as to assure the Pacific Northwest an economical power supply*. Throughout BPA's history, Congress has expressed its intent that BPA act in a businesslike fashion.

Id. at 15 (emphasis added). Reviewing the statutory underpinnings of “sound business principles,” the Administrator noted that “section 2(f) of the Bonneville Project Act was aimed at enabling the Administrator to ‘employ business principles and methods in the operation of a business enterprise . . .’ H.R. Rep. No. 777, 79th Cong., 1st Sess., 3 (June 21, 1945).” *Id.* A similar purpose was recognized for the budgeting provisions of the Transmission System Act:

> One of the primary purposes of the Transmission System Act was to enable BPA to rely on stable and flexible funding, so that it could thereby better act in a timely, orderly and businesslike fashion. *E.g.*, S. Rep. 931030, 93rd Cong., 2d Sess., 78 (July 25, 1974). . . . That Act provides that the budget program of each wholly owned Government corporation shall "provide for emergencies and contingencies and otherwise be flexible so that the corporation may carry out its activities." 31 U.S.C. § 9103(b)(3).

Id. at 16. Finally,

> With the passage of the Northwest Power Act, the Administrator's responsibilities were significantly expanded. Now, the Administrator would be charged with encouraging cost-effective resource development; assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply; protecting, mitigating, and enhancing fish and wildlife resources; and many other responsibilities. In all of these undertakings, Congress charged in section 9(b) of the Northwest Power Act that "The Secretary of Energy, the [Regional] Council, and the Administrator shall take such steps as are necessary to assure the timely implementation of this Act in a sound and businesslike manner." 16 U.S.C. § 839f(b).

Id. As discussed in sections 2.2 and 2.3 above, it is consistent with Bonneville’s statutory directions to operate in a sound and businesslike manner to keep rates low in the new competitive environment. It is also businesslike to respond to regional views on comparable rates, terms and conditions for use of the Federal Columbia River Transmission System (FCRTS). In fact the Settlement Agreements represent substantial regional consensus that, even after cost reductions had been reflected in BPA’s supplemental proposal, there were additional cost cuts Bonneville could make. Thus, it is also consistent with businesslike operation to arrive at a mutually agreeable proposal for determination of issues in a rate proceeding. Finally, given the uncertainty and turmoil in the utility industry in general at this time, it is consistent with sound business principles to offer an element of certainty to customers based on a proposal that is embraced by all but a tiny minority. Such certainty, and the satisfaction it engenders, promotes the widest possible diversified use of BPA’s power and transmission services.

Although the Ninth Circuit Court of Appeals has not addressed directly Bonneville’s ability to settle rate proceedings, it has expressed strong support of settlement of disputes by Bonneville in other situations. In *Utility Reform Project v. Bonneville Power Admin.*, in reviewing Bonneville's settlement of litigation arising out of the Washington Public Power Supply System's Project Number 3, the Court stated:

> [W]e are firmly of the view that this case is heavily colored by the fact that it is a *settlement* that we are reviewing. BPA was facing a claim in which the IOUs estimated their damages as exceeding $2.5 billion; they already had invested some $800 million in WNP-3. The litigation promised to assume epic propositions. There was clearly an overriding public interest in settling the controversy. *See, e.g., United States v. McInnes*, 556 F2d 436, 441 (9th Cir. 1977); *Van Bronkhorst v. Safeco Corp.*, 529 F2d 943, 950 (9th Cir. 1976). This is not to say that BPA could act contrary to a clear statutory directive in settling, but if there is room for doubt, we ought not to resolve it in a manner that sends the parties back to litigation. This settlement will therefore be set aside only for the strongest of reasons. *See Cities Serv. Oil Co. v. Coleman Oil Co.*, 470 F.2d 925, 929 (1st Cir. 1972), *cert. denied*, 411 U.S. 967, 93 S.Ct. 2150, 36 L.Ed.2d. 688 (1973).

Utility Reform Project v. Bonneville Power Admin., 869 F2d. 437, 443 (9th Cir. 1989) (emphasis in original) (*URP*). *See also U.S. v. Cannons Engineering Corp.*, 899 F.2d 79 (1st Cir. 1990) (*Cannons Engineering*) (it is the policy of the law to encourage settlements). In *Cannons Engineering* the court described the settlement discussions as

> a situation where the cards have been dealt face up and a crew of sophisticated players, with sharply conflicting interests sit at the table. That so many affected parties, themselves knowledgeable and represented by experienced lawyers have hammered out an agreement at arm's length and advocate its embodiment in a judicial decree, itself deserves weight in the ensuing balance. [Citation omitted.] The relevant standard, after all is not whether the settlement is one which the court itself might have fashioned or considers as ideal, but whether the proposed decree is fair, reasonable and faithful to the objectives of the governing statute.

Id. at 84. Although *Cannons Engineering* dealt with a consent decree under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), the situation surrounding the Settlement Agreements is similar: the rate and terms and conditions proceedings were fully litigated in the 7(i) process, which is designed for formal creation of a record for review; the issues that were litigated and ultimately settled were controversial and parties had a full opportunity to participate in the creation of the record. The agreements reached in the Settlement Agreements represent regional balancing of interests for this period of transition to competitive power markets.

BPA has taken care to act in conformance with statutory directives: the Settlement Agreements preserve rights of parties under the statutorily required 7(i) process because they are agreed-upon proposals that still must pass muster under Bonneville's organic statutes and, where applicable, EPA'92. Thus, before deciding to adopt the rate proposals embodied in the Settlement Agreements, the Administrator must determine that they comport with the review standards of section 7(a) of the Northwest Power Act and other statutory standards. Rates that the Administrator intends to submit to FERC for approval as rates applicable to FERC ordered transmission access must also meet the "not unjust or unreasonable or unduly discriminatory or preferential" test of EPA'92. 16 U.S.C. §824k(i)(l)(ii) Indeed the parties agreed and the Transmission Settlement Agreement states:

> The Administrator's final decision in the Dockets must be supported by and made based on the records of the Dockets. Neither the fact of this Transmission Settlement Agreement or the Power and Transmission Partial Settlement Agreement . . . being concurrently entered into the record of the Dockets, nor any provision of the Settlement Agreements, nor the fact of the Administrator's eventual adoption of the proposals contained in the Settlement Agreements in any way evidences a closed mind by the Administrator or constitutes a prejudgment or predetermination by the Administrator as to any matter at issue in the Dockets, and no party agreeing to this Transmission Settlement Agreement may argue otherwise; provided, however, that this in no way precludes that party from arguing on the basis of any other evidence that the Administrator has a closed mind or has prejudged or predetermined any matter at issue in the dockets.

Attachment 1, p. 1, "Proposal." The same language is found in the Power and Transmission Settlement Agreement, Attachment 2, p.1, "Proposal." Non-settling parties Clark and APAC have claimed that adoption of the Settlement Agreements deprives them of the procedural guarantees of section 7(i). Procedural issues related to the Settlement Agreements are discussed in section 14.2.5, below.

The Settlement Agreements are the product of regional consensus. FERC has recognized the importance of regional consensus in the implementation of open and comparable transmission access. *See e.g., Order 888*, at 21,666-67. Numerous cases demonstrate that FERC views settlements of disputes reached by the interested parties favorably. *See, e.g., American Electric Power Service Corporation*, 71 F.E.R.C. ¶ 61,393, at 62,542 (1995) [hereinafter *AEP*] (may settle in accordance with the NOPR pro forma tariffs or other "agreed to terms that are fair and reasonable") cited in *Utilicorp United, Inc.*, 74 FERC ¶ 61,138, at 61,492 (1996). Indeed, in *AEP*, FERC stated "we encourage parties to the proceedings to attempt to reach settlements consistent with the intent of the NOPR." *AEP*, 71 F.E.R.C. ¶ 61,393, at 62,540. That is precisely what the settling parties have done in the Settlement Agreements.

Similarly, FERC, in approving the Governing Agreements for the WRTA, which BPA has joined, FERC recognized the importance of regional consensus in implementation of open and comparable transmission access. *See Western Regional Transmission Association*, 71 FERC ¶ 61,158, at 61,524, n.10 (1995) ("When we issued the RTG Policy Statement, the Commission recognized the value of affording flexibility to regional concerns: 'We have decided to adopt a policy statement rather than a rule because . . . the ongoing development of RTGs clearly indicates a need for flexibility to adapt to specific geographic, operational, historical and other circumstances.'") The transmission rates and terms and conditions finally adopted in this proceeding will be submitted by Bonneville to comply with the governing agreements of the Western WRTA and the Northwest Regional Transmission Association (NWRTA).

2.5.3 <u>Compliance of Settlement Agreements with Statutory Ratemaking Standards</u>

<u>Issue</u>

Whether the rates that result from the Settlement Agreements are consistent with Bonneville's statutory rate directives.

<u>Parties' Positions</u>

Clark urges the Administrator to reject the Agreements for a host of reasons including the proposition that the rates and terms and conditions proposed by the Agreements are not consistent with Bonneville's statutory directives, although Clark does not specifically raise the issue of sound business principles. Clark raises issues about the compliance of individual provisions of the Agreements with applicable law. Clark Brief, B-CP-01, at 12-23; Clark Ex. Brief, R-CP-01. APAC argues that the underrecovery of delivery cannot be assigned to Power rates. APAC Brief, WP-96-B-PA-01, at 35. *See also* APAC Ex. Brief, WP/TR-96-R-PA-01, at 34. Parties who signed the Agreements, on the other hand, have urged the Administrator to adopt the Settlements. *See, e.g.*, NIU Brief, WP-96-B-NI-01, at 1; PPC Brief, WP-96-B-PP-01, at 9; Powerex Brief, WP-96-B-BC-01, at 1; PacifiCorp Brief, WP-96-B-PL-01, at 2-3; RCC Brief, WP-96-B-RC-01/TC-96-B-RC-01, at 8-9; PGP Brief, WP-96-B-PG-01/TC-96-B-PG-01, at 5. *See also* Or. Tr. 2376, 2388, 2401, 2413, 2422, 2446, 2455. The signing parties who either briefed or argued the issue urged the Administrator to adopt the settlements in their entirety *Id.*

<u>Evaluation of Positions</u>

As noted above, Clark's arguments are made by assertion with little supporting explanation, documentation or record support. This section deals generally with the rate directives applicable to Bonneville. Individual allegations of inconsistency with or violation of the rate directives are discussed in the appropriate chapters of this ROD.

As Parties urged in Oral Argument, the Settlement Agreements should be viewed as a whole, and should not be evaluated based on whether individual sections taken alone would withstand the statutory tests, but on whether the Settlement Agreements, taken has a whole, are a reasonable solution to the issues presented and litigated in this proceeding. *See e.g.,* Or. Tr. at 2376, 2401, 2455. Indeed, the evaluation of Bonneville's rates as a whole is the appropriate method of analysis. *United States Dep't of Energy--Bonneville Power Admin.,* 39 F.E.R.C. ¶ 61,078, at 61,208 (1987).

Repayment and Cost Recovery

In its brief, Clark raises three issues related to cost recovery. Clark Brief, B-CP-01, 12-15. Clark repeats these assertions in its Brief on Exceptions. Clark Ex. Brief, R-CP-01, at 6-10, 20-22. In general, Clark argues that the rate levels agreed to by the parties in settlement will be insufficient to recover BPA's costs. With regard to the transmission rate schedules, the PF rate and the Delivery Charge, Clark claims that "[i]f adopted by the Administrator, the . . . rate levels proposed in the settlement will not generate revenues sufficient to cover the costs . . . as reflected in the record." Clark Brief, B-CP-01, at 12, 13, 14; Clark Ex. Brief, R-CP-01, at 8, 10, 20. Clark further states, with regard to the transmission rate levels, the PF rate level and the delivery charge, "no evidence has been presented to substantiate this rate reduction by the parties to the settlement agreement." Clark Brief, B-CP-01, at 12, 13 and 14. The substantial evidence test is discussed below.

As discussed above in sections 2.2 and 2.3 (competitiveness, sustainable revenues), and below in section 4.0 (repayment, spending levels and transmission cost recovery), there is ample evidence in the record to support the adoption of the settlement rate levels and to demonstrate that the proposed rate levels are reasonable and will recover costs. Because this is a "spending level" issue, measures BPA is taking to insure that it can meet cost recovery requirements are discussed in the Revenue Requirements chapter, section 4.2, and won't be repeated here. Discussion of the PF rate level is found in section 2.6. Similarly, Clark's claim that the settlement Delivery Charge will be set a level below cost is discussed in Chapter 12, section 12.2.2.

Equitable Allocation

Clark and APAC make several allegations that various cost allocation or rate design proposals contained in the Transmission Settlement Agreement are inconsistent with the equitable allocation standard. For example, Clark alleges that a Delivery Charge set at $9.00 that does not recover the cost of the delivery facilities violates the Northwest Power Act and constitutes an unduly preferential and discriminatory rate. Clark Brief, B-CP-01, at 14-15; see also Clark Ex. Brief, R-CP-01, at 20. APAC claims that the assignment of General Transfer Agreement (GTA) costs and a portion of delivery costs to power purchasers is a violation of the equitable allocation provision of the Northwest Power Act. APAC Brief, B-PA-01, at 33-35; APAC Ex. Brief, R-PA-01, at 34. Clark claims that including former Fringe facilities in the Network results in an inequitable allocation of costs. Clark Brief, B-CP-01, at 28-29; *see also* Clark Ex. Brief, R-CP-01, at 16-17. Clark also argues that allocation of the Delivery facilities charge to power violates the Northwest Power Act equitable allocation standard. Clark Brief, B-CP-01, 15-16;*see also* Clark Ex. Brief, R-CP-01, at 22. In addition, Clark argues that assignment of the costs associated with General Transfer Agreements to all power customers provides an unduly discriminatory and preferential transmission rate to Bonneville's power customers that receive transfer service. Clark Brief, B-CP-01, at 18-19; *see also* Clark Ex. Brief, R-CP-01, at 24-25.

APAC and Clark both claim violations of section 7(a)(2)(C) of the Northwest Power Act which provides that FERC will confirm and approve Bonneville's rates upon a finding that "such rates equitably allocate the costs of the Federal transmission system to Federal and non-federal power using the system." 16 U.S.C. §839e(a)(2)(C)(emphasis added). Generally, Bonneville allocates the costs of the Federal transmission system by first dividing the transmission revenue requirement into segments, and then by further dividing the costs between non-Federal and Federal customers according to use through the Transmission Rate Design Study (TRDS). The TRDS also determines the assignment of costs between and within customer classes. This methodology has been used by Bonneville in prior rate cases and has been approved and confirmed by FERC as a methodology that equitably allocates the transmission costs between Federal and non-Federal power using the transmission system. *Central Lincoln Public Utilities District v. Johnson*, 735 F.2d 1101, 1129 (1984) [hereinafter *Central Lincoln*].

In addition to the equitable allocation standard, section 7(a)(1) of the Northwest Power Act and section 10 of the Transmission System Act provide that the rate must be established to recover the costs associated with transmission of electric power "in accordance with sound business principles." 16 U.S.C. §839(a)(1), 16 U.S.C. § 838h. Section 7(a)(1) of the Northwest Power Act incorporates by reference section 9 of the Transmission System Act, which provides that rates "shall be fixed and 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." 16 U.S.C. § 838g (emphasis added). Similar language is also contained in section 5 of the Flood Control Act. 16 U.S.C. § 825s.

Taken together, the "equitable allocation" and "widest possible use consistent with sound business principles" standards evince a Congressional intent to give BPA's substantial ratemaking discretion. The equitable allocation standard does not expressly or implicitly mandate that each of Bonneville's transmission rates must reflect costs that are equitably allocated between Federal and non-Federal power. It requires fairness in allocating the transmission costs between Federal and non-Federal power using the system in the aggregate.

This view is reinforced by reference to two cases where the "widest possible use standard" or an analogous standard were examined and found to be such a broad grant of discretion as to constitute an "action committed to agency discretion by law" within the meaning of the APA. The Ninth Circuit analyzed the "most widespread use" language of the Flood Control Act and found that the standard was "too vague and general to provide law to apply." *City of Santa Clara, Cal. v. Andrus,* 572 F.2d 660, 668 (9th Cir. 1978). In *Pacific Power & Light Co. v. Duncan,* the District Court for the District of Oregon determined that BPA's statutory ratemaking directives do not require Bonneville to establish rates that are limited to "cost of service" standards. *Pacific Power & Light Co. v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980) [hereinafter *PP&L*]. The *PP&L* court rejected the argument that multiple references to cost recovery required Bonneville to adopt strictly cost-based rates. As noted by the court, "[d]espite all the references to cost, the . . . quoted passages do not support an inference that cost is the only basis upon which rates may be computed." *PP&L*, 499 F. Supp. at 683 (emphasis in original). Moreover, the *PP&L* court ultimately held that BPA's "statutory schemes, taken as a whole, invest the [Administrator] with . . . broad ratemaking discretion . . . ." *Id.* The court expressly considered the equitable allocation standard of section 10 of the Transmission System Act to support this holding. *Id.*

Furthermore, Section 7(e) of the Northwest Power Act, grants the Administrator considerable rate design discretion, including the ability to determine the appropriate method for recovering transmission costs that have been allocated to Federal use. Section 7(e) provides that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time of day, seasonal rates or other rate forms." 16 U.S.C. § 839e(e). Accordingly, where a transmission rate is based upon something less than actual embedded costs of the service, such as the Delivery Charge, Bonneville's rates in total certainly can still be designed to insure that the costs of the transmission system are equitably allocated and recovered.

In this rate proceeding Bonneville proposed various new methods of segmenting (or allocating) the costs of the Federal transmission system to achieve rate comparability. Bonneville generally followed the segmentation methodology approved in *Central Lincoln*. Parties opposed many of BPA's transmission cost allocation or rate design proposal, on the basis that it would result in unfairness. These controversial issues were fully litigated in the rate case. As described above, Bonneville and the vast majority of its customers have reached agreement on a proposal for allocation and recovery of the costs of the transmission system. The Transmission Settlement Agreement was intended to provide a global solution to the thorny problems posed by a shift to a comparable, open-access transmission scheme. Thus it provides that for a 5-year transition period certain costs will be allocated in certain ways in order to achieve the fairness that the equitable allocation standard contemplates.

Pursuant to the settlement agreement Bonneville has assigned the GTA costs to Federal power as the user of those facilities. In addition, the primary users of the Delivery segment are Bonneville's Federal power customers. Accordingly, where Bonneville has not recovered these costs in specific transmission rates, Bonneville may use its rate design discretion to assign the costs to Federal power customers in another manner. Bonneville has done this by identifying these costs in the TRDS as costs to be assigned to the Bonneville Power Business. The Bonneville power business, then may exercise its rate design discretion to determine how to recover these transmission costs.

Similarly, Clark argues setting the Delivery Charge at a rate below the cost of service and assignment of the GTA costs to all power customers provides an unduly discriminatory and preferential transmission rate to Bonneville's power customers that receive transfer service. Clark Brief, B-CP-01, at 18-19; Clark Ex. Brief, R-CP-01, at 20, 24. Clark provides no explanation of why this treatment is unduly preferential and discriminatory.

Bonneville does not agree that the assignment of the GTA costs to all power customers provides a discriminatory and preferential rate to power customers served by transfer. Clark does not explain why Bonneville should be required to allocate the costs of transfer only to the customers served by transfer, instead of defining classes of customers more broadly, as it has done in previous rate cases. To distinguish delivery customers who are served by transfer from customers for whom Bonneville built facilities might in itself result in an unduly preferential or discriminatory classification.

Although, the ratemaking directives do not specify how Bonneville must design its rates, Bonneville's rates must represent a reasonable accommodation of conflicting policies that are committed to its care by statute. *Aluminum Co. of America v. Bonneville Power Administration*, 903 F.2d 585 (9th Cir. 1989). Accordingly, consistent with sound business principles, and to achieve the widest possible use of electric power at the lowest possible rates, it is appropriate for Bonneville to establish the Delivery Charge at a rate less than the cost of service, and assign GTA costs to power and recover the GTA costs for such facilities and the delivery costs not recovered by the Delivery Charge from all power customers.

As described in the next section, Clark implies in its brief that the ratemaking requirements applicable to Bonneville pursuant to section 212(i) of the Federal Power Act (FPA) apply generally to all of Bonneville's rates. They do not. The ratemaking standards of section 212(i)(1)(B)(ii) apply only to transmission service ordered by FERC under section 211 of the FPA. 16 U.S.C. § 824k(i). FERC has issued no order requiring Bonneville to provide transmission over the GTA facilities. Accordingly, the "not unjust or unreasonable or unduly discriminatory or preferential" standard of section 212(i) of the FPA are not applicable.

Bonneville will continue to treat all power customers as a single class, including customers served by transfer, and will assign GTA costs and costs not recovered by the Delivery Charge to power. This treatment does not result in undue discrimination and is not preferential. Assignment of the GTA costs and unrecovered delivery costs to power is also consistent with the Settlement Agreements. In fact, the signing parties agreed that they could not argue that the Transmission Settlement Agreement does not meet the requirements for a FERC Stage One filing, which means that the proposed rates, terms and conditions satisfy the pro forma tariffs, including the applicable rate review standards.

<u>Not Unjust, Unreasonable, Unduly Discriminatory or Preferential</u>

As described above in section 1.3.1, the EPA'92 included new authority for FERC to order access to utility transmission systems, including the authority to order access to the FCRTS. As noted there, Congress added an additional standard to be applied to rate determinations for FERC ordered transmission access: "no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission." 16 U.S.C. § 824k(i)(1)(ii) (1985 & Supp. 1993). The conference report on EPA'92 and the fact that the final language does not incorporate sections 205 and 206 makes clear that Congress intended the "unjust and unreasonable" standard to be applied consistently with the existing requirements for repayment, cost recovery, and equitable allocation. 16 U.S.C. § 839(a)(2); H.R. Conf. Rep. No. 102-1018, 102nd Cong., 2d Sess., 389 (1992), *reprinted in* 1992 U.S.C.C.A.N. 2480. The new standard does not override existing statutes as Clark asserts. Clark Brief, B-CP-01, at 3. Clark also misstates the applicable EPA'92 standard and also claims that it applies generally to BPA's transmission rates. *Id.* FERC has held the that the EPA'92 standards apply only to access ordered by FERC under section 211. *U.S. Department of Energy--Bonneville Power Admin.*, 67 F.E.R.C ¶ 61,351 (1994). In this rate proceeding, Bonneville has proposed comparable rates to be used with open access transmission tariffs designed to meet the standards and to be available for FERC-ordered access.

FERC has not yet applied the "not unjust or unreasonable" standard to any of BPA's rates. In applying the "just and reasonable" standard found in Federal Power Act sections 205 and 206, FERC has approved the rates if they were in a "zone of reasonableness." The "zone of reasonableness" test is helpful when applying the EPA'92 standard. The Supreme Court has defined this "just and reasonable" standard as delimiting a zone of reasonableness between a rate so low as to be a taking, and a rate set higher than the value of the service to the ratepayer. *See Federal Power Comm'n v. Conway Corp.*, 426 U.S. 271, 278 (1976). A "just and reasonable" rate should allow the utility a profit, and a below market value, no-profit rate is confiscatory unless a higher rate would be prejudicial to the public ratepayer. *Duquesne Light Co. v. Barasch*, 109 S.Ct. 609, 615 (1989) (citations omitted). This balance between the investor and public interests is the goal of the "just and reasonable" standard found in sections 205 and 206 of the Federal Power Act. 16 U.S.C. §§ 824d,e (1988). The "just and reasonable" standard as described by the courts for profit-making utilities is not a perfect fit to determine that rates are "not unjust and unreasonable" for a Federal power marketing agency that has no investors. However, what is clear is that FERC will review the rates that are subject to the "not unjust or unreasonable" standard to assure that they are neither too high nor two low, balancing the interests of ratepayers and investors (or in Bonneville's case, the United States Treasury).

Bonneville's existing statutory standards contain analogous provisions. For example, the Administrator must establish rates to meet the widespread use and lowest possible rates standards discussed in section 1.2.1. Thus, the Administrator considers the effect on the ratepayer in determining the rate levels. In this case the need to keep rates at a level to allow BPA to remain competitive serves to assure that the rates will not be set too high. Similarly, setting rates to assure repayment and recover costs protects Bonneville's major investor, the United States Treasury. That is, in determining that the Administrator has met the repayment and cost recovery requirement of the Northwest Power Act §7(a), FERC will also be determining that the rates are not too low. Application of these tests achieves a balancing comparable to that contemplated by the zone of reasonableness test. The zone of reasonableness test also means that there may be many rates that are just and reasonable. Thus there is room for the Administrator to exercise discretion and make rate decisions that satisfy the standards and the Settlement Agreements.

The other standard contained in the EPA'92 section applicable to rates for FERC ordered transmission access is that such rates not be "unduly discriminatory or preferential." Again, reference to existing precedent on discrimination is instructive, although not controlling. In general, even a substantial disparity in rates charged does not equate to undue or unreasonable discrimination. "Differences in rates are predicated upon differences in facts . . . ." *St. Michaels Util. Comm'n v. FPC*, 377 F.2d 912, 915 (4th Cir. 1967). Appellate review is limited to determining "whether the record exhibits factual differences to justify . . . . differences among rates charged." *Id*., *see also Environmental Action*, *Inc. v. FERC*, 939 F.2d 1057 (D.C. Cir. 1991)(there is no undue discrimination "if there are rational reasons for treating [a particular group] differently.")

Clark has alleged that customers served by transfer are "receiving subsidized transmission service which provides an unduly discriminatory and preferential transmission rate to [them]." Clark Brief, B-CP-01, at 19; *see also* Clark Ex. Brief, R-CP-01, at 24-26. As discussed above, this treatment does not result in undue discrimination.

Despite Clark's attempts to denigrate the importance of the Settlement Agreements, they should be viewed as indications of general agreement in the region that the rates they propose achieve a fair balancing of interests. This is especially true in light of the fact that the Settlement Agreements cover a 5 year transition period toward a fully competitive market.

<u>The Settlement is Supported by the Rulemaking Record</u>

As noted above, the parties urged the Administrator to adopt the Settlement Agreements as a whole. Whether each specified term of each agreement is supported by reasonable and substantial evidence is discussed below. *See* the discussion of the PF rate levels at section 2.6, availability charge at section 11.3.3, and partial load shaping in section 11.2.1.4. Similarly, the discussion of consistency of specified resolutions of transmission issues in the Transmission Settlement Agreement with statutory requirements will be found in Chapter 12.

Regarding unspecified issues, Transmission Settlement Agreement provides:

> Except as otherwise specified in this Transmission Settlement Agreement, the Administrator should establish all other transmission rates in the dockets in the manner proposed by Bonneville in its Supplemental Proposal, including errata, subsequent record revisions, and its subsequent testimony.

Attachment 1, p.3, "Transmission Rates." The parties clearly intended the Transmission Settlement Agreement to be a global settlement of transmission issues. Bonneville's supplemental proposal is found in its supplemental studies, *see generally* Supplemental Transmission Rate Design Study, WP-96-E-BPA-62; Supplemental Segmentation Study, WP-96-E-BPA-59; testimony, *see generally* WP-96-E-BPA-84; WP-96-E-BPA-85; WP-96-E-BPA-86; WP-96-E-BPA-96; errata, WP-96-E-BPA-62(E1); and in transcripts of cross examination. Because Bonneville's supplemental proposal is contained in the rulemaking record, and the parties have agreed that, with regard to issues not specified in the Transmission Settlement Agreement, Bonneville should adopt its supplemental proposal, there is substantial evidence in the record to support the decision.

Decision

The adoption of the proposals embodied in the Settlements is consistent with sound business principles, supported by substantial evidence in the hearing record and comports with all applicable statutory requirements. The Agreements represent substantial regional consensus on the issues addressed in them, including transmission rates and the form of the open-access tariffs to be adopted by BPA. For these reasons, and also based on decisions made in other sections of this Record of Decision, the Settlement Agreements are hereby adopted.

2.6 PF Rate Level

Issue

Whether reducing the PF rate to an average 24.4 mills kWh is substantiated by the record.

Parties' Positions

Clark argues that the settlement rates are too low and will not allow Bonneville to recover its costs. Clark Brief, WP-96-B-CP-01, at 12-15; Clark Ex. Brief, WP-96-R-CP-01, at 10-12.

Parties who signed the Agreements, on the other hand, have urged the Administrator to adopt the Settlements as comporting with law and the record in this case. *See, e.g.*, NIU Brief, WP-96-B-NI-01, at 1; PPC Brief, WP-96-B-PP-01, at 9; Powerex Brief, WP-96-B-BC-01, at 1; PacifiCorp Brief, WP-96-B-PL-01, at 2-3; Requirements Customer Coalition Brief, WP-96-B-RC-01/TC-96-B-RC-01, at 8-9; PGP Brief, WP-96-B-PG-01/TC-96-B-PG-01, at 5. *See also* Or. Tr. 2376, 2388, 2401, 2413, 2422, 2446, 2455.

BPA's Position

Reducing the PF rate to an average 24.4 mills kWh is substantiated by the record, is required to provide competitive rates, and is appropriately based on additional cost cuts made during this case by the Administrator.

Evaluation of Positions

Clark, by virtue of its membership in WPAG, had exhorted BPA throughout the testimony and briefs it submitted in this rate case to become more competitive by, among other things, lowering its rates. Carr, Wolverton, WP-96-E-PP/DS/PA/PG/RC/WA-01, at 4; WA Pr. Brief, WP-96-P-WA-01, at 8. Even so, Clark now, in an apparent effort to derail the rate case settlement, complains as follows: "If the proposed average PF-96 Rate is adopted by the Administrator, it will not generate sufficient revenues to cover the costs of the service being provided as reflected in the record." Clark Brief, B-CP-01, at 13; *see also* Clark Ex. Brief, R-CP-01, at 11. Later, and somewhat ambiguously, Clark concludes: "*Absent further cost reductions,* the PF-96 Rate proposed in the Settlement Agreements will violate Bonneville's statutory due [*sic.*] to set rates at a level reasonably expected to cover the cost of the service provided." *Id.* at 13-14. One could infer from this latter statement that Clark's argument is simply an exhortation to the Administrator to make additional cost cuts to support the settlement rates. However, in its Brief on Exceptions, Clark reiterates its position that Bonneville's adoption of cost reductions are "bare assertion[s]" and are not a substitute for record evidence of cost reductions. Clark Ex. Brief, R-CP-01, at 9. Whatever Clark's motivation, as hereafter demonstrated, reducing the PF rate to an average 24.4 mills kWh is substantiated by the record, is required to provide competitive rates, and is appropriately based on additional cost cuts made during this case by the Administrator. The reduced rate clearly effectuates the Administrator's responsibility under Northwest Power Act section 7(a) to establish rates to recover costs in accordance with sound business principles, 16 U.S.C. § 839e(a)(1).

The record in this case is replete with warnings that BPA must reduce its rates if it wishes to survive as a business. Nearly all of BPA's current sales are at risk from competition because all of BPA's sales are in the wholesale power market. Moorman, Evans, WP-96-E-BPA-65, at 11. Parties representing every segment of BPA's customer base--investor-owned utility, direct-service industry, and public utility--have acknowledged the fact that BPA is faced with an increasingly competitive market and is at risk of losing a significant portion of its sales if it does not charge prices for its products and services that are competitive. *See, e.g.*, Brattebo, WP-96-E-GE/PL/PS-03, at 2; Schoenbeck, Bliven, WP-96-E-DS-01, at 3-4; Drummond, WP-96-E-RC-01; Piper, WP-96-E-RC-05, at 1, 7; Eldridge, *et al.*, WP-96-E-PP-01, at 1-3; Beck, *et al.*, WP-96 -E-WA-01, at 6-11; Carr, *et al.*, WP-96-E-PP/PA-03, at 4. Most have urged BPA to become more competitive if it is to stay in business and collect sufficient revenues to meet its statutory obligations. *See, e.g.*, PPC Brief, WP-96/TR-96-B-PP-01, at 9-11; WPAG Brief, WP-96-B-WA-01, at 2-5; RCC Brief, WP-96-B-RC-01, at 1-5; DSI Brief, WP-96-B-DS-01, *passim*; Piper, WP-96-E-RC-05; Eldridge, *et al.*, WP-96-E-PP-01, at 1-3.

In fact, during the course of this rate proceeding, BPA has continued to lose load notwithstanding the fact that its proposed rates generally represent a significant reduction compared to existing rate levels for most customers. Since BPA filed its initial proposal in July 1995, it has lost approximately 700 aMW of DSI sales to alternative suppliers, and projections of public utility purchases from BPA have been reduced to account for utilities that are actively seeking other suppliers. Moorman, Evans, E-BPA-65, at 6; Supplemental Loads and Resources Study, WP-96-E-BPA-57, at 13; Supplemental Loads and Resources Documentation, Vol. 1, WP-96-E-BPA-57A, at 229. Additional evidence suggested that BPA's proposed rates were above the market price of power, in spite of the significant reduction from their current levels. Carr, *et al.*, WP-96-E-PP/PA-03, at 4; Moorman, Evans, E-BPA-65, at 9; Beck, *et al.*, E-WA-01, at 8; Schoenbeck, Bliven, E-DS-01, at 2.

Clearly, BPA’s sales must be earned through competitive prices and quality, reliable service. “BPA would virtually assure that it would lose some or all of the load from many of these utilities” if BPA cannot deliver competitive rates. Piper, E-RC-05, at 7; see also Eldridge *et al*, E-PP-01, at 3. Failure to meet the competitive challenge will make it increasingly difficult, and ultimately impossible, for BPA to meet its statutory mission, including its cost recovery and Treasury repayment obligations. Moorman, Evans, E-BPA-09, at 26.

During the course of this rate proceeding BPA’s customers, including Clark through its participation in WPAG, urged BPA to redouble its cost cutting efforts. Carr, Wolverton, E-PP/DS/PA/PG/RC/WA-01, at 4; Piper, E-RC-05, at 3; Beck, E-WA-13, at 12; Carr, E-PP/PA-03, at 5. WPAG, which then included Clark, complained that BPA was "providing insufficient attention to cutting its costs, and therefore the overall level of its rates. As a result, Bonneville's customers are even more determined to seek power supply elsewhere, which in turn jeopardizes Bonneville's financial position further and makes repayment of funds owed to the United States Treasury less and less likely."WA Pr. Brief, WP-96-P-WA-01, at 8. This belief that BPA could cut additional costs was fundamental to the discussions that resulted in the settlement proposals.

Outside this rate case, as observed earlier, BPA has been struggling to market its power and to effectively compete. Day to day changes in the utility industry clamor for BPA to position itself to become more competitive for both the short term and the long term. Even as BPA's Draft Record of Decision was being written, one of the Pacific Northwest's lowest cost investor-owned utilities announced a plan to allow a portion of its industrial load to obtain retail wheeling and access alternative power suppliers.

In response to pressures such as these, as well as competitiveness concerns raised in the rate case, the Administrator has acted to cut costs. Section 4.1.2 of this Record of Decision and Appendix A to the Final Revenue Requirement Study, WP-96-FS-02, specify actions taken by the Administrator to cut costs, and thereby to provide more competitive rates. These cost cuts and program level redeterminations have been made on the basis of all information known by and made available to the Administrator. His determination considered and factored in information from BPA's internal budget process, budget revisions submitted by other entities, the rate case (even if the material was stricken), Congressional Hearings, the Congressional budget process, meetings held with customers and interested third parties, and any other source. Implementation of the Northwest Power Act in a timely and businesslike manner warrants this approach.

These cost cuts, as well as the overwhelming record evidence that Bonneville must reduce its rates, provides ample and compelling support for the reduction of the average PF-96 rate to 24.4 mills kWh. The fact that all but a few of BPA's customers support the

Settlement Agreements, with their reduction, well nigh dictate that the reduced rates be achieved unless the law would require otherwise.

Clark's aim appears simply to be to upset the Settlements, as opposed to urging cost cuts by the Administrator to assure achievement of the lower rates, because it complains that the Administrator's cost cuts were not formally entered into the rate case record before this time for consideration. Clark Ex. Brief, R-CP-01, at 10-12. Such a claim must fail for at least three reasons. First, it would defeat the purpose of conducting a Northwest Power Act section 7(i) proceeding. Second, it would perversely preclude reduction of rates based on budget actions that the Administrator has determined, based on business needs faced outside the rate case, must be taken to enable BPA to compete. Third, it ignores the fact that program and budgetary issues are properly determined outside the rate case as a matter of law.

First, a central purpose of conducting a Northwest Power Act section 7(i) proceeding is to enable parties to influence the Administrator's final decision establishing rates. *See*, 16 U.S.C. § 839e(i)(2), (i)(5); *Central Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1119, 1118 (9th Cir. 1982) [hereinafter *Central Lincoln*]. It would border on the absurd to suggest that at the end of a case like this, the Administrator could not adjust his proposal—*i.e.*, reduce rates—in response to the overwhelming chorus that he must do so just because evidence had not earlier been placed in evidence to achieve cost cuts necessary to reduce the rates. As recognized by the Court in *Central Lincoln*, the Administrator must enjoy the freedom to respond to parties' suggestions, and this freedom is "supported by the language of section 7(i)(5), which provides no right of rebuttal for materials 'developed' by the Administrator, presumably in response to received commentary." *Id.*

Second, and related to the first, if the Administrator were to conclude from competitive pressures and other day-to-day business events outside the rate case that Bonneville was facing serious customer losses and must therefore cut costs to better competitively position Bonneville, it would contravene sound business principles to preclude rate reductions based on those cost cuts simply because they were achieved following close of the formal evidentiary record. Northwest Power Act section 7(a) requires that the Administrator establish and revise rates to recover costs "in accordance with sound business principles," and section 9(b) of the Act requires that the Administrator implement the Northwest Power Act in "a sound and businesslike manner." 16 U.S.C. §§ 839e(a)(1), 839f(b). It would be unsound and unbusinesslike to preclude the Administrator from establishing rates based, in part, on cost cuts he, as the head of Bonneville, has determined to make, whenever he determines to make them.

This, then, leads to Bonneville's consistent position that programmatic decisions and program level issues are not properly part of the rate proceeding. The full basis for BPA's position was detailed in the 1993 rate case, and will be incorporated by reference herein, rather than repeated in detail. *See* Administrator's Record of Decision, 1993 Final Rate

Proposal, WP-93-A-02, at 11, 319-329, 333-340 (1993 ROD). Parts of that position will be repeated and summarized here.

BPA's Federal Register Notice of 1996 Proposed Wholesale Power Rate and Transmission Rate Adjustment, 60 Fed. Reg. 36464, 36465 (1995), states that

> BPA's spending levels are developed as a part of its Business Plan, which includes a public comment process. They are also determined as a part of the Federal budget process.
>
> . . . .
>
> Pursuant to Section 1010.3(f) of the Procedures, the Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made which in any way seek to visit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's cost evaluation period of FY 1996 through FY 2001 and its test period revenue requirement for FYs 1997 through 2001. *If, and to the extent, any re-examination of spending levels is necessary, that re-examination will occur outside the rate case.*

(Emphasis added.) This position is supportable as a matter of law and sound business policy.

Section 7 of the Northwest Power Act governs BPA rate proceedings. Section 7(a)(1) requires that rates be set

> to recover, 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 (including irrigation costs required to be repaid out of power revenues) over a reasonable number of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law.

Section 7(a)(1) requires rates to be set to recover costs associated with all of BPA's activities. Programs and program levels are not part of the rate case, but the rates must recover the costs of those programs. BPA interprets section 7 not to allow litigation of those activities, program levels, and budgets in the rate case. 1993 ROD, WP-93-A-02, at 319-329.

While BPA is directed to conduct its business in a sound and businesslike manner, *e.g.*, 16 U.S.C. § 839f(b), and is charged with delivering many products and services, no statutory link is ever drawn between those responsibilities and the ratesetting requirement of the lowest possible rates consistent with sound business principles. Section 5 of the Flood Control Act simply provides in pertinent part that BPA

> shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles, . . . Rate schedules shall be drawn having regard to the recovery . . . of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years.

16 U.S.C. § 825s. Clearly, the incurrence of costs is not the object of this language; rather, the language is directed to the marketing of power and setting rates as low as possible consistent with sound business principles to recover the cost of the power, whatever those costs are. Section 7(a) of the Northwest Power Act—in directing BPA to set its rates to recover its costs—similarly takes costs as a given for the ratemaking process. While section 2(2) of the Northwest Power Act indicates that one of the Act's purposes is to "assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply," 16 U.S.C. § 839(2), that purpose is one of many overarching purposes enunciated in section 2 of the Act, none of which are the "lowest possible rates consistent with sound business principles." It is inappropriate to confuse an economical power supply with a power supply priced at the lowest possible rates consistent with sound business principles.

Section 7(a) of the Northwest Power Act's ratemaking requirements provides that rates shall also be established in accordance with the requirements of section 9 of the Transmission System Act and section 5 of the Flood Control Act of 1994. 16 U.S.C. § 839e(a)(1). Section 9 of the Transmission System Act requires in part that BPA set rates having regard to the recovery of its costs and "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 . . . ." 16 U.S.C. § 838g. As previously noted, the Flood Control Act is similarly worded. 16 U.S.C. § 825s.

However, the statutory requirements that BPA "establish" or "periodically review and revise" or "fix and establish" its rates "at the lowest possible rates to consumers consistent with sound business principles," cannot be read as concerning anything more than just that, the establishment of rates. 16 U.S.C. § 838g; 16 U.S.C. § 839e(a)(1). The rates can be no lower than would be consistent with sound business principles. 16 U.S.C. § 838g. In addition, rates are to be established to "recover, in accordance with sound business principles, the costs" financially borne by BPA. 16 U.S.C. § 839e(a)(1). Recovering the costs is, however, a matter separate from the incurrence of the costs.

The decisions made by the Administrator outside the rate case to cut costs constitute fundamental management decisions as to how best to conduct BPA's multiple affairs in light of the current and reasonably foreseeable financial, political, and operational situation of BPA and the region. Issues of competitiveness and keeping costs as low as possible have played an important role in the determination of what program costs to cut, and how far. Factors also considered by the Administrator in making those program cuts included such judgmental matters as increasing financial, economic, and environmental uncertainties; providing the services expected and demanded by BPA's customers and the region, while maintaining competitive rates; the demands on BPA's existing resources; BPA's environmental commitments to protect and enhance the region's natural resources; the need and desirability of program stability; and the need to increase overall confidence in BPA's financial soundness. These are all matters of judgment that clearly fall within the penumbra of implementing the Northwest Power Act in a sound and businesslike manner. However, these matters cannot be said to constitute matters of "establishing rates" under section 7(i) or as defined in the *Procedures Governing Bonneville Power Admin. Rate Hearings*, section 1010.2(j), 51 Fed. Reg. 7611 (1986).

Decision

Reducing the PF rate to an average 24.4 mills kWh is substantiated by the record, is required to provide competitive rates, and is appropriately based on additional cost cuts made during this case and outside this case by the Administrator.

2.7 Five-Year Rates

Since passage of the Northwest Power Act, BPA has developed its power rates for a two-year term, except for its Surplus Firm power rates. Power rates also have included a mechanism to allow for an interim adjustment if costs or revenues deviated from those expected when the rates were developed. In the 1996 rate proposal, BPA is breaking from tradition and developing rates for a 5-year period, except for the Firm Power and Services (FPS) rate, which is proposed for a 10-year term. BPA also is proposing not to include any interim adjustment mechanism in its rates. BPA proposes to develop rates for more than a two-year term in order to better compete and in response to customers' need for price certainty and stability over a longer time horizon. Moorman, Evans, E-BPA-09, at 29. BPA's sales are entirely at the wholesale level and thus are not protected by franchise rights or service territory grants by state law. Tr. 336. As PPC warns, "in order for BPA to continue to thrive in this competitive environment, it must provide power and transmission products and services at prices that its customers are willing to pay *over an extended period of time*." Eldrige, *et al.*, WP-96-E-PP-01, at 2 [emphasis added].

In response to its customers' need for price certainty, BPA initially proposed optional 5-year Priority Firm Power (PF), Industrial Firm Power (IP), and New Resource Firm Power (NR) rate schedules, in addition to its traditional 2-year rate schedules. Metcalf, *et al.*, WP-96-E-BPA-18, at 2-6. The rates offered in the 2- and 5-year rate schedules were the same, but the 5-year rates were available only to customers making a corresponding 5-year purchase commitment. *Id.* Due to customers' positive response to the longer term rate and a desire to simplify the rate filing, in its supplemental proposal BPA eliminated the dual rate schedules, and instead proposed to establish the PF, IP, and

NR rates for a 5-year rate period. Metcalf, *et al.*, WP-96-E-BPA-74, at 2-3. Although BPA eliminated the dual rate structure, it did not eliminate the condition of a contractual purchase commitment to lock in the rate for the 5-year period. *Id.* If a customer does not make a 5-year purchase commitment, BPA retains the discretion, if needed, to revise the rates during the 5-year period. *Id.* As BPA witnesses testified, if the rates are performing satisfactorily, there may be no need to revise them before the end of the 5-year period. Id. In that case, customers would continue to purchase under the 1996 rates until the rates were revised, even without a contractual commitment. *Id.*

In addition to proposing longer term rates, BPA proposes not to include any provisions for interim rate adjustments in its rate schedules, which will increase the rate certainty for its customers. Metcalf, *et al.*, E-BPA-18, at 2-6; Arnold, *et al.*, WP-96-E-BPA-15, at 4-5. Customers who commit to purchase power from BPA for five years also will be able to lock in the price for all of the supporting services for that term, such as transmission and load shaping. Buchanan, *et al.*, WP-96-E-BPA-11, at 12.

Most of BPA's public utility and cooperative customers applaud BPA's proposal to put in place a 5-year rate without an interim rate adjustment. Nelson, WP-96-E-RC-02, at 6; PPC Brief, WP-96-B-PP-01, at 11; Saven, WP-96-E-NI-02, at 13-14. The Northwest Irrigating Utilities (NIU) believe that including a mandatory rate adjustment would lessen BPA's attractiveness as a business partner. As stated by RCC, "BPA's offer of five-year rates is in direct response to customer appeals for rate certainty over time. . . . BPA's five year-rate offer, without the possibility of an interim rate adjustment, tells customers that the agency is making a serious effort at not only offering competitive rate *levels*, but competitive *terms*." Nelson, E-RC-02, at 6 [emphasis in original].

Locking in a rate for five years entails risks, so BPA has attempted to mitigate and share the risk by requiring a 5-year purchase commitment. While BPA is willing to take the necessary steps to manage its costs to mitigate the cost uncertainties, BPA is unwilling to take on the revenue risk of significant load loss and thus needs some load certainty to lock in its rates for five years.

The Power Settlement Agreement preserved BPA's ability to adjust its rates absent a contractual purchase commitment by the customer. The Power Settlement Agreement states:

> Notwithstanding any other provision in this Power Settlement Agreement, nothing in this Power Settlement Agreement is intended to alter in any way any authority and responsibility of the Administrator's to periodically review and revise, whether during or following the five-year rate period (October 1, 1996 through September 30, 2001), the Administrator's power and transmission rates so that they meet statutory requirements, including but not limited to any requirement that the Administrator's rates recover costs.

Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128.

The Power Settlement Agreement also recognizes BPA's contractual obligations. The Power Settlement Agreement states that "[n]othing in this Power Settlement Agreement amends any contract . . . ." *Id.* As such, if BPA's ability to adjust its rates is limited by the contract, the Power Settlement Agreement would not disturb that limitation. Thus, if a customer executes a contractual purchase commitment for five years in exchange for BPA's waiver of its rights to change the rate during that five years (thereby locking in BPA's power and transmission rates for five years), the contract, not the Power Settlement Agreement, controls BPA's ability to adjust this customer's rates.

The Administrator's authority and responsibility to adjust BPA's power and transmission rates during the 5-year rate period is clearly stated in the Power Settlement Agreement. All signatories to the agreement agreed to this provision. Notwithstanding the Power Settlement, PPC argues that regardless of the Administrator's authority to adjust rates, "consumer-owned utilities expect that the five-year rate will not be subject to change during the course of the rate period." PPC Brief, B-PP-01, at 12. BPA understands its customers' desire for rate stability. BPA also recognizes that it must take actions now to control costs. Moorman, Evans, E-BPA-09; Moorman, Evans, WP-96-E-BPA-65. The 5-year rates may be sufficient for the 5-year period without any purchase commitments by BPA's customers. In this situation, BPA would not expect to adjust the rates during the 5-year period. Metcalf, *et al.*, E-BPA-74, at 2-3. If BPA loses substantial load during that time, however, BPA may be forced to raise its rates. In effect, the purchase commitment is a necessary element for BPA to lock in its rates for a 5-year period. To the extent consumer-owned utilities execute a contractual purchase commitment for the 5-year period, their rates will not be subject to change during that period. *Id.*

Because the purchase commitment, in effect, defines the purchase relationship between BPA and its customers, the nature of the purchase commitment is not defined in the rate schedules but will be developed through negotiations with purchasers willing to make a purchase commitment. RCC initially complained that as part of the contract negotiations, BPA was requiring a certain level of load commitment, and other terms and conditions, in exchange for providing 5-year rate certainty. Nelson, E-RC-02, at 6. WPAG raised the same complaint that BPA was demanding a high level of load commitment in exchange for the stability of its 5-year rate. Beck, *et al.*, WP-96-E-WA-13, at 7. In fact, WPAG argued that since the load commitment is a "precondition" to obtaining service under the 5-year rate, it should be included in the availability section of the rate schedule. *Id.* at 86. Both WPAG and RCC claim that by asking for a load commitment in exchange for price stability BPA is imposing conditions on its rate offer that are not imposed by other suppliers. Beck, *et al.*, E-WA-13, at 7; Nelson, E-RC-02, at 6. Nevertheless, WPAG recognizes that securing a purchase commitment from public agency customers is necessary for BPA and for successful implementation of the rate settlement. Or. Tr. 2427. BPA is currently involved in contract discussions with these customers as to the nature of the purchase commitment. BPA remains hopeful that by continuing the discussions and negotiations with its customers, the parties can reach an agreement on the nature of the commitment. However, BPA will not resolve load commitment issues as part of the rate case. Metcalf, *et al.*, WP-96-E-BPA-105, at 28. The nature of the commitment is a contract issue and should not be resolved in the rate case. *Id.* Perhaps the parties, upon reflection, now recognize the advantages associated with resolving the commitment through the contract negotiations. Neither of these parties pursued this issue on brief, and as such, the issue is not addressed here.

3.0 LOADS AND RESOURCES

3.1 Introduction

BPA's Loads and Resources Study provides an overview of BPA's load forecasting process and Federal system resources used for BPA's 1996 wholesale power and transmission rate proposals.

3.1.1 Loads

BPA's load forecasts are developed by analyzing the expected firm electric power requirements of the Pacific Northwest and projecting what "share" of these requirements BPA will serve. The BPA loads are grouped by customer class. BPA's major customer groups are as follows: (1) the non- and small-generating public utilities (NSGPUs); (2) the generating public utilities (GPUs); (3) the IOUs; (4) the DSIs; (5) the contract Federal agencies; and (6) the United States Bureau of Reclamation (USBR).

Standard econometric techniques are used to estimate simple forecasting equations for both NSGPU and GPU regional loads. The IOU regional load forecast used in this rate proposal was produced by BPA in 1993. This long-term forecast updated the economic assumptions from the forecast jointly produced by the staffs of the BPA and the Northwest Power Planning Council in April of 1991, and also used a modified version of the residential sector model. The aluminum DSI load forecast is based on an aluminum price forecast, estimated smelter production costs, and other factors affecting smelter operation and load placement on BPA. The non-aluminum DSI forecast is based on information collected on historical, current, and future operating schedules; plant technology; expected economic and market conditions; and load placement on BPA. The contract Federal agency forecasts are developed by BPA District Offices in cooperation with each Federal agency. Finally, the USBR load requirements are provided by the USBR.

BPA's forecasts of regional loads by customer group are used as the basis for forecasting total Federal system firm loads. Total Federal system firm loads are comprised of BPA's firm DSI load, sales to other Federal agencies, current obligations and projected sales to regional public agencies, and Federal transmission losses. The remaining portion of the projected total Federal system load is comprised of BPA's obligations to the IOUs under their power sales contracts, and other inter- and intra-regional contractual obligations.

WPAG testified that BPA's public utility load forecast is too high, given the potential load reduction that could occur, evidenced by recent Firm Resource Exhibit (FRE) submittals. Beck, *et al.*, WP-96-E-WA-13, at 10-11 and 14. BPA filed testimony disagreeing with WPAG's testimony and stating that in developing its load forecast, BPA reasonably accounted for load growth, FREs accepted based on the 1994 Whitebook deficit, FRE waivers granted through the 1995 rate case settlement process, and additional utility resource diversification that BPA expects will occur. Lee, *et al.*, WP-96-E-BPA-118, at 2. In the same testimony, BPA stated that it might revise the final load/resource study to reflect any new information from the negotiation process BPA was engaged in with its public utility customers. *Id.*

For the final study, BPA proposes to decrease its forecast of GPU purchases to incorporate load loss for this group of utilities. Additional load loss is projected, based on current market information. In BPA's supplemental proposal load forecast, BPA had assumed that GPU customers would purchase power under new contracts instead of the existing 1981 Contracts. For BPA's final study, it is assumed that GPU customers would purchase power under their 1981 Contracts. *See* chapter 10, *infra*. BPA believes that its forecast of public utility purchases for the final study will adequately reflect the potential load reduction that could occur by these utilities within their rights under the 1981 Contract. Because the load commitment negotiations were not at a definitive stage when the load forecast for the final rate proposal was completed, BPA is not basing the final load and resource study on the outcome of those negotiations. Neither WPAG nor any other party submitted surrebuttal testimony on this issue, nor did any party raise this issue in its initial brief. Therefore, pursuant to the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611, § 1010.13(b) (1986), the issues are waived.

BPA also prepared an unbundled products forecast. For GPU, NSGPU, and Federal agency customers, the forecasted unbundled products include Full Load Shaping, Partial Load Shaping, Load Regulation, and Control Area Reserves for Resources. For DSIs, the unbundled products forecast includes DSI Load Shaping, Load Regulation, and Shaping Services. Forecasts of unbundled product purchases by the public utilities and DSIs were developed based on knowledge of these customers' current and future power sales contract arrangements and on available information on customer demand for these products. In addition, forecasts were developed using the proposed billing factors for the products. The unbundled product forecasts for the GPU and NSGPU customers have been revised since the forecasts used in BPA's supplemental proposal. The load shaping forecasts were revised to incorporate the new assumption regarding GPU power purchases under the 1981 Contracts instead of 1996 Contracts. Under the 1981 Contract, Metered and Actual Computed Requirements customers must purchase the load shaping product, while it is an option under the 1996 Contract. The changed assumption regarding contracts increased the load shaping forecast. The load shaping forecast was also adjusted downward to reflect revised estimates of the load qualifying for an industrial exemption. No issues were identified regarding the unbundled products forecast.

3.1.2 <u>Resources</u>

The Pacific Northwest regional resources are comprised of generating resources operated or being built by Federal entities, public agencies, IOUs, and independent power producers. BPA markets power generated by federally owned hydro resources and several non-federally owned resources, including the Washington Public Power Supply System Nuclear Plant No. 2 (WNP-2); Packwood Lake; City of Idaho Falls Bulb Turbine hydro project; Lewis County PUD's Cowlitz Falls hydro project; and Mission Valley's Big Creek hydro project. BPA's available firm resources also include short-term power purchases, exchange energy from capacity/energy exchanges, and non-utility generation from several sponsored small wind and hydro projects . No issues have been identified regarding BPA's forecast of resources.

3.2 Hydroregulation Studies

The hydroregulation studies demonstrate the energy production that can be expected from the Pacific Northwest hydro system when operating in a coordinated fashion. BPA modeled the hydro system using updated project data and operating requirements consistent with those included in Pacific Northwest Coordination Agreement (PNCA) planning. The operating requirements include flow augmentation constraints from the National Marine Fisheries Service's (NMFS's) Biological Opinion (BO), dated March 2, 1995. The hydro system was modeled using 50 years of historical streamflows, modified to reflect current irrigation levels. The system was modeled in two stages. The first stage, an Actual Energy Regulation (AER) type study, determines 50 years of contractually allowable draft at hydro projects, consistent with the PNCA. This stage operates the coordinated hydro system to meet the coordinated system's FELCC. All hydro projects are operated to meet these loads except for the Canadian hydro projects, which are operated according to the Canadian Treaty Assured Operating Plan (AOP). The second stage, an Operational type study, determines 50 years of expected system operations as well as hydro generation. This stage operates the coordinated hydro system to estimated regional firm loads. However, while meeting the regional load, non-Federal projects are kept to their AER operation and all operation changes occur at Federal hydro projects. Running the study in two stages is a change from the initial proposal, which used only an Operational type study. This change is consistent with BPA's supplemental proposal testimony. Misley, Davis, WP-96-E-BPA-68, at 3.

Each of the five study levels of load development, 1997 through 2001, were run through these two steps. The 1997 studies were run with reservoirs starting nearly full, based on recent 1996 runoff information. All other study levels, 1998 through 2001, were run in a "continuous" mode, reflecting no available information about 1997 through 2000 runoff.

As in the initial proposal, BPA's Loads and Resources Study uses the 1930 water conditions from the Operational step of the hydro studies to estimate the firm energy available on the system during the critical period. The 1930 water conditions were used for the analysis because of the similarity to the critical period conditions and to simplify the rate analysis process.

The Operational step of the hydro studies determines the amount of nonfirm energy that is available on the system over 50 water years, as well as system deficits, for which spot market purchases are made. This portion of each study was input into the Federal Secondary Energy Analysis (FSEA), which determines by month the secondary energy, adjusted for interchange between the Federal system and other non-Federal utilities, that will be available from Federal system hydro projects. The FSEA results were then used in the Nonfirm Revenue Analysis Program (NFRAP) to determine nonfirm energy sales and revenues.

3.3 Forecasted Prices of Natural Gas

Issue

Whether BPA should update its forecast of natural gas prices.

Parties' Positions

No party raised this issue in their briefs. Because BPA is proposing to update its forecast, however, it is being addressed as an issue.

BPA's Position

BPA proposes to incorporate an updated gas price forecast in its final studies.

Evaluation of Positions

BPA's annual natural gas price forecast is based on the expected long-term equilibrium price for gas delivered to pipeline at Ignacio, Colorado, and the previous year's price. In the Supplemental Proposal, each year's forecast was composed of 60 percent of the previous year's price and 40 percent of the long-term equilibrium price. Bolden,*et al.*, WP-96-E-BPA-80, at 15. BPA forecasted that it would take five years for gas prices to recover from cyclical lows and reach the long-term equilibrium price. Id. at 17. BPA's current natural gas forecasts are lower than the forecasts contained in BPA's supplemental proposal. BPA now projects that gas prices will reach an equilibrium price of $1.23/MMBtu around 2005. The decline in the price projections results primarily from persistently low western supply basin prices that suggest lower long-term equilibrium prices and the likelihood that prices will take a longer period to reach equilibrium levels.

One factor contributing to low natural gas prices, both current and projected, is abundant supply. United States natural gas production rose 6 percent from 1990 to 1994, despite relatively low prices. During the same period, imports increased by over 15 percent. In 1994, Canada exported 50 percent of its production to the United States, an increase of 13 percent over the prior year's level. Imports of Canadian gas represented about 13 percent of United States natural gas consumption in 1994. During the past two years, imports from Canada provided about 40 percent of gas consumption in California, Oregon and Washington. United States gas production and imports are expected to continue to increase. For the next several years, growth in gas demand in the United States could be met by increased production from the Gulf of Mexico as well as onshore Gulf Coast supplies. This would be a shift from the trend of the early 1990s when the growth in demand was almost exclusively met by higher production in western producing basins.

The average wellhead price of natural gas in the United States declined 7 percent from 1990 to 1995. Greater declines occurred at western delivery points. For example, the price at Ignacio, Colorado declined 29 percent and at Sumas, Washington 22 percent. These declines provide evidence of the increasing separation of eastern and western North American gas markets, which is largely a result of a surplus of natural gas in the West and limited pipeline capacity to transport this gas east. On the national level, for the near term, the natural gas futures market suggests that future natural gas supplies will be adequate relative to expected demand. However, the western region is projected to remain in surplus until either increases in regional gas demand or increased pipeline capacity brings the region closer to balance.

In addition, the changing natural gas market structure puts continuing pressure on the natural gas industry to cut costs and improve efficiency. Deregulation has reinforced cost-cutting measures, put downward pressure on margins and created additional opportunities for both buyers and sellers. As noted in the Natural Gas Long-Term Report, Fall/Winter 1995 published by the WEFA group, "In recent months, several market and pooling centers have sprung up offering end-users an array of services designed to provide greater access to supplies from diverse locations. Although the dominance of the spot supplies has increased the market's exposure to the risks of price fluctuations in a commodity market, end-users can now hedge against such risks through judicious use of the futures contracts and/or the interstate storage facilities."

The reduction in the gas price forecast is also consistent with positions taken by other natural gas forecasting organizations. The Energy Information Administration (EIA) has lowered its natural gas forecast significantly; the 1996 EIA projections of lower 48 wellhead prices for natural gas are 38 percent lower for the year 2010 than its 1995 projections.

The EIA noted in the document Annual Energy Outlook 1996, "EIA forecasts of oil and gas wellhead prices have varied over the past several years, with differences resulting from changes in assumptions and data based on updated information. The significant drop in natural gas wellhead prices between the 1995 and 1996 forecasts is based on a variety of factors, including a reassessment of the resource base and a determination that the impact of technology on the economics of offshore drilling will be greater than previously assumed . . . . Although the undiscovered resource base has not changed significantly, the inferred resource base as assessed by the U.S. Geological Survey has increased substantially. Higher levels of inferred reserves allow for more sustained recovery from known fields, which in turn leads to lower wellhead prices."

Given this information, BPA's new, lower gas forecast should be incorporated into the rate case. Including the updated forecast should result in more accurate projections of natural gas prices and consequently more accurate projections of BPA's revenues and expenses.

In its brief on exceptions, the Public Generating Pool (PGP) notes that the draft ROD did not state either the new long-term equilibrium price or the time when BPA expects gas prices to reach the long-term equilibrium price. In addition, PGP argues that the evidence on which BPA relies for its new gas forecast is not on the record, and therefore that BPA's introduction of the new forecast is a violation of due process. PGP Ex. Brief, WP-96-R-PG-01, at 18 n.2 & 20-21.

The new long-term equilibrium price and BPA's projection of the time needed for prices to reach equilibrium are included in the Final Wholesale Power Rate Development Study. BPA has also included these projections in the Final ROD.

In its direct testimony, the PGP urged BPA to adopt a lower natural gas price forecast. The PGP argued that BPA's Power Marketing Decision Analysis Model overstated marginal costs because it "use[d] forecasts of natural gas prices that include a 40 percent increase real [sic] in prices over the next two years. We have seen no other projection of increases in real gas or oil prices that approach BPA's forecast." Wolverton, *et al.*, WP-96-E-PA/DS/PG-01, at 4. Other parties also concluded that BPA's forecast of nonfirm revenues, which depend on gas prices, was too high. On cross-examination, a number of BPA's witnesses were asked whether BPA intended to substitute a more up-to-date forecast when it calculated final rates. In response, BPA testified that "prices are lower than what we expected at the time that we prepared this forecast [of nonfirm revenues] for the supplemental proposal. And if those conditions were to continue for the next five years, then it's very likely that our forecast that we have on the record is optimistic." Tr. 1582. BPA then testified as follows:

> Q. And are you planning to re-evaluate that forecast before you determine what prices for non-firm to include in the final proposal?
>
> A. Well, there's certainly that information out there about what should the market assumptions be, proposals as to what those market assumptions should be, and we're definitely going to review that information.
>
> Q. And if you conclude that a reduction is appropriate, you'll include it in the final?
>
> A. Yes.

Id.

Another BPA witness testified that BPA did not expect market prices for power to improve during the rate period. He then testified as follows:

> Q. And are you, in fact, projecting that the market from Bonneville's perspective will get worse during the rate case?
>
> A. I think we've already indicated at the moment some prices appear to be lower than we thought they were when we wrote the testimony. When we put together the final rates, we'll be looking again at what we think the markets are going to be.

Id. at 352.

Thus, in its testimony BPA indicated that, when it calculated final rates, it would be updating its projections of market prices and power sales revenues, both of which depend critically on natural gas prices. Participants in the electric utility business are aware that electric power prices and natural gas prices are inextricably linked, and that an update in the former presupposes an update in the latter. *See* Bolden, *et al.*, E-BPA-80, at 14. The PGP criticized BPA's natural gas price forecast because BPA's projections of higher gas prices caused increases in marginal cost and consequently in electric power rates. Wolverton, *et al.*, E-PA/DS/PG-01, at 5-6.

BPA must set rates in accordance with sound business principles to recover the costs associated with the acquisition, conservation, and transmission of electric power. 16 U.S.C. § 839e(a). In order to do so, BPA must make reasonable forecasts of its costs and revenues. BPA's initial proposal in this case was filed July 10, 1995, proposing rates to become effective October 1, 1996, more than one year later. Since last July power markets have undergone substantial evolution. *See infra* § 8.2.2, Parts I(C)(1) and I(D). BPA's supplemental proposal was filed in December 1995, still almost a year before rates were due to take effect.

The length of BPA's rate case process virtually ensures that significant changes will occur before the process is completed. Unless BPA can update its studies, it may be unable to base its rates on reasonable forecasts of revenues and costs. In this instance, BPA has lowered its gas forecast significantly. Had BPA not done so, its forecast of revenues from nonfirm power sales would have been overstated significantly, and BPA would be unlikely to recover its costs during the rate period. The parties raised this prospect during cross-examination of BPA's witnesses in February and March, and BPA indicated that it would be updating its forecasts to ensure that they were based on the most accurate and up-to-date information. The parties' questioning demonstrates their understanding that BPA must base final rates on the best information available.

BPA put the parties on notice that it would be updating its nonfirm revenue forecasts, and consequently its forecast of natural gas prices. BPA made many changes between its initial and supplemental proposals; it could not change its gas forecast until it was convinced that its initial forecast was too high and needed to be updated. Once this became clear, BPA's choice was to knowingly set rates based on an outdated forecast, thus jeopardizing its cost recovery, or to update its forecast. Under the circumstances, BPA chose the appropriate course.

Decision

BPA will incorporate its updated gas forecast in its final studies. This update should result in a more accurate forecast, and consequently more accurate projections of BPA's revenues and costs. In its testimony BPA put the parties on notice that, when it calculated final rates, it would be updating its forecast of revenues from nonfirm power sales, and hence its natural gas forecast. BPA's alternative was to knowingly base rates on an innacurate forecast, and thus jeopardize its cost recovery.

4.0 REVENUE REQUIREMENTS AND RISK ANALYSIS

4.1 Introduction

BPA is a self-financing power marketing agency within the United States Department of Energy. Sales of electric power and transmission services provide BPA's primary sources of revenue. *See Central Lincoln Peoples' Utility District v. Johnson,* 735 F.2d 1101, 1116 (9th Cir. 1984). BPA's power and transmission rates must produce revenues sufficient to assure repayment of all Federal investments in the FCRPS over a reasonable number of years after first meeting the Administrator's other costs. 16 U.S.C. § 832g & 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. *Id.* § U.S.C. 839(a)(1). The Revenue Requirement Study determines the level of revenue required to recover all costs of acquiring, conserving, and transmitting electric power, including the repayment of the Federal investment in the FCRPS (including irrigation assistance) over a reasonable number of years, and all other costs and expenses incurred by the Administrator pursuant to law. *See* Revenue Requirement Study, WP-96-FS-BPA-02.

4.1.1 Revenue Requirement Development

BPA has continued to develop generation and transmission revenue requirements in conformance with the financial, accounting, and ratemaking requirements of the Department of Energy's Order No. RA 6120.2. In compliance with a FERC Order dated January 27, 1984, BPA determines separate revenue requirements for generation and transmission. *United States Dep't of Energy--Bonneville Power Admin.*, 26 FERC ¶61,096 (1984). Each revenue requirement, in turn, is comprised of two parts. First, a repayment study is prepared for each function to determine the projected annual interest expense and amortization payments on the Federal investment. These studies are conducted for the rate test period and extend through the repayment period. Second, projections of annual operating expenses of the FCRPS and planned net revenues are compiled and functionalized to the generation and transmission functions of the FCRPS. Planned net revenues may be included in revenue requirements to cover projected annual cash requirements and to satisfy the Administrator's financial objectives. Revenue Requirement Study, FS-BPA-02, § 4.1.1.

A cost recovery demonstration is conducted for each function, consisting of two important tests. First, revenues must be sufficient to recover all planned annual accrued expenses and annual cash requirements associated with BPA's financial objectives. Second, revenues must be sufficient to repay the Federal investments within their allowable repayment periods. These tests must be satisfied in both the generation and transmission functions for each year of the rate test and repayment periods. Since revenues from current rates fail to meet these tests (*see* Revenue Requirement Study, FS-BPA-02, § 4.2, Tables 10A-B through 14 A-B and 15 A-C), a plan must be developed to satisfy cost recovery and repayment requirements. The plan may include an adjustment to rates and/or reductions in costs. *See* Department of Energy (DOE) Revised Order RA 6120.2, "Power Marketing Administration Financial Reporting" (Sept. 20, 1979). The revenue requirements in the current revenue test already include substantial cost reductions. A rate increase to address this underrecovery would be counterproductive under prevailing market conditions. BPA's sustainable revenues analysis shows that if BPA simply extended or increased its current (FY 1996) rates through the five-year rate period, substantial load loss would occur. This would result in a very large decrease in BPA revenues. *See* Moorman, Evans, WP-96-E-BPA-09, and Moorman, Evans, WP-96-E-BPA-65. There is virtually no chance that BPA would recover its costs and be able to repay Treasury each year during the rate period if the current rates were extended. Therefore, BPA's plan to satisfy cost recovery and repayment requirements entails a decrease in power rates and an increase in transmission rates.

4.1.2 Spending Level Development

The process used to develop the spending levels in BPA's revenue requirements stems from the Competitiveness Project, which BPA initiated in 1993 in response to fundamental changes in the electric utility industry. The project was launched because of BPA's growing realization that its ability to meet its statutory mandates was threatened by increasing costs, decreasing revenues, and the possibility of losing customers to fast-emerging and low-cost competition. The goal of the Project was to "reinvent" the agency to make it more customer-focused, cost-conscious, and market-driven.

As a part of the Project, BPA developed a Strategic Business Plan. The Business Plan is the result of a comprehensive effort to integrate long-term strategic plans of BPA's programs with a strategic financial plan, setting the overall direction for both serving BPA's customers and meeting BPA's financial and legal responsibilities. The Business Plan includes new statements of BPA's mission, values, and strategic business objectives to guide BPA's activities. Spending levels were determined as a part of the development of the Business Plan, and included expense and capital program spending levels for BPA programs and the power portion of the Corps of Engineers, Bureau of Reclamation, and U. S. Fish and Wildlife Service (USFWS) programs, as well as for non-Federal programs such as the Supply System, for FYs 1994 through 2002. The spending levels were developed taking into account already-mounting competitive pressures and BPA's cost-recovery imperatives.

BPA published a draft Business Plan in June 1994 that included preliminary spending levels. BPA encouraged written comments on all aspects of the draft Business Plan. Meetings to take public comments were held in Coeur d'Alene, Seattle, and Portland in August and September of 1994. BPA set spending level parameters in September 1994, which included reductions in spending levels from those released in June 1994, based on public comments and BPA's then-current assessment of the increasingly competitive marketplace. BPA organizations then developed budgets based on the lower spending level parameters.

The Business Plan called for a fundamental change in BPA's approach to determining spending levels. Previously, BPA's practice was to develop budgets "from the bottom up." Each sub-organization would develop its own budget in detail, then organizational budgets would be compiled into a total BPA budget. Now a "top down," strategic approach to budgeting calls for BPA's senior managers to determine broad spending ceilings for each year taking into account competitive pressures, statutory, contractual and other program requirements, and financial policy objectives, including cost recovery imperatives. It also involves a new approach to capital budgeting, in which capital decisionmaking is based on review of all projects through a portfolio approach using BPA-wide fiscal and non-fiscal ranking criteria.

On January 12, 1995, a public briefing was held to address Business Plan issues and to communicate proposed spending levels, including some additional cost reductions. At this meeting BPA executives clarified and encouraged discussion and input on both the draft Business Plan and proposed spending levels. In addition to providing additional data, BPA executives identified people at BPA who could provide further detail and answer follow-up questions on spending levels. Attendees at the meeting were encouraged to contact BPA Account Executives to obtain additional information on the Business Plan and spending levels, and to provide the Account Executives with any further comments and recommendations on the spending plans.

After the January 12 briefing, BPA announced that it planned to reduce the expenses presented at the briefing by $40 million. Subsequently, due to increasing market pressures, BPA determined that further cost reductions were essential. It was decided that expenses needed to be reduced from the January 12 spending estimates by an average of $250 million per year for FYs 1996-2000. Additionally, FY 2001 revenue requirements were to be reduced by $350 million. BPA then engaged in its new, strategic, top-down budget process to establish broad spending ceilings for programs and organizations, and to begin specifying where major cuts would fall. Because the budget process was not completed before BPA finished its 1996 initial rate proposal, the Revenue Requirement Study for the initial proposal included the total expense cut in each function as an "undistributed reduction," that is, as a lump-sum expense decrease in revenue requirements for each year. The undistributed reduction averaged $298 million per year for the rate period. *See* Supplemental Revenue Requirement Study, WP-96-E-BPA-58, at 18; DeWolf, *et al*., WP-96-E-BPA-69, at 8. In August 1995, BPA's budget process identified major program and organizational cuts for all but $13.7 million per year of the targeted average reduction of $298 million per year. The August 1995 spending level process was the basis for the 1996 supplemental proposal revenue requirements, which included a $13.7 million undistributed reduction. *See* Revenue Requirement Study, E-BPA-58, at 18; DeWolf, *et al*., E-BPA-69, at 8.

In January 1996, despite all the cost reductions previously identified, BPA forecasted a potential gap of up to $200 million per year between projected revenues and the projected expenses included in the supplemental rate proposal. To ensure that rates would be competitive and that costs would be recovered, BPA determined that it would have to reduce spending levels even further. In rebuttal testimony, BPA witnesses indicated that BPA was in the process of reviewing and revising the spending levels included in the supplemental proposal. Although BPA had not yet determined where this round of changes in spending levels would be made, the decisions would be reflected in the final proposal revenue requirements. DeWolf, *et al.*, WP-96-E-BPA-101, at 2. BPA anticipated that the budget review would conclude in March 1996. Tr. 492.

In March 1996, BPA revised spending levels to further reduce operating program expenses by about \$70 million, capital outlays by about \$40 million, and overhead costs by about \$25 million from supplemental proposal levels. Then, in April, BPA determined that it was prudent to reduce transmission system development and replacements investments by an additional \$75 million over the rate period, or an average of \$15 million in each year. The net effect of these cuts and some offsetting adjustments result in a reduction in revenue requirements of an average of \$3 million per year in the generation function, and \$51 million per year in the transmission function, from levels in the supplemental proposal. *See* Revenue Requirement Study, WP-96-FS-BPA-02, § 4.3 and Appendix A.

BPA also has taken other actions for the final proposal that have the effect of lowering revenue requirements or increasing revenues, including:

(1) Accessing excess funds in the Supply System WNP-1 Construction Fund to cover a portion of net billing requirements in FY 1997. Funds in excess of expected site restoration costs will be used to cover a portion of net billing requirements that BPA would otherwise pay from current revenues. This use of the Construction Fund, which will be reflected in future WNP-1 Supply System budgets, is expected to produce \$72 million in savings in 1997 in the generation function.

(2) Accessing the Fish Cost Contingency Fund (FCCF). An agreement between the Administration and members of the Northwest Congressional delegation calls for establishment of this fund, consisting of credits available to BPA, but not yet used, for fish and wildlife expenditures that BPA has already paid on behalf of non-power purposes of the dams under the provisions of section 4(h)(10)(C) of the Northwest Power Act of 1980. The agreement allows BPA access to the credits under specified conditions, to be used against its cash transfers to the U. S. Treasury. BPA projects that credits received from the FCCF will average about \$23.5 million per year on a probabilistic basis, a total of \$118 million for the 5-year rate period. These annual credits are treated as increases in power revenues in the final proposal. This is the same accounting treatment applied to section 4(h)(10)(C) credits described in the March 1995 cost-sharing arrangement between BPA and the Administration. DeWolf, *et al.*, WP-96-E-BPA-14, at 7, lines 8-11. *See also infra* § 10.4.2; Revenue Requirement Study Documentation Volume 1, WP-96-FS-BPA-02A, Chapters 13 and 14; DeWolf, *et al.*, E-BPA-69; Arnold, *et al.*, WP-96-E-BPA-71; and Wholesale Power Rates Development Study, WP-96-FS-BPA-05, § 5.2.8.

(3) Applying updated interest rate forecasts, based on projections of a continuing decline in Treasury yield curves. The new forecasts reduce projected interest expense on long-term BPA borrowing and appropriations repayment obligations in both functions, and on a small amount of non-Federal debt for WNP-2 capital additions. This is expected to produce total average savings of $5-6 million in each year.

(4) Consolidating Supply System Trustees. The Supply System has re-negotiated its trustee contracts for WNP-1, -2, and -3, and has consolidated the trustee functions under one trustee. Estimated savings are $5 million over five years in generation.

(5) Reducing the amount of revenue financing for BPA transmission investments from $150 million to $75 million for the rate period, an average of $15 million per year, rather than the $30 million per year as proposed in the initial and supplemental rate proposals. *See infra* § 4.3.

These revenue increases, cost reductions, and financing savings are essential ingredients in BPA's ability to meet its competitiveness challenge. *See* Moorman, Evans, E-BPA-09; Moorman, Evans, E-BPA-65. Cost reductions also are called for in a fish-cost-sharing arrangement that BPA forged with the Administration in March, 1995. *See* DeWolf, *et al.*, E-BPA-69, at 2-7. This arrangement calls for BPA to reduce its costs by $30-40 million per year. *See* DeWolf, *et al.*, E-BPA-14, at 3- 4. Beginning in FY 1995, BPA will receive annual credits on a permanent basis for BPA's direct fish and wildlife expenditures under the cost-sharing arrangement. It also will receive credits through FY 2001 for BPA's power purchase costs related to its fish and wildlife programs. These section 4(h)(10)(C) credits are estimated to total about $60 million annually for FYs 1997-2001. *See* DeWolf, *et al.*, WP-96-E-BPA-14, at 3. Further, under the arrangement BPA may, to the extent necessary, reduce its accumulation of cash reserves. *Id.* at 7-8; Revenue Requirement Study, FS-BPA-02, § 5.2.1.

The Energy and Water Development Appropriation Act of 1996 was passed in November 1995. This Act directs BPA to pay exchange benefits of $145 million in FY 1997, an increase of $78.6 million over what would have resulted from the final proposal. It also prescribes the manner in which the payment is to be distributed among utilities participating in the residential exchange program. BPA has conducted a separate interpretative rulemaking process to determine the proper method for allocating residential exchange benefits for FY 1997 in accordance with the Appropriation Act of 1996. This Act also allows BPA to market surplus Federal power abandoned by regional customers or generated during hydrosystem operations, or purchased, primarily for the benefit of fish and wildlife without regional "call-back" provisions and without the prohibition on resale of Federal power by private entities not in the business of selling power in the retail market. Sales or exchanges of surplus power that is surplus for reasons other than these reasons will continue to be subject to the regional call provisions and the prohibition on resale of Federal power. In addition, the Act authorizes the Corps of Engineers to procure goods through BPA using the authorities available to the Administrator, and provides the Administrator with the authority to use targeted voluntary separation incentives for the next five years.

In direct testimony, the public agencies and large industrial users argued that BPA included in its initial proposal Revenue Requirement Study projections of Corps of Engineer (COE) investment related to the 1995 Biological Opinion that were redundant, infeasible, or imprudent. *See* Carr, Tester, WP-96-E-PP/DS/PA/PG/RC/WA-02, at 2-4. Subsequent to the initial proposal, BPA, National Marine Fisheries Service (NMFS), COE, and the Northwest Power Planning Council (Council) held numerous discussions to refine estimates of the types and timing of investments that would (1) meet the objectives and intent of the 1995 Biological Opinion as well as the Council's Fish and Wildlife Program; (2) be cost effective and technically feasible given ongoing or other planned capital improvements; and (3) stabilize BPA's fish costs. Revised estimates based on these discussions were included in the supplemental proposal. *See* DeWolf, *et al.*, WP-96-E-BPA-42, at 4-6. The parties did not pursue this issue after the refinements to the estimates were made, and did not raise the issue in briefs. Therefore, the issue is not addressed here.

In testimony, the public agencies and large industrial users proposed that BPA reduce the revenue requirement impact of its conservation program. *See* Carr, Carr, WP-96-E-PP/DS/PA/PG/RC/WA-03, at 3. They did not pursue this issue on brief, and, as such, the issue is withdrawn.

4.1.3 Implementation of Revised Bonneville Appropriations Refinancing Act

In testimony and a workshop supporting BPA's 1996 supplemental proposal in January 1996, BPA outlined how the BPA Appropriations Refinancing Act, if enacted, would be implemented in repayment studies and revenue requirements. DeWolf,*et al.*, WP-96-E-BPA-93; Workshop: Implementation of Appropriations Refinancing Act in Rate Proposal, January 31, 1996.

As explained at that time, the bill called for resetting the unpaid principal of FCRPS appropriations and reassigning interest rates. New principal amounts are established at the beginning of FY 1997, at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations in the absence of the Act, plus $100 million. Current Treasury interest rates are assigned to the new principal amounts. The bases for calculating interest during construction and assigning interest rates to future investments funded by appropriations also are specified in the bill. Prepayment of the refinanced appropriations is limited to $100 million during the first five years after the effective date of the refinancing transaction. Other repayment terms and conditions remain unaffected. The bill includes assurances to ratepayers that the Government would not increase repayment terms and conditions on the refinanced appropriations in the future. It also changed the timing of the credits against BPA's year-end cash transfers to Treasury provided by the Colville Settlement Act of 1994. DeWolf,*et al.*, E-BPA-93.

Since BPA's supplemental proposal testimony and the January workshop, the bill was revised in both houses of Congress with the Administration's support. The revisions were limited to: (1) delaying the effective date of the refinancing transaction one year, from October 1, 1995 to October 1, 1996; and (2) eliminating the Colville credits to BPA's year-end Treasury payments in FY 1996 and increasing the credits from $4.1 million to $18.55 million in FY 2001 and from $4.1 million to $4.6 million in subsequent years.

In late April, Congress passed and the President signed the Act as part of an omnibus FY 1996 Appropriations Act. Accordingly, BPA is implementing the Act in this rate proposal. *See* Revenue Requirement Study, § 5.1.5; Revenue Requirement Study Documentation Volume 1, FS-BPA-02A, Chapter 9, for the Act and supporting legislative language.

Implementation of the Act in this proceeding will be performed as outlined in testimony, with the following exceptions:

-- Reflect the revisions to the Act described above. The net effect of the revisions is to avoid increasing BPA's debt service requirement and reducing financial reserves by about $12 million in FY 1996; reduce annual interest expense by an average of $2 million and $0.5 million in the generation and transmission functions, respectively; and increase generation revenues by $14 million in FY 2001.

-- Reduce BPA appropriations principal to be refinanced by the amount of accumulated net property transfers. Since 1978, BPA has transferred about $43 million of assets to Federal agencies outside the FCRPS (net of transfers to BPA). FCRPS audited financial statements have reflected these transfers as reductions to overall outstanding BPA repayable appropriations. Because the transfers were not applied to reduce individual annual appropriations, the $43 million reduction has not heretofore been reflected in repayment studies. This action will effectively bring repayable appropriations shown in repayment studies into line with amounts reflected in audited financial statements. Since the transferred assets were funded by BPA transmission appropriations, the reduction will be reflected in transmission repayment studies. Transmission interest expense will be lower than it otherwise would be by an average of $2.5 million per year.

-- Implement a plan for annual recognition of the capitalization adjustment resulting from the refinancing transaction. The Act entails an estimated $2,183 million reduction to outstanding appropriations liabilities in FCRPS financial statements. The capitalization adjustment is recognized annually over the remaining life of the refinanced appropriations, and is determined separately for the generation ($1,846 million total) and transmission ($337 million total) functions. Annual recognition will be included on BPA's income statement as a negative, non-cash component of interest expense and on the statement of cash flows as a reduction in funds from operations. BPA had indicated at its January workshop that the annual recognition (referred to at the time as "accounting gain") could be shaped flexibly over the remaining repayment period of the refinanced appropriations and that BPA would attempt to preserve the capitalization adjustment for instances when it would provide a reduction in revenue requirements. Subsequently, BPA developed a schedule of recognition that is in clear conformance with generally accepted accounting practices and with the expectations of BPA's financial auditors. The schedule for each function is based on the increase in annual interest expense resulting from implementation of the Act, as reflected in final proposal FY 1997 repayment study results. As such, $185.6 million in generation and $76.8 million in transmission of the capitalization adjustment is recognized over the 5-year rate period.

4.2 Cost Recovery

Issue

Whether transmission rate levels will generate revenues sufficient to cover the costs of the transmission facilities.

Parties' Positions

Clark Public Utilities argues that the Settlement Agreement transmission rates will not cover transmission costs. Clark Brief, WP-96-B-CP-01, at 12-15; Clark Ex. Brief, WP-96-R-CP-01, at 10-12.

BPA's Position

The revised revenue test in the final proposal Revenue Requirement Study demonstrates that the proposed rates will recover the costs in both the transmission and generation functions. Revenue Requirement Study, FS-BPA-02, § 4.3 and Tables 21A-21C.

Evaluation of Positions

In its initial brief, Clark states that the transmission and PF-96 rates proposed under the Settlement Agreements (*see supra* § 1.1.3) violate Bonneville's statutory obligation to set rates at levels that will cover the cost of the service provided, "absent further cost reductions." Clark Brief, at 12-13. They also argue that the average PF-96 rate as proposed in the Settlement Agreements will not generate sufficient revenues to cover the costs of the service being provided as reflected in the record, and that its adoption will materially reduce Bonneville's probability of repaying the U.S. Treasury during the rate period. However, the revised revenue test in the final proposal Revenue Requirement Study demonstrates that the proposed rates will recover the costs in both the transmission and generation functions. Revenue Requirement Study, FS-BPA-02, §4.3 and Tables 21A-21C. The probability that BPA will meet all five years of Treasury payments in full and on time, based on projected revenues at proposed rates, is 80 percent. *Id.* at § 2.2.

In its brief on exceptions, Clark states that in order for the negotiated transmission rates to be found legally sufficient, Bonneville must include in the record evidence of specific cost reductions it has made and will make, in order to ensure that the negotiated transmission rate levels meet the legal standard set forth in Section 7(a)(2) of the Northwest Power Act. Clark Ex. Brief, at 11-12. "At this juncture, the record reflects promises by Bonneville to reduce its costs enough to match the transmission rates it seeks to adopt. These promises, which have not been subject to review or challenge by the parties to this case, are what determines whether the proposed transmission rates are legally sufficient." *Id.* However, as explained in section 2.6 of this Record of Decision, though rates must recover BPA's costs of programs, the programs and program levels are not part of the rate cases. BPA interprets section 7 of the Northwest Power Act not to allow litigation of those activities, program levels, and budgets in the rate case. 1993 Administrator's Record of Decision (ROD), WP-93-A-02, at 319-329. The Administrator's decisions outside the rate case to reduce costs constitute fundamental management decisions as to how best to conduct BPA's affairs. Since its supplemental proposal, BPA has further reduced costs, as described in Sections 2.6 and 4.1 of this document, toward ensuring rates are competitive and costs can be recovered. The functionalized revenue requirements, *id*, § 4.1, include the reduced costs. Appendix A to the Revenue Requirement Study contains a letter sent by the Administrator to customers and interested parties detailing where cost cuts have been made. But the fact that these cost reduction "promises" have not been subject to challenge by the parties in the case is irrelevant. The reduced costs are included in the final proposal revenue requirements, are a part of the record, and do demonstrate cost recovery.

Decision

BPA's final proposal revenue requirement demonstrates cost recovery in both the generation and transmission functions under rates at the levels of the settlement agreements.

4.3 Sources of Capital

Issue

Should BPA fund a portion of transmission and WNP-2 capital investments with current revenues?

Parties' Position

APAC contends that BPA's proposal for revenue financing a portion of long-lived transmission investments and WNP-2 investments does not spread costs to future ratepayers who would benefit from the investments. Therefore, APAC argues BPA should fund all capital investments using debt.

APAC also contends that using debt reduces the pressure on near-term rates during the current period of intense competition. If all transmission and shorter-term WNP-2 investments were funded with debt, BPA's revenue requirement would be reduced by $67 million for each year of the rate period. APAC Brief, WP-96-B-PA-01, at 36; APAC Ex. Brief, WP-96-R-PA-01, at 35.

BPA's Position

BPA contends that it is important at this time to pursue rate stability and financial flexibility through revenue financing of a small portion of its capital investments. Further, BPA contends that the benefits of rate stability and financial flexibility outweigh APAC's concerns regarding intergenerational equity. The Congressional Committees to which BPA reports have made clear their expectations that BPA reduce its reliance on Treasury debt by funding a portion of its capital investments through current revenues.

BPA also contends that the APAC estimate of the revenue requirement impact of revenue financing is overstated.

Evaluation of Positions

The choice between debt financing and revenue financing involves a tradeoff between APAC's goals of intergenerational equity and competitiveness of current rates, and BPA's goals of rate stability and financial flexibility. BPA generally agrees that intergenerational equity and the competitiveness of current rates are important considerations, but on balance BPA finds that it is far more important at this time for BPA to pursue stability and flexibility through revenue financing. APAC argues that intergenerational equity is more important.

APAC argues that costs should be recovered from the rate payers who benefit from the investments. It states that revenue financing does not spread the costs evenly and therefore creates an intergenerational *inequity*. While BPA agrees that intergenerational equity is an important consideration, BPA expects to receive several benefits through revenue financing, including prolonged access to low-cost debt, improved rate stability, reduced fixed interest expenses (and associated improved Treasury repayment probability), greater ability to respond to market opportunities as they arise, and compliance with Congressional and GAO reports on the subject of BPA finances.

BPA is particularly concerned about rate stability. Revenue financing will help BPA achieve greater program and rate stability. If BPA's existing borrowing authority is exhausted before it is replenished legislatively, then at that time revenue will remain the only available source of capital for BPA investments. Revenue financing of most or all of BPA's capital program would likely lead to substantial rate increases. Thus, the intergenerational equity that the parties espouse may be achieved best by including modest amounts of revenue financing in rates now, to help minimize the need for a much higher proportion of revenue financing and potentially large rate increases down the road. The benefits of stability outweigh the "equity" criticisms advanced by the APAC and others. DeWolf, *et al*., E-BPA-42, at 22.

It is especially important to reiterate that Congress expects BPA to make efforts to achieve stability and flexibility and to reduce its reliance on Treasury debt by funding a portion of its capital investments through current revenues. In fact, Congress specifically directed BPA to begin revenue financing as one method to accomplish BPA stability and flexibility. The GAO and House and Senate Committees echo BPA's sentiment that complete reliance on debt financing can greatly hamper BPA's flexibility to address operating and financial challenges. DeWolf, *et al*., E-BPA-14, at 16-18. The GAO, in a report titled "Bonneville Power Administration, Borrowing Practices and Financial Condition" (released in April 1994), stated;

> Substantially all of BPA's new borrowing is projected to come from Treasury. By contrast, investor-owned utilities, public utilities, and Federal entities like the Tennessee Valley Authority (TVA) generally use a higher portion of their current revenues to pay for capital expenditures than BPA does. . . . BPA faces significant operating and financial risk because of its heavy reliance on borrowing. . . . In the short term, BPA's low financial reserves provided little flexibility to respond to further operating losses, increasing the probability that BPA would be unable to make its annual payment to Treasury. In the longer term, BPA's financial viability could also be jeopardized if the gap between BPA rates and the cost of alternative energy sources continues to narrow." *See* DeWolf, *et al*., E-BPA-14, at 6-17.

Congress also is concerned about BPA's capital structure. In a 1994 Senate Appropriations Committee report, the Senate stated, "BPA's reliance on debt financing for capital programs is risky and leaves the agency with little flexibility in meeting future challenges." The Senate report goes on to say that BPA is "too highly leveraged and [the Committee] directs Bonneville to begin rectifying the situation. . . ." *See* DeWolf, *et al.*, E-BPA-14, at 17.

The House of Representatives also expressed concerns about BPA's capital structure. In a House Appropriations Committee report, the House Committee stated that

> the GAO report reinforces the concerns voiced by this Committee that the agency's highly leveraged position and resulting debt servicing gives BPA little flexibility in meeting unexpected operating conditions . . . . The Committee supports the concept of financing a portion of capital investments from revenues . . . . It was the intent of Congress that borrowing from Treasury for capital improvements was to augment available operating funds not replace them totally. . . . With the severe budget constraints expected to continue in the future, appropriating

> additional funds to replenish BPA's borrowing authority will be very difficult. *See* DeWolf, *et al.,* WP-96-E-BPA-14, at 17-18.

BPA believes it is very important to address the concerns of the GAO and Congress through specific measures, including pursuit of revenue financing. In addition to revenue financing, BPA has pursued several other avenues to reduce its reliance on debt financing and to improve its financial position, including heavy cost cutting in capital programs, joint project development, third party financing of new resource acquisitions, and shifting of some debt between the two existing borrowing authority caps. DeWolf, *et al.*, E-BPA-42, at 21-22. APAC's arguments ignore Congressional expectations placed on BPA.

Specifically with regard to BPA investments in WNP-2, BPA adopted a 10-year Financial Plan in the 1993 rate case as an important step in ensuring BPA's long-term financial stability and flexibility. The Financial Plan specified that WNP-2 investments with estimated service lives in excess of 10 years would be financed with debt, and assets with lives under 10 years would be funded by current revenues. 1993 ROD, WP-93-A-02, at C28. BPA continues to follow the 10-year plan by revenue financing WNP-2 short-lived capital additions in order to make progress regarding stability and flexibility.

After consideration of these points, BPA concludes that the benefits of ensuring that a relatively small intergenerational inequity does not occur in the next few years are far outweighed by the benefits of increased stability and flexibility.

APAC also argues that revenue financing causes near-term pressure on rates. APAC Brief, B-PA-01, at 36; APAC Ex. Brief, R-PA-01, at 35. APAC claims that BPA's revenue requirement would be $67 million lower in each year of the rate period if BPA were to pursue all debt financing. APAC Brief, B-PA-01, at 36. APAC's claim is incorrect. The amount of WNP-2 capital additions to be revenue financed was reduced from an average of $47 million per year in the initial proposal to an average of $22 million per year in the supplemental proposal. In addition, most WNP-2 capital additions are items with estimated service lives of 5 years or less. Capital additions with 5-year service lives would be financed with short-term debt. Since the cost of short-term debt is relatively high, debt financing would decrease BPA's revenue requirements by only $4.2 million per year. If debt instead of revenues were used to finance WNP-2 short-lived assets, any savings would more than likely be used to increase repayment probability, not reduce power rates. DeWolf, *et al.*, E-BPA-42, at 20. Specifically with regard to BPA's transmission investments, BPA initially proposed $30 million per year in revenue financing. Since BPA's supplemental rate proposal, additional cuts in transmission capital investments have occurred for the FY 1997 - 2001 rate period. These cuts, together with BPA's intentions to pursue joint project development on a limited basis and shift some debt from borrowing cap 1 to cap 2, should extend existing borrowing authority into the FY 2002 - 2003 time frame. Accordingly, BPA, in its final proposal, is reducing its level of revenue financing for transmission by 50 percent, from $30 million per year to $15 million per year. The combined effect of revenue financing for both WNP-2 and transmission investments on yearly revenue requirements is drastically lower than the $67 million stated by APAC.

Decision

Through heavy capital and expense reductions, BPA has reduced revenue requirements to enable it to set rates to meet the market and still recover costs. Additional reductions to revenue requirements that could be achieved through reduced revenue financing and associated increases in debt leverage would, on balance, be more harmful to BPA's competitive position than the relatively minor effects of increases to price due its proposed revenue financing.

BPA believes that, on balance, the benefits of increased financial stability and flexibility far outweigh the benefits of ensuring near term intergenerational equity. Congress and the GAO have recognized the need for BPA to improve its financial position, and have made clear their expectations that BPA reduce its reliance on Treasury debt by funding a portion of its capital investments with current revenues. The increasingly competitive environment demands that BPA pursue reduced leverage to ensure financial integrity. Abandoning a moderate level of revenue financing now would lead to a much greater likelihood of significantly heavier reliance on revenue financing in the future. The end result would be much greater intergenerational inequity and rate instability. BPA will keep revenue financing at an average of $22 million per year for WNP-2 investments, and reduce its earlier proposal of $30 million per year to $15 million per year for transmission investments.

4.4 Transmission Replacements

Issue

Whether BPA should utilize alternative methods of calculating transmission replacements in its repayment study.

Parties' Position

APAC argues that BPA should adopt the alternative method it has suggested for determining baseline values to be used in calculating the cost of transmission replacements in the repayment study. APAC Brief, B-PA-01, at 36; APAC Ex. Br., R-PA-01, at 35. In testimony, a Joint Customer group, including APAC, argued that BPA's use of the Handy-Whitman index has three major problems. The customer group suggested the use of a combination of the chain-weighted Producers' Durable Equipment deflator and the Handy-Whitman index. Wolverton, Carr, WP-96-E-PP/DS/PA/PG/RC/WA-05, at 4, 8.

BPA's Position

BPA testified that the three alleged problems with the Handy-Whitman index are all based on false premises. Furthermore, the customers' suggested index would be less accurate than the Handy-Whitman index. DeWolf, *et al*., E-BPA-42, at 9.

Evaluation of Positions

The Handy-Whitman index is a price index for public utility construction costs. It contains index numbers for six different regions of the country and for several categories of costs. It measures costs for building construction in general and for electric, gas and water utilities; and it contains numerous subcategories within those four categories. Each category and subcategory contains a number of individual items commonly referred to as a "basket of goods." BPA uses the Handy-Whitman index to determine the capital cost of original units of property at current price levels. Essentially, it is a means of inflating historical costs to calculate the cost of future replacements for the transmission system. *Id.* at 9-10.

The parties argue that BPA's reliance on Handy-Whitman has three major problems. First, they argue that "the indices are applied to accounting data that in the past are not very good." Wolverton, Carr, E-PP/DS/PA/PG/RC/WA-05, at 4. In support of this position they cite a BPA memorandum indicating that the accounting data are only estimates. *Id.* at 4 (citing 1985 Revenue Requirement Study, WP-85-FS-BPA-07A, Chapter 8). The parties have misinterpreted the memorandum, which states that "the component amounts which support the overall figures are not specifically identified in BPA plant accounting records according to the investment categories specified (initial and replacement) in the request. Consequently, the calculated line item amounts . . . are simply estimates . . . ." DeWolf, *et al*., E-BPA-42, at 11 (emphasis added). Thus, only the subdivision of total plant into initial plant and replacement plant is an estimate. The Handy-Whitman index does not distinguish between initial plant and replacement plant; the only relevant figure is the total. Therefore, the use of estimates for this subdivision does not affect application of the index. *Id.*

Next, the parties argue that the Handy-Whitman index has an "index estimation problem" because the basket of goods in a given category in one time period is different from the basket of goods in another time period. For example, according to the parties, the Handy-Whitman index for 1940 included manual switches and land-line installations, while the current index probably does not. Wolverton, Carr, E-PP/DS/PA/PG/RC/WA-05, at 4. The parties state that the basket of goods used in the Handy-Whitman index has changed significantly over 50 years, making comparisons of two time periods difficult. They cite selected portions of an article from the April 1992 issue of Survey of Current Business, in which the author notes that over long periods of time comparisons become increasingly uncertain. *Id.* at 5.

The parties' argument contains two flaws. First, the producers' durable equipment index that they suggest using instead of Handy-Whitman has increased from 183 components to 645 components in only 28 years. The Bureau of Economic Affairs had so many problems with the index's basket of goods that they developed a new index methodology. DeWolf, *et al*., E-BPA-42, at 13. Second, the article the parties cite discusses only the cost-of-living index, and makes clear that the index estimation problem arises because of the great changes in "the economy, in the way people live, and in tastes and customs." *Id.* Thus, the cost-of-living index has an index estimation problem because the index is very wide; that is, it contains a large basket of goods. *Id.* at 9, 13-14. The Handy-Whitman index, which contains such items as nonresidential structures, poles, and fixtures, is both much narrower and far less susceptible to change than the cost-of-living index. *Id.* at 14. Therefore, the same index estimation problem does not exist.

Finally, the parties argue that in many cases BPA does not replace the transmission system in kind but as part of a general upgrade. For example, BPA may replace a 115 kV line with a 240 kV line. Price indices, however, are designed to measure the costs of replacements in kind. Wolverton, Carr, E-PP/DS/PA/PG/RC/WA-05, at 6. The parties misunderstand both the use of the Handy-Whitman index and the assumptions in BPA's repayment study. The only use of the Handy-Whitman index is to forecast transmission system replacements for purposes of the repayment study. The index is not used in BPA's system replacement program or when BPA is making actual system replacements.

Moreover, the future replacements used in the repayment study are not intended to be actual projected future replacements. Therefore, the parties' reference to actual BPA upgrades is misplaced. The repayment study determines the minimum levelized revenue requirement sufficient to retire BPA's outstanding obligations. This levelized revenue requirement assumes that the same power will be sold at the same rates throughout the repayment period. Thus, future replacements are assumed to maintain the existing system so that it is capable of producing and delivering that power and earning those revenues. Replacements in kind will maintain the existing system, and are therefore what the repayment study uses. DeWolf, *et al*., E-BPA-42, at 12.

The parties suggest use of a combination of a chain-weighted index and the Handy-Whitman index. The Handy-Whitman index is a fixed weight index, which uses one basket of goods. The index in a given year is the ratio of the cost of that basket of goods for that year to its cost in the base year. A chain-weighted index uses a different "basket of goods" for each year. According to the parties, the chain-weighted index solves the index estimation problem by redefining the goods that are included in the index. Wolverton, Carr, E-PP/DS/PA/PG/RC/WA-05, at 7-8. In a chain-weighted index, the index for a given year is based on the cost of the basket of goods in that year and the following year, thus chaining the years together.

The parties suggest that the ideal index would be a chain-weighted Handy-Whitman index. They make a compromise suggestion because no such index exists. *Id.* at 8. They propose that the Handy-Whitman index be combined with the Producers' Durable

Equipment index, with the weighting given to each changing over time. The weighting in the early years would favor the Producers' Durable Equipment index, and in the later years the Handy-Whitman index. Thus, in the first year, 1940, the index would consist entirely of the Producers' Durable Equipment index. This proportion would decline until it reached zero in 1994, when the index would consist entirely of the Handy-Whitman index. *Id.* at 8-9. The chain-weighted Producers' Durable Equipment index, however, is available only as of 1959. Therefore, for 1940 through 1958 the parties suggest using the rate of change of the overall GDP index as the implied rate of change of the chain-weighted index. Thus, the parties propose that BPA combine three indices. *Id.* at 7.

The parties' proposal would exacerbate the problem they wish to solve. First, as noted above, the Producers' Durable Equipment index has grown from 183 items to 645 in only 28 years. Therefore, it is subject to a significant index estimation problem. DeWolf, *et al.*, E-BPA-42, at 15. Second, the parties claim that the fixed-weight Handy Whitman index overstates inflation. Wolverton, Carr, E-PP/DS/PA/PG/RC/WA-05, at 3. To test this theory, BPA compared the annual average rates of inflation of a number of chain-weighted and fixed-weighted indices. In almost all cases the rate of inflation of the chain-weighted index exceeded the rate of inflation of the corresponding fixed-weight index. DeWolf, *et al.*, E-BPA-42, at 17 and Attachment 4. Thus, were BPA to employ the parties' ideal—a chain-weighted Handy-Whitman index—the rate of inflation could be expected to increase, not decrease. The parties' ideal index—which their proposal is intended to emulate—would increase the cost estimate for transmission replacements.

BPA also calculated the rate of change of the Producers' Durable Equipment index from 1959 to 1987. The annual rate of change is considerably smaller than the rate of change in the Handy-Whitman index. Therefore, the annual rate of change of the Handy-Whitman index, when calculated as a chain-weighted index, should be greater than the annual rate of change of the fixed weight Handy-Whitman index. *Id.* at 18 and Attachment 4. Thus, the parties' proposed index would first,, seriously understate the actual rate of inflation; and second, deviate further from the parties' ideal index than does the Handy-Whitman index.

Finally, the parties are introducing an "index estimation problem" of their own by proposing to combine three indices: the overall GDP index for 1940 to 1959, the chain-weighted Producers' Durable Equipment index, and the Handy-Whitman index. Thus, for example, BPA compared the parties' index for overhead conducts for 1953 and 1993. The 1953 index is weighted 24.1% Handy-Whitman index and 75.9% GDP. The 1993 index is weighted 98.1% Handy-Whitman index and 1.9% Producers' Durable Equipment index. *Id.* at 15. It is not clear that these two indices are even intended to represent the same basket of goods; they appear to have a deliberate index estimation problem. *Id.* at 15-16. Calculation of future transmission replacements is more accurate using the fixed-weight Handy-Whitman index than using the combination index the parties have proposed.

Decision

The Handy-Whitman indices will continue to be used in the calculation of transmission system replacements. The parties have failed to demonstrate that it results in an inaccurate measure of the cost of replacements. Moreover, the index the parties have proposed as a substitute would be less accurate.

4.5 Risk Analysis

The objective of the Risk Analysis is to evaluate the impact that various economic and generation resource capability variations could have on BPA's ability to make its annual U.S. Treasury payments during the rate period. The Risk Analysis is performed through the use of the Short-Term Risk Evaluation and Analysis Model (STREAM) and the Tool Kit Model. The STREAM simulates the variability in net revenues (revenues minus costs) BPA faces due to operating risks. The Tool Kit Model calculates the probability that BPA will make all of its scheduled payments to the U.S. Treasury in full and on time, based on the projected level of financial reserves at the beginning of the rate period, the projected cash flows during the rate period, and the variability in net revenues simulated by the STREAM.

In the Record of Decision for the 1993 Final Rate Proposal, BPA determined that as a long term policy, BPA will plan to set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each 2-year rate period. 1993 ROD, WP-93-A-02, at 72-73. In addition, the Administrator determined in that Record of Decision that BPA would adopt a phase-in Treasury payment probability standard of 85 percent for the FY 1994-FY 1995 rate period in recognition of a number of factors including the overall level of the rate increase. *Id*. at 76.

The 95 percent, 2-year standard is equivalent to an 88 percent probability of making all five Treasury payments in a 5-year period (.975^5 =.88, .975^2 = .95). Revenue Requirement Study Documentation Volume 1, FS-BPA-02A,§ 3.2. The probability of meeting its Treasury payment obligation is one measure of BPA's expected ability to recover its costs.

Because of competitive pressures and the need to keep costs and rates low, BPA is reducing its probability of making Treasury payments for this rate case. Arnold, *et al.,* WP-96-E-BPA-15, at 4; Moorman, Evans, WP-96-E-BPA-9, at 28. The Administration has agreed that, to the extent necessary, BPA may reduce its accumulation of cash reserves, which is to say, reduce its probability of meeting Treasury payments on time and in full. DeWolf, *et al*., E-BPA-14, at 7-8. BPA's costs are met according to a specific priority of payments out of the Bonneville Fund. The order in which BPA's costs are met are as follows: (1) costs of the Net Billed Projects and the Trojan Nuclear Project, to the extent covered by net billing credits; (2) cash payments out of the Bonneville Fund to cover all required cash payments incurred by Bonneville pursuant to law, including net billing cash payments, other than payments to the United States Treasury; and (3) payments to the U.S. Treasury. Because making payments to Treasury is the lowest priority, maintaining a high probability of Treasury payment also assures that all other costs will be met.

4.5.1 Short-Term Risk Evaluation and Analysis Model (STREAM)

The STREAM is a hydro regulation model that makes operational and economic decisions based on various reservoir, streamflow, load, resource performance, and nonfirm market conditions and estimates revenues and expenses under these various conditions. STREAM projects the expected variation in BPA's annual cash flows by systematically combining and analyzing variations in each of the major risk factors to determine the frequency, duration, and impact of these interactions on BPA's annual cash flows.

In direct testimony on BPA's supplemental proposal, WPAG asserted that BPA has overstated the probability of repaying the Treasury on time and in full. Beck, *et al.*, WP-96-E-WA-13, at 14 . WPAG argues that BPA has been overly optimistic in its projection of load commitments from preference customers and in its associated projection of revenues. *Id.* at 14. BPA testified in rebuttal that the results of its probability analysis reflect prior use of BPA's best estimate of projected average load commitment from Priority Firm (PF) customers of 95 percent in studies impacted by loads. Conger, WP-96-E-BPA-102, 2; *see also* Lee, *et al*., WP-96-E-BPA-118, at 2-3. These studies include the Hydroregulation Study, Loads and Resources Study, Federal Secondary Energy Analysis, Revenue Forecast, and Risk Analysis. Conger, WP-96-E-BPA-102, at 2. BPA believes that it has accurately estimated its Treasury repayment probability.

APAC and PPC testified that utilities have two choices: 1) they can pay a Load Shaping charge to BPA specifically designed to compensate BPA for load variation risk; or 2) they can absorb the risk themselves. In either case, BPA's power rates should not include a risk component to cover load variability due to weather or economic changes. When the lower BPA risk is taken into account, the average Treasury repayment probability rises by 0.6 percent, the amount of expected missed Treasury payment drops by 10 percent, and the number of deferrals drops by almost 2 percent. Hicks, Wolverton, WP-96-E-PP/DS/PA/PG/RC/WA-08, at 2. APAC and PPC correctly note that take-or-pay contracts reduce revenue risk that BPA faces due to load variations. Arnold, *et al.*, WP-96-E-BPA-45, at 4. However, APAC and PPC incorrectly conclude that BPA no longer faces revenue and purchase power expense risks due to load variations for those utilities that purchase BPA's Load Shaping product. *Id.* For utilities that purchase the Load Shaping product, the risk of load variations remains on BPA. The Load Shaping product offered by BPA to its utility customers reduces BPA's customers' risk, not BPA's risk. *Id.* at 5. For customers buying Load Shaping, BPA continues to face the power purchase expense and revenue risks when loads deviate from forecasts. Load Shaping product revenues do not account for the revenue risks associated with load variations due to weather and economic conditions. *Id.* Instead, the revenues from Load Shaping services serve to reduce the amount of generation costs that BPA recovers through its energy charges. Load Shaping is merely a rate design mechanism that defines how BPA will collect its revenue requirement. It does not set the level of costs, or planned net revenues, that should be included in BPA's revenue requirement to cover risks associated with load deviations due to weather or economic conditions. *Id.* Moreover, in contrast with the 1993 Rate Case, BPA is not recovering all the planned net revenues for risks related to load variations due to weather and economic conditions. *Id.*

4.5.2 <u>Tool Kit Model</u>

Inputs to the Tool Kit model include beginning financial reserves (the level of reserves estimated to be on hand at the start of the rate period), the cash flows projected for each year of the rate period, the STREAM output, which consists of a vector of net revenue outcomes (deviations from expected net revenue values), and the potential application of additions to BPA Fund cash reserves occasioned by the use of the Fish Cost Contingency Fund. The primary output of the Tool Kit is an estimate of the probability that BPA will make all of the planned annual payments to the U.S. Treasury in full and on time. The amount of "planned net revenues for risk" that are included in revenue requirements plays a key role in the Treasury payment probability. Planned net revenues for risk are one component of BPA's planned net revenues. Under the less-competitive circumstances BPA faced in 1993 when BPA's 10-Year Financial Plan was crafted and adopted in coordination with customers, inclusion of larger planned net revenues for risk in the revenue requirements resulted in higher rates and cash flows, a build-up of financial reserves, and therefore a higher probability of making Treasury payments. Under the current highly competitive circumstances, if BPA were to add sufficient planned net revenues for risk to its revenue requirement to conform with the long-term probability policy, BPA's rates would rise, making its products less competitive in the market, and BPA would therefore lose revenue, with the effect being a reduction in Treasury payment probability. Arnold, *et al.*, WP-96-E-BPA-15, at 4. There were no issues raised specific to Tool Kit modeling.

APAC and PPC testify that, in the past, BPA included Program Cost Deferrals as a tool to better ensure Treasury repayment probabilities. Hicks, Wolverton, WP-96-E-PP/DS/PA/PG/RC/WA-08, at 3. In the 1996 rate case, BPA has dropped this tool under the belief that no reliable, quantifiable prospect for additional cost cuts could be made under a cost deferral mechanism. *Id.* APAC and PPC assert that the cuts BPA proposed are a permanent baseline that will continue to present opportunities to defer costs and should be retained. *Id.* at 4. BPA did not include a program cost deferral mechanism in its 1996 initial proposal because in that proposal, BPA proposed reducing its costs on average by $250 million per year over FY 1996-2000 and by $350 million per year in FY 2001. *Id.* at 3. Given this level of cost reduction, it is unlikely that additional cost cuts could be reliably achieved through a program cost deferral mechanism, and BPA will not apply the mechanism in this rate case. Arnold, *et al.*, E-BPA-15, at 4.

4.5.3 Probability of Treasury Repayment

According to the risk analysis that has been performed, there is an 80 percent probability of making Treasury payments in full and on time during the 5-year rate period. Revenue Requirement Study Documentation, Volume 1, FS-BPA-02A, Chapter 13. Wholesale rates that are being adopted in the final rate proposal take into account a number of factors and BPA's recognition of the need to offer competitive rates while at the same time meeting its other financial obligations. Reducing the Treasury repayment probability for this rate case is one of the steps BPA is proposing to help maintain competitive rate levels. Arnold, *et al*., E-BPA-15, at 4; Moorman, Evans, E-BPA-11, at 28. In her testimony before the Senate Appropriations Committee, Subcommittee on Energy and Water, Alice Rivlin, Director of the Office of Management and Budget, discussed how BPA's fish mitigation costs would be partly allocated to non-power uses. Ms. Rivlin stated that . . . "to the extent necessary, BPA will reduce its build-up of cash reserves. This may make it more likely that BPA will have to reschedule a portion of its annual Treasury payment in future years. If such an event occurs, BPA will reschedule its debt consistent with existing Treasury policy." Revenue Requirement Study Documentation Volume 1, WP-96-E-BPA-02A, Chapter 14, Attachment 1, at 7.

There were no issues identified in the 1996 rate proposal regarding reducing Treasury repayment probability from the level determined in the 1993 rate case policy.

Because no party raised any issues in their initial briefs concerning the STREAM or Tool Kit models or concerning repayment risk, the issues described in parties' testimony noted above are waived. *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611, § 1010.13(b) (1986).

5.0 RESIDENTIAL EXCHANGE COSTS

5.1 Introduction

The Northwest Power Act created the residential exchange program to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the Northwest Power Act, the BPA Administrator "purchases" power from each participating utility at that utility's average system cost (ASC). The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power at BPA's Priority Firm (PF) power rate. The amount of power purchased and sold is the qualifying residential and small farm load of each participating utility. The Northwest Power Act requires the net benefits of the program to be passed directly to the residential and small farm customers of the participating utilities.

For ratemaking purposes the residential exchange is treated as a "purchase and sale of power." However, the residential exchange is not a conventional power exchange. No actual power is transferred either to or from BPA. It is only an exchange on paper.

Each utility's ASC is determined by the Administrator according to the 1984 Average System Cost Methodology (ASCM) developed by BPA in consultation with its customers and other interested parties. The ASCM is incorporated for reference as Exhibit C to the Residential Purchase and Sale Agreement (RPSA), which BPA signs with each utility that participates in the residential exchange program. In simple terms, a utility's ASC is the sum of the utility's production and transmission-related costs (contract system costs) divided by the utility's system load (contract system load). A utility's system load is the firm energy load used to establish retail rates.

BPA uses the "jurisdictional approach," which relies as a starting point upon the cost data approved by state utility commission (in the case of IOUs) and utility governing bodies (in the case publicly owned utilities) to determine a utility's ASC. Costs that are not approved by the state commissions or utility governing bodies cannot be included in contract system cost.

The cost of the residential exchange program is part of BPA's revenue requirement, which must be recovered through rates. The ratemaking treatment of the residential exchange costs and loads is discussed fully in the WPRDS, WP-96-FS-BPA-05. Additionally, the individual IOU ASCs and the combined public utility ASCs are used as an input to the Supply Pricing Model (SPM) which is used to calculate the section 7(b)(2) rate test. A full discussion of the inputs to the section 7(b)(2) rate test is contained in the Documentation for the 7(b)(2) Rate Test Study, WP-96-FS-BPA-07A.

While the parties have raised a number of issues regarding BPA's residential exchange costs in their briefs, there are a number of issues raised by the parties during the hearing that were not raised in the parties' briefs. Pursuant to section 1010.13(b) of the *Procedures Governing BPA Rate Hearings*, arguments not raised in parties' briefs are deemed to be waived. Such issues will be implemented based on BPA's stated position in the record.

5.2 Adjustment for Coyote Springs in PGE's ASC

Issue

Whether BPA should include costs for Coyote Springs in its forecast of Portland General Electric's (PGE's) average system cost (ASC).

Parties' Positions

PGE argues that this proceeding is not the proper forum to determine the treatment of the Coyote Springs generation plant in PGE's ASC. PGE Brief, WP-96-B-GE-01, at 2. PGE argues that this issue should be addressed in the BPA docket opened by BPA's Exchange Branch when PGE seeks to introduce those costs in its average system cost. *Id.*

WPAG argued that the BPA should replace the output of PGE's Coyote Springs plant with firm power purchased on the open market, which would reduce the costs of Coyote Springs included in ASC. Beck, *et al.*, WP-96-E-WA-01, at 14-15. WPAG did not raise this issue in its initial brief or brief on exceptions.

BPA's Position

WPAG essentially asks BPA to predetermine that Coyote Springs is an imprudent resource. Grinberg, *et al.*, WP-96-E-BPA-43, at 15. It is premature to determine the prudence of PGE's investment in Coyote Springs. *Id.*

Evaluation of Positions

In its testimony, WPAG estimated the production costs of Coyote Springs to climb from $33.34 per megawatt-hour in 1997 to $37.58 per megawatt-hour in 2001. Beck, *et al.*, E-WA-01, at 14-15. WPAG argued that a private utility with a diversified resource base of generating resources would not likely build an additional generating unit with production costs as high as Coyote Springs when cheaper power is available in the bulk power market. *Id.* at 15. WPAG then argued that BPA should replace the output of Coyote Springs with firm power purchased on the market, which would provide a more reasonable estimate of PGE's least cost power supply options in the future. *Id.* In rebuttal testimony, PGE argued that this issue is not properly determined in this rate case and should be addressed in the BPA Exchange Branch docket in which Coyote Springs costs are introduced into PGE's ASC. Piro, Schue, WP-96-E-GE-01, at 1.

WPAG is essentially asking BPA to determine that Coyote Springs is an imprudent resource. Grinberg, *et al.*, E-BPA-43, at 15. It is premature to determine the prudence of PGE's investment in Coyote Springs for a number of reasons. *Id.* First, replacing the

Coyote Springs costs with the costs of a power purchase at market rates would be tantamount to BPA predetermining that Coyote Springs is an imprudent resource. *Id.* BPA does not yet have a complete record upon which to make such a determination. *Id.* PGE has made a request for the recovery of its investment in Coyote Springs in Oregon Public Utility Commission (OPUC) Docket No. UE-93. *Id.* The OPUC, however, has not yet reviewed PGE's fixed costs for Coyote Springs. *Id.* BPA's jurisdictional approach for the establishment of a utility's ASC relies upon the costs approved by the jurisdictional regulator as the starting point of its review. *Id.* Until BPA has the opportunity to review the OPUC's order regarding the Coyote Springs resource, it would be inappropriate to determine that the resource is imprudent. *Id.*

Furthermore, the OPUC has approved the inclusion of the variable power costs of Coyote Springs in the base rates it approved in Docket UE-88. *Id.* BPA reviewed these costs as part of PGE's Revised Appendix 1 Filing, Docket 6-A1-9501. *Id.* Given the OPUC's prior approval of variable power costs, it is reasonable to assume that the OPUC will approve the fixed O&M and capital costs of Coyote Springs in its review of Docket UE-93. *Id.* In BPA's supplemental testimony (Grinberg, *et al.*, WP-96-E-BPA-72), BPA proposed to include the costs of Coyote Springs recently filed by PGE before the OPUC in Docket UE-93. *Id.* The costs filed by PGE are the best data available at this time. *Id.*

In BPA's supplemental testimony, BPA proposed to include the cost data from the revised Appendix 1 filing in BPA's final rate proposal. *Id.* BPA has received the Revised Appendix 1 filing from PGE based on the costs approved by the OPUC in Docket UE-93 and is currently reviewing that filing in BPA Docket No. 5-A1-9503.

Decision

It is premature to determine the prudence of PGE's investment in Coyote Springs. The costs approved by the OPUC and submitted by PGE in BPA Docket 5-A1-9503 are the best data available at this time and should be included in BPA's forecast of PGE's ASC.

5.3 Treatment of Undepreciated Trojan Costs in PGE's ASC

Issue

Whether BPA has properly reflected the costs of the Trojan nuclear plant in BPA's forecast of PGE's ASC.

Parties' Positions

PGE argues that this proceeding is not the proper forum to determine the treatment of the Trojan Nuclear Power Plant investment recovery in PGE's ASC. PGE Brief, WP-96-B-GE-01, at 2. PGE argues that the decision to include Trojan costs was already made by the OPUC and was addressed in BPA's Docket No. 6-A1-9501. *Id.*

PPC argued that BPA did not use its most recent final ASC report, that BPA is not obliged to follow the OPUC's determination on Trojan costs, and that BPA should review its record given that a number of parties have challenged the legality of PGE's recovery of Trojan costs. Carr, Hicks, WP-96-E-PP-07, at 2. PPC did not raise this issue in its initial brief. In its brief on exceptions, PPC argues that a recent Oregon circuit court opinion precludes PGE from recovering the unamortized portion of its investment in the Trojan nuclear facility. PPC Ex. Brief, WP-96-R-PP-01, at 7-8. PPC argues that, if upheld, the decision could reduce PGE's ASC and thus residential exchange benefits. *Id*.

BPA's Position

Because BPA has issued a final report on this matter, the concerns identified by the PPC regarding BPA's use of a revised Appendix 1 filing are moot. Grinberg, *et al.*, WP-96-E-BPA-43, at 14. Ongoing litigation is not a sufficient reason in this instance to assume costs other than those in BPA's report. *Id.*

Evaluation of Positions

In its testimony, PPC argued that BPA did not use its most recent final ASC report in determining PGE's ASC but improperly relied upon PGE's most recent revised Appendix 1, which could change by the time BPA issues its final report. Carr, Hicks, E-PP-07, at 2. PPC also argued that BPA is not obliged to adopt the OPUC's determination for BPA's ASC determination. *Id.* at 4-5. PPC also argued that several parties have challenged the legality of PGE's recovery through rate base of PGE's investment in Trojan and BPA should therefore review the record before it in PGE's Appendix 1 filing and not include the disputed components of the Trojan nuclear plant. *Id.*

On November 8, 1995, the BPA Administrator signed an ASC report regarding PGE's above-noted Appendix 1 filing. Grinberg, *et al.*, E-BPA-43, at 14. For this reason BPA will no longer rely on PGE's Appendix 1 filing for its forecast of PGE's ASC. *Id.* BPA's supplemental exchange cost forecast will be based on BPA's final report. *Id.* Consequently, PPC's arguments are moot. *Id.*

In its Draft Record of Decision, BPA concluded that to the extent that there are legal challenges to the OPUC's treatment of Trojan costs, it would be inappropriate at this time to assume costs other than those contained in BPA's ASC report. Draft ROD, WP-96-A-01, at 84, citing Grinberg, *et al.*, E-BPA-43, at 14. BPA noted that it has not previously changed its treatment of costs simply because of ongoing litigation. *Id.* In its brief on exceptions, PPC notes that an Oregon circuit court judge recently found that PGE could not legally recover the unamortized portion of its investment in the Trojan nuclear facility. PPC Ex. Brief, WP-96-R-PP-01, at 7-8. PPC argues that, if upheld, the decision could reduce PGE's ASC and therefore PGE's exchange benefits by millions of dollars. *Id*. BPA acknowledges that the recent court decision cited by PPC could potentially reduce PGE's ASC and thus PGE's residential exchange benefits. While BPA respects PPC's justifiable concerns, BPA must conclude that it is premature to rely on the decision for purposes of forecasting PGE's exchange benefits. BPA takes official notice of the fact that PGE and the OPUC have appealed the judge's decision. Therefore, the litigation regarding this issue has not been completed. The judge's decision may be affirmed on appeal or reversed. In the event the decision is reversed, it would be inappropriate to rely on the decision in forecasting exchange benefits. Furthermore, even assuming for the sake of argument that the decision is affirmed, the decision must be implemented by the OPUC. BPA is unable to predict the manner in which the OPUC might implement the decision and therefore is unable to forecast the effect that the decision and the OPUC's subsequent order would have on PGE's ASC. In summary, while PPC has raised a legitimate concern, it would be both inappropriate and impractical to revise BPA's forecast of PGE's ASC and exchange benefits at this time.

Decision

BPA will use the OPUC approved costs to determine PGE's ASC. While there may be legal challenges to the OPUC's treatment of Trojan costs, it is inappropriate to assume costs other than those contained in BPA's ASC report at this time.

5.4 Forecast of PRAM 4 True-Up Amount

Issue

Whether BPA has properly estimated the amount of the Periodic Rate Adjustment Mechanism (PRAM) true-up for Puget Sound Power & Light Company's (Puget's) residential exchange benefits for fiscal year 1997.

Parties' Positions

PPC argues that BPA's Draft Record of Decision is inconsistent with the Record of Decision for the Fiscal Year 1997 Residential Exchange Benefit Allocation (Allocation ROD), which provides that BPA will pay Puget the actual amount of the PRAM 4 true up in excess of the $8.354 million used to determine Puget's allocation percentage. PPC Ex. Brief, WP-96-R-PP-01, at 7.

BPA's Position

A $10 million PRAM true-up for FY 1997 was assumed in BPA's rate proposal. Documentation for the Supplemental WPRDS, WP-96-E-BPA-61A, at 533. BPA takes official notice of the Washington Utilities and Transportation Commission's (WUTC's) Docket Number UE-950618, which approved costs for Puget's PRAM true-up for FY 1997 that would increase the true-up amount over the $10 million originally forecasted by BPA. BPA should reflect the additional amount of the FY 1997 PRAM true-up amount as an additional adjustment in determining the probability of BPA making its Treasury payment. *See* Keep, *et al*., WP-96-E-BPA-66, at 4.

Evaluation of Positions

Puget's residential exchange benefits are determined in part by a PRAM true-up. Keep, *et al.*, WP-96-E-BPA-99, Attachment 3, at 2. The PRAM is a ratemaking experiment established jointly by the Washington Utilities and Transportation Commission and Puget in which differences between forecasted costs and actual costs (on a modeling basis) that occurred during the test year are compared at the beginning of the second subsequent PRAM rate period. Any over- or underrecovery of costs are then trued-up, that is, Puget's revenue requirement is adjusted. At that time, Puget makes an average system cost (ASC) filing with BPA. Following the 210 day ASC review period, Puget's PRAM true-up ASC filing results in a change to its ASC and exchange benefits for a period 2 years earlier.

In the 1996 rate case, BPA assumed that Puget's PRAM true-up for FY 1997 would be $10 million. Documentation for the Supplemental WPRDS, E-BPA-61A, at 533. However, BPA's testimony establishes that while the historical forecasts of PRAM payments were $10 million annually for fiscal years 1993 and 1994, the actual PRAM true-up amounts have greatly exceeded the forecasts. Keep, *et al.*, WP-96-E-BPA-99, Attachment 3, at 2. The fiscal year 1993 true-up (PRAM 2) was $26.4 million, or $16.4 million over the forecast. The fiscal year 1994 true-up (PRAM 3) will be $26.1 million, or $16.1 million over the forecast. *Id.;* BPA Docket No. 7-A1-9501. This trend is continuing for the PRAM true-up for fiscal year 1995 (PRAM 4), which is scheduled to be paid in FY 1997.

Pursuant to section 1010.11(c) of the *Procedures Governing BPA Rate Hearings,* BPA takes official notice of WUTC Docket Number UE-950618, Exhibit 39. The WUTC approved costs in WUTC Docket No. UE-950618 that resulted in a $28.9 million dollar PRAM 3 true-up filing by Puget. Keep, *et al.*, WP-96-E-BPA-99, Attachment 3, at 2. The WUTC also approved PRAM 4 costs for the first seven months of the PRAM 4 period in the same WUTC docket. The approved PRAM 4 deferrals for the 7-month period are $32,764,459 and the approved PRAM 3 deferrals for the comparable 7-month period are $40,479,182. The PRAM 4 deferrals are therefore approximately 80 percent of the PRAM 3 deferrals for the comparable 7-month period. The level of PRAM 4 deferrals approved to date indicates that the trend of relatively high PRAM true-ups will continue. Assuming that the PRAM 4 deferrals are 80 percent of the PRAM 3 deferrals, the total PRAM 4 true-up amount will be approximately $21 million. BPA assumed a $10 million true-up in its supplemental proposal. Documentation for the Supplemental WPRDS, E-BPA-61A, at 533. In order to reflect the increase in the PRAM 4 true-up amount, $11 million should be added to the $10 million already assumed for the PRAM 4 true-up to more accurately reflect the actual cost.

The addition of $11 million to the PRAM true-up amount for FY 1997 cannot be incorporated into BPA's ratemaking absent knowledge of the manner in which the additional amount would be handled in the allocation of residential exchange benefits for FY 1997. As noted in BPA's testimony, BPA has conducted an interpretative rulemaking process to determine the proper method of allocating residential exchange benefits for FY 1997. Keep, *et al.*, E-BPA-99, Attachments 2 and 3. BPA's Record of Decision adopting an allocation methodology was released concurrently with the 1996 rate case Draft Record of Decision. Pursuant to section 1010.11(c) of the *Procedures Governing BPA Rate Hearings*, BPA takes official notice of BPA's final allocation methodology. Under this methodology, in simple terms, BPA pays $145 million in FY 1997 residential exchange program benefits. The $10 million previously forecasted for the Puget PRAM 4 true-up is included in total FY 1995 benefits for purposes of determining Puget's percentage share of 1997 exchange benefits.

PPC argues that BPA's Draft Record of Decision is inconsistent with the Record of Decision for the Fiscal Year 1997 Residential Exchange Benefit Allocation (Allocation ROD), which provides that BPA will pay Puget the actual amount of the PRAM 4 true up in excess of the $8.354 million used to determine Puget's allocation percentage. PPC Ex. Brief, WP-96-R-PP-01, at 7. PPC's argument is well founded. In addition to the foregoing discussion, BPA will pay Puget any PRAM 4 benefits due Puget for FY 1995 in excess of $8.354 million. BPA should reflect the additional $12.646 million of the FY 1997 PRAM true-up amount as an additional adjustment in determining the probability of BPA making its Treasury payment. *See* Keep, *et al.*, E-BPA-66, at 4.

<u>Decision</u>

BPA will add $11 million to the $10 million forecast of the PRAM 4 true-up amount to be paid in FY 1997 in order to more accurately reflect the expected level of the PRAM 4 true-up for that year. BPA will reflect the additional $12.646 million of the FY 1997 PRAM true-up amount as an additional adjustment in determining the probability of BPA making its Treasury payment.

5.5 <u>$145 Million Residential Exchange Payment in FY 1997</u>

<u>Issue</u>

Whether BPA recouped a portion of the legislated $145 million in residential exchange payments for FY 1997 from Portland General Electric Company (PGE) in 1998-2001.

<u>Parties' Positions</u>

PGE argues that BPA's supplemental rate proposal recoups from PGE's residential customers approximately $14 million of their FY 1997 benefits in the subsequent 4 years contrary to the legislative history of the Energy and Water Development Appropriations Act, P.L. 104-46. PGE Brief, WP-96-B-GE-01, at 3.

WPAG argues that PGE's conclusion, that an increase in the PF Exchange rate to PGE means that BPA is attempting to recoup the $145 million exchange payment in FY 1997, does not follow from its premises. Beck, *et al.*, WP-96-E-WA-15, at 14. WPAG notes that the PF Exchange rate could increase for other reasons, which does not mean that BPA is attempting to recoup the $145 million. *Id.*

BPA's Position

BPA is not recouping any portion of the $145 million in residential exchange benefits for FY 1997 from PGE. Keep, *et al.*, WP-96-E-BPA-99. Differences in the PF Exchange rate or in residential exchange benefits for a particular utility are the result of other changes between BPA's initial and supplemental proposals, particularly changes in exchanging utilities' average system costs (ASCs). *Id.*

Evaluation of Positions

PGE notes that the Conference Report to the Energy and Water Development Appropriations Act of 1995 indicates that it was not intended that BPA's residential exchange payment of $145 million in FY 1997 be recouped from residential exchange customers in the remaining years of the 5-year rate period. PGE Brief, B-GE-01, at 3; Piro, Schue, WP-96-E-GE-02, at 1. PGE then compares its forecasted exchange benefits under the initial proposal PF Exchange rate to its estimated benefits under the $145million payment. PGE Brief, B-GE-01, at 3; Piro, Schue, E-GE-02, at 2. PGE notes that the increase in benefits is approximately $20 million. *Id.* PGE then notes that PGE's effective PF Exchange rate in the supplemental proposal is higher than its effective PF Exchange rate in the initial proposal, which results in lower forecasted benefits for PGE under the supplemental proposal for 1998-2001. *Id.* PGE then concludes that the $14million difference in projected PGE benefits between BPA's initial and supplemental proposals is somehow a manner of "recouping" the extra $20million in exchange benefits that PGE estimates it should receive under the $145million allocation for FY 1997. *Id.*

These arguments are not persuasive for a number of reasons. First, total residential exchange benefits for the four years FY 1998 through FY 2001 averaged $66.5 million per year in BPA's supplemental proposal compared to an annual average of $56.5 million in BPA's initial proposal. Keep, *et al.*, E-BPA-99, at 2. This constitutes an increase of $10 million per year in total residential exchange benefits under BPA's supplemental proposal. *Id.* BPA has not "recouped" the increased FY1997 residential exchange benefits from exchanging customers in the remaining years of the 5-year rate period. *Id.* In fact, the residential exchange benefits for those remaining years have increased by an average of $10 million per year. *Id.* at Attachment 1.

Furthermore, the Energy and Water Development Appropriations Act of 1995 states that "the cost benefits of eligible utilities' total purchase and exchange sales under 16 U.S.C. 839c(c)(1) shall be $145,000,000 for fiscal year 1997." The Conference Report on the legislation states that "[i]t was not intended that BPA's residential exchange payment of $145 million in fiscal year 1997 be recouped from BPA's residential exchange customers in the remaining years of the 5-year rate period." In the testimony of Keep,*et al.*, WP-96-E-BPA-66, BPA described its implementation of the foregoing legislation. BPA proposed to develop rates in a manner that would not recoup the additional FY 1997 exchange benefits from residential exchange customers and would not increase rates to BPA's public utility and direct service industrial customers. Keep, *et al.*, WP-96-E-BPA-99, at 2-3. BPA's proposal determined rates by calculating BPA's revenue requirement for the rate period in the same manner as it was calculated in BPA's initial proposal. *Id*. at 3. The cost of the residential exchange in FY 1997 was not adjusted to reflect exchange benefits of $145 million. *Id*. This was implemented in the following manner. First, the PF Preference and PF Exchange rates were calculated. *Id*. Second, the amount of the FY 1997 exchange benefits resulting from the PF Exchange rate was determined. *Id*. Finally, BPA calculated the difference between the $145 million and the FY 1997 exchange benefits derived from the PF Exchange rate. *Id*. This additional amount was taken from projected BPA cash reserve estimates that would have otherwise been available for risk mitigation. *Id*. By isolating the additional amount in this way, BPA could not "recoup" the $145 million from the residential customers in the remaining years of the 5-year rate period. *Id*. Differences in the PF Exchange rate or in residential exchange benefits for a particular utility are the result of other changes between BPA's initial and supplemental proposals. *Id.* For example, PGE ignores the fact that its forecasted ASC declined from the initial rate proposal to the supplemental rate proposal. Following adjustments to cost escalators, purchase power costs, and to the Coyote Springs Generating Unit (Grinberg, *et al*., WP-96-E-BPA-72, at 2-4), PGE's forecasted ASC for FY 1998 declined from 34.91 mills per kWh in the initial proposal to 34.62 mills per kWh in the supplemental rate proposal. Supplemental WPRDS, E-BPA-61A, at 530. A reduction in a utility's ASC results in a reduction in a utility's residential exchange benefits. This effect is not a result of BPA recouping exchange benefits from exchanging utilities during the four years following FY 1997.

In addition to changes in PGE's ASC, the ASCs of other exchanging utilities also changed in BPA's supplemental proposal. Grinberg, *et al.*, E-BPA-72, at 1-8. The section 7(b)(2) rate test determines the total amount of exchange benefits available to the exchanging utility customer class as a whole. This total level of benefits has increased in each of BPA's rate proposals. Benefits are then allocated based on utilities' ASCs and exchange loads through the applicable PF Exchange rate. When modeling the distribution of these benefits, an increase in an exchanging utility's individual ASC and/or exchange load relative to PGE's ASC and exchange load will cause PGE's individual share of the total exchange benefits to decrease. In this case, Puget Sound Power & Light Company's (Puget's) ASCs in the initial proposal ranged from 33.51 mills/kWh in FY 1997 to 35.55 mills/kWh in 2001. Initial WPRDS, WP-96-E-BPA-05A(E4), at 53. In BPA's supplemental proposal, Puget's ASCs ranged from 34.19 mills/kWh in 1997 to 37.25 mills/kWh in 2001. Supplemental WPRDS, E-BPA-61A, at 530. As noted above, PGE's ASC declined from the initial proposal to the supplemental proposal. Therefore, a reduction in benefits to PGE is not the result of BPA recouping part of the $145 million from PGE, but instead is the result of BPA reflecting revised ASCs for exchanging utilities in the development of the PF Exchange rate. In simple terms, PGE's reduction in exchange benefits is largely due to Puget's increase in exchange benefits.

Decision

BPA has not recouped any portion of the $145 million in FY 1997 residential exchange payments from PGE.

5.6 In Lieu Transactions and Exchange Loads

Issue

Whether BPA should assume that in lieu transactions will occur in the July 1, 2001, to September 30, 2005 (2002-2005) time period and what the appropriate exchange loads will be during that period.

Parties' Positions

The Major Residential Exchange Participants (MREP or IOUs) argue that BPA's initial proposal assumption that there would be no in-lieu transactions is inconsistent with BPA's "real world position." MREP Brief, WP-96-B-GE/PL/PS-01, at 29-30; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 21-22. The IOUs also argue that BPA has declined to take a position on the assumption about in-lieu transactions. MREP Brief, WP-96-B-GE/PL/PS-01, at 31.

WPAG argues that BPA should assume that the current in-lieu notice requirements continue after 2001. WPAG Brief, WP-96-B-WA-01, at 17. WPAG also argues that the in-lieu notice periods under the post-2001 RPSA commence no earlier than the date such contracts are executed, thereby reducing the amount of exchange load subject to in-lieu transactions. *Id.*

PPC argues that BPA should not assume that it will exercise its in-lieu rights with exchanging utilities after 2001. PPC Brief, WP-96-B-PP-01, at 19-20; PPC Ex. Brief, WP-96-R-PP-01, at 6. PPC argues that the simultaneous pressures of competition and regulation should force the IOUs into a narrow set of alternatives regarding the types of generation and transmission costs eligible for subsidization under the exchange program such that they will not be able to retain full tariff costs after 2001 that would make in-lieu transactions inevitable. *Id.*

BPA's Position

In BPA's initial proposal, BPA assumed that no in-lieu transactions would occur either pre- or post-2001 through 2005. Grinberg, *et al.*, WP-96-E-BPA-16, at 10. In BPA's rebuttal testimony, BPA acknowledged that an assumption of some in-lieu transactions is appropriate because it is likely that in-lieu resources will be available at lower cost than the ASCs of many exchanging utilities during the outyears. Grinberg, *et al.*, WP-96-E-BPA-43, at 2. BPA also agreed with the IOUs that it is appropriate to base an estimate of future in-lieu transactions on transactions occurring after July 1, 2001. *Id.* at 2-3.

Because there are currently no RPSAs in effect that govern the post-2001 period, BPA recognized that any estimate of future in-lieu transactions must be based on assumptions of contract provisions governing the implementation of in-lieu transactions under RPSAs in effect after July 1, 2001. *Id.* BPA recognized that there are two basic approaches to assumptions regarding post-2001 RPSA provisions. *Id.* at 3. One approach assumes that the post-2001 RPSA is similar to both the current RPSA and the principles developed for the subsequent RPSA. *Id.* Using this approach, BPA proposed that a reasonable estimate for in-lieu transactions for the period from 2002 through 2005 is 50 percent of the exchange load of PGE and Puget and 100 percent of the exchange load of Oregon Trail Electric Cooperative and the southern Idaho jurisdiction of PacifiCorp (approximately 1300 aMW). *Id.* at 9. One hundred percent of exchange loads should be assumed to exist for the years 2002-2005. *Id.* at 10-12. The other approach assumed that the post-2001 RPSA is significantly different than the current RPSA and principles. *Id.* Under this approach, it was assumed that new RPSAs would allow BPA to in-lieu 100 percent of exchange loads and that no exchange loads should exist for the years 2002-2005. *Id.* at 10, at 12-13. BPA noted that it would determine the proper approach after reviewing the parties' briefs.

Evaluation of Positions

The residential exchange program involves a "purchase" of power from an eligible utility at the utility's average system cost (ASC) and a "sale" of an equal amount of powerback to the utility at BPA's applicable PF rate. 16 U.S.C. 839c(c). The amount of the purchase and sale equals the utility's residential and small farm load. *Id.* Under section 5(c)(5) of the Northwest Power Act, BPA may "acquire an equivalent amount of electric power from other sources to replace power sold to a utility [as part of the residential exchange] if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility." 16 U.S.C. 839c(c)(5). In other words, in lieu of purchasing power from the utility at the utility's ASC, BPA may purchase power from an alternative source (an "in-lieu resource") if the cost of the acquisition is less than the utility's ASC. *Id.* This acquisition of power from other sources is "in lieu" of the "purchase" of power at the utility's average system cost (ASC) that would otherwise occur under the residential exchange and is designed to provide a mechanism to control the costs of the residential exchange. Grinberg, *et al.*, E-BPA-16, at 9. Without "in lieu" transactions or a similar cost-control provision, BPA's "purchase" of power from utilities participating in the residential exchange would have no limit to the amount of costs that BPA, and its customers, might be required to bear. *Id.* The in-lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable RPSA. *Id.*

The Major Residential Exchange Participants (IOUs) argue that BPA's assumption in its initial proposal that there would be no in-lieu transactions in the 2002-2005 period is inconsistent with BPA's real world position. MREP Brief, B-GE/PL/PS-01, at 29-30. While the IOUs criticize BPA's initial proposal assumption, the assumption of zero in-lieu transactions was abandoned in BPA's rebuttal testimony. *See* Grinberg, *et al.*, WP-96-E-

BPA-43, at 2. Nevertheless, the IOUs argue that BPA has served exchanging utilities with purported notices of its intent to invoke its in-lieu authority. MREP Brief, B-GE/PL/PS-01, at 30. The IOUs cite a June 2, 1995, letter from BPA to exchanging utilities "asserting its right to in-lieu up to 100% of their exchange loads, and asserting that the economics of the power business suggest such a strategy." *Id.;* Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 7. This letter, however, did not require BPA to in lieu 100 percent of BPA's exchange load, but rather noted that BPA may conduct in-lieu transactions for anywhere from zero to 100 percent. Grinberg,*et al.*, E-BPA-43, at 9. This letter therefore does not establish that BPA would conduct in-lieu transactions for any particular amount of exchange load. *Id.*

The IOUs also argue that BPA's economic forecasts support the proposition that there should be in-lieu transactions. MREP Brief, B-GE/PL/PS-01, at 30. The IOUs argue that BPA's supplemental proposal projects more than 4000 MW of firm power available in fiscal year 2001 at prices less than or equal to 29 mills/kWh. *Id.* The IOUs argue that given BPA's forecast that power available to displace DSI and preference customer loads increases from 1998-2001 at rates of 29 mills or less, with average system costs exceeding 29 mills, an assumption of no in-lieu transactions is inconsistent with BPA's case. *Id.* Again, as noted above, BPA abandoned its initial proposal assumption that there would be no in-lieu transactions after 2001. *See* Grinberg, *et al.*, E-BPA-43, at 2. BPA agrees with the IOUs that in-lieu transactions would occur after 2001. *Id.* The issue, however, is what would be the extent of such in-lieu transactions and what would be the effect on post-2001 exchange loads. BPA addressed this issue at great length during the hearing, as recounted in greater detail below.

With regard to the argument that there are 4000 aMW of power available for in-lieu transactions after 2001, the IOUs' argument is not persuasive. The 4000 aMW cited by the IOUs is not based on a forecast of regional resources and costs for the post-2001 period. Indeed, the record establishes that the proper manner of determining the cost of in-lieu resources for 2002-2005 is based upon an estimate of the marginal cost to servean increment of regional load based on the regional planning model developed in BPA's Strategic Planning Group. Grinberg, *et al.*, E-BPA-43, at 6-7. Even this analysis may understate the cost of in-lieu resources. *Id.* at 7. Instead of a direct analysis of in-lieu resources and costs, however, the IOUs rely upon BPA's testimony on competitiveness and, in particular, a table entitled "Potential Sales Losses for High Price Case." Moorman, Evans, WP-96 -E-BPA-65, at 7. This table addresses potential BPA sales losses as opposed to surplus regional resources and resource costs. The table provides that BPA would incur sales losses of up to 4000 aMW if it were assumed that BPA's PF rate were 29 mills/kWh and BPA's IP rate were 27 mills/kWh. BPA's proposed PF and IP rates in BPA's supplemental proposal were 24.94 mills/kWh and 22.60 mills/kWh, respectively, not the higher numbers cited by the IOUs. Therefore, BPA is not forecasting that BPA will experience load losses of 4000 MW or that 4000 MW will be available as in-lieu resources after 2001 based on BPA's competitiveness testimony. Furthermore, the table relied upon by the IOUs only shows data through the year 2001. Moorman, Evans, E-BPA-65, at 7. Therefore, the table does not provide the cost of in-lieu resources for the post-2001 period when in-lieu transactions would occur. Also, the table does not establish the cost or amount of surplus resources available after 2001.

Given that BPA does not forecast sales losses of 4,000 aMW which would make surplus BPA power available as in-lieu resources, the issue becomes whether power that otherwise would have been sold by BPA's competitors to BPA's customers would instead be available as in-lieu resources. Even assuming, arguendo, that BPA incurred sales losses, the table provides no indication of the type of resources that would be used by BPA's competitors to serve BPA's sales losses, nor does the table indicate the terms and conditions that would be assumed to exist between the seller and BPA's former customer. There is no indication whether BPA's potential lost sales would be served by BPA's competitors with existing surplus, nonfirm energy sources, new generation or purchase power. There is no indication that potential sales would be month-to-month, yearly, or long-term. The IOUs have long argued that an in-lieu resource should be a firm resource. Grinberg, *et al.*, E-BPA-43, at 5. Under a post-2001 RPSA similar to the existing RPSA, the term of an in-lieu transaction would have to be at least 5 years duration. *Id*. at 5. The table provides no evidence that 4000 aMW in in-lieu resources would be available from BPA's competitors after 2001 that would satisfy these conditions.

In their brief on exceptions, the IOUs argue that BPA objects to the use of a table entitled "Potential Sales Losses for High Price Case" from BPA's competitiveness testimony because the cited resources may be of a nonfirm nature. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 22. The IOUs argue that BPA's objection is inconsistent with the fact that the sales losses in the table are potential losses of DSI and public agency firm sales. *Id*. The IOUs have misinterpreted BPA's argument. BPA did not argue that BPA's potential sales losses were nonfirm. Instead, BPA argued that the table did not demonstrate the replacement power of BPA's competitors would be firm, and therefore one could not demonstrate that the replacement power would meet the requirements of an in lieu resource. In order for the table to demonstrate the availability of BPA firm power as an in lieu resource, the referenced table would have to contain rates similar to BPA's proposed rates and the time period of the table would have to cover the proposed in lieu period. In order for the table to demonstrate the availability of competitors' power as an in-lieu resource, the replacement power used to displace BPA firm power would have to meet the conditions required of an in lieu resource and the time period of the table would have to cover the proposed in-lieu period. However, the rates used in the table are not the rates BPA is forecasting for the relevant time period. Furthermore, the time period of the table ends in 2001, while the in-lieu period begins in late 2001. Also, there has been no demonstration that the replacement power used to displace BPA firm power would meet the conditions required of an in lieu resource. In summary, the cited table does not establish that 4,000 aMW of in-lieu resources are available after 2001.

The IOUs argue that they cannot discern BPA's position on in-lieu transactions. MREP Brief, B-GE/PL/PS-01, at 31. This is puzzling, however, because BPA's position has been laid out in great detail, as evidenced by the discussion below. In summary, BPA acknowledged that it was appropriate to include the assumption of some in-lieu transactions in the post-2001 period. Grinberg, *et al.*, E-BPA-43, at 2. BPA noted that there is no RPSA currently in effect that would govern the post-2001 period. *Id.* BPA then noted that any assumption regarding the implementation of in-lieu transactions depends upon the assumptions made regarding the terms of the RPSA for the post-2001 period, because the RPSA governs the manner in which BPA implements in-lieu transactions. *Id.* at 3. BPA stated that there are two basic approaches to assumptions regarding post-2001 in-lieu provisions. *Id.* One approach assumes that the post-2001 RPSA is similar to both the current RPSA and the principles developed for the subsequent RPSA. *Id.* The other approach assumes that the post-2001 RPSA is significantly different than the current RPSA and principles. *Id.* Each of these approaches was described in great detail in order that the parties would have a complete opportunity to address any and all issues associated with either approach, or with alternative approaches that BPA did not identify. *Id.* at 3-13. BPA would determine the proper approach in developing its rates after reviewing the parties' briefs on this issue.

The IOUs also argue that BPA ducked the controversy about its assumptions contradicting its conduct and experimented with the assumption that it would invoke the in-lieu provision. MREP Brief, B-GE/PL/PS-01, at 31. To the contrary, however, as discussed in greater detail below, BPA directly addressed every issue raised by the IOUs regarding allegations that BPA's assumptions somehow contradicted its conduct. In addition to falsely accusing BPA of "ducking" issues, which is refuted by the record, the IOUs raise another ad hominem argument, suggesting that BPA incorporated the assumption of a 100 percent in-lieu in developing its supplemental rates in order to "inspire parties receiving rate reductions under BPA's proposal to put evidence in the record purporting to support BPA's initial position that no in-lieu transactions should be assumed." MREP Brief, B-GE/PL/PS-01, at 31. This argument is completely unfounded. BPA never considered that the use of a 100 percent in-lieu assumption would incite any particular party or parties to file testimony supporting BPA's initial proposal assumption of no in-lieu transactions. Furthermore, such an argument makes little sense for many reasons. First, as noted above, BPA abandoned its initial proposal assumption of no in-lieu transactions in its rebuttal testimony. BPA had no incentive to seek new testimony supporting a position it no longer advocated. Second, the actual reason for the assumption of 100 percent in-lieu transactions is plainly stated in the record:

> BPA recognizes that two approaches for determining exchange loads in the outyears have been presented. Because there is currently no contract which governs the residential exchange program after June30, 2001, BPA must make some estimate of the manner in which in-lieu transactions will take place under post-2001 RPSAs. BPA has made no decision to implement either approach at this time, although some approach had to be used in order to perform the supplemental section 7(b)(2) rate test. BPA's initial proposal section 7(b)(2) rate test assumed zero in-lieu transactions and thus incorporated 100 percent of exchange loads. The assumption of zero exchange load in the supplemental proposal allows parties to see the

other extreme regarding the greatest potential impact of in-lieu transactions on the section 7(b)(2) rate test.

Grinberg, *et al.*, WP-96-E-BPA-72, at 9. This rationale states the true reason BPA included this assumption in its supplemental proposal. Finally, the use of a 100 percent in-lieu assumption could equally be seen as a means of inciting parties who favor the 100 percent in-lieu assumption to file testimony supporting BPA's proposal. In summary, the IOUs' ad hominem arguments are unfounded.

The IOUs argue that BPA has expressly stated that it has no position on whether in-lieu transactions should be assumed -- it will let the parties know when the Draft ROD is released. MREP Brief, B-GE/PL/PS-01, at 31. Again the IOUs have mischaracterized BPA's position. As noted above and discussed in greater detail below, BPA identified two options for in-lieu transactions: one assuming that the post-2001 RPSA is similar to both the current RPSA and the principles developed for the subsequent RPSA (using a 50 percent in-lieu of PGE and Puget and a 100 percent in-lieu of PacifiCorp's southern Idaho jurisdiction and Oregon Trail Electric Cooperative), and a second option that assumed an RPSA different from the existing RPSA and principles (using a 100 percent in-lieu of all exchanging utilities). Grinberg, *et al.*, E-BPA-43, at 3-13. Neither of these options advocated an assumption of no in-lieu transactions. Each of these options was presented in great detail in order that parties could comment on each approach during the hearing and the parties' briefs could assist BPA in making a determination of the proper approach in the Draft Record of Decision.

The foregoing discussion of the issues raised by the parties in their briefs is illuminated by a more complete review of the record and the development of BPA's rate proposals. In BPA's initial proposal, BPA assumed that no in-lieu transactions would occur either pre- or post-2001 through 2005. BPA made this assumption for a number of reasons. *Id.* at 10. First, the current RPSA does not allow BPA to start in lieu transactions until 7 years from the date of BPA's notice of its intent to in lieu. *Id.* Because the in lieu would not begin until after the expiration of the current RPSA, BPA will not in lieu a utility under the current RPSA and there are no contracts in place to implement in lieu transactions between now and 2005. *Id.* Second, BPA was unsure if there would continue to be a significant difference between the expected price of in-lieu power and the ASCs of what would today be the most likely utility candidates for in-lieu transactions. *Id.* Finally, BPA was unsure whether utilities would sign the new proposed RPSA that may soon be offered to replace the current RPSA. *Id.* The proposed draft RPSA template was released on June 26, 1995. *Id.* Because of current differences between BPA and certain parties regarding the proposed draft RPSA, it was not clear whether any parties would accept the proposed draft RPSA. *Id.* If, for whatever reason, the utilities did not sign the proposed draft RPSA, then BPA would have no in-lieu opportunities prior to July 1, 2001, and would assume no in-lieu opportunities post July 1, 2001, unless it were assumed that BPA would rely on in lieu under a subsequent RPSA that incorporates "statutory in-lieu" provisions beginning July 1, 2001. *Id.*

While BPA's initial proposal did not assume any in-lieu transactions in the outyears, BPA did not reject the possibility of in-lieu transactions and identified possible alternatives to the assumption of no in-lieu transactions. *Id.* at 10-11. BPA identified two general approaches that might govern BPA's implementation of in-lieu transactions. *Id.* First, utilities representing 75 percent or more of qualifying exchange load might sign the draft proposed RPSA and BPA could then begin in-lieu transactions consistent with the provisions in the draft proposed RPSA. *Id.* In the second approach, utilities might choose not to sign the draft proposed RPSA and BPA, under a later RPSA, could begin in-lieu transactions after June 30, 2001. *Id.*

Under the draft proposed RPSA, BPA determined that if the proper number of utilities were to sign the draft proposed RPSA and loads, resources and costs were to remain unchanged from the present, and BPA were to provide in lieu notices, it would then likely be assumed that BPA would send in-lieu notices to PGE, Puget, and PacifiCorp. *Id.* at 11. The notice to PacifiCorp would be for only its southern Idaho jurisdiction. *Id.* BPA would assume that PGE and Puget would limit BPA to the 100 aMW cap in each of the first two in-lieu periods provided in the draft proposed RPSA. BPA would issue subsequent notices to these utilities consistent with the draft proposed RPSA. *Id.* This would result in in-lieu transactions totaling 226 aMW for the FY 1998-1999 period, 453 aMW for the FY 2000-2001 period, 915 aMW for the FY 2002-2003 period, and 1388 aMW for the FY 2004-2005 period. *Id.* These amounts of in lieu transaction under the proposed draft RPSA are consistent with the ramp-in limits for in-lieu transactions contained in the draft proposed RPSA. *Id.*

Under a future RPSA beginning July 1, 2001, BPA noted that the amount of in-lieu transactions would be different. *Id.* If BPA were to issue in-lieu notices under some future RPSA, BPA assumed that in-lieu notices equal to 50 percent of PGE's and Puget's exchange load would be issued, and PacifiCorp's southern Idaho jurisdiction would be in lieued for its entire exchange load. *Id.* This would total 1225 aMW of in-lieu transactions beginning July 1, 2001. *Id.* These amounts of in-lieu transactions were chosen because both PGE and Puget have large residential exchange loads (approximately 1,000 MW). *Id.* at 12.

BPA initially assumed that it would send in-lieu notices to those three utilities because these utilities, PGE, Puget Power, and PacifiCorp's southern Idaho jurisdiction, have among the highest ASCs of the utilities participating in the residential exchange. *Id.* Additionally, it would be administratively easier to serve a smaller number of utilities that could provide potentially large amounts of savings. *Id.* The combined ASC of PacifiCorp's other jurisdictions is close to resource costs and thus could be marginally attractive for in-lieu purposes. *Id.* Most of the public agency customers that participate in the residential exchange either have ASCs that are not much greater than resource costs or have very small residential exchange loads. *Id.* To in lieu public agency customers would require BPA to issue many in-lieu notices to achieve a comparable level of savings to that which would be available by issuing an in-lieu notice to PGE or Puget. *Id.*

The IOUs argued that BPA inappropriately assumed that there would be zero in-lieu transactions during the years 2002 through 2005. Piro, *et al.*, E-GE/PL/PS-02, at 6-7. In BPA's rebuttal testimony, however, BPA acknowledged that an assumption of some in-lieu transactions is appropriate because it is likely that in-lieu resources will be available at lower cost than the ASCs of many utilities during the outyears. Grinberg, *et al.*, E-BPA-43, at 2. BPA also agreed with the IOUs that it is appropriate to base an estimate of future in-lieu transactions on transactions occurring after July 1, 2001. *See* Piro, *et al.*, E-GE/PL/PS-02, at 6-7. Currently there are no RPSAs in effect that govern the post-2001 period. Grinberg, *et al.*, WP-96-E-BPA-43, at 2. Any estimate of future in-lieu transactions, therefore, must be based on assumptions of contract provisions governing the implementation of in-lieu transactions under RPSAs in effect after July 1, 2001. *Id.* at 2-3.

As noted above, BPA recognized that there are two basic approaches to assumptions regarding post-2001 RPSA provisions. *Id.* at 3. One approach assumes that the post-2001 RPSA is similar to both the current RPSA and the principles developed for the subsequent RPSA. *Id.* The other approach assumes that the post-2001 RPSA is significantly different than the current RPSA and principles. *Id.* BPA must choose one of these approaches, or a variation of these approaches, in determining its in-lieu assumptions. The parties addressed this issue in their briefs. WPAG argues that BPA's ability to exercise in-lieu rights after 2001 depends upon the RPSA provisions governing such transactions at that time and since this is after the current RPSA expires, it is a matter of speculation what provisions will be agreed to in such new contracts regarding the exercise of in-lieu rights. WPAG Brief, B-WA-01, at 17. WPAG argues that in such circumstances it is best to assume that the in-lieu provisions in the current RPSA will be carried forward into the post-2001 period. *Id.* WPAG argues that this approach reduces speculation and allows the section 7(b)(2) rate test to operate on the basis of provisions which are known and determinable. *Id.* WPAG notes that this does not mean that all post-2001 exchange load would be subject to the exercise of in-lieu. *Id.* WPAG argues that any notice given under the existing RPSA would cease to have effect when the RPSA expires in 2001 unless the utilities agree under the subsequent RPSA to be bound by the prior notice. *Id.* WPAG argues that the utilities would not agree to be so bound and therefore the notice period for any in-lieu notice issued under the post-2001 RPSA would commence no sooner than the date such RPSA would be executed. *Id.* at 18.

PPC notes that in-lieu transactions are discretionary and need not occur unless BPA chooses to implement them. PPC Brief, B-PP-01, at 19. PPC argues that while the IOUs successfully compete with BPA in large-load markets, they ask BPA to make the contrary assumption in this rate case that their full tariff costs will still be so high after 2001 that in-lieu transactions will be inevitable. *Id.* PPC argues that the IOUs are charging their residential customers retail rates around 50 mills/kWh while they are simultaneously competing for larger loads at prices of 20 mill/kWh or less. *Id*. PPC argues that this rate disparity will motivate customers to either seek regulatory redress or seek competitive alternatives over the next 5 years. *Id.* If customers fail to act, PPC argues that regulatory intervention will occur on their behalf. *Id*. PPC argues that the simultaneous pressures of competition and regulation should force the IOUs into a narrow set of alternatives regarding the types of generation and transmission costs eligible for subsidization under the exchange program, which will force the IOUs to reduce such costs through elimination or restructuring. *Id.*; PPC Ex. Brief, WP-96-R-PP-01, at 6. PPC concludes that the most reasonable assumption is that the IOUs will have been forced to have reduced their respective ASCs by the time BPA could start making in-lieu transactions in 2001. *Id.* In summary, PPC argues that in-lieu transactions should be unnecessary by 2001. *Id.*

As noted above, the IOUs disagree with the PPC position and argue that there is no basis for an assumption that there would be no in-lieu transactions after 2001. MREP Brief, B-GE/PL/PS-01, at 30-31.

Based upon the record, BPA finds that an approach which assumes that the post-2001 RPSA will be similar to both the current RPSA and the principles developed for the subsequent RPSA is the best approach. Under this approach, as explained in greater detail below, BPA would in-lieu 100 percent of the exchange loads of PacifiCorp's southern Idaho jurisdiction, Oregon Trail Electric Cooperative, PGE and Puget. Such an approach is the most reasonable because it is based on the existing RPSA which has been used to implement the residential exchange program for the past 16 years and it also reflects the principles developed in contract negotiations for the subsequent RPSA. Thus, there is a factual basis for the rules governing in-lieu transactions under this approach. The other approach, which simply assumes that a subsequent RPSA would allow BPA to implement in-lieu transactions virtually without limitation, is both speculative and contrary to the existing RPSA and principles. There is no factual basis supporting such an approach. Tr. 2069.

WPAG argues that BPA should assume that there would be a notice requirement for in-lieu transactions and that BPA should assume that any in-lieu transaction could not begin until after the RPSAs were executed and the notice requirement satisfied. WPAG Brief, B-WA-01, at 17. Under the current RPSA there is a 7 year notice requirement prior to implementing in-lieu transactions. Under the RPSA principles for the subsequent RPSA there is a 2 year notice requirement. While it is true that the notice requirement must be satisfied and can only be satisfied after the RPSA is effective, the date of execution of the next RPSA is not known. The RPSA could be negotiated and executed well before 2001 such that any notice requirement could be satisfied by 2001. Alternatively, notice provisions could be established in the new RPSA that would allow initial in-lieu transactions upon shorter notice than the current RPSA and principles.

As noted above, PPC argues that the simultaneous pressures of competition and regulation should force the IOUs to reduce the costs eligible for subsidization under the exchange program. PPC Brief, B-PP-01, at 19; PPC Ex. Brief, WP-96-R-PP-01, at 6. This would force the IOUs to reduce their respective ASCs by the time BPA could start making in-lieu transactions in 2001. *Id.* PPC's argument regarding future market forces may be correct, however, because BPA cannot know the events to unfold in the retail rate arena in the future, PPC's conclusions are speculative at this time. PPC has not cited any factual evidence presented in the hearing in support of its argument. As noted previously, based on BPA's forecast of utilities' ASCs and the forecasted cost of in lieu resources, BPA believes that it is appropriate to assume that in lieu transactions will occur in the outyears.

During the hearing, the IOUs argued that there would be no exchange benefits in the 2002-2005 period because the cost of in-lieu resources would be below the PF rate. Piro, *et al.*, E-GE/PL/PS-07, at 6-7. Viewed from the perspective of a post-2001 RPSA similar to the existing RPSA and principles, however, BPA should assume that some exchange benefits are available during the 2002-2005 period because, while BPA would in lieu the exchange loads of PacifiCorp's southern Idaho jurisdiction, Oregon Trail Electric Cooperative, PGE and Puget, it may not be administratively or economically feasible to in lieu the exchange loads of BPA's preference customers other than Oregon Trail.

The IOUs argued that BPA's initial proposal assumes that the cost of alternative sources of power will be 24.9 mills per kWh during the 2002-2004 period and 25.4 mills per kWh in 2005. Piro, *et al.*, E-GE/PL/PS-02, at 6-7. The IOUs also noted that the PF Exchange rates for these years ranged from 28.5 mills per kWh in 2001 up to 29.8 mills per kWh in 2004. *Id.* The IOUs, however, did not properly calculate the cost of in-lieu resources. Grinberg, *et al.*, E-BPA-43, at 4. The cost of alternative sources of power cited by the IOUs was an estimate of the cost of BPA's monthly short-term power purchases to serve existing BPA load. *Id.; see* Documentation for Section 7(b)(2) Rate Test Study, WP-96-E-BPA-07A(E1). These purchases are nonfirm over the year and firm for the month. Grinberg, *et al.*, E-BPA-43, at 4. This is an inappropriate resource to use to determine the cost of in-lieu resources because it does not provide guaranteed availability. *Id.* The IOUs have never agreed that short-term purchases alone can be used as an in-lieu resource. *Id.* at 5. The IOUs have long argued that an in-lieu resource should be a firm resource. *Id.* In the recent power sales contract and RPSA negotiations, the Joint Customer Proposal of October 31, 1994, at page 10 stated that "[t]he in lieu resource must be a firm resource which BPA has, at the time of notice, a contractual or statutory right to purchase for the in lieu period." *Id.*, Attachment 1. The "Proposed Tentative Agreements -- Power Sales Contract Negotiations" regarding the Residential Exchange Agreement (hereafter Tentative Agreements) at page 4 stated that "The [in-lieu] resource package shall be a firm resource in the amount of the in lieu notice shaped to the utility's system load." *Id.*, Attachment 2. This was supplemented by the ability to use a combination of "(1) nonfirm energy or spot market purchases used to displace firm in lieu resources in an amount estimated to be available to BPA for such displacement and at a cost equal to the opportunity cost of such displacement, and (2) other spot market firm energy purchases; provided that the other spot market firm energy purchases under (2) may not constitute more than 10% of the total energy of the in lieu package."*Id.* In addition, the Tentative Agreements provided that the identified resources must be of types customarily relied upon by Pacific Northwest customers to meet utility firm loads. *Id.* In summary, short-term power purchases alone are inconsistent with the type of resources the IOUs have argued should be permitted as in-lieu resources and are an inappropriate source to determine the cost of in-lieu resources. Grinberg, *et al.*, E-BPA-43, at 5.

The IOUs' proposal was also inappropriate because there are a number of additional factors that may be considered in determining the cost of in-lieu resources. *Id.* One factor is the term of the in-lieu transaction. *Id.* If an in-lieu transaction must continue for an extended period of time, resources would have to be available throughout the term of the transaction and the cost of acquiring the resources would be higher. *Id.* For example, the current RPSA requires a 5-year minimum term and the Tentative Agreements provide for a 7-year minimum term. *Id.* The cost of the in-lieu resource would therefore be higher than a short-term market price since the power must be available for a longer term. *Id.* at 6.

Another factor is whether there are additional constraints regarding the types of power that can be acquired as an in-lieu resource. *Id.* For example, the Tentative Agreements provide that in addition to resources being types customarily relied upon by Pacific Northwest utilities to meet their firm loads, the resources must be types that are available to BPA at the time of the in-lieu notice and have identified costs which are obtainable at the time of the in-lieu notice. *Id.* In addition, the Tentative Agreements would require that the expected cost of the in-lieu resource include the cost of transmission, necessary reserves, and any appropriate risk premiums. *Id.* Such items would increase the cost of in-lieu resources. *Id.*

A proper estimate of the cost of in-lieu power for the 2002-2005 time period is based upon BPA's estimate of the marginal cost to serve an incremental 1500 aMW of regional load. *Id.* The marginal costs are derived from BPA's regional planning model developed in BPA's Strategic Planning Group. *Id.* The model estimates monthly costs to serve incremental load in the region. *Id.* The model does not identify specific resources that are used to meet the incremental load but instead uses a combination of regional and extraregional firm and nonfirm resources to serve the incremental load. *Id.* Nonfirm energy is used when it is available, primarily April through July. *Id.* The cost of transmission and reserves is included in the cost estimates. *Id.* If the market prices are higher than the cost of building a combustion turbine (CT), then the model assumes that a combustion turbine is built to serve the incremental load (instead of using a combination of regional firm and nonfirm resources to serve incremental load). *Id.* at 6-7.

The model results were shaped to the average residential load of PGE, PacifiCorp's Idaho jurisdiction, Puget and Oregon Trail Electric Cooperative. The cost of power is as follows:

Year	**2002**	**2003**	**2004**	**2005**
mills/kWh	**29.85**	**30.19**	**30.53**	**31.48**

Grinberg, *et al*., WP-96-E-BPA-43 at 7.

In their brief on exceptions, the IOUs argue that the foregoing figures are not supported in the record and are not appropriate for calculating the costs of resources projected to be available for in-lieu transactions. MREP Ex. Brief, WP-96-GE/PL/PS-01, at 22. The argument that the figures are not supported in the record is puzzling. BPA's rebuttal testimony discussed the cost of in-lieu resources at length and included the foregoing figures, indeed, the exact same table noted above, as reflecting the "appropriate manner to calculate the cost of in-lieu resources." Grinberg, *et al.*, WP-96-E-BPA-43 at 6-7. BPA's testimony also described the model used to develop these figures and the shaping of the model results to reflect the average residential load of four exchanging utilities that would be the subjects of in-lieu transactions *Id*. Far from not being supported in the record, the foregoing figures were a central part of BPA's case which was thoroughly documented in BPA's testimony. *Id*.

The IOUs also argue that the foregoing costs are overstated because they are based on the cost of serving incremental regional loads. MREP Ex. Brief, WP-96-GE/PL/PS-01, at 22. The IOUs argue that loads which might be in-lieued are not incremental to regional loads. *Id*. The IOUs cite no evidence in the record to support their argument. In any event, however, this argument is misplaced. In the normal implementation of the residential exchange program, BPA is assumed to purchase power from the exchanging utilities and sell an equal amount of power in return, but the fictional nature of the exchange makes the actual existence of such power unnecessary. Under an in-lieu transaction, however, BPA no longer implements the residential exchange program as a fictional purchase and sale of power. Under an in-lieu transaction, BPA must actually acquire power from in-lieu resources and actually deliver PF power to the exchanging utility for the appropriate portion of the utility's residential load. In other words, BPA must acquire incremental amounts of power to physically meet loads it was not previously required to meet. The fact that these should be viewed as incremental resources is supported by the fact that one of the consequences of an in-lieu transaction is to render the exchanging utility surplus because BPA acquires incremental resources to meet a load it did not previously serve and the utility no longer needs it own resources to meet that portion of the regional load.

In addition, it is appropriate to use the cost of resources to meet incremental regional load as the cost of in-lieu resources because the RPSA and the principles for the subsequent RPSA require BPA to identify the in-lieu resource, that is, the incremental resource, to be acquired. Because this power is incremental to power that is used to meet regional loads, it is appropriate to use the cost of resources to meet incremental regional loads as the cost of in-lieu resources. Although a utility may elect to set its ASC equal to the cost of the in-lieu resource for the amount of the in-lieu transaction instead of accepting an actual delivery of PF power, BPA must demonstrate that the in-lieu resources are available prior to being able to implement the in-lieu transaction. For example, the current RPSA provides that an in-lieu notice must state the amount, duration, source, estimated cost and estimated scheduling provisions of the intended acquisition. *See* RPSA, Section 4(a). In addition, the principles for the subsequent RPSA provide that any in-lieu notice must identify a resource or resources ("in-lieu resource package") in the amount specified in the in-lieu notice, including the amount, duration, source, expected cost and availability of each such resource. Grinberg, *et al.,* WP-96-E-BPA-43, Attachment 2, at 2-3. The principles also require that the identified resources must be types customarily relied upon by Pacific Northwest utilities to meet utility firm loads and be of types available to BPA at the time of the in-lieu notice and have identifiable costs which are obtainable at the time of the in-lieu notice. *Id*. In summary, therefore, given that BPA must identify as in-lieu resources particular resources that are not being used to meet regional loads, it is appropriate to use the cost of resources to serve incremental regional load as an estimate of the cost of in-lieu resources.

The IOUs' argument that BPA should assume no exchange benefits for 2002 through 2005 is not based solely on the cost of in-lieu resources, but also on an assumption that BPA would implement in-lieu transactions for 100 percent of its exchange load. Piro *et al.,* E-GE/PL/PS-02, at 6-7. This assumption is not reasonable. Grinberg, *et al.,* E-BPA-43, at 7. First, the errata distributed at the July 25, 1995, clarification session show that some utilities in the 2002-2005 time period have ASCs that are clearly greater than the PF rate but less than the estimated cost of the in-lieu resource. *Id.,* Attachment 3. Such utilities would still receive positive residential exchange benefits.

Second, some of the utilities have ASCs that are fairly close to the forecasted in-lieu resource cost. *Id.* at 8. This difference could be less, or negative, due to forecast uncertainty in the estimates of both ASC and in-lieu resource costs. *Id*. In-lieu transactions with these utilities would yield minimal, if any, savings. *Id*. The administrative cost of implementing the in-lieu transaction for these utilities could outweigh the savings from the transactions. *Id*. In summary, for forecasting purposes, it is reasonable to assume in-lieu transactions only with utilities that have significant differences between ASC and in-lieu resource costs. *Id*.

A reasonable estimate for in-lieu transactions for the period from 2002 through 2005 is 100 percent of the exchange loads of PGE, Puget, Oregon Trail Electric Cooperative and the southern Idaho jurisdiction of PacifiCorp. This would equal approximately 2300-2400 aMW. In lieu transactions for these loads make sense for a number of reasons. First, each of these utilities has an ASC substantially higher than the cost of in lieu resources. For this reason, these transactions would be economically advantageous for BPA. BPA would reduce residential exchange costs by the difference between the utilities' ASCs and the cost of the in lieu resources multiplied by the utilities' exchange loads. Second, because of the significant difference between the utilities' ASCs and the cost of in lieu resources, BPA would have an incentive to in lieu as much of the utilities' loads as possible. Third, the need to acquire a large amount of in lieu resources may be mitigated by the provisions of the RPSA which allow the utility to elect to reduce its ASC to the cost of the in lieu resource for the amount of the in lieu transaction and continue the normal implementation of the residential exchange program. Under this option, the utility elects not to receive an actual delivery of PF power and BPA is not required to acquire any in lieu resources. Finally, it would be administratively easier to in lieu a small number of large exchanging utilities than a large number of small utilities.

The assumption of in-lieu transactions for only the four specified utilities is supported by the fact that some exchanging utilities have ASCs that are greater than the PF rate but less than the in-lieu resource cost, in which case in-lieu transactions make no sense. *Id.* at 10. This assumption also recognizes that other exchanging utilities have ASCs that are very close to the cost of in-lieu resources, thereby making an in-lieu transaction risky, with little or no financial benefit to BPA. *Id.* In addition, the vast majority of benefits from in-lieu transactions are available from a small number of utilities. *Id.* In summary, BPA's proposed in-lieu transactions would require the acquisition of approximately 2300-2400 aMW of in-lieu resources. BPA would substantially reduce the cost of the residential exchange program by undertaking this level of in-lieu transactions.

The IOUs argued that BPA should assume that there are zero exchange loads during the 2002-2005 period. Piro, *et al.*, E-GE/PL/PS-02, at 7. This is inappropriate. *Id.* First, in order for there to be no exchange load, all exchanging utilities would have to terminate their RPSAs. Grinberg, *et al.*, E-BPA-43, at 10. In order to terminate an RPSA, the rate test of section 7(b)(2) of the Northwest Power Act must trigger and the supplemental rate charge provided for in section 7(b)(3) of the Act must be applied and the cost of the power sold to the exchanging utility must exceed, after application of the rate charge, the average system cost of power sold by the exchanging utility. *Id.* at 11. This, however, cannot occur in BPA's analysis because in determining whether BPA should conduct in-lieu transactions with exchanging utilities, BPA must first assume that the section 7(b)(2) rate test has not triggered and the PF Preference and PF Exchange rates are the same. *Id.* This is consistent with the manner in which BPA has always conducted this analysis. *Id.* Because BPA cannot assume that there is a rate test trigger, BPA cannot assume that utilities would have the ability to terminate their RPSAs. *Id.*

It is also inappropriate to assume that BPA would have zero exchange loads for 2002-2005 because, as noted above, the cost of in-lieu resources is higher than the PF rates for that period. *Id.* The exchange would therefore continue and there would be exchange loads during the 2002-2005 period. *Id.* Utilities' exchange loads are defined in the applicable RPSA. *Id.* The draft RPSA for the 2002-2005 period requires the exchange of a utility's entire residential and small farm load. *Id.*

Furthermore, the residential exchange program operates in two basic modes: (1) a paper purchase and sale; or (2) a real purchase and sale under in-lieu transactions. *Id.* In both cases, the PF sale portion of the transaction constitutes the exchange load. *Id.* During in-lieu transactions, utilities have two options: (1) to adjust their ASC down to the cost of the in-lieu resource in the amount of the in-lieu transaction; or (2) to purchase PF power in the amount of the in-lieu transaction. *Id.* Under the first option, the utility continues to participate in the residential exchange in the normal manner, except that its ASC is reduced and its benefits are decreased accordingly. *Id.* The utility continues to have an exchange load regardless of whether there is a partial or 100 percent in-lieu transaction. *Id.* If there is a 100 percent in-lieu and the cost of the in-lieu resource is less than the PF rate, the election to adjust the ASC to the cost of the in-lieu resource would result in the utility deeming its ASC equal to the PF rate. *Id.* A utility might choose this course if it did not want to receive a delivery of real PF power. *Id.* at 12. A utility might be willing to do so in order to continue its participation in the residential exchange program and the possibility of receiving positive exchange benefits in the future years of the RPSA. *Id.*

Where a utility elects the second option, to purchase real PF power, BPA acquires power from an in-lieu resource instead of the utility and BPA continues to sell PF power to the utility, except that the utility now receives an actual delivery of PF power. *Id.* Where there is a partial in-lieu transaction (that is, only a portion of the utility's load is the subject of an in-lieu transaction) and the utility elects to purchase real PF power, the portion of load not subject to in-lieu continues as a normal exchange load and the other portion continues to have an exchange load because BPA continues to purchase resources and sell PF power, although the purchase is from a source other than the utility. *Id.* Where there is a 100 percent in-lieu transaction and the utility elects to purchase real PF power, the utility continues to have an exchange load for the same reason. *Id.* Even if 100 percent of a utility's exchange load is the subject of an in-lieu transaction, this does not mean that the utility has no exchange load. *Id.* In summary, BPA should assume 100 percent of exchange loads for the years 2002-2005.

The IOUs argued that BPA's supplemental proposal supports the assertion that the residential exchange should not be assumed to exist after September 30, 2001, because the Conference Report to the Energy and Water Development Appropriations Act of 1995 states that "[t]he conference report now before the Senate encourages BPA and its customers to work together to phase out the residential exchange by October 1, 2001." Piro, *et al.*, E-GE/PL/PS-06, at 1-2. The IOUs, however, failed to note a colloquy between Senator Domenici and Senator Hatfield which expressly clarifies the Conference Report. Grinberg, *et al.*, E-BPA-103, at 2. Senators Hatfield and Domenici stated:

> "Hatfield: . . . The conference report now before the Senate encourages BPA and its customers to work together to phase out the residential exchange by October 1, 2001. Furthermore, it is my additional understanding that <u>the conferees did not intend this encouragement to affect the current development of rates by BPA because the outcome of the regional review and settlement discussions are not known at this time</u> Mr. President, let me ask the Senator from New Mexico if this comports with his understanding?
>
> Domenici: Mr. President, let me say in answer to my friend from Oregon, the distinguished chairman of the full committee and the author of the provision we are now discussing, that his statement does indeed comport with my understanding." (Emphasis added.)

In summary, Congress expressly directed that its encouragement to phase out the residential exchange program by October 1, 2001, was not intended to affect the development of rates by BPA in the current rate case. Grinberg, *et al.*, E-BPA-103, at 2-3. The statement cited by the IOUs provides no support for a rate case assumption of the elimination of the residential exchange program after September 30, 2001, because the cited colloquy confirms that the statement was not intended to be reflected as requiring the elimination of the program on that date in BPA's current rate case. *Id.* at 3.

The IOUs also argued that BPA should assume no exchange benefits in the Program Case for the years 2002 through 2005 because BPA's supplemental proposal projects 600-700 aMW of sales under new SP contracts during that period at rates of 24.2 mills/kWh or less and projects a PF Exchange rate without a section 7(b)(2) trigger of 27.79 mills/kWh for each year of the period; thus, resources will be available at a cost less below the PF Exchange rate. Piro, *et al.*, E-GE/PL/PS-06, at 2. The IOUs' argument assumes that the cited resources are acquired in lieu of purchasing power from the exchanging utility at its average system cost (ASC). Grinberg, *et al.*, E-BPA-103, at 3. A portion of the cited resources, about 60 aMW, are already committed sales and therefore not available for an in-lieu transaction. *Id.; see* Documentation for Supplemental 7(b)(2) Rate Test Study, WP-96-E-BPA-63A, at 39, columns "New SP Comb" and "Total." The remaining cited SP resources may be unavailable for use as in-lieu resources and would be inadequate to support in-lieu transactions for BPA's entire exchange load. Grinberg, *et al.*, E-BPA-103, at 3.

BPA would logically begin marketing the SP power as soon as it was available. *Id.* For example, in FY 1997, BPA would attempt to market all SP power available at that time. *Id.* This would also be true for whatever SP power was available in subsequent years, that is, FY 1998, 1999, 2000 and 2001. *Id.* In the event, for example, that BPA sold the power in 2000 for a 5-year term or used the power for other purposes, no power would be available as an in-lieu resource for the period 2002 through 2005. *Id.* at 3-4 The SP resources are therefore not necessarily available as in-lieu resources. *Id.* at 4.

In addition, the cited SP resources comprise only 600 to 700 aMW. *Id.* BPA's total exchange load is approximately 3700 aMW in 2002 and approximately 3850 aMW in 2005. *Id.* Even assuming for the sake of argument that the SP power were used as an in-lieu resource, it would only be sufficient to support in-lieu transactions for a portion of BPA's exchange load. *Id.* The existence of 600 to 700 aMW of SP power therefore is not a basis for assuming zero exchange benefits for 2002 through 2005. *Id.* In order for there to be no exchange benefits during this period, BPA would have to acquire in-lieu resources in the amount of BPA's entire exchange load, all of which were priced less than BPA's PF rate. *Id.*

Furthermore, under the existing RPSA and principles developed for the subsequent RPSA, even if BPA acquired in-lieu resources in an amount equal to BPA's total exchange load and such resources were priced less than the PF rate, there would be no exchange benefits but there would still be 3700 to 3850 aMW of exchange loads. *Id.* This is explained in greater detail in BPA's rebuttal testimony on residential exchange costs. *Id.; see* Grinberg, *et al.*, E-BPA-43, at 12-13. Also as explained in greater detail in that testimony, the only manner to eliminate all exchange benefits and exchange loads during the period 2002 through 2005 would be under the assumption of a post-2001 RPSA which did not have the constraints of the existing RPSA and recent principles. Grinberg, *et al.*, E-BPA-103, at 4. As discussed previously, such is an unreasonable assumption.

PPC/APAC argued that assuming that the IOUs are in-lieued is tantamount to assuming that the IOUs will not be competitive power suppliers even by 2002. Carr, *et al.*, WP-96-E-BPA-PP/PA-03, at 20. In effect, PPC/APAC contended that any IOU subject to an in-lieu transaction in 2002 would not be competitive. Grinberg, *et al.*, E-BPA-103, at 5. This is incorrect. Exchanging utilities' average system costs (ASCs) are generally based on the average cost of generation and transmission. *Id.; see* 1984 ASC Methodology. If the marginal cost of power is below average power costs, and continues to be over an extended period of time, average power costs will trend downward. Grinberg, *et al.*, E-BPA-103, at 5. It is not unlikely, however, for a utility making prudent purchases and sales at prices below its ASC to still be in a position by the year 2002 in which its ASC exceeds BPA's PF rate. *Id.* Despite the availability of low-cost power, the utility's ASC would still be dominated by acquisitions made in a higher cost era. *Id.* Therefore, BPA does not equate a utility's vulnerability to an in-lieu transaction with a utility's competitiveness as a power supplier. *Id.*

Decision

A reasonable approach for estimating in-lieu transactions is based upon the assumption of a post-2001 RPSA that is similar to the existing RPSA and principles developed for the subsequent RPSA. A reasonable estimate of the extent of in-lieu transactions for the period from 2002 through 2005 is 100 percent of the exchange loads of PGE, Puget, Oregon Trail Electric Cooperative and the southern Idaho jurisdiction of PacifiCorp (approximately 2300-2400 aMW). BPA would substantially reduce the cost of the residential exchange program by undertaking this level of in-lieu transactions. A proper estimate of the cost of in-lieu power for the 2002-2005 time period is based upon BPA's estimate of the marginal cost to serve an increment of regional load. One hundred percent of exchange loads should be assumed to exist for the years 2002-2005.

6.0 MARGINAL COST ANALYSIS FOR WHOLESALE POWER

6.1 Introduction

BPA develops its rates by allocating costs to firm loads that BPA is obligated to meet. Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, at 5. However, BPA does not allocate costs to all loads. For instance, BPA does not allocate costs to projected short-term sales of firm and nonfirm power. *Id.* at 18. Revenues from short-term power sales are credited against the costs allocated to firm loads so that BPA does not recover more than its revenue requirement. *Id.* For ratemaking purposes, the cost of an increase in BPA's firm, in-region loads is the cost of any associated resource acquisition or operation or power purchase, plus the revenue foregone due to any associated reduction in nonfirm or surplus firm sales. Therefore, the estimate of BPA's marginal costs reflects both the cost of resource acquisition and operation by BPA, and the price at which BPA buys and sells power products in the West Coast market. Supplemental Marginal Cost Analysis Study, WP-96-E-BPA-60, at 4.

The Marginal Cost Analysis (MCA) estimates BPA's marginal cost of serving firm load on a monthly, daily, and hourly basis. *Id.* at 1. These marginal cost estimates are used to develop seasonal and diurnal shapes for BPA rates, and to classify costs between firm energy and demand. The primary tool used for estimating BPA's marginal costs is the Power Market Decision Analysis Model (PMDAM). *Id.* PMDAM simulates wholesale power market activity throughout the interconnected West Coast system. *Id.* BPA can serve load at the margin either by acquiring new sources of generation or by purchasing power from other West Coast utilities. Because BPA is an active participant in the West Coast market, the marginal cost BPA faces no longer is likely to be the cost of acquiring long-term rights to the output of new generation, but is more likely to be the costs of acquiring products and services from other utilities in the West Coast market. Vatter, *et al.*, WP-96-E-BPA-17, at 17. Therefore, BPA's marginal cost for a product or service often is the price at which that product is sold in the West Coast market. *Id.*

6.1.1 Power Marketing Decision Analysis Model

PMDAM has been reviewed independently by the California Public Utilities Commission (CPUC) and the Western Systems Coordinating Council (WSCC). *Id.* at 10. The CPUC compared PMDAM to several other models and ranked it the highest in terms of accuracy. *Id.* PMDAM is available commercially to all utilities. In addition, PMDAM has been used and continues to be used by several West and East coast utilities. *Id.*

Prior to the beginning of the formal rates process, BPA conducted numerous workshops on the Marginal Cost Analysis, which focused on PMDAM. *Id.* at 9. At these workshops, BPA discussed the model logic, algorithms, input data assumptions, and outputs. In addition, BPA provided tutorials to the workshop participants on all aspects of the model including sensitivities and hands-on experience with running the model.

Perhaps as a result of these workshops, no party took issue with using PMDAM to measure BPA's marginal cost.

Issue #1

Whether BPA should revise PMDAM to account for forced outages on the intertie links with California.

Parties' Positions

APAC, DSIs, and PGP, representing high load factor customers, (hereinafter called the high load factor customers) initially suggested that one shortcoming of PMDAM is that the model fails to take into account forced outages on either a planning or an operational basis on the intertie links with California. Wolverton, *et al*., WP-96-E-PA/DS/PG-01, at 10. The high load factor customers assert that including an allowance for intertie outages in PMDAM increases the marginal cost of capacity. *Id*. at 11. While the DSI and PGP did not pursue this issue in their briefs, APAC, in a footnote, continues to argue that PMDAM should not assume that the southern intertie is available 100% of the time. APAC's Ex. Brief, WP-96-R-PA-01, at 29 n.36.

BPA's Position

While PMDAM does not simulate forced outages on any intertie links, including the Pacific Northwest-Pacific Southwest (PNW/PSW) Intertie, other modeling assumptions tend to reduce the affect that this assumption would have on the estimate of marginal capacity costs. Vatter, *et al*., WP-96-E-BPA-47, at 11. Moreover, even when portions of the PNW/PSW Interties were not in service for extended periods of time in the recent past, the market for capacity in the West Coast was not so constrained or limited that PNW utilities had way to purchase surplus capacity from other West Coast suppliers. *Id*. at 12.

Evaluation of Positions

APAC, DSIs, and PGP initially filed joint testimony arguing that PMDAM under estimates the marginal cost of capacity by failing to take into account forced outages on either a planning or an operational basis on the intertie links with California. Wolverton, *et al*., WP-96-E-PA/DS/PG-01, at 10. Only APAC continues to pursue this issue in its brief. APAC's Ex. Brief, R-PA-01, at 29, n. 36. For purposes of this evaluation, statements in the joint testimony are attributed solely to APAC. Since the DSIs and PGP did not pursue this issue in their briefs, they are deemed to take no position on this issue. *See Procedures*, Section 1010.

APAC claims, without providing any supporting analysis, that if forced outages on the PNW/PSW Intertie were included in PMDAM, the amount of surplus capacity available to the PNW from the Southwest would be reduced. Wolverton, *et al*., E-PA/DS/PG-01, at 11. If capacity from the Southwest is reduced or constricted, APAC opines that Northwest utilities will install additional generating capacity. *Id*. at 9.

As APAC correctly notes, purchasing off-season surplus capacity from the Southwest is cheaper than building new capacity. *Id*. Consequently, as long as PNW utilities and BPA can contract for surplus capacity from the Southwest, PMDAM will select this source of capacity before building additional capacity resources as the least cost approach to meeting additional capacity needs. APAC, in its quest for increasing the marginal cost of capacity, focuses on one modeling assumption in PMDAM that APAC believes will reduce the amount of surplus capacity from the Southwest and thus force the model to install additional capacity resources in the Northwest. APAC's argument ignores both reality and the conservative modeling assumptions in PMDAM that compensate for that affect that forced outages on the interties would have on the marginal cost of capacity.

As BPA witnesses testified, building additional capacity resources would be a lower cost alternative for PNW utilities and BPA than purchasing off-season surplus capacity from the Southwest when the amount of future capacity purchases from the Southwest approaches or reaches the limits of the intertie capability. Vatter, *et al*., E-BPA-47, at 13. Under these conditions, market prices would increase to where installing new capacity resources would be the preferred alternative in PMDAM. Until the transmission capability of the PNW/PSW Interties is insufficient to accommodate the expected level of sales, decreases in Intertie capability due to forced outages has no impact on BPA's estimated marginal costs of capacity. *See also* Beck, *et al*., WP-96-E-WA-11, at 19 (Forced outages that occur when the Intertie is not fully loaded have no impact on [marginal cost]). The expected amount of future capacity purchases by PNW utilities and BPA, in PMDAM, is no where near the limits of the intertie capability. Given the level of capacity transactions expected on the PNW/PSW intertie during the rate period, revising the model to explicitly model forced outage percentages on the intertie would not materially change the expected marginal cost of capacity.

In addition, PMDAM requires that a selling entity have far more system capability than needed to support the sale. *Id*. As such, PMDAM's conservative planning criteria compensates for not explicitly modeling forced outages. *Id*. PMDAM assumes that any intertie over which the seller would move the contracted-for power would be fully loaded. Since transmission losses are greater when the lines are fully loaded, compared to when the lines are not, each transaction over the intertie in PMDAM assumes the maximum associated transmission losses. In PMDAM, the seller must "back up" the transmission losses with its own resources. *Id*. As such, PMDAM requires that any seller provide greater system capability than would normally be required to support the transaction. *Id*. If PMDAM explicitly modeled forced outages on the interties, the conservative planning criteria could be relaxed. *Id*. The net result would not lead to the results postulated by APAC.

Moreover, in the recent past when a portion of the PNW/PSW intertie has been out of service, power still moved across the portion of the intertie still in service. As APAC notes, a forest fire in Northern California recently closed one of the AC lines. Wolverton, *et al*., E-PA/DS/PG-01, at 11. Yet even under these conditions, transactions between the two regions continued on the other lines. As BPA witnesses testified, temporary outages on portions of the intertie do not appear to be a present or perceived near-term problem that would constrict or limit sales of capacity and energy between the two regions. Vatter, *et al*., E-BPA-47, at 12. Assuming a 10% forced intertie outage, in PMDAM, on 3,000 MW of intertie capacity is not a sufficient enough reduction in intertie capability to drive market prices to a level where installing new capacity generation would be the preferred alternative. *Id*. at 13.

Decision

PMDAM will not be revised to explicitly account for forced outages on the intertie links with California in this rate case. PMDAM includes other assumptions that account for and compensate for forced outages on the PNW/PSW intertie line. PMDAM does not underestimate the marginal cost of capacity.

Issue #2

Whether BPA should revise the gas forecast used in PMDAM.

Parties' Positions

APAC, DSIs, and PGP initially suggested that the gas forecast used in PMDAM should be revised. They argued that no other forecast projects increases in gas or oil prices at the rate or to the level indicated by BPA's forecast. Wolverton, *et al*., E-PA/DS/PG-01, at 10. Again, the DSI and PGP did not raise this issue in their briefs. APAC, however, continues to recommend that BPA incorporate a revised gas forecast in PMDAM. APAC's Ex. Brief, R-PA-01, at 29 n.36.

BPA's Position

PMDAM does not generate it own gas price forecast. Rather the gas price forecast incorporated in PMDAM is consistent with the gas price forecast used in the other rate case models. If BPA revises its gas forecast used to develop its rates, that forecast will be incorporated in PMDAM. Vatter, *et al*., E-BPA-47, at 11. BPA updated the natural gas price forecast in its supplemental proposal and that price forecast was incorporated in PMDAM. Vatter, *et al*., E-BPA-73, at 10. For the final rates, BPA proposes to again revise its gas price forecast and that forecast has been incorporated in PMDAM.

Evaluation of Positions

The gas forecast incorporated in PMDAM is consistent with the rate case gas price forecast, which is used in the other rate case models, such as the Nonfirm Revenue Estimating Program and STREAM. APAC, DSIs, and PGP initially suggested that the gas forecast used in PMDAM should be revised. They argued that no other forecast projects increases in gas or oil prices at the rate or to the level indicated by BPA's forecast. Wolverton, *et al*., E-PA/DS/PG-01, at 10. As part of the Supplemental proposal, BPA proposed a revised gas forecast and that forecast was incorporated in PMDAM. Vatter, *et al*., E-BPA-73, at 10. Since the DSIs and PGP did not pursue this issue in their briefs, they are deemed to take no position on this issue. *See Procedures*, Section 1010. APAC continues to pursue this issue in its brief. APAC's Ex. Brief, R-PA-01, at 29 n.36.

APAC's continuing argument that BPA should lower its gas forecast in PMDAM is mystifying. BPA has revised its gas forecast and incorporated the revised gas forecast in PMDAM. When BPA proposed a lower gas price forecast for its supplemental proposal, that forecast was incorporated in PMDAM. Vatter, *et al*., E-BPA-73, at 10. In the draft ROD, BPA proposed to update the gas price in its final study, and that revised forecast has been incorporated in PMDAM. *See* Final Documentation for the Marginal Cost Analysis, WP-96-FS-BPA-04A. Yet, even after the Draft ROD was released, APAC continues to argue that the gas price forecast should be revised and incorporated in PMDAM. To repeat again, the gas price forecast has been updated and incorporated in PMDAM.

APAC's continuing argument to lower the gas price forecast in PMDAM is puzzling for other reasons as well. APAC argues that incorporating a lower gas price in PMDAM will result in a lower underlying base for high-load-factor customers, such as the DSI. APAC's Brief, B-PA-01, at 29; APAC's Ex Brief, R-PA-01, at 29. Incorporating a lower gas price forecast in PMDAM, however, results in higher rates for high-load-factor customers. In PMDAM, gas is the resource on the margin during the heavy load hours. *See* Final Documentation for the Marginal Cost Analysis, FS-BPA-04A. In the light load hours, coal plants are more likely to be the marginal resource in PMDAM than a gas-fired turbine. *Id*. Consequently, a lower gas price forecast results in lower marginal costs during the heavy load hours. The marginal cost during light load hours remains relatively the same. By incorporating the lower gas price in PMDAM, the marginal cost during heavy load hours is closer to the marginal cost during light load hours. *See* Final Marginal Cost Analysis, WP-96-FS-BPA-04. For high-load-factor customers, a rate design where the heavy- and light-load hour rates are only a mill or two different actually results in a higher rate than would be the case if there was a greater difference between the heavy and light load hour rates.

<u>Decision</u>

The revised gas price forecast is incorporated in PMDAM. The final marginal cost analysis reflects the lower gas price forecasts.

6.1.2 BPA's Marginal Cost Components of Serving Load

BPA's marginal cost is the added cost of meeting an additional unit of load. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 4. There are a number of aspects or attributes of load that a utility takes into account in making decisions on how it will meet an additional unit of future load reliably. For purposes of the marginal cost analysis these load attributes are defined in terms of energy, firmness of energy, capacity, and demand. *Id*.

6.1.2.1 Energy

As used here, "energy" means kilowatthours actually produced by BPA during any given hour. *Id*.

6.1.2.2 Firmness of Energy

As used here, "firmness of energy" means energy that a utility must be prepared to produce over the course of a month. *Id*. The cost of firmness of energy does not include the cost of producing the energy, only the costs of being prepared to produce the energy sometime during the month. *Id*. The high load factor customers initially suggested that, because the marginal cost of firmness of energy represents the cost of preparing to produce energy, this cost is associated with meeting peak load, which is a demand cost and not a power energy cost. These customers argued that the marginal cost of firmness of energy should be reflected in BPA's power demand charges and not in BPA's power energy charges. Wolverton, *et al*, E-PA/DS/PG-01, at 7. The costs of preparing to produce energy, however, are not necessarily the costs associated with preparing to meet peak loads, which are costs appropriately recovered through demand charges. The marginal cost of firmness of energy is the cost of preparing to produce additional energy over the course of the month, which may not add to the utility's ability to meet the highest single-hour peak load in the month. Vatter, *et al.*, WP-96-E-BPA-47, at 3-4. Because commitments during any hour of the month, not just the monthly peak hour when demand costs are incurred, cut into BPA's supply of firmness of energy, the marginal cost of firmness of energy is appropriately added to the marginal cost of energy and not demand. *Id*. The high load factor customers did not pursue this issue in their brief and, as a result, the issue is not addressed any further here.

6.1.2.3 Capacity

As used here, "capacity" means the maximum number of kilowatthours a utility must be prepared to produce within the heavy load hours during each week of a given month. The marginal cost of capacity is the cost associated with being prepared to serve loads during the heavy load hours. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 5. NIU, APAC and PPC criticized BPA's estimate of the monthly marginal cost of capacity in its supplemental proposal. Most of the criticism was directed to the marginal cost of capacity in August, which was high compared to the other months and compared to the initial proposal. Olsen, Saven, WP-96-E-NI-03, at 3; Carr *et al*., WP-96-E-PP/PA-03, at 16. These parties note that the marginal cost for heavy load hours in August increased more in the supplemental proposal than the marginal cost for heavy load hours in the other months. Olsen, Saven, E-NI-03, at 3; Carr *et al.*, E-PP/PA-03, at 16. NIU, PPC and APAC point out that the difference between heavy and light load hour marginal costs in August was much greater in the supplemental proposal than in the initial proposal. Olsen, Saven, E-NI-03, at 3; Carr *et al*., E-PP/PA-03 at 16. NIU also argues that power system and West Coast operations do not support the large differential in BPA's supplemental proposal between the marginal costs in the winter/early spring period and August. Olsen, Saven, E-NI-03, at 5-6. NIU attributes the August heavy load hour increase to the adjustment BPA made to bring the shape of summer capacity costs in line with the monthly shape of Southwest capacity loads. Olsen, Saven, E-NI-03, at 3.

In response to the criticism from NIU, PPC and APAC, BPA reviewed its estimate of the marginal cost of capacity. Based on this review, BPA discovered that it was double counting the marginal cost of demand, in that the capacity product in PMDAM contains both a capacity and a demand component. Vatter,*et al*., WP-96-E-BPA-104, at 4-9. In the supplemental proposal and before, the marginal cost of demand was treated incorrectly as an additional and separate cost from the marginal cost of capacity. *Id*. at 8. As such, the marginal cost of power in the heavy load hours double counted the marginal cost of demand, once in the marginal cost of capacity and again in the marginal cost of demand. *Id*.

To correct this error, BPA proposed to subtract the marginal cost of demand from the marginal cost of capacity. *Id*. This correction lowers the marginal cost of firm energy during heavy load hours, especially during months, like August, when the marginal cost of capacity is relatively high. *Id*. Apparently, this correction addresses the concern expressed by NIU, PPC and APAC. No party opposed the correction. While NIU continued to oppose the July through September, and particularly August, capacity costs in BPA's supplemental proposal, NIU did not challenge the costs as corrected. NIU's Brief, B-NI-01, at 2-3. PPC and APAC did not raise the August heavy load hour marginal cost issue in their briefs. BPA will adopt the proposed approach for measuring the marginal cost of capacity, as corrected.

6.1.2.4 <u>Demand</u>

As used here, "demand" means the number of kilowatthours that a utility must be prepared to produce during the hour of its monthly peak energy load. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 5. To meet a customer's demand, a utility must have access to sufficient generating and contracting capability to ensure that it can provide this number of kilowatthours during the peak hour of the month. *Id*. In the initial proposal, the marginal cost of demand was based on the current market price of a 60-hour per-week, 24-hour return capacity product. Initial Marginal Cost Analysis Study, WP-96-E-BPA-04, at 15. The market price for demand reflected BPA's judgment and experience with marketing capacity. *Id*. In the supplemental proposal, BPA provided additional analysis to supplement and corroborate BPA's judgment and experience. For the supplemental proposal, BPA looked at costs of acquiring peaking resources, which were adjusted to account for the expected capacity surplus during the rate period. Vatter, *et al.*, WP-96-E-BPA-73, at 5. BPA calculates the marginal cost of demand based on the marginal cost of capacity in PMDAM, as adjusted by the ratio of the capital cost of a 150 MW single-cycle combustion turbine compared to the capital cost of a 250MW combined-cycle combustion turbine. *Id.*

WPAG initially recommended that the capital costs of the two combustion turbines, the single-cycle combustion turbine and the combined-cycle combustion turbine, should be based on turbines of equal capacity, instead of costs from different-sized machines. Beck, *et al.*, WP-96-E-WA-13, at 68. BPA explained that the two combustion turbines selected were lowest cost turbines. Vatter, *et al.*, E-BPA-104, at 4. In making the selection, BPA assumed that utilities would acquire the least-cost source of capacity, and would operate those plants at cost-efficient levels either because the utility's retail loads were large enough to absorb the output of the machines, or because the utility would be able to market any surplus machine capability on a wholesale basis. *Id.* WPAG did not pursue this issue in its brief and, as such, WPAG is deemed to no longer take a position on this issue.

6.1.3 <u>Selection of Seasonal Costing Periods</u>

BPA's costs vary over different times of the year and day. Often, BPA's costs vary from one hour to the next. The market price for the different products and services reflects these cost variations. Vatter, *et al.*, E-BPA-17, at 13. In order for BPA to effectively compete in the market, BPA needs to provide customers with information on the variation in BPA's costs over time. *Id.* Therefore, BPA identified the changes in its marginal cost over different times of the year and day.

Monthly pricing periods or seasons are identified by grouping different periods of the year when marginal costs are similar and separating them from other periods that are dissimilar. The monthly pricing periods were selected so that (1) the months grouped together were contiguous, and (2) the difference between monthly marginal costs of firm energy and average marginal costs for the pricing period was limited to 2 mills or less. Based on these criteria, BPA proposed 6 different monthly pricing periods: September-December, January-March, April, May-June, July, and August. Vatter, *et al.*, E-BPA-73, at 3. *See also* Supplemental Marginal Cost Analysis Study, E-BPA-60, at 11.

NIU supports the increase in the seasonal differentiation of BPA's power rates, compared to previous rates which reflected two seasons. Olsen, WP-96-E-NI-01, at 7-8. RCC concurs and notes that BPA's six seasons provide a fair approximation of market conditions given Pacific Northwest and California load profiles, and the Federal system's predominately hydro based operations. Nelson, WP-96-E-RC-02, at 1-3.

WPAG, on the other hand, opposes the greater number of seasonal pricing periods. Beck, *et al*., WP-96-E-WA-01, at 27. WPAG initially urged BPA to reduce the number of seasonal pricing periods to two as in previous rate schedules. *Id*. WPAG recommends two seasonal pricing periods: August through March, and April through July. *Id*. As BPA witnesses noted, WPAG did not provide support for their conclusions through either statistical analysis or verbal explanation. Conger, Schloth, WP-96-E-BPA-46, at 11. WPAG did not pursue this issue in its brief and, as such, WPAG is deemed to no longer take a position on this issue.

6.1.4 <u>Selection of Heavy and Light Load Hours</u>

Heavy- and light-load hours are identified by grouping together hours of the week with similar marginal costs of energy. Vatter, *et al*., E-BPA-17, at 13. Hours with high marginal costs are assigned to heavy load hours, and hours with low marginal costs are assigned to light load hours. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 9-10.

RCC agrees with the results of BPA's analysis and notes that BPA's price differences between heavy and light load hours are consistent with the secondary market "rule-of-thumb" of about $3.00/MWh. Nelson, E-RC-02, at 2.

WPAG disagrees. WPAG asserts that as competition grows within the industry, so do opportunities for arbitrage. Beck, *et al*., E-WA-01, at 26. Under these conditions, WPAG claims that the difference between prices of homogeneous products tends to dissipate. *Id*. To support this claim, WPAG points to the shrinking seasonal prices within the deregulated natural gas industry. *Id*. WPAG recommends reducing the price differential between heavy and light load hours by 50 percent from approximately a two mill differential to a one mill differential. *Id*. WPAG also recommends including a portion of the hours on Sunday (the hours of 6 a.m. to 10 p.m.) in the heavy load hours. *Id*.

Again, WPAG relies on historical monthly nonfirm price differences to support its recommendations by developing a Univariate Box-Jenkins ARIMA model. Beck, *et al*., E-WA-01, at 24-27. The high load factor customers note that the data used by WPAG have serious shortcomings. Wolverton, *et al*., WP-96-E-PA/DS/PG-02, at 1. BPA witnesses, independently, reached the same conclusion. *See* Conger, Schloth, E-BPA-46, at 2-9. As previously stated, the analysis prepared by WPAG contained fundamental and fatal flaws. *Id*. WPAG's analysis relies on questionable data and misuses statistical techniques. *Id*. In effect, WPAG unknowingly constructed its analysis to predetermine the outcome. *Id*. While WPAG initially took issue with BPA's proposed heavy and light load hour differential, WPAG did not pursue this issue in its brief. Therefore, the issue is not evaluated and discussed here.

6.2 Firmness of Energy

Issue

Whether BPA should shape the annual marginal cost of firmness of energy into months in proportion to the ratio of BPA's total monthly demand for firm energy to monthly inflows to BPA's hydrosystem.

Parties' Positions

APAC, DSIs, and PGP initially recommended that BPA shape the annual cost of firmness of energy into the months when standby power is needed, November through February. Wolverton, *et al.*, E-PA/DS/PG-01, at 10. The high load factor customers note that the months November through February are the months when the Pacific Northwest is likely to experience extreme cold weather. These customers conclude that the annual cost of firmness should be assigned only to these months. *Id.* Only APAC continues to advance this recommendation in its brief. APAC's Ex. Brief, R-PA-01, at 29 n.36.

WPAG argues that the annual marginal cost of firmness of energy should be shaped across the months based solely on the monthly demand in the West Coast market. Beck, *et al.*, E-WA-13, at 70; WPAG's Brief, B-WA-01, at 9. WPAG recommends shaping the annual cost of firmness of energy based on BPA's monthly purchase transactions in the West Coast market. WPAG urges BPA to return to the approach used in the initial proposal, and to shape the annual marginal cost of firmness of energy according to the relationship between monthly off-system purchases of firmness of energy and the average off-system purchases for the year. *Id.*

NIU suggests that the monthly shape of the marginal cost of firmness should reflect conditions on BPA's system. Olsen, E-NI-01, at 9. NIU notes that during the months May through August, the Federal system has abundant energy due to spring runoff and minimum flow requirements imposed on the hydrosystem. *Id.* Based on these conditions, NIU concludes that the marginal cost of firmness of energy for the months May through June should be "quite low" compared to the other months. *Id.* NIU questions whether BPA's monthly purchases in the West Coast market adequately captures these conditions on BPA's system. *Id.*

BPA's Position

BPA proposes to distribute or shape the annual marginal cost of firmness of energy into the months in a manner that reflects the monthly demand for firm energy by BPA's power customers and monthly variation in supply conditions on BPA's system. Initial Marginal Cost Analysis Study, E-BPA-04, at 8. In the initial proposal, BPA suggested one approach for reflecting the monthly demand for firmness of energy. Initially, BPA proposed to shape the annual marginal cost of firmness of energy based entirely on the demand for firmness of energy by regional customers. *Id.* In the initial proposal, the annual marginal cost of firmness of energy was shaped based on the ratio of (1) expected monthly purchases of firmness of energy by BPA from other utilities in the West Coast market, less any BPA sales of firmness of energy during the month to other utilities, to (2) BPA's total annual purchases of firmness of energy less any BPA sales. *Id*. In response to comments by the parties, BPA proposed another approach in the supplemental proposal. In the supplemental proposal, BPA proposed to shape the annual marginal cost of firmness of energy into the months based on the ratio of the total demand for firm energy from BPA to BPA's supply of firm energy, with hydro inflows used as a proxy for monthly variation in supply conditions. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 8.

<u>Evaluation of Positions</u>

The marginal cost of firmness of energy represents the marginal cost that BPA incurs in being prepared to produce energy sometime during the month. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 4. Put another way, the annual cost of firmness of energy represents the costs that BPA would incur to convert nonfirm energy purchases or generation to firm energy. Documentation for the Initial Marginal Cost Analysis Study, WP-96-E-BPA-04A, at 231. PMDAM measures the marginal cost of firmness of energy in the West Coast market on an annual basis but does not measure any monthly variations in that cost. Vatter, *et al*., E-BPA-17, at 12. The fact that PMDAM does not measure the monthly variations in the marginal cost of firmness of energy does not mean that the cost does not vary by month. As BPA witnesses testified, the costs to BPA of having sufficient generation or contract capability to insure that it can produce firm energy during a month do vary by month due to supply conditions on its system. *Id*. For instance, BPA generally has large amounts of energy between May and August due to spring runoff and minimum flow requirements imposed on the hydrosystem. *Id*. In these months, the costs of being prepared to produce energy during the month are relatively low compared to other months. *Id*. In fact, the parties tacitly agree that the marginal cost of firmness of energy varies by month. The area of disagreement is over how to apportion the annual cost of firmness of energy to reflect the monthly cost variations.

Because BPA's marginal cost analysis forms the basis for BPA's rate design, BPA's objective in distributing the annual cost of firmness of energy into the months was to assign these costs in a manner that would track the difference in the monthly costs that BPA would incur to provide this service. Initial Marginal Cost Analysis Study, E-BPA-04, at 9. As such, the marginal cost of firmness of energy would be higher in the months when providing this service imposes more costs on BPA, compared to other months when the cost may be lower.

BPA initially proposed to use expected firmness of energy purchases by BPA, less any BPA sales of this product, as a proxy for reflecting the monthly differences in cost. *Id*. This approach rests on the assumption that the amount of expected net purchases in a month indicates the relative demand for firmness of energy in that month. Economic theory indicates that higher demand for a product means the buyer is willing to pay a higher price, all other factors being equal. *Id.*

The high load factor customers argue that purchases by BPA and other suppliers are an inappropriate proxy for shaping BPA's annual cost of firmness of energy. Wolverton, *et al.*, E-PA/DS/PG-01, at 10. The basic thrust of the high load factor customers' argument is that the time of year when a utility buys or sells firmness of energy may have no relationship to when that energy is used or needed to meet load. *Id.* The high load factor customers point out that, because of storage capabilities, in a hydro system the pattern of purchases to fill reservoirs differs from the pattern of withdrawals or use of the water in the reservoirs. *Id.*

APAC, DSIs, and PGP initially filed joint testimony recommending that an equal amount of the marginal cost of firmness of energy should be shaped into the months in which standby power is needed -- the four winter months. *Id.* Only APAC continues to pursue this issue in its brief. APAC's Ex. Brief, R-PA-01, at 29, n. 36. For purposes of this evaluation, statements in the joint testimony related to shaping the marginal cost of firmness of energy into the four winter months are attributed solely to APAC. Since the DSIs and PGP did not pursue this issue in their briefs, they are deemed to take no position on this issue. *See Procedures*, Section 1010.

APAC recommends shaping an equal amount of the marginal cost of firmness of energy into the months in which standby power is needed—the four winter months. *Id.* APAC argues that assigning firmness of energy costs to the fish flush months is nonsensical because the region has far more power in these months than there is any reasonable market for that power. *Id.*

NIU also takes issue with the net purchase approach BPA used in its initial proposal to shape the annual marginal costs of firmness of energy. Olsen, E-NI-01, at 9. Like the high load factor customers, NIU questions the level of firmness of energy costs assigned to the months May through July. *Id.* NIU hints that the method for assigning the annual cost of firmness of energy should reflect price differences between the months in addition to the amount of purchases between the months. *Id.* Moreover, NIU hints that the method for assigning the annual costs of firmness of energy should be comparable to the current price differences between months. While NIU does not suggest, as APAC does, that the marginal cost of firmness of energy should be zero in the fish flush months, NIU implies that the firmness of energy costs in the period May through July should be quite low or close to zero when compared to the other months. *Id.*

BPA agrees with APAC and NIU that the approach for shaping the annual cost of firmness of energy into the months should account for supply conditions on BPA's system, as well as the demand for this by BPA in the market. Vatter, *et al.*, E-BPA-47, at 5. That is, BPA agrees that supply conditions on the Federal system are more limited and thus more stressed in the winter than in the spring when the hydrosystem produces energy in excess of BPA's firm obligations. *Id.* While BPA agrees with the general concepts advanced by APAC and NIU, no party advanced a workable approach for how to reflect supply conditions on BPA's system in the method for distributing the annual marginal cost of firmness of energy into the months.

NIU did not advance any method for apportioning the annual marginal cost of firmness of energy to the months. NIU suggests that the monthly marginal cost of firmness of energy should be comparable to the current monthly differential in the market price for firmness of energy, but did not provide any specifics on how the monthly market price for firmness of energy would be estimated or determined. Although APAC advanced an approach for apportioning the annual marginal cost of firmness of energy to the months, its approach provides customers with misleading information on BPA's monthly costs of firmness of energy.

By assigning an equal amount of the annual cost of firmness of energy to the four winter months, November through February, APAC simplistically assumes that the cost of firmness of energy is the same in each of the four winter months, and zero in all other months. This assumption ignores the fact that BPA prepares to meet its obligations in all months, and in no month is the cost of preparing to meet its obligations zero. Vatter, *et al.*, E-BPA-47, at 4. With its new fish obligations, BPA's operational flexibility has been reduced, which, in turn, limits BPA's ability to use the hydrosystem to shape energy to follow monthly loads. Documentation for the Loads and Resources Study, WP-96-E-BPA-57B, at 41. In the past, BPA could shape or shift energy from other periods into the fall as a way to meet its firm obligations. *Id*. at 39. The new operational constraints reduce this ability to draft the system proportionally in the fall. *Id*. The changing constraints on the operations of the hydro system mean that BPA has less firm energy available to meet firm loads in the months when the system is storing water (January through mid-April) and in the months when the system is recovering from fish operations (September through December). *Id*. Consequently, it no longer is true that BPA has to prepare to serve loads only in the winter months and can use the hydrosystem's flexibility to meet its obligations in the fall months and spring months. Furthermore, using the hydrosystem's flexibility is not without cost. The cost of using the flexibility of the hydrosystem reasonably may be reflected in the marginal cost of firmness of energy. This cost can be expected to track customers' demand for firm energy relative to BPA's supply of firm energy.

Moreover, even though the Federal system produces more than enough energy to meet BPA's firm obligations during the spring "fish flush" period, the energy produced by the fish flush is not guaranteed to be available continuously: it lacks a firmness of energy component. Guaranteeing or preparing to make the energy available at the time the purchaser needs the energy, even during the spring months, imposes a cost on BPA. For instance, even during the spring, there is a marginal cost to firmness of energy because utilities must carry reserves to back up purchases of nonfirm, but not of firm, energy. Vatter, *et al.*, E-BPA-47, at 4.

While BPA does not agree with the approach advanced by APAC, BPA agrees that the winter months should have a greater share of the annual costs of firmness of energy, and the fish flush months a lesser share, than in the initial proposal. Accordingly, BPA proposed an alternative approach to reflect the relationship with the market and conditions on its own system. Vatter, *et al*., E-BPA-73, at 3. *See also* Supplemental Marginal Cost Analysis Study, E-BPA-60. In the supplemental proposal, BPA proposed to shape the annual marginal cost of firmness of energy based on the ratio of demand for BPA's firm energy, including secondary sales, forecasted in PMDAM, to the natural monthly inflows to the hydrosystem, also from PMDAM. *Id*. This approach assigns a higher portion of the marginal cost of firmness of energy to the winter months, and a lower portion of the annual marginal cost of firmness of energy to the fish flush, than were assigned to these months in the initial proposal. *Id*. In fact, in the "fish flush" months of May through July, the marginal cost of firmness of energy is very close to zero. *Id*. Neither NIU nor the high load factor customers objected to the approach advanced by BPA in the supplemental proposal.

WPAG, however, challenged the approach proposed by BPA in its supplemental proposal. Beck, *et al*., E-WA-13, at 69-71; WPAG's Brief, B-WA-01, at 9-10. WPAG argues that BPA's supplemental proposal mixes operational and market data. Beck, *et al*., E-WA-13, at 69. Because BPA chose to use a West Coast approach to measure marginal cost, WPAG asserts that BPA must use only West Coast purchases and sales as the approach for shaping the annual marginal cost of firmness of energy. *Id*. at 70. In its initial brief, WPAG argues for the first time that the shift away from using only market data results in a loss of accuracy and objectivity. WPAG's Brief, B-WA-01, at 10. WPAG apparently believes that by choosing the West Coast market as the appropriate market for measuring BPA's marginal cost, BPA can look only at market transactions and cannot look at information related to its own system. Beck, *et al*., E-WA-13, at 70. WPAG's view of market information is very narrow and somewhat disingenuous.

While WPAG accuses BPA of selectively dismissing broad market information in favor of information specific to BPA, WPAG ignores that the market prices available to an individual utility as a purchaser and a seller in the West Coast market are partly a function of supply conditions on that utility's system and partly a function of demand conditions on that utility's system. For BPA, that means that the market prices for BPA are partly a function of the supply and demand conditions on BPA's system. Vatter, *et al*., E-BPA-104, at 10. Because the interaction of demand and supply conditions for each West Coast utility determines market prices, the interaction of BPA's demand and supply conditions affect the market price for BPA. *Id*. Contrary to WPAG's assertion, the relationship between demand and supply conditions on BPA's system is an objective standard for shaping the annual cost of firmness of energy and is consistent with the market approach for measuring BPA's marginal costs of firmness of energy.

In addition, WPAG either misunderstands or ignores the fact that BPA's demand for firm energy used in this shaping methodology includes off-system sales in the wholesale market, the role of which WPAG emphasizes. Although the supply side data are specific to BPA's system, unlike most other supply sources, expected hydro inflows exhibit significant variation in availability on a seasonal basis. As such, hydro inflows represent an appropriate proxy for seasonal variation in BPA's supply conditions.

Perhaps WPAG's view is based on the misunderstanding that PMDAM is measuring the marginal cost for the West Coast as a whole and not for individual utilities such as BPA. PMDAM is not estimating a single marginal cost for the entire West Coast. Rather, PMDAM measures the marginal costs for BPA and for 12 other West Coast parties. Supplemental Marginal Cost Analysis Study, E-BPA-60, at 4. Each party's marginal cost, as estimated by PMDAM, is different. Vatter, *et al.*, E-BPA-104, at 11. In PMDAM, BPA buys power from or sells power to another utility at a price that balances BPA's and the other party's supply and demand. Initial Documentation for the Marginal Cost Analysis Study, WP-96-E-BPA-04A, at 218. In other words, the model determines the market price to BPA by finding the price at which the transaction(s) between BPA and another party or parties is beneficial to both—a "win-win" solution—and results in a supply and demand balance for BPA and the other party. *Id.* However, the market price for each utility modeled in PMDAM may be somewhat different. Vatter, *et al.*, E-BPA-104, at 11. The cost to each utility differs because of the cost of buying and selling with one another, and conditions on their respective systems. *Id.*

For the first time in its brief, WPAG argues that BPA should return to the approach used in its initial proposal because using market prices for net purchases of firmness captures the stress on BPA's system. WPAG's Brief, B-WA-01, at 10. In support of this position, WPAG asserts that the method BPA used in the initial proposal relied on market prices to assign the marginal cost of firmness of energy to the months. *Id.* at 11. WPAG's statements in their brief suggest that WPAG misunderstands the method BPA used in its initial proposal. In the initial proposal, BPA did not use the monthly relationships of market prices to assign the marginal cost of firmness of energy to the month, but the monthly relationships of purchase amounts. Vatter, *et al.*, E-BPA-04, at 8. Again, the objective was to distribute the annual marginal cost of firmness of energy to the months in a manner that reflects BPA's customers' monthly demand for firmness of energy. As the high load factor customers correctly point out, monthly power purchases may differ from the monthly demand for firmness of energy. Wolverton, *et al.*, E-PA/DS/PG-01, at 9. The high load factor customers correctly observe that a utility may purchase the power at times when demand is low and store that power for later use. *Id.* In addition, utilities may purchase power before it is needed because the price is low.

<u>Decision</u>

BPA will shape the annual marginal cost of firmness of energy from PMDAM into months in proportion to the ratio of demand for firm energy from BPA, on- and off-system, to natural hydro inflows. This shaping approach reflects the monthly demand for firmness of energy and recognizes that the market price to BPA for this component of providing power is a function of market conditions and BPA's own system conditions.

7.0 WHOLESALE POWER COST OF SERVICE ANALYSIS AND RATE DESIGN ADJUSTMENTS

7.1 Introduction

The cost allocation process involves four major steps. First, costs are functionalized between generation and transmission. Second, transmission costs are segmented according to the types of transmission services provided. Transmission cost allocations are discussed in chapter 12.0 of the ROD. This section discusses the power cost allocations. Third, generation costs are classified to capacity, energy, or rights to energy. Fourth, generation costs are allocated to the various customer classes. 1996 Supplemental Rate Proposal, Wholesale Power Rate Development Study (WPRDS), WP-96-E-BPA-61, at 6.

The purpose of the cost allocation process is to assign preliminary responsibility for the test period generation revenue requirement to each of BPA's customer classes. The test period revenue requirement allocated to BPA's customers is subsequently modified through rate design adjustments: (1) to reflect BPA's rate design objectives, including BPA's objective to achieve competitive rates; (2) to comport with contractual requirements; (3) to reflect the results of other BPA studies; and (4) to conform with the requirements of applicable legislation. *Id*. at 5.

BPA allocates its test period generation revenue requirement to the various customer classes based on their use of services or facilities and the cost allocation directives contained in the Northwest Power Act. *Id*. at 9. The Northwest Power Act identifies three resource pools: (1) Federal Base System (FBS) resources; (2) resources acquired through the Residential Exchange program under section 5(c); and (3) any new resources acquired by the Administrator. *Id*. at 10. In addition, short-term power purchases are made during the rate period to provide operational flexibility and to replace reductions in the capability of the FBS. The costs of these purchases are treated as FBS costs and are allocated as such. *Id*. All other costs not specifically included in those resource pools, including, but not limited to, "conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6 [billing credits], operating services and the sale or inability to sell excess electric power" are to be "equitably allocated to power rates" in accordance with "generally accepted ratemaking principles and the provisions of this [Northwest Power] Act." 16 U.S.C. § 839e(g).

For the 1996 rate case, BPA has made several changes in its generation cost allocation and rate adjustment methodologies. Keep, Revitch, WP-96-E-BPA-23, at 2-4. Most of BPA's cost allocation and rate design adjustment methodologies established in prior rate cases remain unchanged, however. While the parties raised a number of issues during the hearing regarding BPA's cost allocation methods and BPA's use of the marginal cost analysis in designing its rates, a number of these issues were not raised in the parties' brief. These issues are not discussed here and are deemed withdrawn in accordance with section

1010.3 of the *Procedures Governing Bonneville Power Admin. Rate Hearings*, 51 Fed. Reg. 7611 (1986).

7.2 Recovery of Transmission Costs Allocated to Power Users

BPA classifies costs to three components of power: Capacity, Rights to Energy, and Delivered Energy. The costs of capacity and rights to energy are not directly allocated to customer classes; instead, the costs are classified based on expected revenues from these products. Supplemental WPRDS, E-BPA-61, at 9. Generation costs classified to energy are the generation costs remaining after subtracting revenues received from the sale of capacity and rights to energy. *Id*. These energy costs are then allocated to the individual customer classes. Transmission costs are allocated to the BPA power business for all its uses of the FCRTS. Power customers are also assigned transmission costs for transactions from which they benefit, such as Capacity/Energy exchanges, and uses of interties for storage or purchases. In the supplemental proposal power transmission costs that are not directly associated with a particular customer class, such as the cost of the Generation-Integration segment, were treated as revenue deficiencies and included in the power energy rates. *Id*. at 18. In the Draft Record of Decision, BPA proposed to allocated and recover transmission cost not directly recoverable from power users in their transmission rates through the power demand charge. 1996 Draft Record of Decision (ROD), WP-96-A-01, at 117-118. These transmission costs include, but are not limited to, Utility Delivery costs, General Transfer Agreement (GTA) costs, Generation-Integration Transmission Segment costs, and costs for using the interties for storage or purchases. *Id*.

Issue

Whether BPA should allocate and recover transmission costs that are not directly recoverable from power users in their transmission rates, such as the Utility Delivery Charge underrecovery, the General Transfer Agreements cost, Generation Integration costs, and transmission costs associated with capacity/energy exchanges and intertie us for storage and purchase, through its power demand charge.

Parties' Positions

APAC, DSIs, and PGP (representing high load factor customers) argue that BPA's rate design to high load factor customers results in uncompetitive price levels. Wolverton, *et al*., WP-E-PA/DS/PG-01, at 2. The high load factor customers recommend increasing BPA's demand charge. *Id*. at 12; APAC Brief, B-PA-01, at 29; APAC Ex. Brief, R-PA-01, at 29; Or. Tr. 2388; Or. Tr. 2453. These parties suggest that BPA's demand charge could be as high as $6.84/kW-mo for the months November through February. Wolverton, *et al*., E-PA/DS/PG-01, at 12. In oral argument, PGP suggested recovering some of the transmission costs collected from power customers through the BPA demand charge, as a way to increase the demand charge. Or. Tr. 2448.

WPAG cautions against rate design choices that eliminate the benefits that low load factor customers would receive from the lower PF rate in the Power Settlement Agreement. Or. Tr. 2427. WPAG urges BPA to apportion the Utility Delivery Charge underrecovery and the GTA costs between its demand and energy cost so that no party is unfairly burdened with the costs of implementing the Transmission Settlement Agreement. WPAG Ex. Brief, R-WA-01, at 6, 7. The allocation of transmission costs associated with capacity/energy exchanges, Generation-Integration facilities and intertie use associated with purchases and storage transaction, WPAG argues, should be allocated entirely to energy. *Id*. at 7-8.

PPC complains that BPA has not explained the reason for the increase in the demand charge for power. PPC, R-PP-01, at 8. PPC suggests that the Administrator should return the power demand charge to the level presented in BPA's supplemental proposal. *Id.*

<u>BPA's Position</u>

In both the initial and supplemental proposals, BPA set its power demand rate equal to the marginal price for capacity developed in the Marginal Cost Analysis Study (MCA). Initial WPRDS, WP-96-E-BPA-05; Supplemental WPRDS, E-BPA-61, at 16. BPA no longer allocates generation capacity costs to its different classes of service directly. Instead the expected revenues from demand are subtracted from BPA's total generation revenue requirement. Supplemental WPRDS, E-BPA-61, at 16. Transmission costs are allocated to the BPA power business for all its uses of the FCRTS. Power customers are allocated transmission costs for transactions from which they benefit, such as Capacity/Energy exchanges, and uses of interties for storage or purchases. In the supplemental proposal, power transmission costs that are not directly associated with a particular customer class, such as the cost of the Generation-Integration segment, were treated as revenue deficiencies and included in the power energy rates. *Id*. at 18. In the Draft Record of Decision, BPA proposed to allocated and recover transmission cost not directly recoverable from power users in their transmission rates through the power demand charge. 1996 Draft ROD, WP-96-A-01, at 117-118. These transmission costs include, but are not limited to, Utility Delivery Charge costs, GTA costs, Generation-Integration costs, and costs for using the interties for storage or purchases. *Id*.

<u>Evaluation of Positions</u>

The high load factor customers argue that BPA understated its demand charge. Wolverton, *et al*., E-PA/DS/PG-01, at 2. These customers claim that BPA's rate design produces rates for high load factor customers that exceed the costs of alternative power sources. *Id*. These customers caution that "unless BPA changes its rate design to recognize that fact, the agency risks the loss of major portions of its base load." *Id*. at 2, 6. The high load factor customers warn that BPA's current rate design, which seeks to recover most of BPA's costs through energy charges, encourages low-load factor loads to be placed on BPA and high load factor loads to purchase from others, which in turn could erode BPA's system load factor, and "thereby reduc[e] the flexibility of resource operations and [BPA's] ability to market 'naked' capacity." *Id*. at 6.

Initially, the high load factor customers suggested various adjustments to BPA's Marginal Cost Analysis that would increase the marginal cost of capacity. *See generally Id*. at 7-12; Wolverton, *et al*., PA/DS/PG-02, at 15-16. The adjustments suggested by the high load factor customers, however, were flawed and not supportable. *See* section 6.0, which evaluates the high load factor customers' recommendations related to BPA's Marginal Cost Analysis. Later, however, the high load factor customer advanced another suggestion for increasing the demand charge: recovering the Utility Delivery Charge underrecovery and GTA costs assigned to Federal power users through BPA's demand charge. Or. Tr. 2448. PGP claims that because demand charges are difficult to avoid, "it is in Bonneville's best interest to collect more of its costs through demand charges." *Id*.

PGP's suggestion has merit. Firm power customers benefit from certain uses of the Federal transmission system. Supplemental WPRDS, BPA-61, at 18. Recovering the cost of transmission through a demand charge is a standard utility practice. BPA's transmission system planning is based on peak load. Woerner, *et al*., WP-96-E-BPA-85, at 8. As such, transmission costs are associated more with meeting peak loads than with meeting energy loads. BPA incurs transmissions costs to meet peak periods load. Off-peak loads on the Federal transmission system do not impose additional costs on BPA. Recovering transmission costs assigned to power users through the demand charge results in rates that more accurately track BPA's cost incurrence.

There are other transmission costs, besides the Utility Delivery Charge underrecovery and GTA costs, that are not directly recoverable from power users in their transmission rates and which also are incurred to meet peak loads. Such costs include use of the transmission system for Capacity/Energy exchanges, Generation-Integration costs, and use of interties for storage or purchases. In the initial and supplement proposals, these costs were treated as a revenue deficiency and collected through BPA's energy charges. Supplemental WPRDS, E-BPA-61, at 18. However, like the GTA costs and Utility Delivery Charge underrecovery, these transmission costs are associated peak loads and as such should be recovered from power users through BPA's power demand charge.

WPAG disagrees. WPAG argues that BPA should look at the reason the costs were incurred, what product or benefit was obtained, and who was the beneficiary of the costs incurred. WPAG Ex. Brief, R-WA-01, at 4. WPAG acknowledges that the GTAs serve the same function as, and are replacement for, Network transmission facilities. *Id*. However, because the GTA costs were moved out of the Network and into power to implement the Transmission Settlement Agreement, WPAG argues that these costs should be viewed as settlement costs and spread equally to both the demand and energy components of all firm power rates. *Id*. Similarly, WPAG argues that the Utility Delivery Charge underrecovery results from implementing the Transmission Settlement Agreement and, as such, should be spread equally to both the demand and energy components of all firm power rates. *Id*. at 5, 7. WPAG also claims that based on principles of cost causation the transmission costs of capacity/energy exchanges, Generation Integration and intertie use associated with purchases and storage transactions are incurred to obtain energy and as such should be recovered through energy charges. *Id*. at 8-9.

WPAG's argument misses the point. The fact that these costs are settlement costs or are being recovered by all power customers does not change the characteristic of these costs. The GTA costs and Utility Delivery Charge underrecovery still are transmission costs. Moreover, contrary to WPAG's claims, the GTA costs, the Utility Delivery Charge underrecovery and the other transmission costs allocated to power users are costs associated with meeting peak loads. For instance, BPA's Delivery facilities and Generation-Integration facilities are sized to meet peakload. Generation/Integration facilities are designed to integrate the full capacity of the hydro system, including peak capacity. In addition, both the Delivery Charge and the GTA costs are billed on a demand basis. That is BPA pays a demand charge for power delivered across the GTAs. As such the reason these costs were incurred is to meet peak loads, not energy loads.

WPAG argues that spreading the GTA costs and the Utility Delivery Charge underrecovery between both the power rates demand and energy components ensures that the cost allocation does not disproportionately impose the cost of the settlement on any particular customer class. *Id*. at 7. Concentrating these costs in the power demand charge, WPAG asserts, imposes the costs of the Transmission Settlement Agreement disproportionately on low load factor customers. *Id*. PPC argues for the similar results, urging BPA to set the power demand charge at the level presented in BPA's supplemental proposal. PPC Ex. Brief, R-PP-01, at 9. WPAG's and PPC's arguments ignore the fact that before the settlement these costs were recovered through demand charges. To now change and recover more of these costs through an energy charge would result in a cost shift between low load factor customers and high load factor customers, with high load factor customer receiving more of the costs. BPA believes that the costs shifts between customers from implementing the Transmission Settlement Agreements should be no more than necessary. In this case, there is no overriding reason to shift costs to high load factor customers.

Recovering the transmission costs from power users through their demand charge is firmly grounded in the generally accepted ratemaking principle of cost causation. Moreover, recovering transmission costs from power users through a demand charge provides rate continuity. Historically, following principles of cost causation, this is precisely how BPA recovered its transmission costs assigned to Federal power users. *See* 1983 Administrator's Record of Decision, WP-83-A-02, 40, at 64 (transmission costs classified 100 percent to capacity); 1985 Administrator's Record of Decision, WP-85-A-02, at 40-41 (transmission costs classified 100 percent to capacity). BPA's long-standing practice has been to recover transmission costs from power customers through a demand charge. Recovering transmission costs assigned to power users through a demand charge is consistent with standard utility practice, and promotes rate stability and continuity.

Decision

The level of BPA's demand charge will be based on the marginal cost of capacity plus any transmission costs not directly recoverable from power users in their transmission rates. These transmission costs include, but are not limited to, Utility Delivery Charge underrecoveries, GTA costs, Generation Integration Transmission Segment costs, and costs for using the interties for storage or purchases.

7.3 7(b)(2) Industrial Adjustment

The 7(b)(2) Industrial Adjustment re-links the IP rate to the PF Preference rate when the section 7(b)(2) rate test triggers. BPA's rates include rate protection for the Priority Firm preference class, as indicated in the Supplemental Section 7(b)(2) Rate Test Study, WP-96-E-BPA-63. The section 7(b)(2) rate test is discussion in section 9.0 of the ROD.

Issue

Whether the 7(b)(2) Industrial Adjustment should be used to link the Industrial Firm Power (IP) rate with the Priority Firm Power (PF) Preference rate when the section 7(b)(2) rate test triggers.

Parties' Positions

The Major Residential Exchange Participants (MREP or IOUs) claim that the 7(b)(2) Industrial Adjustment is unnecessary and improperly shift costs to the residential exchange. Piro, *et al*., WP-96-E-GE/PL/PS-02, at 24. The MREP state that BPA "ties the DSI rate to a preference rate that is already lowered as a result of the rate test trigger. . . . The effect is to give the DSI's the same rate test protection as the preference customers. This is a violation of the law and should not withstand scrutiny by the Administrator or on judicial review." MREP Brief, B-GE/PL/PS-01, at 46. The MREP complain that BPA's position violates the language and legislative history of the section 7(b)(3) rate directive, and that BPA's contrary construction of the section is unpersuasive. MREP Ex. Brief, R-GE/PL/PS-01, at 21-22.

BPA's Position

The applicable wholesale rate paid by BPA's public agency and cooperative customers is the PF Preference rate. The 7(b)(2) Industrial Adjustment re-links the IP rate to the PF Preference rate when the section 7(b)(2) rate test triggers. Keep, Revitch, WP-96-E-BPA-89, at 3. In effect, the 7(b)(2) Industrial Adjustment is a second calculation of the 7(c)(2) delta. *Id.*

Evaluation of Positions

The 7(b)(2) rate test first triggered in BPA's 1987 rate case. Keep, Revitch, E-BPA-89, at 4. The 7(b)(2) rate test is discussed in section 9.0 of the ROD. As part of its 1987 rate case, BPA first proposed the 7(b)(2) Industrial Adjustment. During the 1987 rate case the MREP raised the same issues that they now repeat in this case, that the 7(b)(2) Industrial Adjustment provides the DSIs "price protection" provided to preference customers. *Id.* In 1987 the Administrator carefully considered those comments but concluded that "the 7(b)(2) Industrial Adjustment is required by section 7(c)(2) of the Northwest Power Act." 1987 Administrator's Record of Decision, WP-87-A-02, at 121. Thereafter, whenever the 7(b)(2) rate test triggered, BPA followed the same approach as first adopted in 1987. Keep, Revitch, E-BPA-89, 4. BPA followed that same approach in this case. That is, after the 7(b)(2) rate test triggers, BPA bifurcates the PF rate into the PF Preference rate and the PF exchange rate. BPA credits the PF Preference rate and allocates IP rate its share of the 7(b)(2) cost. As such, if the 7(b)(2) rate test triggers, the 7(b)(2) cost is allocated to the DSIs, as well as other non-preference customers. After applying the 7(b)(2) credit to the PF Preference rate, BPA then recalculates the IP rate such that it is re-linked to the PF Preference rate. *Id.* The MREP ask that BPA abandon past practice and its first interpretation of the statutory requirements for setting the IP rate, when the only change in circumstances is that now the market simply will not sustain a higher DSI rate. For a more detailed discussion on the need for competitive DSI rates see section 8.2 of the ROD.

The MREP claim that the 7(b)(2) Industrial Adjustment is "redundant." Piro, *et al.*, E-GE/PL/PS-02, at 24. The MREP assert that the "first 7(c)(2) adjustment effectively increases the PF rate in the program case, putting upward pressure on the 7(b)(2) trigger. This is another example of improper shifting of costs onto the residential exchange, away from the DSI's." *Id.* According to the MREP, BPA is not required to make a second 7(c)(2) adjustment. As such the MREP assert that the second 7(c)(2) adjustment "is another example of BPA making arbitrary decisions to shift costs among customer classes" *Id.* at 25. "BPA now proposes to give the publics' rate test protection to the very party that was supposed to share in paying for it, the DSI's, thereby leaving the entire burden to the residential and small farm customers of exchanging utilities and relieving the DSI's of their responsibility to pay." MREP Brief, B-GE/PL/PS/01, at 45.

Section 7(c) of the Northwest Power Act determines how the DSI equitable rate is to be set. Section 7(c)(1)(B) very specifically provides that after July 1, 1985, the DSI rate or rates shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." 16 U.S.C. § 839e(c)(2). Section 7(c)(2) goes on to provide that the determination of equitability is to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. *See* section 8.2 in the ROD, which discusses "typical margin" included in the DSI rate determination. Section 7(c)(3) further provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. Supplemental WPRDS, E-BPA-61, at 21. *See* section 8.3 in the ROD, which discusses the value of reserves credit. In effect, section 7(c) contains a prescribed and, on its face, complete formula for setting the level of the DSI equitable rate. The DSI equitable rate is set equal to the applicable wholesale rate, plus a typical margin, minus a credit for value of reserves (VOR). *Id*. at 22.

Public body and cooperative customers are BPA's preference customers, and if the section 7(b)(2) rate test triggers, the PF Preference rate, including the 7(b)(2) credit, is the applicable wholesale rate paid by these customers. Keep, Revitch, E-BPA-89, at 4; s*ee also* 1987 ROD, WP-87-A-02, at 120. Section 7(c)(2) does not state that the rates applicable to the DSIs shall be the Administrator's wholesale rates to such public body and cooperative customers before any 7(b)(2) protection is included. The statute specifies that the DSI equitable rate should be based on the applicable wholesale rate paid for BPA's preference customers. That rate is the PF Preference rate. *Id*. The 7(b)(2) Industrial Adjustment assures that the IP rate is tied to BPA's PF Preference rate. *Id*.

The MREP claim that the nothing in the legislative history identifies the DSIs as even potential beneficiaries of the section 7(b)(2) rate test. MREP Brief, B-GE/PL/PS-01, at 44. They argue that Congress intended the section 7(b)(2) rate test to protect preference customers, not the DSIs. *Id*. In support of this, the MREP cite to passages from the House and Senate Reports accompanying the bill that reference section 7(b)(2) as establishing a preference customer rate ceiling or rate limit. *Id*. (citations omitted). While the cited language expresses Congress's intent that the section 7(b)(2) rate test protect preference customers, nowhere in the language does Congress state that the DSIs are not to be incidental beneficiaries of the test despite the express linkage of the DSI and preference customer rates in section 7(c). Congress clearly intended that the DSIs pay a rate that is equitable to the preference customers' rate to their retail industrial customers. Congress intended that the equitable rate be based on the actual rate charged BPA's preference customers, not some hypothetical or imaginary rate that these customers would have paid without the 7(b)(2) credit. In describing the DSI equitable rate, the Senate Report identifies the applicable wholesale power rate as the rate paid by preference customers.

> The [DSI] rate will be set *at a level no less than that set for the year 1984-85* and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers. This level is determined by applying a typical margin of cost . . . to the BPA wholesale rates to the preference customers for all power used to serve their industries.

S. Rep. No. 272, 96th Cong., 1st Sess. 59 (1979) (emphasis added).

The reference in the quote above to "a level no less than that set for the year 1984-85" refers to the DSI floor rate test, which effectively ensures that DSI rates on or after July 1, 1985, recover revenues that would be recovered by applying the rates that were in effect for the contract year ending on June 30, 1985. *See* 16 U.S.C. § 839e(c)(2). By the end of the contract year ending on June 30, 1985, the residential exchange was almost completely phased in pursuant to section 5(c)(2) of the Northwest Power Act. *See* 16 U.S.C. § 839c(c)(2). Also, prior to the end of the contract year ending on June 30, 1985, the SDI's rates were "to recover the cost of resources required to serve such customers' loads, *plus the otherwise unrecovered net costs of the section 5(c) exchange* . . ." H. Rep. No. 96-976, Pt. 1, 96th Cong., 2d Sess., at 69 (1980); *see* 16 U.S.C. § 839e(c)(1). It is under this initial ratesetting process that the DSIs pay higher rates so as to "'permit the Administrator *to enter into*" the residential exchange contracts. MREP Brief, B-GE/PL/PS-01, at 45, quoting S. Rep. No. 272, 96th Cong., 1st Sess., at 29 (emphasis added). However, Congress clearly enunciated in section 7(c)(2) and elsewhere that after July 1, 1985, the DSI "rates are to be equitable in relation to the retail rates charged by the Administrator's public body and cooperative customers to their industrial consumers in the region." H. Rep. No. 96-976, Pt. 1, at 69; *see* 16 U.S.C. § 839e(c)(1). Despite this shift away from rates that recovered exchange costs to rates based on equitability considerations, the floor rate test--not the section 7(b)(2) test--has the effect of setting a minimum level of DSI responsibility for cost recovery, including whatever exchange cost recovery would be covered through application of the floor rate.

Nothing in the Senate Report or the other legislative history cited by the MREP supports the notion that the DSIs' responsibility for paying exchange costs is unlimited or, except for the floor rate test, extends unabated past June 30, 1985. Indeed, the Congressional Committees on the legislation were clear that "[t]the cost of the exchange *during the first five years* is charged to the rates applicable to DSI's under section 7(c)(1)(A)," H. Rep. No. 96-976, Pt. 1, at 61 (emphasis added), and

> Customers of preference utilities will not suffer any adverse economic consequences as a result of this [residential] exchange since, as discussed below, the 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 utilities during later years.

H. Rep. No. 96-976, Pt. II, 96th Cong., 2d Sess., at 35. The rate ceiling protects preference customers, not the exchange customers.

With regard to the DSI rate after June 30, 1985, the purpose and intent of the 7(c) rate directives is to establish a DSI rate that reflects rates paid by other major industrial customers served by preference customers. In effect, the 7(c)(2) rate setting directives put the "DSIs on a comparable basis with most of the region's other industries particularly those industries served by the utility systems that would be most likely to serve the DSIs in the absence of the legislation." Letter from Sterling Monroe, BPA Administrator to Hon. Abraham Kazen, Jr. Chairman, Subcommittee on Water and Power Resources, House Committee on Interior & Insular Affairs of 8/9/80 (presenting BPA's analysis of projected 7(c)(2) rates under the House bill). In fact, one of the objections to the Act, raised by Congressional members who opposed the Act, was that the section 7(c)(2) rate directives "command BPA to set prices at the level which these [direct service industries] would pay if they received energy from local utilities . . ." Dissenting remarks of Reps. Weaver, Kostmayer, Vento, Markey and Miller, H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. at 89 (1980). BPA's rate to local utilities is the PF Preference rate, not an imaginary PF rate. In turn, their rate to retail industrial customers reflects the PF Preference rate, not some hypothetical PF rate. That preference rate reflects the full protection of section 7(b)(2).

The MREP point out that section 7(b)(3) of the Northwest Power Act states that the 7(b)(2) amount, which serves to reduce the PF rate for preference customers, shall be allocated to all other customers. MREP Brief, B-GE/PL/PS-01, at 43. The MREP assert that "BPA has not followed this direction. It has not proposed surcharging the DSI's." *Id*. The MREP argument appears to be that 7(b)(3) requires that BPA surcharge all other customers by the 7(b)(2) credit, and since BPA did not surcharge the DSI, *ipso facto*, BPA violates section 7(b)(3). The MREP's argument overlooks the fact that if the 7(b)(2) rate triggers, the 7(b)(2) cost is indeed allocated to the IP rate. Moreover, the MREP argument ignores that the plain language of the statute requires the IP rate to be linked to the PF rate. BPA's approach gives effect to the provisions of section 7 as a whole, which is a fundamental principle of statutory construction. *See, e.g., Massachusetts v. Morash,* 490 U.S. 107, 115 (1989).

Even if the statutory language is plain, if reliance on that language would defeat the plain purpose of the statute, the literal language must be disregarded. *Bob Jones Univ. v. United States*, 461 U.S. 574, 586 (1983); *Lynch v. Dawson*, 820 F.2d. 1014, 1019 (9th Cir. 1987). The plain purpose of section 7(c) is to link the DSI and PF rates in a certain manner, and the rate directives for each class of customer are subject to the paramount directive that "BPA must continue to set its rates so that its total revenues continue to recover its total costs." H. Rep. No. 96-976, Pt. II, at 36. In interpreting the section 7(b)(3) allocation scheme, BPA considers a number of factors including whether BPA could recover the surcharge from a particular customer or customer class. For instance, BPA does not include the 7(b)(2) surcharge in its nonfirm energy rates. To do so would be futile, as these rates are determined by the market not by BPA's cost. Another example of where BPA does not include the 7(b)(2) surcharge is sales of surplus firm power when BPA has long-term contracts which contain rate formulas, such as the PP&L capacity rate. Since the contract formula does not include any provision for surcharging the customers in the event the 7(b)(2) rate test triggers, BPA does not surcharge these customers. Like the PP&L capacity rate, the IP rate also is based on a formula that does not make mention of the 7(b)(2) surcharge. Unlike the PP&L capacity rate, the formula for the IP rate is determined by statute.

The MREP also state that the 7(b)(2) Industrial Adjustment is "arbitrary." Piro, *et al*., E-GE/PL/PS-02, at 25. BPA has consistently applied the 7(b)(2) Industrial Adjustment in same manner since the 1987 rate proposal, the first time that the section 7(b)(2) rate test triggered. Keep, Revitch, E-BPA-89, at 4. Thus, the decision to use the

7(b)(2) Industrial Adjustment cannot reasonably be characterized as arbitrary, as the MREP allege.

The MREP's primary concern appears to be the costs that are allocated to the PF Exchange rate as a result of the 7(b)(2) and 7(c)(2) adjustments. Piro, *et al.*, E-GE/PL/PS-02, at 24, 25; MREP's Brief, B-GE-PL/PS-01, at 46. The MREP assert that BPA is "making arbitrary decisions to shift costs among customer classes" by creating "a new adjustment not identified in the rate directives of section 7 of the Regional Act . . ." MREP Brief, B-GE/PL/PS-01, at 25, 45. The MREP's statement that the adjustment is arbitrary has no basis. The 7(b)(2) Industrial Adjustment is performed since 1987 to fulfill the requirements of section 7(c)(2) as well as section 7(b)(2) of the Northwest Power Act. 1987 ROD, WP-87-A-02, at 120. Neither section 7(c)(2) nor section 7(b)(2) of the Northwest Power Act protects the PF Exchange rate from allocation of costs necessary to protect the rate levels of BPA's preference and DSI customers. Moreover, the MREP ignore that the 7(b)(2) Industrial Adjustment not only is required by section 7(c)(2), but necessary for BPA to recover its costs consistent with sound business principles in accordance with section 7(a) of the Northwest Power Act. 16 U.S.C. § 839e(a)(1).

Decision

BPA will continue to use the 7(b)(2) Industrial Adjustment to link the IP rate with the PF Preference rate, as required by section 7(c)(2) of the Northwest Power Act.

7.4 Power Purchases as FBS Resources

BPA uses power purchases to replace reductions in capability of the Federal hydrosystem and other FBS resources. Keep, *et al.*, WP-96-E-BPA-117, at 5. The IOUs disagree with BPA's practice. MREP Brief, B-GE/PL/PS-01. The context for the IOUs' concern is the section 7(b)(2) rate test. *Id.* Treatment of FBS resources for the 7(b)(2) rate test is discussed in the ROD section 9.4.

7.5 Crediting Excess Revenues from Capacity Sales

Issue

Whether BPA should directly credit revenues from capacity sales to light load hour loads.

Parties' Positions

APAC, DSIs, and PGP initially recommended that the excess revenues from capacity sales should be directly credited to all light load hour sales. Wolverton, *et al.*, WP-96-E-PA/DS/PG-01, at 14. These customers argued that direct crediting of the excess capacity revenues to light load hour sales recognizes that light load hour sales contribute to BPA's ability to sell capacity. *Id.* Therefore, these customers conclude that light load hour sales should receive the benefits of the excess revenues associated with these capacity sales. *Id*. The DSIs and PGP did not pursue this issue in their brief. APAC, however, continues to argue this issue in its brief. APAC Ex. Brief, R-PA-01, at 29, n. 36.

BPA's Position

BPA allocates its costs and subsequent rate adjustments based on annual average energy loads or allocation factors. Supplemental Wholesale Power Rate Design Study, E-BPA-61, at 12. The allocated generation energy costs are then apportioned into different seasons and hours of the day using the results of the Marginal Cost Analysis. *Id*. at 26. The results of the Marginal Cost Analysis reflect the benefits in light load hours associated with capacity sales through lower marginal costs during these hours. Vatter, *et al*., WP-96-E-BPA-47, at 2.

Evaluation of Positions

In developing its 1996 rates, BPA apportions its generation costs between capacity, energy, and rights to energy. Supplemental WPRDS, E-BPA-61, at 8. To apportion the costs of these joint products, BPA sets the costs of generation demand and rights to energy based on the marginal costs of these products. *Id*. at 9. The costs of energy are the residual generation costs. *Id*. Since the generation costs of demand and rights to energy are defined by the marginal cost of the products, these costs are the same for all customers. Consequently, the only costs directly allocated to the different customer classes are energy costs. *Id*. Energy costs and any subsequent cost adjustments are allocated based on annual average energy allocation factors or loads. *Id*. at 12. The annual average energy costs are apportioned into different seasons and hours of the day using the results of the Marginal Cost Analysis. *Id*. at 26. No costs are allocated to capacity loads. It is precisely because of this allocation scheme that sales of capacity are recognized as a "revenue credit."

BPA includes the revenues from surplus capacity sales with the excess revenues from surplus power sales. These revenues then are apportioned uniformly to all loads. *Id*. at 21. In this way all customers benefit from BPA's surplus sales.

APAC, DSIs, and PGP initially filed joint testimony recommending that the excess revenues from capacity sales should be directly credited to all light load hour sales. Wolverton, *et al*., E-PA/DS/PG-01, at 14. These customers argued that direct crediting of the excess capacity revenues to light load hour sales recognizes that light load hour sales contribute to BPA's ability to sell capacity. *Id*. Therefore, these customers conclude, that light load hour sales should receive the benefits of the excess revenues associated with these capacity sales. *Id*. The DSIs and PGP did not pursue this issue in their brief and therefore they are deemed to take no position on this issue. APAC continues to argue this issue in its brief. APAC Ex. Brief, R-PA-01, at 29, n. 36. For purposes of this evaluation, statements in the joint testimony are attributed solely to APAC.

Capacity sales are sales where the purchaser receives energy from BPA during heavy load hours and then returns the same amount of energy to BPA during the light load hours. APAC argues that if BPA does not have light load hour loads above its minimum generation constraints to consume this return energy, BPA would not be able to make any capacity sales. Wolverton, *et al*., E-PA/DS/PG-01, at 14. APAC then concludes that light load hours should receive the benefits of the "capacity revenue credit" by directly crediting the revenues from capacity sales to all light load hour loads. *Id*. To accomplish this direct crediting, APAC recommends that BPA separate the revenues from the capacity sales from its other revenue adjustments. *Id*. After apportioning the adjusted allocated energy costs between the months and hours, APAC proposes to then subtract the capacity revenues from the light load hour revenues. *Id*.

APAC's proposal is somewhat disingenuous. APAC selects one of the excess revenues adjustments and argues that this adjustment should be allocated directly to light load hour sales instead of being allocated to annual average energy loads like all other adjustments. APAC did not provide any rationale for why this one source of excess revenues should be treated differently than all the other sources of excess revenue. Nor did APAC suggest that BPA should allocate all costs and subsequent rate adjustments based on heavy and light load hour costs and benefits. APAC merely picked one adjustment, excess capacity revenues, to offer as a thinly disguised approach for lowering the light load hour energy rate. APAC's proposal would shift the entire benefit from BPA's sales of surplus capacity to high load factor customers.

APAC's proposal also is flawed. BPA's heavy and light load hour rates are based on the relationship between heavy and light load hour marginal costs. The relationship between heavy and light load hour marginal costs reflects the benefits of energy returns during light load hours. Vatter, *et al*., E-BPA-47, at 2. Energy returned to BPA's system lowers the marginal cost of energy during light load hours when these returns occur. *Id*. The relationship between the heavy and light load hours rates already captures the benefits to light load hour loads related to energy returns from BPA's capacity sales. *Id*. APAC's proposal, in effect, inflates and exaggerates the benefits that light load hours sales add to BPA's ability to make capacity sale.

<u>Decision</u>

Excess revenues from capacity sales will be included with other surplus firm power revenues and apportioned uniformly to all loads.

7.6 <u>Calculation of Bonneville's Average System Cost</u>

In 1987, BPA proposed to include the calculation of Bonneville's Average System Cost as part of a formula for capping its sales of nonfirm energy rates. 1987 Administrator's

Record of Decision, WP-87-A-02, at 186-187. After the Administrator adopted BASC in 1987, BPA and parties to long-term contracts agreed to use changes in BASC as an index for escalating long-term contract rates. The PPL-90 rate is one of the long-term contract rates that escalates based on changes in BASC from the BASC calculated in 1987. Keep, *et al*., WP-96-E-BPA-94, at 89. BASC is determined by dividing BPA's Total System Costs by BPA's Total Annual System Loads. *Id*. The terms BPA's Total System Costs and BPA's Total Annual System Loads are defined in BPA's General Rate Schedule Provisions (GRSPs). Supplemental Wholesale Power and Transmission Rate Schedules, WP-96-E-BPA-64, at 152.

Parties' Positions

PacifiCorp urges BPA to include its currently projected cost cuts, as well as cost cuts needed due to the lower total revenues from firm power sales, in its revenue requirement. PacifiCorp Brief, B-PL-01. PacifiCorp cautions that in no case should BPA project artificially high firm and nonfirm revenues and as a result either (a) retain expenditures in the final rate study which are higher than BPA actually plans to spend, or (b) project a buildup of reserves that BPA does not actually expects to achieve. *Id*. PacifiCorp also urges BPA to include the Fish Cost Contingency Fund (FCCF) credit in the calculation of BASC. PacifiCorp Ex. Brief, R-PL-01, at 3-4.

Evaluation of Positions

PacifiCorp recommends that BPA incorporate its anticipated reductions in revenues and expenses in the calculation of BASC. *Id*. BASC determines the rate PacifiCorp pays for surplus firm capacity from BPA under a long-term capacity sale. *Id*. PacifiCorp notes that BPA has an implied obligation of good faith under its contracts, and PacifiCorp is relying on BPA's good faith calculation of BASC. *Id*. at 5.

PacifiCorp argues that the evidence on the record suggests that BPA's supplemental proposal overstated BASC. *Id*. at 6 PacifiCorp points to a number of factors, which taken together, suggest that BPA must reduce its cost from the costs projected in the supplemental proposal. First, PacifiCorp notes that even prior to the Transmission and Power Settlement Agreements BPA planned to take additional cost cuts not reflected in its supplemental proposal. *Id*. With these settlement agreements, PacifiCorp posits that BPA will need additional cost and revenue requirement reductions. *Id*. Second, PacifiCorp argues that the market outlook for BPA's sales is lower than BPA previously estimated, which in turn reduces BPA's revenues from these sales. *Id*. PacifiCorp asserts that gas prices are not expected to improve as rapidly as BPA previously forecasted. *Id*. Also, PacifiCorp claims that BPA is facing lower firm sales to its customers. *Id*.

For the final proposal, BPA will reflect the change in market conditions since the initial and supplemental proposals. These changes will affect BPA's expected revenues and sales during the test period. BPA proposes to incorporate a revised gas forecast that is lower than the forecast used in BPA's supplemental proposal. In additional, BPA expects that its generating utilities will take actions to reduce their purchases from BPA during the test period. For BPA's final load forecasts, generating utility customer loads are lower than projected in the supplemental proposal. *See* section 3.3 and 3.1.1, which discuss revisions to BPA's gas price forecast and generating utility customers' load forecast.

BPA has included in its revenue requirements the additional cost cuts that BPA planned to take before the Transmission and Power Settlement Agreements. In March 1996, BPA further revised its spending levels, resulting in lower operating program expenses than were included in its supplemental proposal. *See* section 4.0 of the ROD and Final Revenue Requirement Study, WP-96-FS-BPA-02, Appendix A, which provide greater detail on the actions BPA is taking to cut its costs even further than it anticipated at the time of the supplement proposal. The net effect of these cost cuts reduces BPA's total revenue requirements by about $67 million. BPA has taken other actions that will also lower BPA's Total System Costs. These additional actions include: (1) accessing excess funds in the Supply System WNP-1 Construction Fund to cover a portion of net billing requirements in FY 1997; (2) accessing the Fish Cost Contingency Fund; (3) using updated interest rate forecasts to project interest expense on long-term borrowing and appropriations repayment obligations; (4) consolidating supply system trustees; and (5) reducing revenue financing for BPA's transmission investments. *See* section 4.0 of the ROD; Final Revenue Requirement Study, FS-BPA-02, Appendix A. Each of these actions is directly reflected in the BASC calculation. BPA expects that the final BASC will be lower than BASC calculated in BPA's supplemental proposal.

PacifiCorp expressed concern that because the Fish Cost Contingency Fund (FCCF) is accounted for as a revenue credit, this credit may not be included in the BASC calculation. PacifiCorp Ex Brief, R-PL-01, at 4. As PacifiCorp notes, it is not concerned with the method BPA chooses to account for the FCCF in its revenue and income statements.*Id*. Rather PacifiCorp is concerned that for purposes of determining BASC, the FCCF credit is included as a reduction in Total System Costs. *Id*. PacifiCorp raises this concern because even though the Draft Record of Decision stated that the FCCF credit would lower BPA's Total System Costs used in computing BASC, in other sections of the Draft Record of Decision BPA described the FCCF credit as a revenue credit. PacifiCorp assumed that if the FCCF credit is treated as an increase in BPA power revenues than it would not be included in the BASC calculation. *Id*.

BPA appreciates how the statements relating to the accounting treatment of the FCCF credit and treatment of the FCCF credit for purposes of calculating BASC may have been inconsistent or confusing. Even though annual access to the FCCF credit will be accounted for as increased power revenues and will not reduce BPA's revenue requirement for the rate period, the FCCF credit is included in BPA's Total System Costs used in the BASC calculation. Although BPA's Total System Costs used in calculating BASC are based on BPA's revenue requirements, BPA's Total System Costs are not identical to BPA's revenue requirements. BPA's Total System Costs is a term defined in BPA's GRSPs for calculating BASC; as such it is not a financial or accounting term. BPA's Total System Costs are lower than BPA's revenue requirement by the amount of revenue credits BPA projects during the test period. Expected revenues associated with COE and USBR project revenues, interchange, irrigation pumping power, and CSPE were subtracted from the FBS costs included in BPA's revenue requirement for the test period in BPA's cost allocation steps. Supplemental WPRDS, E-BPA-61A, at 185-187. These adjusted FBS costs then are included in BPA's Total System Costs used to calculate BASC. While these revenues are accounted for as increased revenues and do not reduce BPA's revenue requirement, these revenue credits always have been included in the calculation of BASC. In this rate case, BPA has additional revenue credits that will be accounted for as increase revenues such as expected annual access to the FCCF, prospective 4(h)(10)(C) credits, and Colville credits. Each of these revenue credits is included as an adjustment to the test year revenue requirement for purposes of calculating BASC.

Decision

BPA is proposing a number of revisions to its revenues and costs, based on the best information BPA has available. These revenue and cost adjustments will be reflected in BPA's Total System Costs and the calculation of BASC. For purposes of calculating BASC, expected revenue credits during the test period will be subtracted from BPA's revenue requirement for the test period.

7.7 Residential Exchange Billing Determinants

Issue

Whether the residential exchange billing determinants should be diurnally differentiated.

Parties' Positions

The DSIs argue that the residential exchange load should be split between heavy and light load hours. The DSIs suggested using the relationship between the PF Preference heavy and light load hour loads as a proxy to separate the PF Exchange loads between heavy and light load hours. Schoenbeck, Bliven, WP-96-E-DS-06, at6.

BPA's Position

The residential exchange transaction is a paper transaction and not an actual sale of power. Keep *et al.*, E-BPA-94, at 7. Since these customers do not place any actual load on BPA, incorporating time of day energy price signals is unlikely to result in any cost savings to BPA, and therefore seems unnecessary. In addition, BPA does not have load information for the individual exchanging utilities to differentiate the residential exchange load between heavy and light load hours. *Id*.; Boling, Doubleday, WP-E-BPA-36, at 4.

Evaluation of Positions

In BPA's initial proposal, the PF Exchange loads were not separated between heavy and light load hours. Initial WPRDS, E-BPA-05A. Instead, BPA assumed that all PF Exchange load was in the heavy load hours. *Id*. One of the reasons that BPA did not attempt to estimate the amount of the PF Exchange loads during heavy and light load hours is that BPA did not have sufficient data to support such a forecast. Boling, Doubleday, E-BPA-36, at 4. BPA invited parties to comment on data sources and procedures that BPA could use to account for exchange utility-specific load shapes. *Id*.

The only party offering any suggestion was the DSIs. The DSIs suggested that the relationship between the PF Preference customers' heavy load hour loads and their light load hour load could be used as a proxy to separate the PF Exchange customers' load between heavy and light load hours. Schoenbeck, Bliven, E-DS-06, at 5. The DSIs admit that residential exchange heavy and light load hourly data are not available to construct the actual shape of the PF Exchange loads over the different hours of the day. *Id*.

BPA agrees with the DSIs that residential exchange load occurs in both heavy and light load hours. Nevertheless, BPA initially questioned whether the characteristics of the PF Preference load were similar enough to the characteristics of the PF exchange load such that the hourly shape of the PF Preference load is a good proxy for the hourly shape of the PF Exchange load. PF Exchange loads are by definition residential and small farm loads. PF Preference loads include residential and small farm loads, but also include significant amounts of commercial and industrial load. Keep, *et al*., E-BPA-94, at 7. Residential and small farm consumers tend to consume more electricity during the heavy load hours than during the light load hours. Commercial and industrial loads, on the other hand, tend to be flatter across the hours of the day. *Id*. at 7-8. Or said another way, the PF Exchange load has a lower load factor than the PF Preference load and occurs mostly in heavy load hours. The hourly shape of the PF Preference load also reflect the fact that generating utilities are able and often do shape their power purchases from BPA into the light load hours. *Id*. at 8. Consequently, the PF Preference load would have higher loads in the light load hours compared to the loads of residential and small farm customers.

Nevertheless BPA agrees with the DSIs that assuming all PF exchange load occurs in the heavy load hours does not comport with how the actual load occurs. Some PF exchange load occurs in light load hours. Upon reflection and absent better information, BPA believes using the PF Preference load as a proxy for shaping the PF Exchange load is a better approach than simply assuming that all PF Exchange load occurs in the heavy load hours.

Decision

The residential exchange billing determinants should be diurnally differentiated to reflect the fact that some load will occur in light load hours. Absent better information, the hourly shape of the PF Preference load will be used as a proxy for the hourly shape of the PF Exchange load. The PF Exchange rate for each season will be based on a weighted average of the heavy and light load hour PF Exchange rates calculated for that season.

8.0 DIRECT SERVICE INDUSTRY POWER RATE DEVELOPMENT

8.1 Introduction

The rates charged to Bonneville Power Administration's (BPA's) direct service industrial (DSI) customers are based on section 7(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), this determination is to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. Section 7(c)(2) also provides that the DSI rates shall be no less than the rates in effect for the contract year ending June 30, 1985.

BPA last calculated the typical margin and the value of reserves credit in the 1985 rate case. In 1987, BPA established the Industrial Firm Power (IP)-Priority Firm Power (PF) rate link (IP-PF Link), under which the typical margin and the value of reserves credit were inflated each rate period by the Gross National Product (GNP) deflator. Therefore, it was unnecessary to recalculate the typical margin and the value of reserves credit each rate case. However, the IP-PF Link will expire with the expiration of the current Variable Industrial Rate Contract and cannot be used to set rates in this rate proceeding. Therefore, BPA has calculated new values for the typical margin and the value of reserves credit.

This chapter addresses issues relating to the 7(c)(2) Industrial Margin Study and the Value of Reserves Study that BPA performed to determine new values for the typical margin and the value of reserves credit. Issues related to each study are addressed in separate sections below. Furthermore, this chapter includes a section that addresses an issue related to the DSI floor rate calculation.

8.2 7(c)(2) Industrial Margin

8.2.1 Data To Use In Calculation Of The Margin

Issue

Whether the 1985 data base as updated by the DSIs should be the starting point for BPA's industrial margin study.

Parties' Positions

The IOUs argue that the Administrator should reject BPA's margin study because it is based on data supplied by the DSIs, an economically interested party. They argue further that, because BPA did not verify the data or the margin calculations with the utilities in the sample, the data are not reliable. MREP Brief, WP-96-B-GE/PL/PS-01, at 18-22. APAC urges the Administrator to reject BPA's margin study for the same reasons. APAC Brief, WP/TR-96-B-PA-01, at 15-18. The DSIs argue that their interest in the margin does not make the information they provided unreliable. They add that the information includes utilities' COSAs and financial statements that they photocopied and gave to BPA. DSI Brief, WP-96-B-DS-01, at 27-28.

BPA's Position

BPA notes that most of the data used in the margin study come from utility documents, and argues that the evidence demonstrates that the data are reliable. BPA also argues that the parties have offered no evidence that the data are unreliable. Tr. 1701.

Evaluation of Positions

Until 1985, the Industrial Firm Power (IP) rate was established pursuant to section 7(c)(1)(A) of the Northwest Power Act. 16 U.S.C. § 839e(c)(1)(A). Since 1985 the IP rate has been established pursuant to section 7(c)(2), under which the rate is based on BPA's applicable wholesale rates and the "typical margins" included in public body and cooperative customers' retail industrial rates. *Id.* § 839e(c)(2). In the 1985 rate case BPA performed an industrial margin study to calculate the typical industrial margin. The margin was then added to the applicable wholesale rate to determine the IP rate. In 1987, BPA established the Industrial Firm Power-Priority Firm Power Link (IP-PF Link), under which the industrial margin that BPA had derived in 1985 was inflated each rate period by the Gross National Product deflator and added to the applicable wholesale rate. Therefore, BPA did not recalculate the margin each rate case, and subsequent margin studies were unnecessary. Chang, Cocks, WP-96-E-BPA-25, at 2.

By its terms, the IP-PF Link applied to any IP rate that went into effect on or before July 1, 1996. In February 1995 BPA filed its Preliminary Rate Proposal in the 1995 rate case. The purpose of that rate case was to set rates for two years beginning October 1, 1995. Therefore, the proposed IP rate was based on the Link. No margin study was required, and none was performed. Chang, Cocks, WP-96-E-BPA-54, at 2.

Shortly after BPA filed its preliminary rate proposal, BPA and its customers began negotiating a settlement of the 1995 rate case. A settlement agreement with most of the customers was signed March 15, 1995. Under the agreement, BPA's existing rates were extended for one year, until September 30, 1996, with a 4-percent surcharge. BPA began work on five-year rates to go into effect October 1, 1996, after expiration of the IP-PF Link. Therefore, as of mid-March, 1995, a new industrial margin study became necessary. *Id.*

BPA's initial proposal in the 1996 rate case was published July 10, 1995, less than four months after the settlement agreement was signed. It would have been difficult at best for BPA to gather the data and perform a margin study in such a short time. The DSIs had updated the data compiled in the 1985 study. Because of the sudden need for a new margin study and the severe time constraints, BPA obtained the updated data from the DSIs and used these data as the initial basis for the new study. *Id.*

Under the circumstances, BPA's only feasible alternative was to use the data compiled by the DSIs. In its brief on exceptions, however, APAC asserts that because BPA knew the IP-PF Link would expire at a date certain, its "failure to exercise foresight in gathering its own data" does not justify "wholesale reliance" on an interested party's data. APAC Ex. Brief, WP/TR-96-R-PA-01, at 16. Since 1990, when the Link was extended, BPA knew the Link would expire at a date certain; namely, for rates that were effective after July 1, 1996. Had BPA begun gathering data in 1990, the data would have been grossly out of date before they were needed. BPA began the 1995 rate case in the fall of 1994, expecting to use the IP-PF Link to set rates for the period October 1, 1995, through September 30, 1997. Thus, it was still three years before rates adopted pursuant to a new margin study were due to take effect. In early 1995, while the 1995 rate case was ongoing, expected implementation of a new margin study was still almost three years in the future. Moreover, BPA anticipated that, once the 1995 rate case concluded, it would have a full year or more before the start of the 1997 rate case. This would have been ample time to conduct a new margin study. Gathering the data earlier would only have meant that the data would be out of date.

As discussed below, the only specific objection the parties raised to any of the data in the margin study was in fact that some of the data were out of date. It is inconsistent for APAC to suggest that BPA should have gathered data that necessarily would have been out of date before it was needed. When the 1995 rate case settled in March 1995, and BPA began a 1996 rate case, the time line for conducting a new margin study suddenly advanced by more than one year. BPA did not fail to exercise foresight; circumstances changed, and BPA adapted by taking the most reasonable and feasible course open to it at that time.

Furthermore, as discussed extensively below, BPA hardly exercised "wholesale reliance" on the data supplied by the DSIs. BPA changed 12 of the 20 utility margins in the study, as well as the test period energy for five utilities. BPA updated many of the margins with additional information. (In their briefs on exceptions, neither APAC nor the IOUs challenge any of the draft ROD's extensive discussion (identical to the discussion contained in this Final ROD) of BPA's independent analysis of the data. Instead, APAC simply asserts that BPA exercised "wholesale reliance" on the data provided by the DSIs.) The parties argue, however, that any reliance on the data base is inappropriate because the

DSIs are an interested party and because BPA failed to verify the data with the utilities. MREP Brief, B-GE/PL/PS-01, at 22; APAC Brief, B-PA-01, at 16. For five reasons, it is appropriate to rely on the BPA margin study to determine the industrial margin:

First, the parties have presented no evidence that the data are biased. Their argument relies entirely on innuendo. Second, most of the data in the study are copies of documents generated by the utilities themselves. Further verification of the data would serve little purpose. Third, independent, uncontested evidence in the case supports the credibility of the data. Fourth, the parties have had a full opportunity to rebut the data and BPA's margin calculation. Fifth, the parties have failed to offer a reasonable alternative to BPA's margin study.

The first issue is bias. APAC argues that the DSIs are "a biased party with the strongest economic interest in lowering the margin." APAC Brief, B-PA-01, at 16. APAC points out that the study was furnished to BPA "by the DSIs to whom the margin applies." Wolverton, WP-96-E-PA-01, at 7. The IOUs testified that the DSIs are "a biased party . . . with a strong economic interest in the outcome." Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 13. They argue that BPA should not rely on a "data base supplied by a biased party." MREP Brief, B-GE/PL/PS-01, at 18.

As the DSIs point out in response, all of the parties to this proceeding have an economic interest in the margin. DSI Brief, B-DS-01, at 27. Indeed, the parties' interest is amply demonstrated by the vigor with which the parties have contested BPA's margin study. But economic interest alone does not prove that the DSIs, or any party, manipulated or otherwise biased the data. In their brief on exceptions, the IOUs argue that the DSIs have the most interest in the margin. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 12. Even assuming this is so, an allegation of bias still cannot substitute for evidence of bias. The parties have introduced no evidence of bias or manipulation, despite having had a copy of the data base since August 1995. *See* WP-96-E-GE-05; WP-96-E-PA-07. They have filed their own testimony challenging BPA's margin study, and have had the opportunity to engage in discovery and to cross-examine the DSI witnesses. At no stage of this proceeding have they offered any evidence supporting their charges. The parties have relied not on evidence but on allegation.

The evidence that has been introduced demonstrates that BPA reasonably relied on the data as its starting point for the study. For fourteen of the twenty utilities in the sample (70 percent of the sample), the data the DSIs supplied are actual utility documents. Tr. 1697; *see also* E-PA-07. As BPA testified, and as can be seen by reviewing the documents themselves, nothing on the documents gives any indication that they are "anything other than documents that had been obtained from the utility and turned over in the same form to BPA." *See* Tr. 1697 and E-PA-07. Nor have the parties alleged that the documents have been altered in any way.

A review of the data base illustrates its reliability. In the 1985 margin study the identities of the utilities were kept confidential; they were identified by code numbers and letters. In the data base, the utilities are also identified by their codes. *See* E-PA-07. APAC, however, introduced into evidence a data response that includes a sheet identifying the utilities. *See* WP-96-E-PA-10. In addition, BPA identified the utilities by both code and name. *See*, *e.g.*, Chang, Cocks, WP-96-E-BPA-120, Attachment E. Most of the utilities in the current sample are the same ones from the 1985 sample, and the codes are the same.

For ten of the utilities, the data consist of actual pages from the utilities' cost of service analyses (COSA). These utilities are the following: Utility 2A (Columbia River PUD); 4A (Oregon Trail Cooperative); 15A (Chelan County PUD); 18C (EWEB); 20A (City of Port Angeles); 22A (Grays Harbor PUD); 26A (Benton County PUD); 27A (Tacoma City Light): 31A (Clark County PUD); and 35B (Snohomish County PUD). *See* WP-96-E-PA-07. (*See* Chang, Cocks, E-BPA-120, Attachment E, for the identities of the utilities.) It is obvious in reviewing these documents that they were generated by the utilities themselves.

For two utilities, the data consist of portions of their COSAs and other utility documents. For utility 1A (Grant County PUD) and 21A (Seattle City Light), the data base contains portions of the utilities' COSAs and financial statements. For utility 34C (McMinnville Water and Light), the data base includes the utility's Financial and Operating Report. Finally, for utility 36A (Clatskanie County PUD), the information in the data base is the utility's Industrial Contract Rate Schedule. *See* E-PA-07. (In the data base, Clatskanie County PUD, utility 36A, is mistakenly identified as utility 36C. In its study, BPA listed Clatskanie as 36A, the same designation it bore in the 1985 study. Neither this study nor the 1985 study contains a utility with code 36C. Chang, Cocks, E-BPA-120, Attachment E. In addition, the data response that APAC introduced into evidence also identifies Clatskanie as utility 36A. *See* E-PA-10. Finally, it is clear from the other evidence in the case that this utility is Clatskanie County PUD. The Industrial Contract Rate Schedule contained in the data base for utility 36C lists proposed rates for summer and winter energy charges and for the demand charge that match the rates contained in Clatskanie's 1993 Industrial Contract Rate Schedule. *See* E-PA-07 and Chang, Cocks, WP-96-E-BPA-79, Attachment 3. The BPA margin analysts obtained the utilities' rate schedules from the BPA area economists. Tr. 955. The rate schedule for Clatskanie matches the data in the data base. This rate schedule is additional evidence of the accuracy of the documents in the data base, which, as noted, are for the most part documents generated by the utilities themselves.)

APAC argues that BPA was unable to verify the data base because it contained only excerpts from the utilities' COSAs. APAC Brief, B-PA-01, at 16. One of the BPA analysts testified that the data base contained no indications that any data were missing. Tr. 1716. She concluded that the data were sufficient to calculate each utility's margin. *Id.* APAC has presented no evidence that any necessary data are missing. In fact, as the BPA analyst testified, excerpts from a utility's COSA are all that is necessary to calculate the utility's industrial margin.

For example, APAC introduced into evidence the 1995/96 COSA for Seattle City Light. Seattle's COSA consists of 164 pages plus 35 pages of appendices, or approximately 200 pages. *See* E-PA-10. Most of the COSA consists of narrative about the rate-setting process. Chapter 1 is titled "Introduction and Organization of Report"; chapter 2 is titled "Mayor's Recommendations"; chapter 3 is "Policy Framework." After these introductory materials, the COSA contains a lengthy "Overview of Cost of Service Methodology" that explains the overall framework for the utility's rate-setting methodology. Finally, further narrative follows on the various details of the process, including a variety of tables that have nothing to do with calculating the margin. *Id.*

In short, practically the entire COSA is irrelevant to the calculation of the margin. What <u>is</u> relevant are the pages displaying the utility's revenue requirements. Tr. 1727. Based on this information, the analyst can determine the revenue allocated to each customer class and thus the industrial margin. *Id.* The data base BPA received from the DSIs contains this information. *See* E-PA-07.

In its brief on exceptions, APAC asserts that the DSIs did not act simply as a conduit for utility documents, because they supplied only excerpts and summaries of the documents. APAC Ex. Brief, R-PA-01, at 16. APAC did not, however, respond to BPA's conclusion, supported by evidence in the record, that the excerpts were sufficient to calculate each utility's margin. Nor has APAC presented any evidence that the excerpts are insufficient, or provided any rationale by which the Administrator could draw that conclusion. The DSIs in fact acted as a conduit for all necessary utility documents.

APAC added that a number of the supporting documents were not turned over by the DSIs until well after the rate case had begun. *Id.* This fact is irrelevant; all out-of-date margins were updated with the additional data, and the updates were introduced into evidence. Thus, the final margin is based on all of the documents, not simply on the original data base. Moreover, the parties had ample opportunity to contest both the original and the final margins, as well as the data used in all calculations. (Although APAC asserts that the data were not turned over "by the BPA" until after the case had begun, the context suggests that APAC meant to refer to the DSIs. In either case, the point is irrelevant.)

The data base contains data for six utilities that are not solely utility documents. For one of these utilities, utility 14A (Mason County PUD), the data base contains the margin calculation summary sheet from the 1985 study. *See id.*, Utility 14A. This document in fact is the same summary sheet introduced for this utility in the 1985 study. *See* WP-96-E-GE-16, Page A11 of A46. Therefore, the data for this utility also are independent of the DSIs.

Thus, the data base contains only five utilities for which the data can in any way be tied to the DSIs. One of these is utility 28C, Cowlitz County PUD. *See* E-PA-07. In the case of Cowlitz, the data base contains a table prepared by the DSIs rather than an actual Cowlitz document. This table lists Cowlitz's demand charges for loads from 0-50,000 kW and for loads above 50,000 kW, and summer and winter energy charges. *See* E-PA-07, Utility 28C. These charges were used in calculation of the margin; they match the charges in Cowlitz's Industrial Rate Schedule, which the BPA analyst obtained from the BPA area economists. *Id.*, Attachment 2 (Rate Schedules); *see also* Chang, Cocks, E-BPA-79, Attachment 5, at 2.

Thus, in the case of both Mason and Cowlitz, the documents prove that the DSIs did not bias or manipulate the figures in the data base. For 16 of the 20 utilities, the data in the data base either consist of actual utility documents, or can be verified in whole or in part by reference to other, uncontested evidence. Considered together with the parties' failure to present any contrary evidence, this is strong evidence that the data are reliable. In its brief on exceptions, however, APAC argues that BPA's failure to gather the data itself forced BPA to use "questionable data." APAC Ex. Brief, R-PA-01, at 17. BPA has already explained why, as of mid-March 1995, the need to conduct a new margin study (or the desirability of conducting a new study) had not yet arisen. Moreover, APAC has still failed to provide <u>any</u> evidence that the data supplied by the DSIs are questionable. Instead, as with BPA's independent analysis of the data, APAC challenges none of the discussion in the draft ROD wherein the Administrator concluded that the evidence demonstrated the reliability of the data. Again, APAC substitutes assertion for evidence.

For their part, the IOUs do not argue that any particular margin is suspect; they rely entirely on general allegation. APAC cites one margin, Seattle City Light's (SCL), as the "most telling" example of BPA's failure to verify the data. APAC Brief, B-PA-01, at 16. According to APAC, at cross-examination BPA admitted that "the DSIs' data produces an unusually high distribution cost for SCL." *Id.* APAC concludes that Seattle's high distribution costs "are indicative of how the study's data can be manipulated to lower the margin." *Id.* at 17.

The facts are much different. First, what BPA acknowledged at cross-examination was that the distribution costs for two utilities, Seattle City Light and Oregon Trail Cooperative, were "substantially higher than any of the other distribution costs for any of the remaining utilities." Tr. 1643. By changing "substantially" to "unusually," APAC implies that BPA acknowledged the suspiciousness of the data. BPA did no such thing. The fact that two utilities have higher distribution costs than the others, taken by itself—and this is APAC's only evidence of "manipulation"—proves only that those two utilities allocate more costs to distribution than do the others. (Oregon Trail's distribution costs are actually higher than Seattle's. Chang, Cocks, E-BPA-120, Attachment E. By citing only SCL's distribution costs, APAC implies falsely that SCL stood suspiciously alone.)

Second, Seattle's distribution costs are not "the DSIs' data"; they are taken directly from Seattle City Light's financial statements, which APAC has in its possession and which APAC introduced into evidence. E-PA-10. On cross-examination regarding Seattle's margin, the BPA analyst testified that the distribution expense for Seattle was listed on a DSI summary sheet. Tr. 1648. She noted that the summary sheet contained two figures for distribution expense, $3,841,000 and $28,573,000. *Id.* at 1649 (citing E-PA-07, Utility #21 Margin Analysis, Page 3 of 3, lines 7 and 8). When counsel for APAC challenged the analyst to locate those numbers in an actual Seattle document, the analyst cited a page from Seattle's financial statements titled "Operations/Maintenance By Major Function For The Period Ending 12/31/92." Tr. 1649. As the analyst explained, under the column on that page titled "Current Year," a number of costs appear as part of "Total Distribution Expense." *See id.* and E-PA-07. The costs labeled "Metering Expenses" and "Customer Installation Expenses" add up to $3,841,000, the first figure on the DSI summary sheet; the rest of the expenses add up to $28,573,000, the second figure on the DSI summary sheet. *See* Tr. 1649 and E-PA-07. Again, the utility documents confirm the DSIs' numbers.

Third, in the 1985 margin study, which the IOUs urge the Administrator to adopt, two utilities also had substantially higher distribution costs than the rest. Thus, the result in the current margin study is consistent with the result in the 1985 study. Moreover, one of the utilities that had high distribution costs in 1985 was Seattle City Light, utility 21A. *See* E-GE-16, Page 13 of 20. (Oregon Trail was not in the 1985 study.) Once again, the independent, uncontested evidence corroborates the data the DSIs compiled.

Fourth, APAC argues that if Seattle's distribution costs were reduced, the difference would be reallocated to the "other costs" category, and therefore would be included in the margin. APAC Brief, B-PA-01, at 17. APAC provides no evidence or argument supporting this assertion. Its citation for the assertion is a summary sheet that simply lists Seattle's costs by category. *See id.* (citing Initial Proposal Wholesale Power Rate Development Study, WP-96-E-BPA-05, Appendix A, at A-19.) In fact there is nothing automatic about this reallocation; as with all costs, the category to which the costs would be reallocated depends on what the costs consist of. The BPA analyst testified that the costs relate to maintaining the distribution system, and therefore would be allocated to either transmission or distribution, depending on whether the customer was a distribution customer or a transmission customer. Tr. 1723.

Fifth, if APAC believes the data support a different margin calculation, it had every opportunity to make its case. As noted, APAC introduced the entire Seattle City Light COSA and Seattle's financial statements into evidence. Yet its case rests on unsupported allegations that BPA and the DSIs manipulated data that, in fact, were generated by the utility itself. The DSIs simply passed on photocopies of Seattle's COSA and financial statements. APAC in effect asserts that the documents have become tainted by having passed through the DSIs' hands.

Thus, the record contains substantial evidence verifying the accuracy of the data base: first, most of the data come from actual utility documents, which have been introduced into evidence. Second, in every case in which the record contains independent information regarding the utilities' margins, this evidence corroborates the information in the data base. Moreover, to the extent that additional verification might serve some purpose, BPA reasonably relied on the DSIs' statements that they had sent the calculations of the margin to the utilities. On the last page of notes the BPA analyst took of her conversations with

DSI representatives, she wrote that "Everybody in study, except Seattle, has bought off on margin—don't expect anyone to challenge." WP-96-E-GE-06. On cross-examination regarding this note, the analyst testified that a DSI representative had told her that he had sent the margin calculations to every utility in the sample, and that none of the utilities had disagreed with the numbers. He added that Seattle City Light had replied by letter that it would not check the calculations. Tr. 974. This conversation took place on May 19, 1995, before discovery in this case had begun. E-GE-06.

BPA issued data request BPA/DS:49 to the DSIs on January 9, 1996. WP-96-E-PA-09. Included in the response to this data request was a letter from Seattle City Light to the DSI representative, in which Seattle wrote that it had looked at the tables the DSIs had used to calculate its margin and had "no comment regarding the methodology and have not checked the accuracy of your calculations." (APAC has included the attachments to BPA/DS:49 as part of E-PA-10.) This letter, which the BPA analyst received approximately eight months after her conversation with the DSI representative, corroborated what the representative had told her. (As can be seen from the letter, Seattle's "refus[al]" to verify the data, as APAC puts it, was simply a statement of no comment. *See* APAC Brief, B-PA-01, at 17.) Given the other corroborating evidence in the case, BPA has substantial reason to rely on the DSI representations about the data, and no reason to assume these representations are false. (It should also be noted that all of the utilities included in the data base are represented in this proceeding by at least one umbrella group, including the Requirements Customer Coalition, the Western Public Agencies Group, and the Public Power Council. No utility has challenged any of the data used to calculate its margin, nor offered any testimony that either the data or the margin is inaccurate.)

The parties suggest that, in addition to verifying the raw data with the utilities, BPA should have verified the "calculations of the margin." Piro, Semro, WP-96-E-GE/PL/PS-08, at 1. As noted above, when the DSIs sent their calculations to Seattle City Light, the utility replied that it had "no comment regarding the methodology." E-PA-10 (Letter from Paula Laschober, Supervising Rates Analyst, to Larry Frank, Regulatory & Cogeneration Services, Inc. (January 18, 1994)). This reply is telling: Seattle is in no position to comment on the methodology or the calculation of its industrial margin because the "industrial margin" is a term of art employed in section 7(c)(2) of the Northwest Power Act. Although to some extent the industrial margin is intended to mimic the margins that BPA's preference customers add to their retail industrial rates, it is not a calculation the utilities themselves do. It is not an aspect of utility ratemaking.

To illustrate this point, consider the issues that were raised when the industrial margin was first calculated in 1985. A number of these issues concerned the appropriate cost components of the margin. The costs at issue included non-BPA funded conservation costs; high-voltage transmission costs; revenue taxes; and legal expenses related to generation resources. *See* WP-96-E-GE-19 (*Administrator's Record of Decision, 1985 Final Rate Proposal*, WP-85-A-02), at 134-40. To take three of these examples (revenue taxes are discussed elsewhere in this Record of Decision,*See infra* § 8.2.2): In 1985 the parties agreed that transmission costs should be excluded from the margin because BPA's Priority Firm Power rate (which was the "applicable wholesale rate" to which the margin is added) already included transmission costs. E-GE-19, at 136. Northwest Utilities argued, however, that certain transmission costs were related to distribution and therefore should be included in the margin. The Administrator concluded that he could not segregate transmission functions related to generation-integration, which represented costs not included in the margin, from transmission functions related to distribution, which represented costs that were included in the margin (before accounting for the size of load adjustment). Therefore, he excluded all transmission costs from the margin. *Id.*

Under the formula contained in section 7(c)(2), the inclusion of any transmission costs in the margin would have resulted in double recovery: the costs would have been included in both the "applicable wholesale rate" and the margin. This issue turned on an application and interpretation of section 7(c)(2) of the Northwest Power Act rather than on any nuances of utility ratemaking. Similarly, legal expenses related to generation resources were excluded from the margin because they are related to power expense, which under section 7(c)(2) is not a component of the margin. *Id.* at 139. Public utilities, which do not set rates under section 7(c)(2) of the Northwest Power Act, would not face the same issue in the calculation of their margins.

Whether to include conservation costs in the margin turned on whether such costs were reimbursed by BPA under its Average System Cost methodology, and whether they were related to acquisition of a resource. *Id.* at 135. The Administrator concluded as follows:

> It is difficult to determine the extent to which utility-funded conservation activities, including advertising and customer information, lead to the acquisition of conservation resources. However, it would not be appropriate to include identifiable non-BPA funded conservation expenditures related to nonacquisition in the power cost component.
>
> Conservation costs not associated with direct acquisition of a resource or energy savings and not reimbursed by BPA are included as a margin component.

Id.

Thus, the decision whether to include conservation costs in the industrial margin was based on one, the fact that power costs (which include conservation acquisition costs) are excluded from the industrial margin under section 7(c)(2); and two, the fact that certain conservation costs are reimbursed by BPA under the residential exchange program because they are included in utilities' average system cost. These issues are unique to BPA; retail utilities calculating industrial margins would not have to first resolve them. All of the above arguments concerned application of the Northwest Power Act rather than utility ratemaking. (There is no indication that the Administrator checked with the utilities after issuing the 1985 Record of Decision to ask whether he had correctly calculated their margins.) In short, the industrial margin is a creature of the Northwest Power Act, and utilities are in no position to verify it.

The IOUs also suggest that BPA should have updated or verified the study with Northwest Utilities, which, along with the DSIs, sponsored the data base used in the 1985 study. Piro, *et al*. E-GE-PL/PS-02, at 13. BPA testified that it had no belief that Northwest Utilities had updated the data. Tr. 957. Northwest Utilities is not a party to this rate case. Since the industrial margin is irrelevant for all purposes other than this rate case, there is no reason to believe it has updated the study. The IOUs also fault BPA for not checking with the Public Power Council (PPC), which participated in the study in 1985. MREP Brief, B-GE/PL/PS-01, at 20 n.18. The IOUs neglect the fact that the PPC is a party to this rate case and has not objected to any of the data used in the margin study or indicated that any of it is incorrect. It certainly has had the opportunity to do so. In addition, given the evidence corroborating the data and the DSIs' representations, and the absence of contradictory evidence, the BPA analysts reasonably believed the DSIs' statement that they had sent the data to the PPC. *See* E-GE-06, page six of notes.

Both APAC and the IOUs filed testimony challenging a number of the margins BPA had calculated. Although neither party suggested what the correct margin should be for any utility in the study, they did point out problems in BPA's analysis. APAC testified that several of the margins were out-of-date and that BPA had omitted several qualifying utilities from the sample. Wolverton, E-PA-01, at 7-9. The IOUs agreed with this conclusion. Piro, *et al*., E-GE/PL/PS-02, at 14.

BPA agreed with most of the parties' criticisms. APAC testified that Tacoma Public Utilities, Mason County PUD #3, and Grays Harbor PUD had increased rates since publishing the data used in the study. Wolverton, WP-96-E-PA-01, at 8. (Although APAC lists only the first of these by name, the evidence makes the identity of the other two utilities clear. *See* Chang, Cocks, E-BPA-54, at 4-5.) BPA updated all three margins based on the utilities' data. BPA updated Tacoma's margin based on its new COSA, and it updated the margins for Mason County PUD and Grays Harbor based on their financial statements. Chang, Cocks, E-BPA-79, at 2-3 and Attachments 1 and 2. Thus, while the data base was the starting point for calculating the margins, the final margins were based on additional utility documents.

APAC also testified that the margins for Clatskanie County PUD and Cowlitz County PUD are tied to BPA's rates by contract. Because BPA had increased its rates since the contracts included in the data base were executed, the margins were out-of-date. Wolverton, WP-96-E-PA-01, at 4, 8. BPA updated the margins for both of these utilities, based on their more recent Industrial Rate contracts. Chang, Cocks, E-BPA-79, at 3-4 and Attachments 3-6.

The parties did not challenge any of the recalculated margins. In its initial brief, however, APAC argued that Seattle City Light's margin is still based on out-of-date financial statements. APAC Brief, B-PA-01, at 17. Here APAC misrepresents BPA's testimony.

As discussed above, APAC cross-examined the BPA analysts regarding Seattle's distribution costs. In his cross-examination, APAC's counsel asked the witnesses to refer to "the supporting documentation to go with the summary table in your initial proposal from July of 1995, which was BPA-05, [Appendix] A." Tr. 1644 (emphasis added). Then, referring to Exhibit WP-96-E-PA-07, which contains the original data base, counsel asked whether that exhibit included "the documents you provided as supporting documentation for the table in [BPA-]05, Appendix A?" (emphasis added). *Id.* The witness agreed that it did. *Id.* Counsel then asked the witness whether it was accurate that the margin numbers for Seattle City Light in Exhibit BPA-05 were derived from a "'94 cost of service study and 1992 year-end figures." *Id.* The witness agreed that this was accurate. *Id.* at 1644-45.

At cross-examination, therefore, the witness agreed with APAC's counsel that Seattle's margin as contained in BPA's initial proposal was based on a 1994 COSA and 1992 financial statements. In its brief, however, APAC referenced exhibit WP-96-E-BPA-120, Attachment E as its source for Seattle City Light's margin numbers. APAC Brief, B-PA-01, at 17, line 1. Then, citing the above cross-examination, APAC asserted that "BPA staff admit the [sic] these figures were derived from out-of-date financial statements, even though Seattle's 1995 COSA had been available to BPA for several months before it issued the proposed rates." *Id.* at 17 (emphasis added). Exhibit WP-96-E-BPA-120 is BPA's surrebuttal testimony on the margin study. It was published in February 1996 and includes the final updated margin calculations for each utility in the study. As demonstrated above, however, in its cross-examination APAC specifically directed the witness's attention to BPA's initial proposal from July of 1995, and asked questions regarding the supporting documentation for the margin listed in that proposal.

In the cross-examination, therefore, BPA staff acknowledged only that the figures for Seattle City Light in the initial proposal were out-of-date. This was the acknowledgment APAC's counsel requested. In its initial brief APAC cites pages 1646-47 of the transcript for its allegation that the figures for Seattle remain out-of-date. APAC Brief, B-PA-01, at 17. On those pages the BPA analyst acknowledged that the margin for SCL in BPA's initial proposal was based on out-of-date information. Also on page 1647, the analyst told APAC counsel that "in our—the numbers that appear in [BPA-]120 are based on 1994 and 1995." Tr. 1647. In its rebuttal testimony to the parties' direct case on BPA's supplemental proposal, BPA responded as follows to the DSIs' criticism that its margin for Seattle was out-of-date: "In the supplemental study, BPA used 1994 load data and 1994 revenues. The 1995/1996 data, however, are the most up-to-date. BPA has substituted these data in its margin study." Chang and Cocks, WP-96-E-BPA-110, at 2. On redirect examination at the hearing, the witness testified that Seattle's margin was based on "1994 financial statements and 1995/96 COSA," not, as APAC suggests, 1992 financial statements and a 1994 COSA. Tr. 1717.

During cross-examination, counsel for APAC acknowledged that BPA had updated Seattle's margin in its final calculation:

> Q. Just to make sure I understand this, your updates to the Seattle City Light figures contained in BPA-110, Attachment 1 and carried forward to the final summary table in BPA-120, those reflect your updating of the July 1995 Seattle City Light figures from your analysis of the COSA and the financial statements provided to you by the DSIs, correct?
>
> . . . .
>
> A. (Ms. Chang) That's correct.

Id. at 1661.

Nevertheless, in its brief APAC suggested that BPA's final calculation was out-of-date. It is clear, however, that BPA's margin calculation for Seattle City Light is based on up-to-date data. Moreover, APAC's assertion that BPA admitted that the updated information had been available to it for several months before BPA issued the initial proposal subtly changes the import of BPA's testimony. On cross-examination the witness agreed only that Seattle's 1995/96 COSA had been published in September 1994. *Id.* at 1646. This date is printed on the cover page of the COSA. *See* E-PA-10. The witness testified that she received the COSA in January 1996, after BPA published its initial proposal. Tr. 1717. Again APAC relies on innuendo, this time to suggest that BPA simply ignored an updated COSA. Once BPA received the COSA, however, it incorporated the updated information in its analysis, and the parties have presented no evidence that Seattle's margin is incorrect.

APAC also testified that the data for several of the utilities in the sample did not include the effect of BPA's 1993 rate increase. Wolverton, E-PA-01, at 8. BPA rebutted this assertion, and APAC has not continued to make it an issue. Chang, Cocks, E-BPA-54, at 2-3. As BPA testified, the data for all of the utilities in the sample are from January 1993 or later, after BPA published its initial proposal in the 1993 rate case. Most utilities in the sample were setting rates to go into effect October 1, 1993, coincident with the BPA rate increase. Standard ratemaking practice suggests that the utilities included the effect of BPA's rate increase in their rates. *Id.* at 3.

Finally, APAC asserted that BPA omitted four utilities from the sample. Wolverton, WP-96-E-PA-01, at 9. As BPA pointed out in its rebuttal testimony, one of these utilities was included in the sample. Chang, Cocks, E-BPA-54, at 5. BPA acknowledged that it omitted the other three utilities because it did not have cost data for them. BPA's sample, however, includes 89 percent of all industrial load in the region that meets the sample's criterion. *Id.* This proportion of load is sufficient to calculate an accurate margin. As shown below, BPA adjusted the margins of twelve utilities, and changed the test period energy for five, with little effect on the final margin, because changes tend to cancel each other out. In addition, sensitivity analyses demonstrated that changing the number of utilities in the sample has little effect on the margin. E-GE-05, Attachment 2. In 1985, the Administrator noted only that the joint data base contained "the majority of loads in the region above 3.5 megawatts of peak demand [the sample criterion.]" E-GE-19, at 130. A sample of 100 percent of qualifying loads is ideal, but is not essential.

In addition to the above updates, for five of the utilities BPA updated the test period energy included in the initial proposal, substituting more recent data. (Compare Initial Proposal Wholesale Power Rate Development Study, E-BPA-05, Appendix A, at A-6, and Chang, Cocks, E-BPA-120, Attachment E). Because each utility's margin is weighted by its energy sales to determine that utility's effect on the overall margin, these changes affect the final margin. *See* Supplemental Proposal Wholesale Power Rate Development Study, WP-96-E-BPA-61, Appendix A, at A-3.

Finally, the DSIs themselves offered testimony that the margin should be higher than the margin BPA calculated in its initial proposal. Tr. 1701. In its initial proposal, BPA calculated a margin of 0.45 mills/kWh. Initial Proposal Wholesale Power Rate Development Study, E-BPA-05, Appendix A, at A-6. The DSIs filed testimony indicating that a number of BPA's individual margin calculations were incorrect, and that the margin should be 0.55 mills/kWh. Schoenbeck, *et al.*, WP-96-E-DS-03, at 4. In response to the DSIs' testimony, BPA updated the margins for Seattle City Light, Whatcom County PUD, and the City of Port Angeles. Chang, Cocks, E-BPA-120, at 2; Chang and Cocks, E-BPA-110, at 2. The DSIs' testimony supports BPA's conclusion that the DSIs were attempting to derive an accurate margin. Tr. 1701.

All told, the parties raised objections to 16 of the 20 individual utility margins in BPA's initial proposal. Not a single objection was based on the credibility of the data or called its credibility into question. The parties' only objection was that data for some of the utilities were out-of-date. In every case in which this objection was borne out, BPA updated the data based on additional information. BPA reviewed all 16 objections, and changed 12 of the margins in response to the challenges. Tr. 1729-30. As noted above, BPA also changed the test period energy for five utilities. It is clear that the data base provided by the DSIs was only the starting point for BPA's analysis.

The IOUs argue, however, that "judgment is required to put the data into a usable and comparable format." Piro, *et al.*, E-GE/PL/PS-02, at 13. As the DSIs have pointed out, such judgment "was exercised throughout the entire testimony phase of this proceeding." DSI Brief, B-DS-01, at 28. In the data base, the DSIs included not only the raw data for each utility but a complete explanation of how they derived each margin. E-PA-07. Their "judgment" was on full view for all parties to challenge. BPA responded to the parties' every argument regarding the margin, and recalculated most of the margins. The parties did not present any evidence that any of the final margins are incorrect, even though APAC's witness testified that every other year he conducts "a survey of Northwest public agencies to obtain information on their industrial rates." Wolverton, E-PA-01, at 8.

Every rate case begins with BPA's publication of a rate proposal in all its intricate detail. The parties then have an opportunity to present their own case, to point out problems in BPA's case, and to argue for different treatment of any rate element. This is the course the parties took regarding the industrial margin study, just as they did regarding many aspects of BPA's initial proposal (as demonstrated by both the volume of testimony in the case and this Record of Decision). In the margin study, as in many other aspects of its case, BPA adopted the parties' positions whenever it concluded that these positions were justified. The parties pointed out problems with BPA's initial proposal, but not in any subsequent calculations.

Thus, the fact that many of the initial margins were changed in BPA's final calculations does not suggest that BPA's margin study is invalid. To the contrary, it demonstrates that the data provided by the DSIs were the starting point for the analysis, and that BPA was receptive to new evidence. In its brief on exceptions, APAC asserts that, based on a claim that BPA has verified the data and that "the parties have not disproved the data's accuracy," the draft Record of Decision "adopts the industrial margin study provided to BPA by the DSIs." APAC Ex. Brief, R-PA-01, at 15. APAC cites for this assertion the draft ROD's "Draft Decision," which is repeated verbatim in this final Record of Decision. (See concluding paragraph of this section.) In that decision, the Administrator adopts "[t]he industrial margin study conducted by BPA." (emphasis added). The Administrator added that "BPA has presented persuasive evidence that the data base provided by the DSIs is a reliable source of data to be used as the starting point for the study. . . . The parties have presented no evidence that the data provided by the DSIs are biased."

As both the evidence in the case and this Record of Decision make clear, the Administrator has not "adopted" a study provided by the DSIs. BPA has conducted substantial analysis to update the data and ensure the accuracy of the margins. Moreover, the Administrator has not concluded that the parties have "not disproved" the data's accuracy. BPA has presented substantial evidence that the data are accurate and unbiased. Throughout the case, from their initial testimony to their briefs on exceptions, the parties have alleged that the data must be biased because they were supplied by the DSIs. Yet at no point in the case have they presented even a shred of evidence to support their allegations. The Administrator recognizes that BPA must support the validity of its study. BPA has done so. The parties' failure to prove bias is relevant because they have alleged that the data are biased. Mere unsupported allegations of bias, however, are no reason to reject BPA's study.

APAC cites *Friends of the Earth v. Hintz*, 800 F.2d 822 (9th Cir. 1986), for the proposition that BPA should be required to independently verify the data submitted by the DSIs. APAC Brief, B-PA-01, at 17-18. In *Friends of the Earth*, the court held that the Army Corps of Engineers had a duty to independently verify data submitted by an applicant for a permit under section 404 of the Clean Water Act. As APAC acknowledged, regulations governing the Corps required independent verification. (The regulations provided that when information was prepared by the applicant for a permit, "the district engineer is responsible for independent verification and use of the data, evaluation of the environmental issues, and for the scope and content of the [Environmental Assessment].” *Friends of the Earth*, 800 F.2d at 835 (quoting 33 C.F.R. Part 230, App. B § 8(b)).

As APAC also acknowledged, no such regulation governs BPA’s preparation of the industrial margin study. Just as significant, however, are the differences between the data and the administrative process in each case. In *Friends of the Earth*, ITT Rayonier applied for a permit to discharge fill material into a wetlands area. In support of its application Rayonier provided a report to demonstrate that its activities were water-dependent, and that there was no practicable alternative to the discharge of the fill material that would have less adverse impact on the aquatic ecosystem. In its submission, Rayonier evaluated four alternative sites. It concluded that two were not practicable while the other two would require substantial additional expense. The Corps reviewed Rayonier’s report and issued the permit.

In *Friends of the Earth*, Rayonier submitted subjective, evaluative reports analyzing biological and economic issues. Most of the data the DSIs provided were simply photocopies of documents prepared by the utilities in the study. Moreover, the crucial information on these documents was not subjective, analytical assessments but simply numbers. The parties have presented no evidence nor even made any allegation of tampering. The documents can be verified by looking at them.

In addition, to the extent that any judgment was necessary to make use of the numbers, the parties have had ample opportunity to engage in discovery, to cross-examine BPA and the DSIs (they waived their rights with regard to the DSIs), and to file testimony challenging any number or calculation in the margin study. In *Friends of the Earth*, the public process was far more limited. The Corps accepted comments on the application without an adjudicative proceeding, and then issued the permit.

Finally, there is the question of alternatives. BPA reasonably explained why circumstances dictated that it rely on the DSIs’ data as a starting point. The parties have challenged none of this testimony. APAC suggests, however, that the Administrator adopt a margin “based on independent analysis.” APAC Brief, B-PA-01, at 20. Given the course of this proceeding, it is clear that BPA has developed a margin that meets this criterion. Moreover, APAC does not explain where the Administrator should turn for an alternative margin. Although APAC filed testimony suggesting that a number of BPA’s margin calculations were out-of-date (all of which BPA subsequently updated without further challenge), it has presented no alternative margin either in the aggregate or as to any individual margin in the study. APAC may be suggesting that the Administrator not adopt any industrial margin until another margin study is performed. If the Administrator took this course, he would be unable to establish an Industrial Firm Power rate until the margin study was completed and subjected to another rate case. This course would leave BPA’s rates and cost recovery in an extremely uncertain state. Yet the parties have presented no evidence that the DSIs’ data were biased, and BPA has addressed all of their specific objections. Given the substantial record that has been compiled in this case in support of BPA's margin study, APAC's suggestion is not reasonable.

The IOUs suggest that the Administrator should rely on the existing study that was used to calculate the margin in the 1985 rate case. Tr. 2438; *see also* MREP Brief, B-GE/PL/PS-01, at 23. The IOUs offered no evidence that BPA's margin study was flawed; instead, they relied on APAC's objections. *See* Piro, *et al*., E-GE/PL/PS-02, at 14. BPA has addressed all of these objections. The IOUs' principal objection was that they "found data that are out-of-date." *Id.* (In fact, this was the <u>only</u> basis on which the parties challenged any particular utility margins.) Yet the IOUs suggest adoption of an eleven-year-old study whose every margin would be out of date. This alternative is unreasonable. (The parties pointed out that in 1985 the Administrator rejected a study prepared by the DSIs in favor of a consensus study offered by three parties, including the DSIs. The Administrator did not reject the DSIs' study because it was prepared by an interested party. Instead, he concluded that, because the study contained only 13 utilities, it was too limited. E-GE-19, at 130. He added that the joint data base had "the same quality of data for an additional six utilities." *Id.* Finally, in 1985 the Administrator had a choice of up-to-date data bases. Here, the parties have offered no real alternative. Instead of presenting an alternative data base, or even an alternative calculation for any margin in the study, the parties have been content with making allegations against BPA's study.)

BPA has presented credible, substantial evidence that its margin study is credible and valid. The parties have presented no contrary evidence. BPA's study will be adopted.

<u>Decision</u>

The industrial margin study conducted by BPA will be adopted for calculation of the industrial margin. BPA has presented persuasive evidence that the data base provided by the DSIs is a reliable source of data to be used as the starting point for the study. BPA has corrected the problems in its Initial Proposal. The parties have presented no evidence that the data provided by the DSIs are biased, or that any margin in the margin study is incorrect.

8.2.2 <u>Revenue Taxes</u>

<u>Issue</u>

Whether revenue taxes should be included in the industrial margin.

<u>Parties' Positions</u>

The IOUs argue that BPA arbitrarily excluded revenue taxes from the industrial margin. They assert that the Administrator addressed this issue in 1985, and concluded that revenue taxes were a cost utilities incurred in distributing power. Finally, they argue that the number of utilities that pay revenue taxes is irrelevant to whether revenue taxes are part of the typical margin. MREP Brief, WP-96-B-GE/PL/PS-01, at 24-26. APAC also argues that BPA's proposal to exclude revenue taxes from the margin contradicts the Administrator's decision in 1985. APAC adds that BPA's effort to achieve a competitive DSI rate has no statutory basis. APAC Brief, WP/TR-96-B-PA-01, at 12-15. The DSIs argue that revenue taxes represent legislative policy choices regarding how to collect revenues and are not part of providing electric service. They argue further that because most of BPA's public body and cooperative customers with industrial customers do not pay revenue taxes, such taxes are not part of the typical margin. Finally, they argue that BPA's decision is consistent with the Administrator's decision in 1985, and that even if the two decisions are inconsistent, changed competitive circumstances justify the exclusion of revenue taxes from the margin today. DSI Brief, WP-96-B-DS-01, at 23-26.

BPA's Position

BPA argues that revenue taxes should be excluded from the margin because the majority of BPA's public body and cooperative customers with industrial loads do not incur them, and do not include revenue taxes in their retail industrial rates. Chang, Cocks, WP-96-E-BPA-25, at 7; Chang, Cocks, WP-96-E-BPA-54, at 5-7. Therefore, revenue taxes are not a component of the typical industrial margin. In addition, the wholesale power market today is extremely competitive. BPA argues that it cannot establish a competitive DSI rate, and retain DSI load and revenues, if it includes in the margin a cost that most power suppliers do not incur. Chang, Cocks, E-BPA-25, at 4, 7-8.

Evaluation of Positions

Introduction

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to the DSIs shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers [also known as preference customers] to their industrial consumers in the region." 16 U.S.C. § 839e(c)(1)(B). Section 7(c)(2) provides that the determination under section 7(c)(1)(B) shall be based on BPA's applicable wholesale rates to its public body and cooperative customers "and the typical margins included by such public body and cooperative customers in their retail industrial rates." *Id.* § 839e(c)(2). BPA asserts that revenue taxes are not a component of the typical industrial margin because a majority of BPA's preference customers with industrial customers do not pay revenue taxes, and therefore the majority do not include revenue taxes in their retail industrial rates.

Two factors distinguish the situation today from that in 1985, and warrant a reversal of the Administrator's previous decision. First, since 1985 the electric utility industry has undergone a revolution. In 1985 BPA was the unchallenged low-cost provider of power. Today, it is a participant in a fiercely competitive electric market, and has already lost substantial DSI and public agency load to the competition. The inclusion of revenue taxes in the margin would make its DSI rate uncompetitive, and the loss of loads and revenues would be even greater. Section 7(c) of the Northwest Power Act must be read in conjunction with section 7(a), which requires BPA to recover its costs. The parties assert incorrectly that, in the draft ROD, BPA posited a conflict between these two sections. Far from positing a conflict between the two statutory sections, BPA's exclusion of revenue taxes allows BPA to comply with both.

Second, the record in this case is more fully developed than the record was in 1985. In 1985, the Administrator could not determine from the record how many of BPA's public body customers with industrial customers were subject to revenue taxes. This record contains such evidence. Therefore, the Administrator has a more complete record on which to base his decision.

In addition, BPA's conclusion in this case is consistent with the Administrator's reasoning in 1985. In the 1985 rate case, the DSIs argued that revenue taxes should be excluded from the margin because they were not incurred by all utilities. The Administrator rejected this argument. He did not address the question of whether a cost should be included in the typical margin when it is included in only a minority of utilities' rates.

I. In Applying Section 7(c) Of The Northwest Power Act, The Administrator Must Take Into Account The Need For A Competitive DSI Rate In Order To Retain Load

A. Section 7(c) Of The Northwest Power Act Must Be Read In Conjunction With BPA's Other Ratemaking Directives, Including Section 7(a)'s Mandate That BPA Recover Its Costs And The Ratemaking Directives Of BPA's Other Enabling Statutes

Section 6 of the Bonneville Project Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. 16 U.S.C. § 832e. Section 7 provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including amortization of the capital investment over a reasonable period of years. *Id.* § 832f.

Section 9 of the Federal Columbia River Transmission System Act provides that BPA's rates shall be established: (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 amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that 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 Act. *Id.* § 838g.

The Flood Control Act of 1944 contains similar rate directives. Section 5 of the Flood Control Act directs that rate schedules should 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 electric energy, including the amortization of the Federal investment over a reasonable number of years.

The Northwest Power Act contains rate directives that apply to particular customer classes. Section 7(c)(1)(B) of the Northwest Power Act provides that rates to the DSIs shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers in the region." *Id.* § 839e(c)(1)(B). Section 7(c)(2) provides that the Administrator's determination under section 7(c)(1)(B) "shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the <u>typical margins</u> included by such public body and cooperative customers in their retail industrial rates." *Id.* § 839e(c)(2) (emphasis added).

Section 7(a) of the Northwest Power Act is BPA's primary rate directive; it provides that rates shall be established

> to recover, 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 . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law.

Id. § 839e(a)(1).

BPA's rates must be approved by the Federal Energy Regulatory Commission, on a finding that the rates "are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs." *Id.* § 839e(a)(2)(A). The Administrator has previously noted that

> [section 7(a)] states, point blank, that BPA's rates must be established to recover its costs and that the Federal Energy Regulatory Commission (FERC) cannot approve rates which fail to recover BPA's total costs. This simple, declarative statement in section 7(a) controls all other statutory provisions on BPA ratemaking, because BPA cannot implement rates without first obtaining FERC approval.

Administrator's Record of Decision, 1986 Variable Industrial Power Rate Proposal, VI-86-A-02, at 13 [hereinafter 1986 Variable Industrial Rate ROD].

Thus, the Administrator's primary ratemaking obligation is to set rates sufficient to recover his costs and assure repayment of the United States Treasury. The legislative history of the Northwest Power Act confirms this conclusion. The House Report accompanying the final bill stated that the rate directives for particular customer classes are "[s]ubject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs." H.R. Rep. No. 976, Part II, 96th Cong., 2d. Sess. 36 (1980) [hereinafter House Report 976]. To accomplish this objective, section 7(a) authorizes BPA to set rates within a wide discretionary range. 1986 Variable Industrial Rate ROD, at 12. The Act's legislative history confirms this conclusion as well. In reference to section 7(e) of the Northwest Power Act, which grants the Administrator wide discretion in establishing various rate forms, *see* 16 U.S.C. § 839e(e), the House Report stated that "[t]his subsection also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money." House Report 976, at 53. Thus, the Administrator has concluded as follows:

> [T]he proper test for judging the efficacy and legality of a rate or rates under section 7(c) of the Northwest Power Act is a revenue test, not an average rate test.
>
> . . . .
>
> Viewed in this context, Northwest Power Act sections 7(c)(1) and 7(c)(2) provide a DSI revenue target toward which BPA should strive if economic conditions permit. Section 7(a) is the paramount ratemaking directive, because it requires BPA to design rates that recover costs <u>under all economic conditions</u>.

1986 Variable Industrial Rate ROD, at 14-15 (emphasis added).

BPA cannot fulfill the purposes of the Northwest Power Act unless it first ensures that it will recover its costs. As the Administrator recognized ten years ago, BPA can make this assurance only if it sets rates taking into account the prevailing economic conditions. BPA must apply its ratemaking authorities with this overarching goal in mind.

B. <u>Statutes Must Be Read As A Whole So As To Effectuate The Statute's Overall Purpose</u>

The United States Supreme Court has called it a "familiar principle" that "in expounding a statute, we [are] not . . . guided by a single sentence or member of a sentence, but look to the provisions of the whole law, and to its object and policy." *Massachusetts v. Morash*, 490 U.S. 107, 115 (1989) (quoting *Pilot Life Ins. Co. v. Dedeaux*, 481 U.S. 41, 51 (1987)). In *Morash*, the Court held that the payment of unused vacation time to discharged employees was not an "employee welfare benefit plan" under the Employee Retirement Income Security Act of 1974 (ERISA), because such payments presented none of the risks ERISA was intended to address. *Morash*, 490 U.S. at 115. Therefore, it was unnecessary to regulate such payments to effectuate the Act's overriding policy; the Court analyzed the issue by "viewing the [Act's] reference to vacation benefits not in isolation but in light of the words that accompany it and give the provision meaning." *Id.*

Similarly, in *King v. St. Vincent's Hosp.*, 502 U.S. 215 (1991), the Court emphasized the "cardinal rule that a statute is to be read as a whole . . . since the meaning of statutory language, plain or not, depends on context." *King*, 502 U.S. at 221. Thus, "[w]ords are not pebbles in alien juxtaposition; they have only a communal existence; and not only does the meaning of each interpenetrate the other, but all in their aggregate take their purport from the setting in which they are used." *Id.* (quoting *NLRB v. Federbush Co.*, 121 F.2d 954, 957 (2d Cir. 1941)).

Following these precepts, in *United States Nat'l Bank of Or. v. Independent Ins. Agents of Am., Inc.*, 508 U.S. 439, 113 S. Ct. 2173 (1993), the Court interpreted section 92 of a 1916 Act by reference to the Act's structure, title, and, as "final and decisive evidence . . . the language and subject matter of section 92 and the paragraphs surrounding it." *United States Nat'l Bank,* 508 U.S. 439 at ___, 113 S. Ct. at 2185. Noting that statutory construction is a "holistic matter," the Court said that in interpreting a statutory provision, it must look to "the provisions of the whole law, and to its object and policy." 508 U.S. at ___, 113 S. Ct. at 2182 (quoting *United States v. Heirs of Boisdore,* 8 How. 113, 122 (1849)).

Even if statutory language is plain, a court must "go beyond the literal language of a statute if reliance on that language would defeat the plain purpose of the statute." *Bob Jones Univ. v. United States,* 461 U.S. 574, 586 (1983). Thus, in *Bob Jones Univ.*, the Court denied tax-exempt status to a private school that enforced racially discriminatory admissions policies, even though the school qualified for an exemption under the literal language of the Internal Revenue Code. The Court said that the Internal Revenue Code's provision for tax exemptions "must be analyzed and construed within the framework of the Internal Revenue Code and against the background of the congressional purposes." *Id.* The Court concluded that tax-exempt organizations must meet certain common-law standards of charity, even though the Code did not explicitly contain such a requirement.

Finally, the Ninth Circuit Court of Appeals has also consistently held that even the literal language of a statute must be disregarded if its application would thwart the statute's purpose. *See, e.g., Lynch v. Dawson,* 820 F.2d 1014, 1019 (9th Cir. 1987).

Section 7(c) of the Northwest Power Act does not mention revenue taxes. It contains no language addressing the components of the typical industrial margin. Instead, the Act leaves the Administrator substantial discretion to determine these components. Since the plain language of the statute does not govern this question, it must be answered by reference to the statute's overall purpose and policy. BPA must read section 7(c) in conjunction with its other statutes, and give effect to the entire statutory scheme. The exclusion of revenue taxes from the industrial margin fulfills the overall purpose of section 7 that BPA recover its costs and repay the United States Treasury for its investment in the Federal Columbia River Power System. In addition, it helps fulfill the Transmission

System Act's policy of encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. As discussed below, the inclusion of revenue taxes through a refusal to consider the realities of today's competitive marketplace would defeat these statutory purposes.

C. BPA's Failure To Consider The Competitive Market In Calculating The Industrial Margin Would Defeat The Purpose Of Section 7 Of The Northwest Power Act

1. Competition For BPA's DSI Load Puts That Load At Risk If BPA Raises The Industrial Firm Power Rate Above The Proposed Level

As discussed at length elsewhere in this Record of Decision, BPA faces fierce competition for its loads. *See supra* § 2.2. This was not true in 1985, when the Administrator last calculated the industrial margin. Throughout the 1980s, BPA remained the low-cost provider of power. Moorman, Evans, WP-96-E-BPA-09, at 5. Only in the 1990s, particularly after passage of the Energy Policy Act of 1992, did the utility industry become truly competitive. *Id.* at 12. Given the relatively recent emergence of a competitive bulk power market, competition can only be expected to increase. Norman, Oliver, WP-96-E-BPA-10, at 12. The wholesale power market is going through "a transformation of huge proportion"; during just the few months when BPA was preparing its initial rate proposal, the number of participants in the bulk power and transmission markets expanded markedly. Beck, *et al.*, WP-96-E-WA-01, at 6, 7.

The parties, including BPA's customers and others, agree that BPA must set competitive rates in order to survive. The Public Power Council (PPC), which represents most of BPA's preference customers, has testified that "in order for BPA to continue to thrive in this competitive environment, it must provide power and transmission products and services at prices that its customers are willing to pay over an extended period of time." Eldridge, *et al.*, WP-96-E-PP-01, at 2. The PPC testified that if BPA's prices remain above competitive levels, as its existing rates are, it will continue to lose significant load. *Id.* at 3.

The Western Public Agencies Group (WPAG) represents 21 BPA customers that historically have purchased almost all their power requirements from BPA. Beck, *et al.*, WP-96-E-WA-01, at 2, 8. WPAG agrees that BPA no longer enjoys the significant price advantage over the competition that it had in the past; it testified that if BPA continues to set rates based on the sum of its costs without regard to the market it will risk losing "a significant portion of its bulk power sales." *Id.* at 9. The Requirements Customer Coalition (RCC) represents 53 BPA customers that together comprise approximately 20 percent of BPA's load. Drummond, WP-96-E-RC-01, at 1. The RCC has also testified that BPA cannot simply set rates to cover pre-set spending levels. If it does so, it will fail to attain revenues as customers choose to purchase their power elsewhere. Piper, WP-96-E-RC-05, at 2. When BPA was the low-cost provider of power, higher prices meant greater revenues. That is no longer the case. *Id.* at 1-2.

Although APAC challenges BPA's reference to the competitive market in interpreting section 7(c), APAC also urges BPA to set competitive rates. APAC has testified that in today's highly competitive market, raising prices will not increase revenues. Wolverton, WP-96-E-PP/DS/PA/PG/RC/WA-07, at 2. APAC has further testified that, in a competitive market, a supplier that raises prices and thus overprices its goods will in fact lose revenue. Tr. 2134. Finally, APAC has acknowledged that "the market will not sustain a higher BPA price." Wolverton, E-PP/DS/PA/PG/RC/WA-07, at 2. APAC's argument is contradictory: it urges BPA to ignore competitive pressures and raise the DSI rate, while acknowledging that raising the rate will reduce BPA's revenues from the DSIs and therefore would not be a sound business decision. As noted earlier, section 7(c) of the Northwest Power Act requires BPA to attain sufficient revenues from the DSIs so that, along with its other revenues, BPA will be able to meet its cost recovery obligations under section 7(a). As APAC acknowledges, raising the DSI rate above the proposed level would make fulfillment of these obligations highly uncertain.

BPA's revenues from all its customers are at risk. However, BPA has already lost considerable DSI load. Chang, Cocks, WP-96-E-BPA-110, at 4. Since publishing its initial proposal, in which BPA proposed virtually the same IP rate it is establishing in this Record of Decision, BPA has lost approximately 700 megawatts of DSI load (out of approximately 2,600 megawatts) to alternative suppliers. Moorman, Evans, WP-96-E-BPA-65, at 6. Some of BPA's competitors are targeting DSI loads in particular, offering variable rates and seeking to lure away the larger loads. Norman, Oliver, E-BPA-10, at 12. The DSIs can demand better prices from BPA's competitors because they offer valuable loads: they have high load factors and their loads are fairly constant throughout the day and over the course of the year. Thus, their loads are cheaper to serve than loads that vary more, and they are the objects of more intense competition than BPA's other loads. Moorman, Evans, E-BPA-65, at 5.

The evidence indicates that the market simply will not sustain a higher DSI rate. When BPA published its initial proposal in July 1995, its proposed rates approximated market prices. Moorman, Evans, E-BPA-09, at 15. Since then market prices have fallen. Tr. 383. None of BPA's proposed rates are below the market. *Id.* at 291. Therefore, any increase in the DSI rate would bring it above the market. According to APAC's testimony as well as BPA's analysis, this increase would result in a loss of revenue. Inclusion of revenue taxes in the industrial margin would increase the margin by 1.75 mills/kWh. Final Wholesale Power Rate Development Study, WP-96-FS-BPA-05, Appendix A. The DSIs testified that if BPA increased the margin by this amount it would make few if any sales to them. Instead, BPA would be forced to sell the power on the open market at even lower rates, resulting in a significant loss of revenues. Schoenbeck, Bliven, WP-96-E-DS-03, at 10-11. Given the substantial loss of DSI load even when revenue taxes are excluded from the margin, this testimony is credible.

Furthermore, BPA's own analysis indicates that an increase of approximately 2 mills in the DSI rate would result in a loss of 1592 megawatts of load, causing in turn a significant revenue loss. Moorman, Evans, E-BPA-65, at 7-8. Given today's fierce competition, even rates slightly above the proposed rates—as little as half a mill—would likely result in significant sales and revenue losses. *Id.* at 9. Therefore, inclusion of revenue taxes in the margin would surely reduce BPA's revenues, and put virtually the entire DSI load at risk.

2. <u>If BPA Ignored The Competitive Market In Setting The DSI Rate, It Would Violate The Requirement Of Section 7(a) That It Set Rates Consistent With Sound Business Principles To Recover Its Costs Under All Economic Conditions</u>

Under the Federal Columbia River Transmission System Act, BPA must establish "the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. § 838g. Section 7(a) of the Northwest Power Act incorporates this standard; it requires BPA to set rates to recover costs "in accordance with sound business principles." *Id.* § 839e(a)(1). Similarly, section 9(b) of the Northwest Power Act requires BPA to implement the Act "in a sound and business-like manner." *Id.* § 839f(b). In adopting the Variable Industrial Power Rate in 1986, the Administrator concluded that "[i]t is simply not a sound business principle to set rates that price BPA out of the market during times of power surplus and unrecovered fixed costs." 1986 Variable Industrial Rate ROD, at 13.

The Administrator adopted the Variable Industrial Power Rate, under which the DSI rate varies with the price of aluminum, at a time when fluctuations in aluminum prices had caused dramatic fluctuations in DSI load. *Id.* at 9. The fluctuations in load "cause[d] problems for BPA and the region. The nature of these problems lay in the uncertainty about BPA's future resource planning, financial strength, and rate stability." *Id.* The goals of the variable rate were to discourage aluminum plant closure during the short-run; encourage high aluminum plant operating rates during BPA's surplus period; and increase BPA's total revenues. *Id.* at 27.

Similar reasoning applies today. As previously noted, section 7(a) of the Northwest Power Act requires BPA to recover its costs "under all economic conditions." In 1986, DSI loads and revenues were at risk because of low aluminum prices. Today they are at risk because of competition. As in 1986, BPA must be concerned with a power surplus and the prospect of unrecovered fixed costs. The Administrator's reasoning in 1986 is equally applicable today:

> If BPA is unable to recover costs from any customer class (including the DSIs), sections 7(a) and 7(g) require the agency to design its other rates to cover the anticipated underrecovery. Section 7(g) expressly requires the Administrator to allocate to other customers the costs associated with BPA's "inability to sell excess power." Thus, any ratemaking language in section 7(c)—or sections 7(b) and 7(f)—is subject to override by the cost recovery requirements of sections 7(a) and 7(g). Given these interrelationships within the Northwest Power Act, BPA's most prudent alternative to loss of DSI load would be to recover as much

> revenue as practical under a variable rate in order to minimize the costs shifted to other customers, including public agencies.

Id.

In its brief on exceptions, APAC takes exception to BPA's reliance on the Variable Industrial rate. APAC argues that the Variable Industrial rate was implemented when aluminum prices were low and the DSIs were "unable, not simply unwilling, to pay the normal rates derived under section 7(c)." APAC Ex. Brief, WP/TR-96-R-PA-01, at 7. Today, however, the threat to BPA arises not from low aluminum prices but from competition. *Id.*

The DSIs <u>will</u> be paying rates derived under section 7(c). Moreover, APAC raises a distinction without a difference. As noted above, when he adopted the Variable Industrial rate the Administrator concluded that section 7(a) requires BPA to recover its costs under "all economic conditions." In 1986 the obstacle to this goal happened to be low aluminum prices. Today, the obstacle is the competitive market. Nothing in the Variable Industrial Rate ROD suggests that its precepts apply to only one set of economic conditions; to the contrary, the ROD enunciated broad precepts, and applied them to the economic conditions at the time.

In addition, no reason appears (and APAC offers none) for drawing the distinction that APAC suggests. Although the prevailing economic conditions are different, the result of ignoring them would be the same. As in 1986, so today BPA must be concerned with its resource planning, financial strength, and rate stability. As in 1986, so today BPA faces the prospect of power surplus and unrecovered fixed costs if it loses substantial load. That the DSIs may be unwilling, rather than unable, to pay higher rates is immaterial; if they purchase power elsewhere because BPA's rate is above the market, the consequences the Variable Industrial Rate ROD was intended to forestall will come to pass.

If BPA ignored the competitive environment and raised the DSI rate above competitive levels, the revenues it failed to collect from the DSIs would have to be recovered from other customer classes. The public utilities and residential exchange customers would be forced to bear costs that BPA otherwise would have recovered from the DSIs. Moorman, Evans, E-BPA-09, at 25. These costs could be many millions of dollars. Tr. 293; Moorman, Evans, E-BPA-65, at 8. As the PPC has indicated, if BPA's prices remain above competitive levels, PPC member utilities will be responsible for additional fixed costs, adding further rate pressure on this customer class. Eldridge,*et al.*, E-PP-01, at 3. The PF exchange rate would necessarily have to increase as well. Many of BPA's public utility customers would be seriously harmed if they were forced to bear additional costs because BPA is unable to set a competitive DSI rate and retain DSI load. Drummond, E-RC-01, at 3.

In their briefs on exceptions, the parties suggest that in the draft ROD BPA posited a conflict between sections 7(a) and 7(c), and therefore disregarded section 7(c). MREP

Ex. Brief, WP-96-R-GE/PL/PS-01, at 13; APAC Ex. Brief, R-PA-01, at 3. To the contrary, as BPA has argued above, BPA posited that all related sections of a statute must be read both together and in conjunction with other related statutes, so that the entire statutory scheme can be fulfilled. This is hardly an argument for ignoring statutory directives. In this part BPA concludes that, in order to give effect to the statutory scheme, it must take the prevailing economic conditions into account. BPA cannot apply its statutory mandates in a vacuum. Part II of this section addresses the section 7(c) rate directives at length. Part II demonstrates that BPA's decision to exclude revenue taxes from the margin is consistent with both sections 7(a) and 7(c). BPA has interpreted the two sections harmoniously in order to reach a conclusion that is consistent with both.

Indeed, APAC itself cites case law holding that all parts of a statutory scheme must be given effect. APAC Ex. Brief, R-PA-01, at 3-4. This case law supports BPA's analysis. In *Morton v. Mancari*, 417 U.S. 535, 551 (1973), the Supreme Court held that "when two statutes are capable of co-existence, it is the duty of the courts, absent a clearly expressed congressional intention to the contrary, to regard each as effective." In *Hellon & Associates, Inc. v. Phoenix Resort Corp.*, 958 F.2d 295, 297 (9th Cir. 1992), the court held that "[t]o the extent that statutes can be harmonized, they should be."

BPA's analysis harmonizes sections 7(a) and 7(c) and ensures that they can co-exist. If BPA ignored the competitive market, it would violate section 7(a)'s mandate that it recover its costs. The IOUs' argument does not even recognize the existence of section 7(a). APAC agrees that "BPA is obligated to produce a rate that satisfies <u>both sections 7(a) and 7(c)</u>." APAC Ex. Brief, R-PA-01, at 4 (emphasis added). APAC argues that BPA can develop a competitive DSI rate by revising its marginal cost analysis to benefit high load factor customers such as the DSIs. *Id.* at 29 & n.36.

BPA has addressed all of APAC's proposals. As APAC proposed, BPA has adopted a revised natural gas forecast. *See supra* §§ 3.3 & 6.1.1, Issue 2. BPA has increased its demand charge to benefit high load factor customers. *See supra* § 7.2. BPA has adopted in part APAC's suggestion that it allocate a greater share of the annual costs of firmness of energy to the winter months. *See supra* § 6.2. APAC has also proposed that BPA assume that the Southern Intertie is not available 100 percent of the time. This assumption would not have the effect APAC suggests. Therefore, BPA has not adopted it. *See supra* § 6.1.1, Issue 1. Finally, APAC proposed that BPA credit light load hour sales with the excess revenues from surplus capacity sales. BPA concluded that this proposal was flawed and did not adopt it. *See supra* § 7.5.

D. <u>It Is Appropriate For BPA To Consider The Competitive Market In Calculating The Industrial Margin Because BPA's Public Body and Cooperative Customers, On Whose Margins The Industrial Margin Is Based, Are Basing Their Industrial Margins On The Competitive Market</u>

Like BPA, BPA's customers operate in a competitive market, and must set rates competitively to retain load. The industrial customers of BPA's public body and cooperative customers are pressuring their utilities to set competitive rates or to provide them with direct access to the market so they can reduce their power costs. Hill, *et al.*, WP-96-E-BPA-51, at 4. For example, citing "the advent of genuine price competition at the wholesale power supply level," the Boeing Company has pressured Snohomish County PUD, a BPA customer, to reduce its power costs. *Id.*, Attachment A. Boeing indicated that

> price competition at the wholesale level has also prompted a competitive pricing environment at the retail level as well. For Bonneville, Snohomish PUD and Bonneville's other utility customers, the consequences of these changes are clear. To retain customers, whether at the retail or wholesale level, sellers of electricity must offer power at a price that meets the market. Failure to do so will result in a loss of load. . . . It is our expectation that market competition will produce lower prices.

Id.

BPA's other public body customers are also looking for ways to lower their industrial power rates. Chelan County PUD is developing a new "market-plus rate" for industrial customers with loads of 10 MW or more. *Id.*, Attachment B. Chelan noted that these customers are "probably going to have an interest in watching the markets." *Id.* Chelan concluded that, given the changes in the power market, its current rate was uncompetitive. *Id.* Longview Fibre, which is served by Cowlitz County PUD, another BPA customer, recently installed 45 aMW of self-generation. *Id.* at 4. Seattle City Light has issued a request for proposals for 40 aMW, in order to supply one of its larger industrial customers. *Id.*

As APAC has itself acknowledged, BPA's public power customers will use all means at their disposal to access the competitive market in order to lower their power rates. Carr, *et al.*, WP-96-E-PP/PA-03, at 4. APAC has testified that large industrial customers of BPA's public utility customers are exerting considerable pressure on their utilities to reduce their power prices and to allow them access to the transmission system so they can seek alternative suppliers. *Id.* at 5. Because of this pressure, public utilities will be forced to reduce the margins they add to their power costs. Hill, *et al.*, E-BPA-51, at 5. As it is, industrial margins have decreased since 1985. *See* Chang, Cocks, E-BPA-25, at 8-9; Chang, Cocks, WP-96-E-BPA-120, Attachment E. The industrial margin that BPA has calculated in this case is based on existing public utility rates. Tr. 1732. BPA is setting rates for the next five years; to the extent that industrial margins decline, BPA's margin will be overstated.

BPA's consideration of competition in setting its DSI rate mirrors the rate-setting process of its public utility customers, and fully comports with the methodology outlined in section 7(c) of the Northwest Power Act. Moreover, although the industrial margin is based on the margins included in rates by BPA's public body and cooperative customers, it is instructive to consider actions that investor-owned utilities (IOUs) are taking to set competitive rates for their industrial customers. All utilities must operate in the same competitive environment, and must account for the market in their rate-setting. *See, e.g.*, WP-96-E-PA-10, pages 3-4 (unnumbered) of "[Seattle City Light's] 1994 Financial Review": "Deregulation of the electric utility industry along with economic and technological changes are key issues confronting [Seattle] City Light. The Department will be challenged to continue providing quality electrical services at a competitive price. Uncertainties over purchased power costs, the salmon recovery issue, the effect of deregulation and competition, and environmental matters will influence policy and rates for the near term.") Thus, the IOUs' actions, like BPA's, mirror those of the public body customers and form a guide to likely market responses during the five-year rate period.

In both Oregon and Washington, statutory provisions permit regulated utilities (IOUs) to charge reduced rates to customers whose loads are at risk because of competitive pressures. Oregon Revised Statutes § 757.230 provides that classification of customers for rate-setting purposes shall include "the existence of price competition or a service alternative." Revised Code of Washington § 80.28.075 provides that natural gas and electric utilities may establish banded rates, which contain minimum and maximum charges, for any nonresidential natural gas or electric service "that is subject to effective competition from energy suppliers not regulated by the utilities and transportation commission."

Both PacifiCorp and Puget Sound Power and Light Company are competing for BPA load. *See* Norman, Oliver, E-BPA-10, at 7-12, and Attachments B and E. Both argue that BPA cannot consider the need for a competitive DSI rate when calculating the industrial margin. Both have taken advantage of the above statutes to set competitive rates for their large industrial customers.

In 1988, even before the electric industry had become truly competitive, the Oregon Public Utility Commission approved a special tariff for PacifiCorp (then Pacific Power & Light Company) so that it could retain several large pulp and paper customers that had competitive service alternatives, including self-generation, cogeneration, and obtaining service from public utility districts and other sources. *Pacific Power and Light Company*, 95 P.U.R.4th 459, 461 (1988). (These customers were James River Corporation, Weyerhaeuser, and Willamette industries, all also customers of BPA's public utility customers.) The special tariff represented a discount of approximately 30 percent from Pacific's existing rate. *Id.* The Commission concluded, however, that "net revenues will be higher [with the reduced rates] because of the retention of loads that otherwise would have been lost." *Id.* The Commission added that "[b]ecause the alternatives available to the four participating customers are lower in cost than service under the proposed pulp and paper tariffs, the Commission concludes that it is not reasonable to expect that Pacific could have negotiated higher tariff rates." *Id.* at 462-63. Finally, the Commission held that the tariffs were reasonable because "[l]oss of these customers would have a significant impact on Pacific's ability to generate revenues to cover fixed costs." *Id.* at 463.

The rates in Pacific's special contracts exceeded Pacific's avoided costs. The uncontested evidence indicated, however, that Pacific's net revenues under the special rates would be lower than under existing rates until the time when the pulp and paper customers would have displaced Pacific's service. *Id.* at 461. (Net revenues would be higher thereafter because the alternative to the lower rate would be loss of the load.) Thus, in order to retain the load Pacific reduced the margin it received on its power. In 1992, the Commission granted ratemaking treatment for the contracts and ordered that the discounted rates be made permanent *PacifiCorp dba Pacific Power and Light Co.*, UE76, Order No. 92-1128 (August 4, 1992).

On July 12, 1995, the Washington Utilities and Transportation Commission (WUTC) approved a special contract between Puget and Arco Products Company, under which Arco receives a reduced rate on its electric service. *In Re the Special Contract Filed by Puget Sound Power & Light Co. and the Requested Waiver of the Thirty-day Advance Filing Requirement*, Docket No. UE-950599 (July 12, 1995). (The Commission deferred ratemaking treatment of the contract until Puget's next general rate case.) On April 15, 1996, the Commission set for hearing Puget's proposed special contract to provide electric service to Intel Corporation. In its filing, Puget stated that without the special rate Intel would not locate its manufacturing facility in Washington State; that Intel believed that Puget's tariff rates were excessive and that electricity must be priced "according to Intel's particular circumstances"; that the contract rate provided for the recovery of all costs directly associated with the provision of electric service; and that the agreement did not result in undue discrimination between customers receiving like and contemporaneous service. *Washington Util. and Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket No. UE-960299, Notice of Prehearing Conference (April 15, 1996).

On June 7, 1996, the WUTC approved special contracts between Puget and Georgia-Pacific West, Inc. and Bellingham Cold Storage. Puget requested approval of the contracts in order to avoid bypass of its system by these large customers *In re the Special Contract Filed by Puget Sound Power & Light Co.*, Docket No. UE-960612, Order Imposing Conditions on Special Contract Allowed To Go Into Effect (June 7, 1996); *In re the Special Contract Filed by Puget Sound Power & Light Co.*, Docket No. UE-960613, Order Imposing Conditions on Special Contract Allowed To Go Into Effect (June 7, 1996).

Both commissions have also allowed natural gas companies, which compete with electric utilities, to charge reduced rates to large industrial loads. In 1989 the Oregon Public Utility Commission approved a special rate for Northwest Natural Gas, again for a James River paper mill. *Northwest Natural Gas Co.*, 107 P.U.R.4th 306 (1989). In 1994 the WUTC approved a special contract with reduced rates between Cascade Natural Gas Corporation and BP Exploration & Oil, Inc., because of the threat of bypass. *Washington Util. and Transp. Comm'n v. Cascade Natural Gas Corp.*, 152 P.U.R.4th 76 (1994). The WUTC noted that banded rates and special contracts are "a necessary step for [utilities] to meet competition and retain high volume customers. . . . A consequence of bypass is that core customers may be in very real danger of bearing the burden of large sunk costs for bypassed facilities, or of paying more than an appropriate share of overhead and general costs." 152 P.U.R.4th at 78.

In December 1994 the WUTC began an Inquiry into changes in the electric industry and the consequences for utility regulation. In August 1995, noting that "[t]he pace of change and activities which profoundly affect the environment of the electricity industry in Washington has accelerated in recent months," the Commission issued a status report on the Inquiry. *Interim Principles for Regulation of Electric Utilities*, 163 P.U.R.4th 453, 454 (1995). The Commission noted that "[t]he BPA is faced with significant price competition." *Id.* at 455. It found that competition for industrial customers was particularly fierce:

> Industrial customers, reacting to the declining price of wholesale power, are pressuring some utilities for rate concessions. The Commission recently approved a special contract between Puget Power and ARCO in Whatcom County. Some utilities are adding new retail industrial loads through attractively priced power deals. Washington Water Power has negotiated a contract to serve an industrial customer formerly served exclusively by BPA as a direct service industry. Puget Power has filed an exit fee tariff, WWP has indicated interest in filing a "competitive service" tariff, and some industrial customers have expressed interest in unbundled local distribution services.

Id.

In its brief on exceptions, APAC asserts that state regulatory commission actions cannot be used as precedent for BPA's actions, because "those Commissions are interpreting different statutes and regulating different entities than BPA." APAC Ex. Brief, R-PA-01, at 6 n.7. As noted above, however, BPA is not citing state actions as "precedent." Instead, the rates that the regulatory commissions are approving exemplify the market responses of <u>all</u> utilities, IOUs as well as municipal utilities and others. These rates are an indication of where the electricity market is headed for all participants.

For the IOUs' part, given the extent to which they perceive that sound business principles, and indeed survival, require that they respond to the competitive market, their assertion that Congress did not allow BPA to take competition into account is extraordinary. Indeed, on May 24, 1996, after the draft ROD was published, Puget Sound Power & Light Co. made yet another official filing with the WUTC pursuant to Washington Administrative Code 480-80-040 and 480-80-050, requesting approval of competitive rates for its large customers. In the filing, Puget indicated that it was implementing "a market transition plan that is intended to provide customers with a choice of accessing competitive energy markets." Letter from Christy A. Omohundro, Director, Rates and Regulation, Puget Sound Power & Light Co., to Steve McLellan, Secretary, Washington Utilities and Transportation Commission 1 (May 24, 1996). Puget noted that it "faces increasing competitive pressures, as evidenced by the recent filing of special contracts with Georgia-Pacific West, Inc. and Bellingham Cold Storage in Docket Nos. UE-960612 and UE-960613, respectively. Given Puget's maturing competitive situation, it is essential that customers be provided some indication that Puget will be in a position to respond to these pressures through the service options made available under this proposed tariff." *Id*. at 2.

In the filing, Puget proposed a new rate schedule, Schedule 48, under which its larger customers would be able to purchase energy at "market-based prices." *Id*., Attachment labeled "Explanation of Market Transition Plan and Schedule 48," at 2. Puget concluded that the new rate schedule would help all its customers:

> Puget's large customers have demonstrated their intention, and increasing ability, to pursue options for electric supply. Customers are forced to pursue these options in the face of intense competitive pressures on a national, and even global, basis. For this reason, it is appropriate to address the situation related to large customers as the initial step in the process to achieve benefits for all customers.
>
> . . . .
>
> Customers benefit from the resolution of Puget's maturing competitive situation related to its large customers. All other customers would be harmed if large customers were to leave Puget's system. In the event of a loss of those customers, fixed costs, currently recovered from those customers, would remain. Such fixed costs are significant. Remaining customers would be made worse off regardless of the regulatory treatment of costs.

Id. at 3.

As can be seen, competitive pricing is fast becoming the norm for industrial rates on the retail level. The IOUs' ratemaking mirrors the emerging ratemaking of BPA's public body customers. All the evidence indicates that rate-setting based on competitive pressures will become even more widespread during the five-year rate period. Therefore, it is appropriate that BPA's industrial margin also take competitive pressures into account.

<u>Summary</u>

For the following reasons it is appropriate, and indeed essential, that BPA consider the need for a competitive DSI rate in calculating the industrial margin:
a. BPA's primary rate directive is section 7(a) of the Northwest Power Act, which requires BPA to set rates in accordance with sound business principles to recover its costs and to assure repayment of the United States Treasury.
b. Section 7(c), which applies to the Industrial Firm Power rate, establishes the amount of revenues BPA must recover from the DSIs. This section must be read in conjunction with section 7(a)'s mandate that BPA recover its costs.
c. If BPA sets the IP rate above competitive levels, it will lose substantial DSI load and will recover fewer revenues than required by section 7(c).

d. This shortfall would result either in BPA's failing to recover its costs and repay the United States Treasury, thereby violating section 7(a), or in BPA's shifting substantial amounts of fixed costs to its remaining customers, thereby jeopardizing their continued economic viability. The latter scenario would increase BPA's loss of load from its public utility customers, thereby putting even greater cost pressures on the remaining customers, leading to a continuing spiral of higher rates and greater load and revenue losses. In addition, the PF Exchange Rate would increase, reducing exchange benefits to residential and small farm customers.

e. BPA's public body and cooperative customers are setting rates for their industrial customers based on the competitive market. They can be expected to continue to reduce their margins to retain load. Under section 7(c), the DSI rate is based on the applicable wholesale rate and the industrial margins of BPA's public body customers. Taking into account the competitive market tracks these customers' rate-setting process and is therefore consistent with section 7(c).

II. <u>Revenue Taxes Are Not A Component Of The Typical Margins Included By BPA's Public Body And Cooperative Customers In Their Retail Industrial Rates</u>

BPA testified that only Washington utilities are subject to a gross revenue tax. Chang, Cocks, E-BPA-25, at 7; Chang, Cocks, E-BPA-54, at 6. The original margin study was performed in 1985. Whether to include revenue taxes in the typical industrial margin was an issue in the 1985 case as well. In 1985, the DSIs argued that, since only Washington utilities pay revenue taxes, the tax was not part of the typical margin. No party contested the DSIs' evidence. *See* WP-96-E-GE-19, at 137-39. (Although the DSIs included "certain Oregon municipalities" in their statement, Oregon municipalities actually pay an in-lieu property tax on their transmission and distribution lines. Chang, Cocks, WP-96-E-BPA-79, at 4.)

In this case BPA relied in part on the uncontested evidence in the 1985 record for its conclusion that revenue taxes were not part of the typical margin. Tr. 989. In addition, BPA testified that only Washington State collects gross revenue taxes from utilities, and that it was unaware of any other state in the region imposing a revenue tax. *Id.* at 988.

PGE is dissatisfied with this evidence, unrefuted both in 1985 and today, and asks BPA to further prove a negative: to further prove that utilities located outside of Washington do not include revenue taxes in their industrial margins. The evidence in the case, however, confirms BPA's testimony. BPA used a sample of twenty utilities with large industrial customers to calculate the industrial margin. The uncontested evidence is that, of these utilities, only those in Washington include revenue taxes in their margins. Chang, Cocks, E-BPA-120, Attachment E. Thirteen of the utilities in the sample are located in Washington, and all 13 allocate a portion of costs to revenue taxes. Seven of the utilities are located outside of Washington. None of these seven utilities allocates any costs to revenue taxes. *Id.*

In addition, APAC and Portland General Electric Company both introduced into evidence the industrial rate schedules for all twenty utilities. WP-96-E-PA-07, Attachment 2; WP-96-E-GE-05, Attachment 4. Four of the rate schedules contain provisions under which the utility has the authority to add revenue taxes to its industrial rates. All of these utilities are located in Washington. Tr. 1710-12. Seven of the rate schedules are schedules for Oregon utilities. None of these schedules contain provisions for the addition of revenue taxes to the rate. *Id.* at 1712-13; WP-96-E-PA-07, Attachment 2. None of the remaining nine rate schedules includes a provision for revenue taxes. E-PA-07, Attachment 2.

APAC has itself acknowledged that only Washington utilities pay revenue taxes. In its initial testimony, APAC testified that a majority of the utilities in BPA's sample are in Washington State, "which has revenue taxes, versus the other states." Wolverton, WP-96-E-PA-01, at 10. APAC's testimony then included the following question and answer:

> "Q. Is there any measure under which a majority of BPA customers do not face revenue taxes?
>
> A. I suppose one could count the number of states served by BPA. On that basis it is six states to one against revenue taxes. . . ."

Id. at 11.

BPA suggests that, at a minimum, a cost must be included in a majority of utilities' margins for it to be considered typical. Tr. 993. "Typical" means "representative of a whole group"; <u>The American Heritage Dictionary of the English Language</u> 1388 (1976); "serving as a characteristic example"; "representative." <u>New Shorter Oxford English Dictionary</u> 3442 (1993). If a given trait is peculiar only to a minority of a population, it cannot be said to be either "representative of [the] whole group" or "a characteristic example." If anything, the opposite is the case: the absence of the trait is representative and characteristic. Therefore, if only a minority of utilities include revenue taxes in their margins, then such taxes are not a component of the typical industrial margin.

BPA has 81 public utility customers that have retail industrial loads. Chang, Cocks, E-BPA-54, at 6. Of these, 34 are in Washington, and therefore are subject to revenue taxes, and 44 are located elsewhere, and therefore do not pay revenue taxes. *Id.* at 6 and Attachments A and B. (BPA was unable to determine the customer classes for three of its public body customers. All of these customers, however, are located outside of Washington, and therefore are not subject to revenue taxes. *Id.* at 7.) Moreover, as APAC indicated, revenue taxes are paid in only one of seven states served by BPA. Wolverton, E-PA-01, at 11. Therefore, they are not representative of the region as a whole. Given this evidence, it can hardly be said that the payment of revenue taxes (and their inclusion in industrial margins) is typical; to the contrary, if anything it is typical for a utility not to include revenue taxes in its margin.

Citing BPA's testimony in support of its initial proposal, the IOUs argue that BPA based its conclusion regarding revenue taxes on the margins of all utilities, rather than on utilities with industrial customers. MREP Brief, B-GE/PL/PS-01, at 26 (quoting Chang, Cocks, E-BPA-25, at 7). The IOUs note that, under the Northwest Power Act, the DSI margin is based on the typical margins included in "retail industrial rates." MREP Brief, B-GE/PL/PS-01, at 7 (quoting 16 U.S.C. § 839e(c)(2)). The IOUs conclude that BPA "seem[s] to be arguing" that revenue taxes should be excluded from the margin if most public body and cooperative customers do not pay revenue taxes, "regardless whether the utilities with industrial customers or the utilities in [the] sample do." MREP Brief, B-GE/PL/PS-01, at 26.

The IOUs have lifted one sentence from BPA's initial testimony, ignored the rest of BPA's testimony, and misrepresented BPA's position. In its rebuttal testimony, BPA posed the question, "Which utilities are the appropriate ones to use to determine whether a given cost category is part of the typical margin?" BPA responded, "The appropriate measure is all utilities with industrial customers. . . . If most utilities with industrial customers do not include revenue taxes in their margins, then taxes are not a typical margin component." Chang, Cocks, E-BPA-54, at 6.

It is clear from the record that BPA based its analysis only on utilities with industrial customers. In the same rebuttal testimony, BPA included a list of 107 of BPA's 123 public body and cooperative customers that are included in a BPA data base. On this list, BPA identified the state in which each utility was located and whether the utility had industrial customers. *Id.*, Attachment A. The list contained no other information; its only purpose was the identification of those utilities with industrial customers. Sixteen of BPA's customers are not in the data base. *Id.* at 6. Based on other information available to BPA, however, BPA testified as to which of these 16 utilities have industrial customers, and which do not. These utilities were included on an additional attachment, whose sole purpose also was the identification of those utilities with industrial customers. *Id.*, Attachment B. As noted above, BPA determined that it has 81 public body and cooperative customers that have industrial customers, of which 34 are located in Washington and 47 are located in other states. *Id.* at 6-7. This testimony, which was filed after the testimony the IOUs cite and is much more detailed, makes clear that BPA's conclusion was based solely on those utilities with industrial customers.

The IOUs note that most industrial customers in the sample used to calculate the margin pay revenue taxes. MREP Brief, B-GE/PL/PS-01, at 25. They argue that BPA has contradicted itself by presenting the sample as "representative enough to demonstrate the 'typical margin,' but not representative enough to demonstrate that the 'typical margin' includes revenue taxes." *Id.*; *see also* Piro, *et al.*, WP-96-E-GE/PL/PS-08, at 3. The IOUs confuse two separate issues. In this rate case as in 1985, two separate and unrelated determinations are made to calculate the typical margin. First, of the five categories of utility costs, BPA must determine which are appropriately included in the margin. This determination is made independently of the sample. Once having made this determination, BPA must calculate the level of costs, in mills/kWh, for each cost category. The sample is used for this determination.

Under section 7(c)(2) of the Northwest Power Act, the IP rate is based on BPA's applicable wholesale rates and the typical margins "included by [the Administrator's] public body and cooperative customers in their retail industrial rates." 16 U.S.C. § 839e(c)(2). This reference is to all of BPA's public utility customers with retail industrial loads. In 1985, as now, the Administrator's decisions regarding which costs to include in the margin were not based on the sample. In the 1985 rate case, four cost categories were in dispute: non-BPA funded conservation costs; transmission costs; legal expenses related to generation resources; and revenue taxes. *See* WP-96-E-GE-19, at 134-40. The issue as to conservation costs was whether such costs are production costs, which are excluded from the margin, or customer service costs, which are included. *Id.* at 135. The issue regarding transmission costs was whether they could be segregated from distribution costs. Transmission costs were excluded from the margin; distribution costs were originally included (before the size of load adjustment, *see* Chang, Cocks, E-BPA-25, at 6). E-GE-19, at 136. As to both issues, neither the parties' arguments nor the Administrator's decisions included any reference to the sample.

The issue regarding legal expenses was whether "they are related in any way to margins charged retail industrial customers." *Id.* at 140. This question was framed in terms of the population of utilities with retail industrial customers rather than in terms of utilities included in the sample. Finally, the DSIs argued that revenue taxes should be excluded from the margin because they were not incurred by all of BPA's public body and cooperative customers. Northwest Utilities responded that this approach "would exclude from the margin any cost that appears in some, but not all, public utility industrial rates." *Id.* at 138. It is clear that both parties based their arguments on the universe of utilities with industrial customers; neither made any reference to the sample.

The only reason for using a sample is to determine the level of costs in each category in mills/kWh. This determination is independent of the cost categories included in the margin, which would remain the same regardless of the sample chosen. Chang, Cocks, E-BPA-54, at 6. The sample contains utilities that have at least one industrial customer with a peak load of at least 3.5 megawatts. Chang, Cocks, E-BPA-25, at 3. The sample ensures that, to the extent possible, the level of costs in each cost category approximates the level that BPA's public body customers charge to large industrial customers like the DSIs. Chang, Cocks, E-BPA-54, at 5-6. The level of costs is lower for large industrial customers because of economies of scale. *See*, *e.g.*, E-PA-10, Cost of Service and Cost Allocation Report 2.6 ("In June 1989, [Seattle City Light's] largest customers were organized into a new High Demand General Service class. This modification of the rate classification system was based on analyses confirming these customers have cost characteristics—particularly in terms of efficiencies of scale in transformer costs and in amount of energy used—that warranted separating them from the rest of the Large General Service class.") Therefore, the sample, which is limited by customer size, is used to determine the level of costs in each category, whereas the universe of BPA's public body customers with industrial loads is used to determine the cost categories themselves.

As noted, the sample served the same limited purpose in the 1985 margin study. In 1985, the parties presented three separate samples for possible use in the margin study. The Administrator chose the sample that best allowed him to calculate the appropriate level of costs. E-GE-19, at 129-31. ("The joint data base provides data necessary to compute average power costs to retail industrial customers. . . . [It allows] detailed disaggregation of margin components." *Id.* at 130-31.) In a separate and unrelated section of the Record of Decision, the Administrator determined the appropriate cost categories to include in the margin. *Id.* at 134-40. The decisions in this section were made independently of the information in the sample.

In addition, because the sample is restricted to utilities with larger industrial loads, most of the utilities in the sample are located in Washington, the largest state in the region. Most utilities with industrial customers, however, are not. Based on "the DSI data," the IOUs claim that 69 of 72 industrial customers in the sample pay revenue taxes. MREP Brief, B-GE/PL/PS-01, at 25. Elsewhere, the IOUs argue vigorously that BPA should not rely on <u>any</u> data the DSIs provide, even when the data consist of photocopies of utility documents. *See supra* § 8.2.1. BPA's analysis demonstrates that a much smaller percentage of customers in the sample pay revenue taxes, although the percentage remains skewed because the sample is biased toward Washington utilities. *See* Chang, Cocks, E-BPA-120, Attachment E.

The IOUs, however, challenge BPA's conclusion that revenue taxes should be excluded from the typical margin because they are not paid by the typical utility. They argue that section 7(c)(2) requires the calculation of the "typical margin" rather than the "typical cost elements . . . included in the margin." MREP Brief, B-GE/PL/PS-01, at 27. In the 1985 rate case, the DSIs argued that a cost should not be included in the margin unless it was incurred by all utilities. Northwest Utilities argued in response that this approach "would exclude from the margin any cost that appears in some, but not all, public utility industrial rates and therefore would result in calculation of 'typical costs included in industrial rates,' rather than the 'typical margin.'" E-GE-19, at 138. The IOUs contend that the Administrator adopted this argument. MREP Brief, B-GE/PL/PS-01, at 24.

The Administrator never adopted an interpretation of section 7(c) that distinguished between "typical costs included in the margin" and the "typical margin." He never addressed the argument Northwest Utilities advanced; instead, he rejected the DSIs' argument that a cost was typical only if it was incurred by <u>all</u> utilities. Since the margin is composed of costs, it is difficult to understand the distinction the IOUs are drawing. They provide an example intended to illustrate this distinction: the IOUs assume fifty utilities, each charging an industrial margin of 3 mills/kWh "based on a different type of cost element for each utility (such as one utility charging for taxes, another utility charging for overhead, etc.)." *Id.* at 27 n.26. According to the IOUs, in this scenario the typical industrial margin would be 3 mills/kWh, while under BPA's approach it would be zero, because no particular cost element is charged by a majority of utilities. *Id.*

The IOUs' assumptions are implausible, and therefore their hypothetical scenario is not a logical extension of BPA's analysis. The margin study includes five cost categories: production, transmission, distribution, revenue taxes, and other overhead costs. Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, Appendix A, at A-5. These five categories cover all utility costs. The IOUs' hypothetical assumes an indefinite number of cost categories. Moreover, all retail utilities incur production, transmission, distribution, and overhead costs ("other" costs). (As the sample demonstrates, some utilities do not allocate all of these costs to their industrial loads, but they cannot operate a utility without incurring them.) Therefore, the IOUs' hypothetical (or even a similar but less extreme example) is virtually inconceivable. (It is noteworthy that every utility in the sample allocates production costs to the industrial class; 85 percent allocate other costs; 70 percent allocate distribution costs; and 55 percent allocate transmission costs. *See* Chang, Cocks, E-BPA-120, Attachment E. Moreover, in contrast to the case of revenue taxes, the sample's preponderance of Washington utilities does not skew these allocations.)

Unlike the other costs in the sample, revenue taxes are not an inherent cost of producing and delivering power; utilities do not incur them unless they are imposed from without. Therefore, they are the only category of costs that a large number of utilities will<u>not</u> include in their margins. Inclusion of revenue taxes in the typical margin would increase the margin by 1.75 mills/kWh; thus, their inclusion would severely distort the calculation.

In its brief on exceptions, APAC asserts that in 1985, the Administrator considered whether various costs, "including revenue taxes and transmission costs, were appropriately classified as part of the underlying PF rate or as part of the industrial margin. . . . [I]t was obvious to BPA then, as it should be now, that each cost must be assigned to either the PF rate or the margin." APAC Ex. Brief, R-PA-01, at 14.

As demonstrated above, this assertion is incorrect. The Administrator never considered assigning revenue taxes to the PF rate. The question he considered was whether to exclude revenue taxes from the IP rate altogether. *See* E-GE-19, at 137-39. The appropriate classification of transmission and production costs was an issue because the PF rate already recovered these costs. Therefore, assignment of transmission or production costs to the margin would have resulted in double recovery. Because BPA does not pay revenue taxes, the PF rate does not recover revenue taxes, and the same issue did not arise.

In addition to revenue taxes, the four cost categories in the margin study are production, transmission, distribution, and other overhead costs. In 1985, all parties and the Administrator agreed that costs in these four categories should be assigned to either the PF rate or the margin because, as discussed above, all utilities incur these costs. Therefore, it was appropriate to include them in the IP rate. Not all utilities incur revenue taxes, and the parties did not all agree that revenue taxes should be included in the IP rate. The DSIs argued for their exclusion, and it was this argument that the Administrator addressed.

APAC makes an additional argument similar to the one the IOUs raised in their initial brief, discussed above. APAC argues that BPA's analysis "attempts to determine the *typical utility's margin*, not the *average margin used by utilities*." APAC Ex. Brief, R-PA-01, at 14 (emphasis in original). As shown above, there is no real distinction between these two formulations. Because the typical utility does not pay revenue taxes, inclusion of revenue taxes in the margin would increase the margin far above the average margin included in retail industrial rates. Moreover, although APAC asserts that its distinction is mandated by the language of section 7(c), which, it suggests, "leaves little room for interpretation," *id*. at 15, in fact the generality of the language leaves the Administrator substantial discretion to determine the appropriate margin components. Section 7(c) requires inclusion of "typical [retail industrial] margins" in the IP rate. "Typical margins" do not include revenue taxes. In 1985 the Administrator attempted to determine the components of the typical industrial margin. He did not draw the distinction APAC suggests.

Moreover, exclusion of revenue taxes from the margin will result in a more accurate margin than would inclusion of such taxes. Therefore, it is an appropriate interpretation of the Act to conclude that, because revenue taxes are not typically included in retail industrial rates of the Administrator's preference customers, they should be excluded from the industrial margin.

Finally, the parties challenge BPA's exclusion of revenue taxes from the margin on the ground that it marks a reversal of the Administrator's decision in 1985. Several differences between 1985 and today justify today's decision. First, as explained extensively above, in 1985 BPA was the low-cost provider of electric power. Neither the DSIs nor BPA's other customers had the choice of suppliers that they have today. In 1985, raising the IP rate increased BPA's revenues; today, raising the IP rate would reduce BPA's revenues. In 1985, raising the IP rate enhanced BPA's ability to repay the United States Treasury; today, it would lessen that prospect.

In 1985 it was economically feasible for BPA to include in the industrial margin a cost component that is not included in the margins of the majority of its public body customers with industrial loads. In a competitive environment, this course is not realistic. A power provider cannot expect to compete if it includes in its rates a cost that the majority of other power providers do not include. It is far from clear that even those power providers subject to a state revenue tax will pass the cost on to their industrial loads. As BPA's customers have testified, in a competitive market it is not possible simply to add up one's costs and set rates to recover them. Instead, a supplier must set a competitive rate and manage its costs to meet the market.

Thus, for example, assume two utilities with costs of 22 mills/kWh, one of which is also subject to a two-mill revenue tax. If one utility charged a 22-mill rate, and the other charged 24 mills, a purchaser with a choice of supplier would purchase power from the utility that charged 22 mills. Tr. 309. By adding the tax to the rate, the second utility will lose the sale. In order to compete, therefore, the utility would likely do everything possible to bring its price down to 22 mills or less. *Id.* at 357. The utility could be expected to reduce its margin on the sale, and to seek opportunities to allocate costs to other customers. *Id.* Thus, because not all utilities incur revenue taxes, such taxes are an obstacle to competitiveness for those utilities that do incur them. Increasingly, those utilities will be forced to compensate for the taxes elsewhere in their rates.

Second, this record contains significant evidence that was not entered into the record in 1985. In performing the 1996 margin study, BPA relied in part on the record from the 1985 case. BPA testified that the 1985 record contained no data regarding how many public utilities with industrial customers paid revenue taxes. Tr. 1690. Therefore, in reviewing the record from 1985, BPA analysts were unable to determine how many utilities with industrial loads paid revenue taxes, and how many did not. *Id.* at 1691. In 1985 the Administrator decided to include revenue taxes in the margin without the benefit of this evidence. *Id.*

The IOUs, however, assert without documentation that the same evidence "was available to the Administrator in 1985." MREP Brief, B-GE/PL/PS-01, at 26. BPA's witnesses reviewed the testimony regarding revenue taxes submitted in the 1985 rate case, as well as both the Initial and the Final Margin Studies. *See* WP-96-E-GE-09. Their review revealed that no data were submitted in the 1985 case as to how many utilities with industrial customers paid revenue taxes. Tr. 1690. In the Record of Decision, the Administrator gave no indication that this information was available. *See* E-GE-19, at 137-39. BPA's witnesses reviewed every piece of evidence the Administrator cited in his decision. *See id.* and E-GE-09. (In addition to the two Margin Studies, the evidence the witnesses reviewed included BPA's direct testimony and surrebuttal testimony; the DSIs' testimony; and the rebuttal and surrebuttal testimony of Northwest Utilities. These are the only pieces of testimony the Administrator cited in his decision. *See* E-GE-09 and E-GE-19, at 137-39.) There is no reason to believe that the record in 1985 contained any additional evidence regarding the payment of revenue taxes.

The IOUs also assert, again without supporting documentation, that the evidence in 1985 included "the list of preference customers in the region. The record did include evidence from which anybody . . . could have discovered how many preference customers did and did not pay revenue taxes." MREP Brief, B-GE/PL/PS-01, at 27. There is no evidence in <u>this</u> record that the 1985 record contained the list of preference customers. Moreover, although BPA's witnesses reviewed the 1985 record, there is no evidence that the IOUs' witnesses did so. Therefore, the IOUs have no basis for their assertion.

In addition, in this instance the IOUs make the mistake they accuse BPA of making: they refer to "preference customers" rather than to preference customers <u>with industrial</u>

customers. Even if the 1985 record did contain a list of preference customers, the Administrator would be unable to determine from that list how many of those customers had retail industrial loads. In the Record of Decision in the 1985 case, the DSIs framed their argument for the exclusion of revenue taxes in terms of all utilities, not utilities with industrial customers. E-GE-19, at 137. The evidence in the present record gives no reason to believe that the 1985 record included a list of preference customers with industrial loads. To the contrary, it appears that it did not. BPA's decision in this case to exclude revenue taxes from the margin was based in part on the detailed evidence in the record. Tr. 986. The record in this case is much more developed than was the record in the 1985 rate case.

Finally, the issue as framed today was never presented to the Administrator in 1985. BPA suggests that revenue taxes are not a typical margin component because the majority of BPA's preference customers with industrial loads do not incur them. In 1985 the DSIs argued that revenue taxes should be excluded from the margin because they were not paid by all of BPA's preference customers. E-GE-19, at 137. In response, Northwest Utilities pointed out that if the Administrator accepted the DSIs' reasoning, he would have to exclude from the margin any cost that appeared in "some, but not all, public utility industrial rates." *Id.* at 138. The Administrator rejected the DSIs' argument: "The fact that not all utilities incur revenue taxes is no more a basis for a blanket exclusion from the margin than would be the exclusion of any other cost not incurred by each and every public agency in the region." *Id.* (emphasis added).

The IOUs assert that "the Administrator made it abundantly clear in 1985 that the number of utilities or customers, majority or otherwise, who pay taxes does not matter—when they do, they are in the margin." MREP Brief, B-GE/PL/PS-01, at 26. As the 1985 Record of Decision demonstrates, this assertion is incorrect. In 1985 the Administrator responded to a DSI argument that, unless a cost was included in all utilities' margins, it should not be included in the typical industrial margin. For two reasons, he never addressed the question of whether a cost incurred by only a minority of utilities with industrial customers should be included in the margin: first, this argument was never advanced; and second, the record did not contain the evidence needed to address it. (Under the IOUs' logic, a cost should be included in the margin even if only one utility incurs it.)

BPA's decision today is consistent with the Administrator's reasoning in 1985. BPA is not suggesting that a cost must be incurred by all utilities, or in every jurisdiction, to be included in the margin. Indeed, such an argument would be as unconvincing today as it was in 1985. A cost need not appear in every utility's industrial rate to be typical of the class; the statute's use of the word "typical" rather than, for example, "universal" belies this approach. When a cost appears in only a minority of utilities' industrial rates, however, and when that minority is concentrated in only one state in the region, the cost is neither universal nor typical, and should be excluded from the margin.

In its brief on exceptions, APAC, citing "[a] well-recognized line of authority," argues that courts need not defer to agency action that is contrary to a long-standing prior position. APAC Ex. Brief, R-PA-01, at 13. APAC cites two cases for this proposition. The first is *Motor Vehicle Mfrs. Ass'n v. State Farm Mutual Auto. Ins. Co.*, 463 U.S. 29 (1983). In 1970, the Department of Transportation issued a rule requiring the installation of passive restraint systems (automatic seatbelts or airbags) in motor vehicles. The Department amended the standard in 1972 and, after statutory amendments, again in 1977. Over the next several years, the automobile industry geared up for compliance with the new standard. In 1982, however, the Department rescinded the rule. A group of insurers challenged the rescission.

The Court said that it "fully recognize[s] that '[r]egulatory agencies do not establish rules of conduct to last forever' (citation omitted), and that an agency must be given ample latitude to 'adapt their rules and policies to the demands of changing circumstances.'" (citation omitted) *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 42. The Court noted, however, that the Department of Transportation had reaffirmed the passive restraint standard several times; in a 1981 rulemaking, the Department indicated that "'[t]he agency has no basis at this time for changing its earlier conclusions in 1976 and 1977 that basic air bag technology is sound and has been sufficiently demonstrated to be effective in those vehicles in current use.'" *Id.* at 48. Nevertheless, one year later, without analysis, the Department rescinded the standard.

The Court noted that language from a prior case was "apropos" to the current one: "'There are no findings and no analysis here to justify the choice made, no indication of the basis on which the [agency] exercised its expert discretion.'" *Id.* (quoting *Burlington Truck Lines., Inc. v. United States*, 371 U.S. 156, 167 (1962)). The Court concluded that "'[a]n agency's view of what is in the public interest may change, either with or without a change in circumstances. But an agency changing its course must supply a reasoned analysis.'" *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 57 (citation omitted). The Court remanded the decision because the Department had "failed to supply the requisite 'reasoned analysis' in this case." *Id.*

Thus, the Court did not hold that an agency's change in position is not entitled to deference. To the contrary, the Court recognized that an agency must be free to change its position. It held only that the agency must supply a reasoned analysis for the change. The Administrator has done so here. Moreover, in *Motor Vehicle Mfrs. Ass'n*, the agency rescinded a rule it had reiterated several times, the last time only a year before the rescission. Here, BPA is changing a decision it considered only once before, eleven years ago, under much different circumstances. The decision is "long-standing" only because it was made a long time ago, not because the agency continually reaffirmed it.

In *United States v. Leslie Salt Co.*, 350 U.S. 383 (1956), the second case on which APAC relies, the Department of the Treasury interpreted a statute "[i]n contrast to the position it had consistently taken throughout the many years preceding the [new] decision." *Leslie Salt Co.*, 350 U.S. at 395. The Court noted that "[a]gainst the Treasury's prior longstanding and consistent administrative interpretation its more recent *ad hoc* contention as to how the statute should be construed cannot stand." *Id.* at 396. By contrast, the Administrator's exclusion of revenue taxes from the margin in this case is not "*ad hoc*"; the decision was reached after the issue was thoroughly addressed in the rate case, and is based on a reasoned analysis of new circumstances, new evidence, and a new argument. Moreover, as noted above, the decision is not at odds with a position "consistently taken throughout many years."

Finally, APAC cites *PacifiCorp v. F.E.R.C.*, 795 F.2d 816 (9th Cir. 1985), for the proposition that the Administrator simply has no discretion to reverse a long-standing position involving an issue of statutory interpretation. APAC Ex. Brief, R-PA-01, at 13. Such a rule, which *PacifiCorp* does not establish, would be unworkable. It would mean that even mistaken statutory interpretations were cast in stone. Instead, as demonstrated above, the courts require that a change in statutory interpretation or in the exercise of administrative discretion be supported by a reasoned analysis for the change.

PacifiCorp v. F.E.R.C. concerned BPA's adoption of a revised Average System Cost methodology in 1984, after BPA adopted the initial methodology in 1981. Unlike the initial methodology, the revised methodology excluded taxes and return on equity from average system cost. In challenging the new methodology, petitioners argued that BPA was not entitled to deference for a changed statutory interpretation. Noting "two defects" in petitioners' argument, the court upheld the new methodology. *PacifiCorp*, 795 F.2d at 821. First, the court indicated that BPA "has not reversed any longstanding interpretation. BPA implemented the first methodology in 1981, and based upon its experience, it adopted the second in 1983 after extended rule making proceedings. The Supreme Court has recognized that agencies need some flexibility to change regulations based upon increased experience and information." *Id.* (citation omitted).

The same reasoning applies here. As demonstrated by both *Motor Vehicle Mfrs. Ass'n* and *Leslie Salt Co.*, the courts do not use the term "longstanding" to indicate only duration; indeed, duration alone is of questionable significance. Instead, the courts scrutinize closely an agency change in an interpretation that is longstanding in the sense that the agency has, over a long period of time, consistently reiterated that interpretation. The Administrator has addressed the margin calculation only once before; because of the IP-PF Link, the issue was never ripe for revisitation until now. Since 1985, the Administrator has never reaffirmed his prior decision or considered whether to adhere to it or alter it. In this rate case, as in BPA's adoption of a revised Average System Cost methodology, the Administrator adopted a new position after extended proceedings, based on additional experience and information.

The second defect in petitioners' argument in *PacifiCorp* was that BPA's interpretation of the statute had not changed. The court noted that in 1981 the Administrator did not conclude that the Northwest Power Act required inclusion of taxes and return on equity in average system cost. Therefore, his interpretation of the statute did not change. *Id.* Presumably this statement is the basis of APAC's assertion that the Administrator cannot change a statutory interpretation. If so, APAC's argument also has two defects. First, the court's statement was a refutation of petitioners' argument that the Administrator had changed his statutory interpretation, not a holding that the Administrator has no discretion to do so. Second, the Administrator similarly did not conclude in 1985 that the Northwest Power Act required the inclusion of revenue taxes in the margin. In *PacifiCorp*, the court noted that "[a]lthough section 5 of the [Northwest Power] Act provides for the development of a method of calculating the 'average system cost' of each utility's resources, the Act does not explain the term." *Id*. at 819. Nor does the Act explain the term "typical margin." In 1985 the Administrator rejected a DSI argument that costs should be excluded from the margin unless they were included in all retail industrial rates. The Act itself does not address this issue. In *PacifiCorp*, the court said that "[i]t is significant that [the Administrator] did not state [in 1981] that the statute required inclusion of equity returns." *Id*. at 821. In 1985, the Administrator did not state that the Act required the inclusion of revenue taxes in the margin. *See* E-GE-19, at 137-39.

Finally, in their brief on exceptions the IOUs assert, without citation of evidence, that the decision to exclude revenue taxes from the margin was decided in advance of the hearing in private conversations with the DSIs. MREP Ex. Brief, R-GE/PL/PS-01, at 11. The IOUs cite no evidence for this assertion because the record contains no evidence for it. It is addressed and fully rebutted *infra* § 14.2.2.

In sum, revenue taxes should be excluded from the industrial margin because they are not included in the typical margins charged by BPA's preference customers to their industrial customers. Three factors distinguish the situation today from that in 1985: first, the competitive marketplace requires BPA to achieve a competitive DSI rate. BPA cannot do so if it includes in its margin a cost that the majority of utilities with industrial customers do not include. Second, the record today contains significant evidence regarding the number of utilities with industrial customers that pay revenue taxes that was not contained in the 1985 record. Third, the issue as presented by BPA today was not presented to the Administrator in 1985. It is impossible to say what decision the Administrator would have made in 1985 had the record contained more substantial evidence, and had the issue been framed properly. This record, however, contains both more substantial evidence and a properly framed issue. Taken as a whole, the evidence in this record establishes that revenue taxes should be excluded from the industrial margin.

Decision

Revenue taxes will be excluded from the industrial margin. If BPA includes revenue taxes in the margin, its DSI rate will be uncompetitive. BPA will lose substantial DSI load, and either will fail to recover its costs, as required by section 7(a) of the Northwest Power Act, or will be forced to allocate additional costs to its public body and cooperative customers, thereby endangering their competitiveness and potentially leading to even more loss of load. In a competitive market, BPA cannot include in the industrial margin a cost that is not included in the margins of most power providers. The existence of the competitive market, and the additional evidence in this case regarding *the number of BPA's customers with industrial loads that pay revenue taxes, justify a different decision today from the one made by the Administrator in 1985. In addition, today's decision is consistent with the Administrator's reasoning in 1985, since the issue presented for his decision was whether all utilities had to incur a cost in order for it to be considered typical. The issue today is whether a cost should be considered typical when only a minority of utilities incur it.*

8.2.3 Character of Service Adjustment

Issue

Whether the Industrial Firm Power (IP) rate should be adjusted by up to 3 mills/kWh to account for the character of DSI loads.

Parties' Positions

The DSIs argue that the IP rate should be adjusted to account for DSI load characteristics that benefit BPA. The DSI loads are characterized by high load factors that do not vary throughout the day or the season or based on weather conditions. DSI Brief, WP-96-B-DS-01, at 22. The DSIs suggest an adjustment of 3 mills/kWh. *Id.* at 23.

BPA's Position

BPA argues that the DSIs' proposal incorrectly assumes that BPA's rates do not accurately reflect marginal costs. In addition, the DSIs have presented no evidence to support their request for a 3-mill/kWh adjustment. Chang, Cocks, WP-96-E-BPA-54, at 10.

Evaluation of Positions

The DSIs note several factors that account for the lower cost of serving loads characteristic of the DSIs. Because of the DSIs' constant load, installed CT capacity can be utilized efficiently to reduce average costs. In addition, DSI loads are not weather-sensitive and therefore do not require excess generation or transmission facilities. Finally, the DSI loads are quite large and are served at very few points of delivery, thus producing economies of scale. Schoenbeck, Bliven, WP-96-E-DS-01, at 39-40.

The DSIs assert that, based on "media reports of recent power sales," the market price for delivered firm power at 100 percent load factor is 20 mills/kWh or less. *Id.* at 39. The proposed average IP rate is 22.6 mills/kWh. Therefore, the DSIs conclude that they should receive a character of service adjustment of 3 mills /kWh. *Id.* at 41.

The DSIs' proposal is based on their contention that the applicable wholesale rate component of the equitable rate fails to reflect the cost of serving loads that are characteristic of the DSIs. *Id.* at 38-39. This assertion is incorrect. In testimony, a number of parties, including the DSIs, recommended that BPA increase its demand charge to better reflect the cost of serving high load factor customers. Wolverton, *et al.*, WP-96-E-PA/DS/PG-03, at 2. BPA is increasing its demand charge. *See supra* § 7.1.1. In addition, the applicable wholesale rate component of the IP rate is calculated by applying the Priority Firm Power (PF) rate charges to test-year DSI billing determinants. By using DSI billing determinants instead of the average PF rate, this calculation accounts for the DSI load characteristics. Finally, the DSIs already benefit from having large loads served over few points of delivery. The DSIs pay only for the costs of those delivery facilities that are used to deliver power to them. Woerner, *et al.*, WP-96-E-BPA-85, at 25-26.

Moreover, the DSIs have presented no evidence that DSI load characteristics produce cost savings of 3 mills/kWh. Instead, they have simply assumed that the difference between BPA's IP rate and the market price for power must reflect these load characteristics. They have presented no evidence that this is the case. The market price for power is based on any number of considerations. The DSIs have arbitrarily assumed that, if the market price is less than BPA's IP rate, the difference must measure the cost savings of serving loads with DSI load characteristics.

Finally, the DSIs have presented no evidence that the market price for power sold at 100 percent load factor is in fact under 20 mills/kWh. They have not named the source of their assertion, nor included the terms of the power sales to which they refer. BPA's IP rate is a flat rate for five years. The evidence indicates that the market price for five-year power is more than 20 mills/kWh. See Chang, Cocks, E-BPA-54, at 10.

Decision

A character of service adjustment of up to 3 mills/kWh is not warranted. The DSIs mistakenly assume that BPA's IP rate does not account for the DSI load characteristics. Furthermore, they have presented no evidence for their assertion that DSI load characteristics result in cost savings of 3 mills/kWh. Finally, they have presented no evidence that the market price for five-year power is under 20 mills/kWh.

8.3 Value of Reserves

Issue 1

Whether BPA should credit the DSIs with the entire value of the reserves the DSIs provide.

Parties' Position

The IOUs argue that BPA should continue the share-the-savings approach, under which it credits the DSIs with half of the value of reserves. The IOUs assert that this approach is consistent with precedent and with economic rationality. MREP Brief, WP-96-B-GE/PL/PS-01, at 36. APAC supports the IOUs' position. APAC Brief, WP-96-B-PA-01, at 28. The DSIs argue that the Northwest Power Act does not mandate the share-the-savings approach, and that a reserves credit based on the full value of the reserves is consistent with competitive markets. DSI Brief, WP-96-B-DS-01, at 30-31.

BPA's Position

BPA argues that, in a competitive market, a purchaser of services must expect to pay full value for those services. BPA could afford to compensate the DSIs for only half of the value of the reserves they provide when the DSIs had no choice but to purchase all their power from BPA. Now that the DSIs have competitive alternatives, BPA cannot expect to obtain reserves from them at a reduced price. Neal,*et al*., WP-96-E-BPA-24, at 20.

Evaluation of Positions

In establishing a value of reserves in the 1983 and 1985 rate cases, BPA adopted a "share-the-savings" approach, under which it credited the DSIs with only one-half of the value of the reserves they provide. The IOUs suggest that BPA should not change this methodology "absent legislative change." Piro,*et al*., WP-96-E-GE/PL/PS-02, at 16. They argue further that BPA's proposal contradicts all its rate case decisions since 1983. *Id.*

These arguments misconstrue the history of both the Northwest Power Act and BPA's ratemaking. The Northwest Power Act says nothing regarding the percentage of the reserves value the DSIs should receive. Therefore, no legislation is necessary for BPA to change this percentage. The IOUs note that the Ninth Circuit Court of Appeals has upheld BPA's prior adoption of the share-the-savings methodology. MREP Brief, B-GE/PL/PS-01, at 36, citing *Central Lincoln People's Util. Dist. v. Johnson*, 735 F.2d 1101, 1127 (9th Cir. 1984). In *Central Lincoln*, however, the court did not hold that this methodology was required by the Northwest Power Act, or that another methodology would be inappropriate. Instead, it simply upheld BPA's exercise of discretion. *Id.*

Congress has made clear that the Northwest Power Act does not mandate the share-the-savings approach. In its report on the final bill, the Senate Committee on Energy and Natural Resources included a numerical analysis of BPA's ratemaking. That analysis assumed that, in its initial rate case, BPA would credit the DSIs with half of the value of reserves. The Committee then noted as follows:

> The crediting of 50 percent of the value of the reserves to the DSIs does not set a precedent for future BPA rate cases. The form of availability credit or other reserve credit mechanism to be applied is not meant to be specified or prejudiced by the assumptions that are here.

S. Rep. No. 272, 96th Cong., 1st Sess. 64 (1979).

The Administrator quoted this statement when he originally adopted the share-the-savings methodology, making clear he was not setting a precedent for future rate cases. Neal, *et al.*, E-BPA-24, at 20. Moreover, since 1985 the DSI rate has been set pursuant to the IP-PF Link. *See* Chang, Cocks, WP-96-E-BPA-25, at 2. Under the link, in each rate case the industrial margin (which includes the value of reserves credit) has been increased by the Gross National Product deflator. *Id.* Thus, neither the value of reserves credit itself, nor the appropriate percentage to credit the DSIs, has been revisited since 1985. The IOUs argue that BPA's proposal in this case contradicts "all of BPA's rate case decisions since 1983." Piro, *et al.*, E-GE/PL/PS-02, at 16. They neglect to note that BPA has addressed this issue only once since 1983, and that was in the 1985 rate case. Far from contradicting a series of rate case decisions, BPA is revisiting this issue for the first time in over ten years.

Since 1985 the electric utility industry has undergone massive change. *See supra* section 2.2. In 1985 BPA was the low-cost provider of service, and its customers had no reason to seek power elsewhere. In the last few years the industry has become fiercely competitive, and BPA's customers now have many choices of power provider besides BPA. *Id.* In this rate case, BPA concluded that in a competitive environment a purchaser of services must expect to pay full value for those services. Neal, *et al.*, E-BPA-24, at 20. Forced outage reserves were a significant issue during the negotiation of new DSI contracts. *Id.* Even though BPA's proposed IP rate includes a credit for the full value of reserves, BPA has lost significant DSI load to the competition. Moorman, Evans, WP-96-E-BPA-65, at 6.

Relying on BPA's testimony that reserves were an issue in the contract negotiations, the parties assert that BPA's decision to discontinue the share-the-savings method was reached during private discussions with the DSIs. APAC Ex. Brief, WP-96-R-PA-01, at 28; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 11. The record contains no evidence that this is the case, and BPA has fully rebutted the parties' assertion elsewhere in this Record of Decision. *See infra* § 14.2.2. As BPA explains in that section, it is a great and unjustified leap of fact and logic to conclude that, because reserves were an issue in the negotiations (the only evidence the parties cite), the parties discussed the share-the-savings method. It is a yet greater leap to conclude that the decision to discontinue the method was reached during those negotiations.

BPA is discontinuing the share-the-savings method because it no longer can expect to obtain the right to trip DSI load without paying full value for that right. In both 1983 and 1985, when BPA applied the share-the-savings methodology, the region benefited from that approach. The DSIs still received the lowest power rate available, while BPA's other customers enjoyed lower rates because they, in effect, retained half of the reserves valuation. Today, neither of these conclusions would hold. If BPA credited the DSIs with only half of the reserves value, the IP rate would be above competitive levels and BPA could expect to lose substantially more DSI load. *See supra* §§ 2.2 and 8.2.2; *see also* Schoenbeck, Bliven, WP-96-E-DS-03, at 23. Thus, the DSIs would not be receiving a competitive rate, while BPA's remaining customers would inevitably face additional costs that BPA was unable to recover from the DSIs because of the loss of load. *See supra* §§ 2.2 and 8.2.2. Neither party would benefit, while the region as a whole would suffer. The IOUs argue that BPA's proposal departs from "economic rationality" and is intended only to achieve a competitive DSI rate. MREP Brief, B-GE/PL/PS-01, at 36. To the contrary, paying full value for a product in a competitive market is highly rational; it is the way any competitive business must expect to operate.

Moreover, BPA bases its reserve valuation on the avoided cost of installing an alternative scheme to provide reserves if the DSI reserves were unavailable. Neal, *et al.*, E-BPA-24, at 3, 10. The full reserves value measures this cost. Were BPA to lose the DSI load (as it could be expected to do if it continued the share-the-savings approach), then BPA would need to obtain reserves through its least-cost alternatives. In this situation BPA would incur the full cost of installing and maintaining those alternatives. Therefore, BPA is appropriately compensating the DSIs by crediting them with the full value of the reserves they provide.

Finally, the IOUs suggest that BPA should use the share-the-savings approach because the DSIs also benefit from the reserves. MREP Brief, B-GE/PL/PS-01, at 36. This benefit, however, is only indirect; BPA's customers benefit from reserves to the extent that BPA benefits. Tr. 1148. The true benefit of the reserves is in BPA's ability to meet its reserve obligation under Northwest Power Pool operating criteria. *Id.* at 1147-48. Thus, in "safety net schemes," which protect against a variety of low-probability occurrences, the customer is the primary beneficiary. In the case of reserves, which protect against more likely occurrences, it is the utility itself that benefits. Kreipe, *et al.*, WP-96-E-BPA-53, at 9-10.

Decision

BPA will credit the DSIs with the full value of the reserves they provide. This figure measures the value of the reserves to BPA, and represents the cost BPA would incur if it lost the DSI load and were required to install the least-cost alternatives to obtain the reserves. In addition, in a competitive market, BPA must expect to pay full value for services. Today, unlike 1983 and 1985, BPA's other customers would be harmed by a share-the savings-approach, since under such an approach BPA would lose DSI load and be forced to allocate additional costs to other customer classes.

Issue 2

Whether BPA should base the valuation of forced outage reserves on the full 1,880 megawatts of CTs that were assumed to be built in 1982.

Parties' Positions

The IOUs argue that BPA should base the valuation of forced outage reserves on the full 1,880 MW of CTs that were assumed to be built in 1982. They assert that BPA would still be incurring the full cost of the CTs. MREP Brief, WP-96-B-GE/PL/PS-01, at 37-38.

BPA's Position

BPA prorates the reserve amount to reflect the amount of reserves the DSIs actually provide during the rate period. Because the DSIs are providing only 921 MW of forced outage reserves, BPA has credited them with the value of 921 MW of CTs. Had the CTs actually been built, the additional megawatts would be devoted to other uses. Crediting the DSIs with the full amount would overstate the value of the reserves to BPA. Kreipe, *et al*., WP-96-E-BPA-53, at 10.

Evaluation of Positions

In the 1982 rate case, BPA concluded that combined cycle combustion turbines were the least-cost alternative to the DSI forced outage reserves, and that BPA would have installed 1,880 MW of CTs had the DSI reserves not been available. In the 1983 and 1985 rate cases, BPA again assumed that CTs had been built in 1982, and based the reserves valuation on the capital costs that had been assumed in the 1982 rate case. Neal, *et al*. WP-96-E-BPA-24, at 3. In the 1982 rate case BPA assumed that the hypothetical CTs had a twenty-five year life. Therefore, had they actually been built, they would still be operating today, and BPA again has based the value of DSI forced outage reserves on the hypothetical CTs.

During the rate period, the DSIs will be providing only 921 MW of forced outage reserves. Therefore, BPA prorated the capital costs of the CTs and credited the DSIs with 921/1,880 of the costs, equivalent to the actual reserve amount they provide. Had the 1,880 MW of CTs actually been built, only 921 MW of that amount would be used during the rate period as an alternative to the DSI reserves. The remainder would be used for other purposes, such as serving load or providing additional reserves. Kreipe,*et al*., WP-96-E-BPA-53, at 10; s*ee also* WP-96-E-PS-02. The costs and benefits of the remaining 959 MW would be attributed to these other uses. Kreipe,*et al*., WP-96-E-BPA-109, at 8. Therefore, the prorated costs represent the value of the reserves the DSIs actually provide.

The IOUs note that the value of reserves has declined from $106,488,000 in the 1993 rate case, to $55,941,000 in the 1996 initial proposal, to $43,047,000 in the 1996 supplemental proposal. MREP Brief, B-GE/PL/PS-01, at 37. These figures simply reflect a change in the value of reserves to BPA and are not relevant to this issue. Moreover, no value of reserves study was performed in 1993 because the IP rate was established pursuant to the IP-PF Link. Chang, Cocks, WP-96-E-BPA-25, at 2. Therefore, the value from 1993 cannot be directly compared to values derived in this rate case.

The decline between the 1996 initial and supplemental proposals reflects a decline in projected DSI load, and consequently a decline in the amount of reserves the DSIs are providing. In addition, it reflects a change in BPA's assumption regarding the interest rate at which the CTs were refinanced. Kreipe, *et al*., WP-96-E-BPA-78, at 14. The IOUs agree that, had BPA built the CTs in 1982, "it would have refinanced those acquisitions and lowered their annual cost." MREP Brief, B-GE/PL/PS-01, at 37. They approve of the new assumption, because it reflects "prudent utility practice." *Id.* at 38; *see also* Piro, *et al*., WP-96-E-GE/PL/PS-06, at 6.

Thus, the IOUs' complaint that the value of reserves has declined by approximately $12,000,000 between the initial and supplemental proposals is disingenuous; in fact, they agree with one of the assumptions responsible for this decline. Their only complaint, therefore, is with BPA's proposal to compensate the DSIs only for the reserves they actually provide; the IOUs call this proposal a "departure from common sense." *Id.* at 37. To the contrary, paying only for value received is both common sense <u>and</u> prudent utility practice.

The IOUs assert that BPA has assumed that, as reserves supplied by the DSIs were reduced, BPA could have eliminated the cost of an equal amount of combustion turbines. Piro, *et al*., E-GE/PL/PS-06, at 7. This assertion mischaracterizes BPA's testimony. As BPA has testified, if the CTs did exist they surely would not be sitting idle. The remaining capacity would be used for other purposes, and its costs and benefits would be attributed to such purposes. This would be so regardless of the level of those costs and benefits. *Id.* A cost-benefit analysis is unnecessary. The IOUs in effect suggest that BPA should assume that the 1,880 MW of combustion turbines will provide 921 MW of forced outage reserves, with the remaining 959 MW serving no function.

Finally, the IOUs overlook the fact that the only purpose of assuming the existence of the hypothetical CTs is to determine the value of the DSI forced outage reserves. Although the CTs are a useful construct for this purpose, they do not actually exist. WPAG testified that the IOUs "are confusing 'common sense' with the purpose of the [7(b)(2)] Study [to which the value of reserves is an input]." Beck, *et al*., WP-96-E-WA-15, at 38. WPAG added that the 7(b)(2) study considers particular conditions, under specific assumptions, for the rate period and the ensuing four years. *Id.* at 39. For a new rate period, the value of reserves may change. *Id.* As discussed *infra* § 9.4, the 7(b)(2) Methodology requires BPA's Program Case to simulate the current rate proposal. Were BPA to credit the DSIs with the costs of the full 1,880 MW, it would be overvaluing the DSI reserves—by a factor of over 100 percent—merely in service to a hypothetical construct.

In every rate case, BPA has prorated the CTs to the amount of reserves the DSIs provide. In the 1983 rate case, the Administrator noted that

> the total cost of the combustion turbine is not used to value the reserves provided by the DSI restriction rights since this would overstate the value. (citation omitted). The amount of reserves that the DSI's can provide is

> less than [the] BPA reserve requirement, so the proration is based on the amount of reserves actually provided.

1983 Administrator's Record of Decision (ROD), WP-83-A-02, at 337.

Similarly, in 1985 the Administrator said that

> [t]he test year reserve requirement, 1290 MW, is less than the 1880 MW capacity of the combustion turbines. Therefore, the existing assumed facilities will cover the reserve requirement for FY 1987. (citation omitted). The value of forced outage reserves is the annual cost of the combustion turbines prorated based on the amount of reserves required in the test year to the amount of generation installed.

1985 Administrator's Record of Decision, WP-85-A-02, at 197-98.

Because the only purpose of the reserve valuation is to determine the value of the DSI reserves, and because the failure to prorate the reserve amount would overstate that value, it is appropriate to follow this precedent and continue to prorate the 1,880 MW to the amount of reserves the DSIs will provide during the rate period.

<u>Decision</u>

BPA will base the DSI forced outage reserves valuation on 921 MW of combustion turbines, equivalent to the amount of forced outage reserves the DSIs will be providing during the rate period. This proration accurately measures the value of the reserves to BPA. Had the CTs actually been built, the additional capacity would be used for other purposes, and their costs and benefits would be attributed to those purposes. Moreover, the only purpose of assuming the existence of the CTs is to establish the DSI reserve valuation. If BPA did not prorate the CTs, it would be overcompensating the DSIs.

<u>Issue 3</u>

Whether BPA should assume that the alternative to the DSI stability reserves includes tripping residential and commercial loads.

<u>Parties' Positions</u>

The DSIs argue that, because of safety concerns, BPA would be unable to trip residential and commercial loads as an alternative to the DSI stability reserves. They add that BPA has not identified which loads can be tripped or analyzed the costs associated with identifying those loads. Finally, the DSIs suggest that the purpose of a stability reserve scheme is to protect service to residential and commercial loads. Therefore, it is illogical to assume that the alternative to the DSI stability reserves is to trip residential and commercial loads. DSI Brief, WP-96-B-DS-01, at 16-18.

BPA's Position

BPA argues that no safety reason precludes BPA from tripping residential and commercial loads as an alternative to the DSI stability reserves. Kreipe, *et al.*, WP-96-E-BPA-53, at 2. Since BPA would contract with utilities for the reserves, it would not have to identify the end-use customers to hook up to the system. Kreipe, *et al.*, WP-96-E-BPA-109, at 5. BPA asserts that the DSIs have misstated the purpose of stability reserves, which is to ensure a power source for all loads, including the DSIs, under unusual conditions. *Id.*

Evaluation of Positions

The DSIs cite three reasons why BPA cannot assume that the alternative to tripping DSI load for stability reserves includes tripping residential and commercial load: first, tripping residential load raises safety concerns; second, BPA has ignored the cost of identifying residential load willing to be tripped; and third, it is illogical to assume that BPA would trip residential load in order to avoid interruptions to that same residential load. Schoenbeck, Bliven, WP-96-E-DS-08, at 4-6.

The DSIs' argument that it is unsafe to trip residential loads is premised entirely on one sentence in BPA's supplemental testimony, in which BPA indicated that sites for the underfrequency load shedding (UFLS) program were chosen in order to minimize safety and health concerns. Schoenbeck, Bliven, E-DS-08, at 4 (citing Kreipe, *et al.*, WP-96-E-BPA-78, at 3). The DSIs have presented no evidence that tripping residential and commercial loads raises unacceptable safety concerns. Nor did BPA make this point. In the testimony the DSIs cite, BPA did not indicate that residential and commercial loads were excluded from the UFLS program, only that industrial loads were favored. Kreipe, *et al.*, E-BPA-78, at 3. Thus, residential and commercial loads were not eliminated from the program, and, like industrial loads, they face the prospect of being tripped.

The only example BPA provided in which load tripping raised potential safety concerns was loads serving hospitals. *Id.* Yet BPA did not testify that hospitals were excluded from the UFLS scheme. Nevertheless, the DSIs have expanded this one example to argue that, according to BPA, the agency cannot trip <u>any</u> residential or commercial loads. To the contrary, BPA engineers testified that there exists no planning criterion that would prevent the inclusion of residential and commercial loads in a load-tripping scheme. Kreipe, *et al.*, E-BPA-53, at 2-3. The DSIs have presented no contrary evidence.

As BPA also noted, a stability reserves system trips loads for a maximum of 30 minutes, while BPA has projected one load tripping event approximately every fifteen years. Kreipe, *et al.*, E-BPA-109, at 4-5. Residential and commercial loads are exposed to many more outages, of potentially longer duration, because of normal transmission and distribution outages. *Id.* at 5. Therefore, any safety concerns raised by inclusion of such loads in a stability reserves scheme are minimal. BPA's stability reserve alternative would cost approximately $6 million per year. Supplemental Wholesale Power Rate

Development Study, WP-96-E-BPA-61, Appendix B, at B-12. Under the DSI proposal, forced outage and stability reserves would both be provided by CTs, thus utilizing the full 1,880 MW of CTs assumed to be built in 1982 to provide forced outage reserves, plus an additional 520 MW of CTs. Schoenbeck, Bliven, WP-96-E-DS-01, at 17. The DSIs assumed that the additional 520 MW of CTs would cost the same amount per megawatt as the CTs built in 1982. Therefore, under the DSI proposal the $6 million annual cost jumps to $71 million, all to avoid the minimal safety concerns of a small number of additional possible outages. This proposal is not reasonable.

The DSIs' second argument assumes incorrectly that BPA would be searching out and negotiating with individual households to determine whether they would be willing to be tripped for stability reserves purposes. However, BPA has no contractual relationship with these end users. Instead, BPA would negotiate with the utilities, with which it does have contractual relationships. Kreipe, *et al.*, E-BPA-109, at 4. If BPA did not have access to the DSI reserves, it would be required to implement an alternative stability reserves scheme in order to maintain its import rating over the DC Intertie. Therefore, it would be in the utilities' interests to agree to their inclusion in the system, and they could be expected to do so. *Id.* at 4.

The DSIs' third argument betrays a misunderstanding of the purpose of stability reserves. The DSIs argue that it is illogical to assume that BPA would trip residential and commercial loads in order to protect import capability to serve the same loads. Schoenbeck, Bliven, E-DS-08, at 6. The purpose of a stability reserves scheme, however, is to ensure a power source for all loads, including the DSIs, under unusual conditions such as drought or cold weather. Kreipe,*et al.*, E-BPA-109, at 5. Therefore, if it is illogical to assume that BPA would trip residential and commercial loads for stability reserves, it is equally illogical to assume that BPA would trip DSI loads for stability reserves. Yet DSI load tripping is exactly the system in place now; it is the system BPA is valuing in this rate case.

The DSIs argue that BPA's proposal denies much of the benefit of the reserves to many residential and commercial customers. DSI Brief, B-DS-01, at 16. This logic assumes that BPA's increased ability to serve load because of its higher import rating is offset by the load tripping that can be expected to occur. In fact, however, the benefit BPA receives from the increased import capability far outweighs the risk of tripping residential and commercial loads. Kreipe, *et al.*, E-BPA-109, at 5. The existence of a stability reserves scheme allows BPA to import at high load levels over the Intertie under a variety of conditions. *Id.*; Neal, *et al.*, WP-96-E-BPA-24, at 6-8. On the other hand, as stated earlier, BPA projects one load-tripping event every fifteen years. The increased ability to serve residential and commercial loads far outweighs any losses these loads might incur from being tripped.

Decision

It is appropriate to assume that the alternative to DSI stability reserves includes tripping residential and commercial loads. No planning criterion prohibits tripping such loads for stability reserves purposes. In addition, the benefit BPA receives from its increased import capability far outweighs the risk of tripping residential and commercial loads.

Issue 4

Whether BPA should compensate Columbia Falls Aluminum Company (CFAC) for providing stability reserves in the Conkelley area.

Parties' Positions

The DSIs argue that BPA should compensate Columbia Falls Aluminum Company for the local stability reserves it provides in the Conkelley area. They assert that in the absence of these reserves, BPA would be required to construct a third transmission line to serve the Conkelley area. Finally, they argue that customers in the Conkelley area benefit from the reserves. DSI Brief, WP-96-B-DS-01, at 20-21.

BPA's Position

BPA asserts that service to the Conkelley area would meet the BPA Reliability Criteria even in the absence of the stability reserves that CFAC provides. Therefore, if CFAC did not provide these reserves, BPA would take no alternative action. In addition, the Columbia Falls load is 90 percent of the load in the area. Therefore, to the extent that the stability reserves are beneficial, it is because of CFAC's load. Columbia Falls is seeking compensation for mitigating a problem that it has caused. Kreipe, *et al.*, WP-96-E-BPA-53, at 4-5.

Evaluation of Positions

In this rate case, as in past rate cases, BPA's reserves valuation is based on the least-cost alternative to the DSI reserves. The underlying premise of this methodology is that, in the absence of the DSI reserves, BPA would obtain reserves from another source in order to meet either BPA or WSCC Reliability Criteria. The methodology determines the cost BPA would incur to provide the alternative reserves. *See* Neal, *et al.*, WP-96-E-BPA-24, at 3, 9-10.

In the case of the Conkelley reserves, BPA would incur no alternative cost, because service to the Conkelley area would meet all Reliability Criteria even in the absence of the Columbia Falls reserves. Kreipe, *et al.*, E-BPA-53, at 4-5. Therefore, BPA would take no action to replace the reserves. *Id.* at 5. The DSIs' statement that BPA would have to construct a third transmission line is incorrect, and the rationale underlying the right to compensation for providing reserves is absent.

The DSIs assert that BPA nevertheless should compensate CFAC because other customers benefit from the reserves. Schoenbeck, Bliven, WP-96-E-DS-01, at 29. That other customers may benefit, however, is not a rationale for providing compensation for reserves that are unnecessary for meeting the Reliability Criteria. Moreover, the CFAC load is approximately 90 percent of the load in the Conkelley area. Kreipe, *et al.*, E-BPA-53, at 5. To the extent that the Columbia Falls reserves are beneficial, therefore, it is only because of a problem caused by the Columbia Falls load. *Id.* CFAC should not receive compensation for mitigating a problem that it has caused, and that, if not for its load, would not exist.

Decision

It is not appropriate to compensate Columbia Falls Aluminum Company for providing local stability reserves in the Conkelley area. These reserves are not necessary to meet the BPA Reliability Criteria, and BPA would not adopt an alternative stability reserves scheme if CFAC did not provide the reserves. In addition, the CFAC load is approximately 90 percent of the load in the area. Therefore, the reserves are beneficial only in mitigating a problem CFAC itself has caused.

Issue 5

Whether BPA should compensate the DSIs for their participation in the Northwest Power Pool Underfrequency Load Shedding Program (NWPP UFLS).

Parties' Positions

The DSIs argue that BPA should compensate them for their participation in the Northwest Power Pool Underfrequency Load Shedding Program, under which both DSI loads and other loads are tripped in the event of serious disturbances beyond the scope of the BPA and WSCC Reliability Criteria. They argue that according to the Northwest Power Act, the NWPP UFLS scheme is a reserve for which they are entitled to compensation. Finally, the DSIs assert that virtually all the loads first in line to be tripped are DSI loads, thereby benefiting other customers. DSI Brief, WP-96-B-DS-01, at 19-20.

BPA's Position

BPA argues that the NWPP UFLS program is not a stability reserve, and that it is standard utility industry practice to require all utility customers to participate in UFLS programs without compensation. In the case of stability reserves, the utility benefits from having the reserve. In the case of a UFLS program, it is primarily the customer that benefits. Therefore, it would be inappropriate to compensate the customer for its participation. Kreipe, *et al.*, WP-96-E-BPA-53, at 7-10.

Evaluation of Positions

BPA testified that the NWPP UFLS program is not a stability reserves scheme. A stability reserve is a reserve that is designed to protect the power system in the event of a known first or second transmission contingency. Kreipe, *et al.*, E-BPA-53, at 8. The NWPP UFLS program is a safety net scheme, which protects the system from extremely improbable contingencies that are not regarded as credible. *Id.*

The DSIs argue that the Northwest Power Act does not distinguish between reserves and safety net schemes for purposes of compensating the DSIs for reserves. DSI Brief, WP-96-B-DS-01, at 19. The DSIs quote the Act's definition of "reserves":

> "Reserves" means the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers.

16 U.S.C. § 839a(17).

This definition does not encompass the NWPP UFLS system. First, the system is not designed to avert "particular planning or operating shortages." Stability reserves, like operating reserves, are designed to protect the power system from "known risks caused by identifiable system conditions." Kreipe, *et al.*, E-BPA-53, at 8. The NWPP UFLS scheme, on the other hand, "is not designed to protect the power system from a specific known contingency." *Id.* at 9. It is insurance against a "myriad of improbable events" rather than against any particular planning or operating shortage. *Id.*

Second, as contemplated by the statute, BPA must acquire both planning and operating reserves. Planning reserves protect against a shortage caused when a planned generating unit that is new or coming back from major rehabilitation is not available when planned. Kreipe, *et al.*, WP-96-E-BPA-109, at 3. Operating reserves, or forced outage reserves, are needed when an existing generating unit fails to perform or is shut down for emergency service. Neal, *et al*. WP-96-E-BPA-24, at 2. These are the "particular planning or operating shortages" referenced in the statute. The statute contains no comparable language that would encompass the NWPP UFLS scheme.

Third, the NWPP UFLS system is set up to trip other customers' load in addition to the DSIs. Kreipe, *et al.*, E-BPA-53, at 10. As common practice, all utilities require customers to participate in UFLS programs as a condition of service, and customers are not compensated for their participation. *Id.* at 9. Section 7(c)(3) of the Northwest Power Act provides that the Administrator shall adjust the DSI rates "to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." 16 U.S.C. §

839e(c)(3). The DSIs argue that with this language, Congress required BPA to compensate the DSIs for their participation in the NWPP UFLS scheme. Since all customers participate in UFLS schemes, it is illogical to assume that Congress directed BPA to compensate the DSIs for their participation, but expected all other customers to participate without compensation. Congress did not direct that the DSIs be first in line to be tripped.

Moreover, BPA obtains reserves only from the DSIs. It is not logical to assume, as the DSIs do, that the value of being first in line to be tripped equals the value of being the only provider of load tripping. (The DSIs implicitly make this assumption because they base their valuation on the least-cost alternative, assuming the absence of the DSIs. Schoenbeck, Bliven, WP-96-E-DS-01, at 36-37.) The more logical conclusion is that Congress did not consider the NWPP UFLS scheme to be a reserve. This conclusion is supported both by the Act's definition of "reserve" and by the fact that the NWPP UFLS scheme does not meet an engineering definition of a reserve.

Finally, another distinction between UFLS programs and reserves is the identity of the beneficiary. In the case of stability reserves, it is primarily the utility itself that benefits from the reserve. In the case of safety net programs such as the NWPP UFLS scheme, it is the customers that benefit through having power restored faster than it would be if the scheme were not in place. Kreipe, *et al*., E-BPA-53, at 9-10. Thus, utilities do not customarily compensate customers for their participation.

Decision

BPA should not compensate the DSIs for their participation in the Northwest Power Pool Underfrequency Load Shedding Program. This program is not a stability reserve, and section 7(c)(3) of the Northwest Power Act does not require BPA to compensate the DSIs for their participation in it. All utilities require their customers to participate in such programs without compensation.

Issue 6

Whether BPA should compensate Intalco Aluminum Corporation for providing local stability reserves in the Bellingham area.

Parties' Positions

APAC argues that, by compensating Intalco for both regional stability reserves and Bellingham area reserves, BPA is paying for the same reserves twice. APAC Brief, WP/TR-96-B-PA-01, at 22. The DSIs argue that the regional load tripping protects the Southern Intertie, while the Bellingham area load tripping protects the Northern Intertie. Therefore, the reserves are different, and Intalco is entitled to compensation for both. DSI Brief, WP-96-E-DS-01, at 34.

BPA's Position

BPA also argues that the regional stability reserves and the Bellingham area reserves protect against different contingencies, and therefore it is appropriate to compensate Intalco for both. BPA asserts that Intalco is at risk of being tripped under both stability reserves schemes, and that it is extremely unlikely that both would be needed at the same time. Kreipe, *et al.*, WP-96-E-BPA-109, at 2.

Evaluation of Positions

BPA compensates all the DSIs for providing stability reserves to protect its ability to import power into the Pacific Northwest over the Southern Intertie. Neal, *et al.*, WP-96-E-BPA-24, at 5-6. In addition, BPA proposes to compensate Intalco Aluminum Corporation for providing local stability reserves in the Bellingham area. These reserves protect BPA's ability to export power to Canada over the Northern Intertie. Kreipe, *et al.*, WP-96-E-BPA-53, at 7; Schoenbeck, Bliven, WP-96-E-DS-12, at 5-6. APAC argues that, because Intalco reserves cannot simultaneously be available for both sets of contingencies, BPA is paying for the same reserves twice. Wolverton, WP-96-E-PA-03, at 4. APAC adds that BPA acknowledged the possibility of having to interrupt Intalco for both sets of reserves at the same time. *Id.* at 4-5.

As is apparent from the above description of the reserves, however, BPA is not paying for the same reserves twice. The regional stability reserves, for which all DSIs receive compensation, protect against outages of the Pacific Northwest/Southwest DC Intertie (Southern Intertie) when it is being used to import power into the Pacific Northwest. Neal, *et al.*, E-BPA-24, at 5-6. These reserves are needed to meet both BPA and Western Systems Coordinating Council (WSCC) criteria. They make it possible for BPA to import power simultaneously from California and Idaho at a higher level than would be possible without them. *Id.* at 6.

The Bellingham area reserves protect against outages of both Custer-Monroe transmission lines when moderate to high levels of power are flowing south to north over the BPA-British Columbia Hydro and Power Authority Intertie (Northern Intertie). Kreipe, *et al.*, E-BPA-53, at 7. These reserves are needed to meet WSCC Criteria, which require that an intertie be rated at a level at which it can be demonstrated that other WSCC member systems will not be adversely affected by an outage on the host system. The present south-to-north rating on the Northern Intertie requires Intalco load tripping to prevent such adverse impacts. *Id.*

Therefore, the two sets of stability reserves protect against outages of different transmission lines, for different power system operations, under different conditions. The regional stability reserves protect BPA's ability to import power into the Northwest over one transmission line; the Bellingham area reserves protect BPA's ability to export power to Canada over another line. Intalco faces additional exposure to load tripping that no other DSI faces. It is exposed to tripping from two separate and unrelated load tripping schemes, and it is appropriate to compensate Intalco for the additional risk and the additional possibilities of being tripped. Kreipe, *et al*., E-BPA-109, at 2.

APAC acknowledges that the Bellingham area reserves protect exports to Canada over the Northern Intertie. Wolverton, E-BPA-03, at 5. It does not dispute BPA's testimony that the regional reserves are intended to protect imports over the Southern Intertie. Therefore, it acknowledges that the two sets of reserves are not in fact the same reserves. APAC argues, however, that in off-the-record clarification sessions, BPA witnesses admitted the possibility that interruptions of both sets of reserves could occur at the same time. *Id.* at 4-5. Therefore, it argues, BPA is paying double compensation.

APAC presented no evidence of its own on this point, instead relying solely on BPA's statement at clarification. When making this statement, however, BPA added that the possibility of tripping both schemes at the same time was "virtually nil." Kreipe, *et al*., E-BPA-109, at 2. The Bellingham area reserves are needed when BPA is in surplus hydro conditions and is storing the excess in Canada. *Id.*; Schoenbeck and Bliven, E-DS-12, at 6. The regional stability reserves are needed when BPA has limited hydro capability and is importing large amounts of power. Kreipe, *et al*., E-BPA-109, at 2; Schoenbeck, Bliven, E-DS-12, at 6. Therefore, the two reserves schemes are needed in precisely opposite situations. It is extremely unlikely that BPA would be importing large amounts of power over the Southern Intertie while storing excess power in Canada. Schoenbeck and Bliven, E-DS-12, at 6.

In addition, as noted above, the regional stability reserves protect against outages of the Southern Intertie, while the Bellingham area reserves protect against outages of both Custer-Monroe lines. Even assuming that somehow BPA were importing power from California while simultaneously storing power in Canada, both schemes would be tripped simultaneously only if the Southern Intertie and both Custer-Monroe lines experienced simultaneous outages. This contingency is extremely unlikely. The BPA and WSCC Criteria do not consider it to be a credible contingency, and the system is not planned to withstand such an outage. Kreipe, *et al*., E-BPA-109, at 2.

In its brief on exceptions, APAC does not dispute BPA's conclusion that the prospect of tripping both reserves schemes simultaneously is virtually nil. Instead, APAC asserts that BPA "does acknowledge that such an event can happen," and argues that the mere possibility of such an event, no matter how remote, means that BPA will be paying twice for the same reserves. APAC Ex. Brief, R-PA-01, at 21. To the contrary, BPA's "acknowledgment" means what it says: that the possibility of paying twice for the same reserves is virtually nil. BPA's conclusion that the prospect of tripping both sets of reserves simultaneously is "virtually" nil merely recognizes that it is not impossible for the situation to occur. However, BPA does not base rates on mere possibilities but on reasonable probabilities. If BPA fails to compensate Intalco for the additional reserves, it is extremely likely (if not certain, since the value of the reserves lies largely in their being available to be tripped, *see* Kreipe, *et al*., E-BPA-53, at 19) that Intalco will be facing additional risk, and providing an additional product—different reserves—for free. This likelihood is far greater than the remote prospect that BPA will need both sets of reserves simultaneously.

Finally, APAC also argues that the draft ROD failed to address APAC's argument that the possibility of tripping both sets of reserves simultaneously raises issues regarding the Block Sale contract's penalty payments for exceeding the event magnitude limit. APAC Ex. Brief, R-PA-01, at 22. The draft ROD did not address this argument specifically because the argument depends on the assumption that BPA would in fact trip both sets of reserves simultaneously. As explained in the draft ROD and reiterated here, this prospect is so remote that it raises no meaningful rates issues.

For the above reasons, it is an extremely remote possibility that BPA would need to trip Intalco for both stability reserve schemes at the same time. Therefore, BPA is not paying for the same reserves twice. Intalco faces the prospect of being tripped for two entirely unrelated sets of contingencies and is entitled to compensation for its additional risk.

Decision

BPA will compensate Intalco Aluminum Corporation for providing Bellingham area stability reserves through a credit to Intalco's power rate. Intalco faces exposure to being tripped for two unrelated stability reserves schemes and is entitled to compensation for its additional risk.

Issue 7

Whether the value of stability reserves includes the cost of constructing an alternative load-tripping scheme.

Parties' Positions

APAC argues that the value of the stability reserves scheme includes only the compensation BPA would have to pay to non-DSI customers to obtain their agreement to be tripped. APAC asserts that BPA has added a redundant component by also including the cost of constructing an alternative load-tripping scheme capable of tripping non-DSI customers. APAC Brief, WP/TR-96-B-PA-01, at 21. The DSIs argue that the value of the reserves includes the cost of constructing the alternative scheme, since without the scheme the cost to the customers would be substantially greater than the assumed compensation. DSI Brief, WP-96-B-DS-01, at 33.

BPA's Position

BPA argues that the reserves valuation is intended to measure the alternative cost BPA would incur if the DSIs did not provide reserves, and that part of this cost includes the construction of an alternative load-tripping scheme. Kreipe, *et al.*, WP-96-E-BPA-109, at 2.

Evaluation of Positions

BPA values the DSI reserves by calculating the cost of the least-cost alternative, assuming that the DSI reserves are unavailable. BPA currently obtains stability reserves through its right to trip the DSI load. BPA assumed that the least-cost alternative for stability reserves was an alternative load-tripping scheme that tripped customers other than the DSIs. BPA valued this scheme by the cost of constructing and maintaining it and the cost of compensating the customers who would be hooked up to it. Kreipe, *et al.*, WP-96-E-BPA-78, at 2.

APAC argues that the valuation should include only the cost of compensating the customers who would be hooked up to the scheme. APAC suggests that this cost fully compensates those customers for their cost of interruption, and that the cost of constructing and maintaining the scheme is a "redundant component." Wolverton, WP-96-E-PA-03, at 2.

APAC's argument turns the stability reserve valuation on its head. APAC argues that because the assumed compensation "fully compensates [the] customers" for the cost of interruption, a "rational consumer" would pay no more than this for protection. *Id.* APAC confuses the cost to the customer of being tripped with the value of the reserves to BPA. BPA, not the customer who is being tripped, is compensating the DSIs for their reserves; a "rational consumer" will pay the value it receives for a product. This value is the full cost BPA avoids by not having to install an alternative stability reserves scheme. *See* Kreipe, *et al.*, E-BPA-109, at 2.

In its brief on exceptions, APAC argues that it is not rational to pay full value for a product; instead, a rational consumer will pay "as little as possible to obtain the product." APAC Ex. Brief, WP-96-R-PA-01, at 20. APAC then repeats its argument (without addressing the draft ROD's rebuttal of the argument) that BPA is paying ten times the actual value of the reserves. *Id.*

In its initial brief, APAC argued that the "total value" of the reserves is $.61 million, and concluded that "a rational consumer would pay no more than that for protection [from system disturbances]." APAC Brief, WP/TR-96-B-PA-01, at 21. When it wrote its initial brief, therefore, APAC apparently believed that paying full value for a product <u>was</u> rational. In addition, as BPA has already pointed out, the electricity market is quite competitive, and the DSIs have a wide choice of suppliers. In a competitive market, BPA cannot expect to retain the DSI load without paying full value for the reserves. *See supra* Issue 1; *see also supra* § 8.2.2. Therefore, full value <u>is</u> the lowest possible payment for the reserves.

BPA employs the same basic method for valuing forced outage reserves. BPA values forced outage reserves by the cost of constructing and maintaining a combustion turbine (CT) as the alternative to the DSI reserves. Neal, *et al.*, WP-96-E-BPA-24, at 3. This is the cost BPA would incur it if did not have access to the DSI forced outage reserves; hence it represents the value of the reserves to BPA. APAC has not challenged this methodology. (On an entirely different basis, it challenges BPA's use of a CT to value forced outage reserves. *See infra* Issue 8.) For purposes of the methodology, however, there is no distinction between forced outage reserves and stability reserves. Thus, for example, if BPA concluded that the least-cost alternative to the DSI stability reserves was also a CT (as the DSIs argue), the question of compensation would not even arise. It arises here only because BPA concluded that the least-cost alternative to DSI stability reserves was an alternative load-tripping scheme; therefore, part of the cost BPA would incur for the alternative scheme is compensation to other customers.

Thus, the cost of constructing and maintaining the alternative system is not redundant. Instead, it is integral to BPA's ability to trip other customers, just as the existing load-tripping equipment is integral to BPA's ability to trip the DSIs. If BPA did not construct the alternative scheme, there would be no compensation to pay the other customers because BPA would have no load-tripping capability. Kreipe, *et al*., E-BPA-109, at 2.

In its initial proposal, BPA proposed an alternative load-tripping scheme without assuming the payment of compensation. BPA based the valuation on the cost of constructing and maintaining the scheme. Neal, *et al*., E-BPA-24, at 10. APAC testified that "BPA has done an adequate job in defining and valuing stability reserves." Wolverton, WP-96-E-PA-01, at 17. In its Supplemental Proposal, BPA included an assumed level of compensation. This assumption does not make the cost of construction redundant. If BPA did not include the cost of construction, the assumed compensation would have to be much higher. In the event of a transmission outage, load tripping prevents system separations and loss of load and generation, and helps to re-establish the energy balance in the Pacific Northwest. If a load-tripping system were not in place, the consequences of an outage of the system would be far more severe. Neal,*et al*., E-BPA-24, at 5-7. An outage could cut off much of the power in the Northwest, while restoration of service could take a significant amount of time. Schoenbeck and Bliven, WP-96-E-DS-12, at 4. The compensation assumed in BPA's stability reserves scheme was for a controlled interruption of 30 minutes or less, not for an uncontrolled outage of indefinite duration. Kreipe, *et al*., E-BPA-78, at 6; Kreipe, *et al*., E-BPA-109, at 4. APAC mistakenly assumes that the required amount of compensation would not change even if BPA did not construct an alternative stability reserves scheme and thereby placed its customers at far greater risk. APAC has presented no evidence of the compensation that customers would require in such case.

Finally, if BPA failed to construct an alternative scheme it would not meet either BPA or WSCC Reliability Criteria for the transmission system. Therefore, such an alternative would be unacceptable.

Decision

The appropriate valuation of the DSI stability reserves includes the cost of constructing and maintaining an alternative stability reserves scheme and the cost of compensating customers who would be hooked up to that scheme. These costs represent the cost BPA would incur if it did not have access to the DSI stability reserves, and therefore the value of the reserves to BPA. Moreover, the compensation BPA derived is for a controlled, short-term outage. It does not measure the compensation customers would require for an uncontrolled, indefinite interruption, such as would occur if no stability reserves scheme were in place. Finally, if BPA did not construct an alternative stability reserves scheme it would violate both BPA and WSCC Reliability Criteria.

Issue 8

Whether BPA should base the valuation of DSI forced outage reserves on the cost of a combustion turbine.

Parties' Positions

APAC argues that BPA has overvalued the forced outage reserves it obtains from the DSIs because they are less flexible and valuable than a combustion turbine (CT). APAC Brief, WP/TR-96-B-PA-01, at 24. The DSIs argue that, under the 1996 Power Sales Contracts, BPA receives all the forced outage reserves it requires, and therefore it is appropriate to base their value on the cost of a CT. DSI Brief, WP-96-B-DS-01, at 32-33.

BPA's Position

BPA argues that the forced outage reserves it obtains from the DSIs under the 1996 Power Sales contracts are at least as flexible and valuable as a CT. Therefore, it is appropriate to base their value on the cost of a CT. Kreipe, *et al*., WP-96-E-BPA-53, at 12-13.

Evaluation of Positions

BPA bases its valuation of DSI reserves on the cost of the least-cost alternative for providing non-spinning operating reserves, assuming that the DSIs reserves are unavailable. BPA has based its valuation of the DSI forced outage reserves on the cost of a combustion turbine as the least-cost alternative. Neal, *et al*., WP-96-E-BPA-24, at 3. In September 1995 BPA entered into new Power Sales contracts with the DSIs. Deliveries of power under the contracts are expected to begin October 1, 1996. APAC argues that the reserves the DSIs provide under these contracts are less flexible and valuable than a CT, and therefore that BPA has overvalued them. Wolverton, WP-96-E-PA-01, at 18.

APAC's arguments reveal a misunderstanding of both BPA's reserve needs and the way in which a CT must be operated in order to provide reserves. APAC argues that the Power Sales contract contains certain limitations on the reserves that would not apply to a CT, including a limitation on the duration of load interruptions and the reinstatement of load interruptions; a required tracking of events; a limit on the amount of reserves available to half of the Federal load; and a requirement that BPA use all other reserves before tripping the DSIs. *Id.* at 19-20; APAC Brief, B-PA-01, at 24. None of these provisions affects the value of the reserves to BPA.

Under the Power Sales contract, DSI reserves are available for up to 90 minutes. Kreipe, *et al.*, E-BPA-53, at 14; *see also* Wolverton, WP-96-E-PA-03, Attachment 1, § 17(a)(3). BPA's reserve obligation is defined by the Northwest Power Pool (NWPP) Operating Reserve Sharing Program. Under this program, the maximum time that BPA should need access to operating reserves is 60 minutes. Kreipe, *et al.*, E-BPA-53, at 14. Therefore, the DSI reserves provide all the access BPA needs in order to recover from system disturbances. *Id.*

In its brief on exceptions, APAC argues that, because BPA concluded only that it "should" need access to reserves for a maximum of 60 minutes, there is a "very real possibility" that BPA will encounter the limitations in the contract. APAC Ex. Brief, WP-96-R-PA-01, at 23 n.30. As with its argument regarding the Bellingham area reserves, *see* Issue 6, APAC again argues that BPA's ratemaking should take account of any situation that is not impossible. This is not a reasonable way to set rates. BPA must base its rates on reasonable probabilities, not remote possibilities.

Moreover, that something may not be impossible does not mean that it is a "very real possibility." As BPA has explained, under the NWPP Operating Reserve Sharing Program BPA needs access to forced outage reserves for up to 60 minutes. The DSI reserves are available for 90 minutes before the contractual limitations apply. Thus, BPA concluded that "the DSIs provide the full access required by BPA in order to recover from system disturbances." Kreipe, *et al.*, E-BPA-53, at 14. APAC has not challenged this conclusion or BPA's reliance on the requirements of the NWPP program. Nor has it presented any evidence that BPA is likely to encounter the limitations in the contract; instead, it has seized on BPA's use of the word "should" in one sentence to make its entire case. That case is not supported by evidence in the record.

Similarly, the delay in reinstatement of interruptions does not diminish the value of the reserves to BPA. After BPA interrupts the DSI load for reserves, in certain cases BPA must pay a use fee for additional interruptions within a certain time period. However, BPA may interrupt the DSI load for 90 minutes without payment of the fee. Since this time period is the maximum for which BPA would need the reserves, the requirement of an additional fee thereafter does not diminish the value of the reserves to BPA. Kreipe, *et al.*, WP-96-E-BPA-109, at 2-3. As stated in the contracts, the additional fee is for liquidated damages in the event of damage to the DSI plant because of the interruptions. Wolverton, E-PA-03, Attachment 1, § 17(c)(5). Therefore, they are not payments for the reserves themselves, but for damage in the event that an outage exceeds the maximum reserve limit. Kreipe, *et al*., E-BPA-109, at 2-3. Once the outage exceeds this limit, the outage is no longer a reserve. *Id.*

APAC next cites the requirement that BPA keep records of its usage of reserves. This is merely an administrative matter regarding the implementation of the Power Sales contract. It does not limit the availability of the reserves to BPA, nor in any way reduce their value. Kreipe, *et al*., E-BPA-53, at 14.

The limitation of the reserve amount to half of the Federal load simply quantifies the amount of reserves for which BPA is compensating the DSIs. Under the contract, the DSIs provide BPA with reserves equal to 50 percent of their energy purchases. Therefore, contrary to APAC's assertion that BPA has no assurance of how much reserve it is buying, BPA is assured of obtaining reserves equal to 50 percent of the energy delivered under the contract. The reserve credit is based on this figure regardless of the actual amount provided in megawatts. Since the credit is embodied in the DSI rate, if the DSIs reduce their power purchases, they receive a corresponding reduction in the value of reserves credit. They will receive no credit for power not purchased. *Id.* at 15.

APAC next argues that the DSI reserves are less valuable than a CT because, under the Power Sales contract, BPA must use all other available operating reserves before using the DSI reserves. Wolverton, E-PA-01, at 20. As a technical operational matter, however, the order in which reserves are accessed does not affect their value. Their value to BPA lies in their being available when BPA needs to utilize them, and the DSI reserves are continuously available. Kreipe, *et al*., E-BPA-53, at 17.

Moreover, under the NWPP Operating Reserve Sharing Program, which APAC never cites, utilities are required to use all other reserves before either starting a CT or tripping load in order to provide reserves. Therefore, BPA would use the CT for reserves at the same point in its response to a system disturbance that it uses the operating reserves provided by tripping the DSI load. *Id.* In this regard, there is no distinction between the two sources of reserves.

APAC next argues that a CT is more valuable than the DSI reserves because it stands ready for service year round, except for its annual maintenance outage. Wolverton, E-PA-01, at 18. APAC adds that the CT can provide standby energy capability, and even operate for months or years on end to serve load. *Id.* at 20-21. Both of these assertions are incorrect. A CT is standing ready for service only if it is ready to ramp to its maximum generation level within 10 minutes. Kreipe, *et al*., E-BPA-53, at 15. As APAC acknowledges, however, CTs must be taken out of service periodically for maintenance, during which time they are unavailable as a reserve. In addition, they must be periodically tested to ensure their ability to operate. During the testing, the portion of the CT providing energy is unavailable as operating reserve. Finally, a CT is subject to equipment failure, making it useless as a reserve until it is repaired. DSI reserves, by contrast, are never out of service, and BPA's methods for tripping DSI load ensure its continual availability as a reserve. *Id.* at 15-16. The DSIs must stand by to be tripped at all times during the year. *Id.* at 19; Schoenbeck, Bliven, WP-96-E-DS-03, at 20. Therefore, DSI load tripping is more reliable as a reserve than a CT.

Moreover, a CT being used for non-spinning operating reserve cannot provide standby energy or be used to serve load. The CT cannot simultaneously generate energy and provide reserves. It must be running to provide energy, and must be idle to provide reserves. Kreipe, *et al.*, E-BPA-53, at 16. Therefore, if BPA uses the CT as a source of standby energy, it sacrifices the operating reserve capability of the unit. Use of the CT for any purpose other than providing reserves would make it unsuitable to provide reserves. If it is operated "for months or years on end," as APAC suggests, it is valueless as a reserve. *Id.* at 18.

In its brief on exceptions, APAC again asserts that a CT offers standby energy capability, an advantage "the Draft ROD does not refute." APAC Ex. Brief, R-PA-01, at 24. To the contrary, the two paragraphs immediately above, which also appeared in the draft ROD, refute this argument. APAC adds, however, that BPA's rebuttal "fails to realize that the CT can be used to provide interruptible power that is available for reserves while still generating revenues from power sales." *Id.* BPA failed to rebut this assertion because it is an evidentiary argument regarding the capabilities of a CT that APAC raises for the first time in its brief on exceptions. Had APAC intended to establish that a CT can provide reserves in this manner, it should have made the argument in its testimony. It is not possible to resolve this factual issue at this point in the case.

In any case, the fact that power is interruptible does not mean that it is available for reserves. Nonfirm power is interruptible but is unavailable for use as reserves. Even if it were appropriate to raise new evidentiary arguments in a brief, APAC has failed to make its case.

APAC's arguments raise technical issues regarding the operation of the power system. In its testimony BPA rebutted all of these arguments, and APAC did not respond to BPA's rebuttal. Instead, APAC's brief repeats the arguments in its direct testimony as if BPA's rebuttal testimony did not exist. APAC's failure to respond to BPA's testimony is especially noteworthy in that BPA's testimony was sponsored in part by three BPA engineers, one of whom works in System Operations and has responsibility for determining and implementing system operations policies regarding operating reserves. *See* Phillips, WP-96-Q-BPA-45; Kreipe, WP-96-Q-BPA-49; Smiley, WP-96-Q-BPA-50. Thus, for example, BPA's analysis is based in part on the requirements of the Northwest Power Pool Reserve Sharing Program, a program APAC never mentions.

Next, APAC argues that the CT would provide BPA locational benefits. According to APAC, BPA could use a CT in the Puget Sound area at a time when it could not interrupt a DSI in that area, as long as BPA had "less useful" reserves elsewhere. Wolverton, E-PA-01, at 20. This argument is incorrect. First, there are no locational benefits associated with a CT. The sole purpose of operating reserves is to re-establish the load/resource balance within a control area. Therefore, operating reserves are required and utilized strictly on a control area basis. No location within the control area is better than any other location for the source of the reserves. Kreipe,*et al.*, E-BPA-53, at 17-18. Moreover, APAC does not explain what "less useful" reserves are. Finally, as noted above, if BPA were using a CT for reserves instead of load tripping, the NWPP Criteria would require it to access the CT for reserves only after it had used all other available reserves. Therefore, even if reserves did provide locational benefits, BPA would not have the discretion APAC mistakenly assumes it would have.

Next, APAC argues that BPA itself has acknowledged the superiority of a CT to the DSI reserves. APAC cites the 1995 Pacific Northwest Loads and Resources Study (White Book), in which BPA noted that the DSI reserves were removed from Federal system loads and resources balances because "the duration of the DSI real-time operating reserves is much less than the 50-hour per week duration used in capacity loads and resources planning." Wolverton, E-PA-03, at 6-7. Here APAC has confused planning reserves and non-spinning operating reserves. Planning reserves listed in the White Book cover contingencies that occur years or months before delivery, up to a week or so before delivery. They are needed in case a planned generating unit that is either new or coming back from major rehabilitation is not available for service when planned. Kreipe, *et al.*, E-BPA-109, at 3.

Operating reserves are needed when a generating facility unexpectedly fails to perform or is shut down for emergency reasons. Neal,*et al.*, E-BPA-24, at 2. They are needed only for events that occur during the hour of delivery. Therefore, the 50-hour per week criterion in the White Book is important for planning reserves, but is not a requirement for non-spinning operating reserves. Kreipe,*et al.*, E-BPA-109, at 3-4. The White Book distinguished planning reserves from the "DSI real-time operating reserves." The operating reserves BPA obtains from the DSIs, just like the reserves it would obtain from a CT, are needed in "real time"; that is, immediately upon a system disturbance. *See* Kreipe, *et al.*, E-BPA-53, at 16. The planning reserves listed in the White Book are needed to cover contingencies over a much longer time period; hence the 50-hour per week criterion.

Finally, APAC argues that the DSI reserves are available only for two hours a week, and therefore the reserves credit should be reduced by a ratio of 2/168. Wolverton, E-PA-01, at 22. This argument also reveals a misunderstanding of the purpose of operating reserves in the power system. The value of the reserve lies in its availability to be used in times of system disturbance; the DSIs are providing BPA with reserves by standing ready to be tripped. As noted above, they are obligated to stand ready to be tripped for reserves at all times. Moreover, under the contract BPA can trip the DSIs at any time. Therefore, no reduction in the reserves credit is justified. Kreipe,*et al.*, E-BPA-53, at 19.

BPA testified that in some ways the DSI reserves are more valuable than a CT. As noted earlier, a CT periodically must be tested or taken out of service for maintenance, during which time it is unavailable as reserve. The DSI reserves are continually available. In addition, under BPA operational criteria, operating reserves must be accessed within ten minutes of a system disturbance. Under the DSI contract, the DSI load must be off-line within five minutes of notification. Therefore, the BPA dispatcher has the first five minutes after a disturbance to take action to resolve the situation before committing to trip DSI load. A combustion turbine, however, takes approximately ten minutes to start and ramp to full capacity. Therefore, the BPA dispatcher would have to decide immediately whether to commit to the CT in recovering from a system disturbance. This inability to wait five minutes before committing a CT would severely limit the flexibility of the options available to the BPA dispatcher and could drastically increase the frequency with which the dispatcher would have to call upon operating reserve in response to an actual system disturbance. *Id.* at 16.

Decision

BPA will base the valuation of the DSI operating reserves on a CT. The DSI reserves are at least as valuable and flexible as reserves obtained from a CT. The provisions in the new DSI Power Sales contract do not in any way reduce the value of the reserves to BPA.

Issue 9

Whether BPA should compensate the DSIs for stability reserves through a credit to the IP rate.

Parties' Positions

APAC argues that BPA should compensate the DSIs for stability reserves through a reservation fee, which can be paid in the form of a credit to the DSIs' power rate, and a separate use fee paid when the reserves are used. APAC argues that this method of payment would avoid BPA's having to make complex calculations to project the expected use of the reserves. In addition, APAC argues that this method would avoid payment of a use fee to Columbia Falls Aluminum Company (CFAC), whose reserves are largely unavailable because of CFAC's location. APAC Brief, WP/TR-96-B-PA-01, at 26-27.

BPA's Position

BPA has applied the full value of reserves as a credit to the DSIs' power rate, as it has done in all prior rate cases. BPA cites the Northwest Power Act's requirement that the Administrator adjust the DSIs' rates to take into account the value of reserves. Kreipe, *et al.*, WP-96-E-BPA-53, at 13.

Evaluation of Positions

Section 7(c)(3) of the Northwest Power Act provides that "[t]he Administrator shall adjust [the DSIs'] rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers." 16 U.S.C. § 839e(c)(3). Pursuant to this legislative direction, in every rate case since passage of the Northwest Power Act the Administrator has adjusted the DSI rate to take into account the value of the DSI reserves. BPA has made the same adjustment in this case.

BPA's action accords with the Northwest Power Act's direction. Nevertheless, APAC argues that, instead of crediting the DSIs with the full value of reserves, BPA should credit them with a minimal reservation fee for equipment installation and training, and pay separately for use of the reserves when DSI loads are tripped. Wolverton, WP-96-E-PA-01, at 22-23; Wolverton, WP-96-E-PA-03, at 3. According to APAC, this methodology would solve two problems. First, it would avoid a set of "complex calculations" BPA has made to estimate usage of the reserves. Wolverton, E-PA-03, at 3. Second, it would avoid BPA's paying CFAC for stability reserves that, according to APAC, are of diminished value to BPA. Wolverton, E-BPA-01, at 22-23.

Neither of APAC's rationales is persuasive. The calculations BPA made to estimate usage of the reserves are no more complex than any number of other calculations BPA must make in a rate case, and a good deal less complex than most. They are based on only three variables. The first two concern usage of the Southern Intertie, and are based on data BPA keeps as part of its normal operation of the system. Based on six years of data, BPA determined that the Intertie is loaded above 1,600 MW (the level at which stability reserves are needed) two percent of the time. Kreipe, *et al.*, WP-96-E-BPA-78, at 10. Based on 17 years of data, BPA determined that the Intertie experiences an average of 3.4 bipole outages per year. *Id.* Neither of these figures was an extrapolation or an estimate.

The third variable is the amount of load BPA would expect to be tripped in a load-tripping event. The data demonstrate that, when the Intertie is loaded above 1,600 MW, the average loading is 1,893 MW. BPA Operations Standing Order No. 301, Pacific DC Intertie Remedial Action Schemes, requires that 1,000 MW of load be tripped for an outage when the Intertie is loaded between 1,800 and 2,000 MW. *Id.* at 10-11. Therefore, BPA assumed that 1,000 MW would be tripped.

From these three variables, BPA was able to calculate the appropriate level of compensation for load tripping. The calculation is based on credible data collected in the normal course of business and a reasonable estimate of the amount of load that would be tripped. Significantly, APAC did not offer any evidence challenging BPA's valuation. Instead, APAC testified that it would not challenge BPA's calculation of the appropriate compensation amount, and that it accepted the calculation for the purposes intended. Wolverton, E-PA-03, at 2. Although, in the same breath, APAC claimed that it neither agreed nor disagreed with the calculation, APAC implicitly accepted the validity of the result by arguing that the compensation BPA derived is the appropriate valuation of the DSI stability reserves. *Id.*; *see also supra* Issue 7.

APAC's second argument is that, if BPA adopts APAC's methodology, it will avoid having to compensate Columbia Falls Aluminum Company for reserves. According to

APAC, CFAC's reserves are of diminished value to BPA because they are geographically isolated. Wolverton, E-PA-01, at 22. BPA has already rebutted this argument. *See supra* Issue 8. As BPA has demonstrated, the location of reserves within a control area is irrelevant. Therefore, the reserves CFAC provides are as valuable to BPA as any other DSI reserves. Kreipe, *et al*., E-BPA-53, at 17-19.

In its brief on exceptions, APAC claims that the draft ROD did not rebut its argument that APAC's suggestion would avoid the need for complex calculations. APAC asks the rhetorical question, "Why make complex calculations when they are unnecessary?" APAC Ex. Brief, WP-96-R-PA-01, at 25. This question assumes a premise that the draft ROD, and the final ROD, both rebut: that the calculations are in fact complex. APAC's argument pretends that BPA's calculation of the compensation is fraught with difficulty. Yet neither in testimony nor in either of its briefs has APAC challenged a single element of BPA's calculation. Instead, APAC simply asserts that because of its "complexity" the calculation should be abandoned. As demonstrated above, the calculation is straightforward, which may explain APAC's failure to challenge it.

APAC also asserts that the draft ROD contained "absolutely no refutation" of APAC's argument that DSIs that do not provide reserves should not be compensated. *Id*. To the contrary, the draft ROD pointed out, in a paragraph that is repeated above, that all the DSIs provide reserves. Therefore, all are entitled to compensation. As the draft ROD noted, APAC's argument is based on the false premise that Columbia Falls Aluminum Company is so isolated from the rest of the BPA system that its reserves are of diminished value to BPA. BPA engineers testified that, because the only purpose of reserves is to establish the load/resource balance within a control area, the location of the reserves within the control area is irrelevant. *See supra* Issue 8. In its brief on exceptions, APAC asserts, without supporting evidence or argument, that this conclusion "belies logic." *Id*. at 26. Instead of presenting contrary evidence or argument, APAC simply asserts that the BPA engineers must be wrong. BPA's testimony, however, is persuasive.

APAC argues that the "minimal" reservation fee included as a credit to the DSI rate should include the cost of installation of necessary equipment and training. Wolverton, E-PA-01, at 22; Wolverton, E-PA-03, at 3. The second part of the compensation would consist of the use fee for the reserves when load is tripped. Wolverton, E-PA-01, at 23; Wolverton, E-PA-03, at 3. APAC has presented no evidence regarding the level of these two fees, nor has it challenged BPA's evidence. Based on BPA's evidence, APAC's logic leads to only one possible conclusion. BPA has separately calculated the cost of construction of the reserves scheme ("installation" in APAC's phrase) and the cost of compensation for use. Kreipe, *et al*., E-BPA-78, at 2-11. Under APAC's own logic, the reservation fee would consist of the construction costs; the compensation of $.61 million would be the use fee. The reservation fee would not be the "minimal" fee APAC suggests, but would be the construction and maintenance costs that are approximately 90 percent of the cost of the scheme. Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, Appendix B, at B-12. Therefore, even if APAC had presented persuasive reasons in behalf of its methodology, the credit to rates would decline only slightly.

APAC does make one argument regarding the appropriate amount of the reservation and use fees. APAC cites the reservation and use fee contained in a General Transmission Agreement that BPA has executed with its DSI customers for the transmission of non-Federal power. Wolverton, E-PA-03, at 3. Without analysis or evidence, APAC concludes that the fees in that agreement would be more appropriate than BPA's proposal. *Id.* at 3-4. As noted above, however, APAC offered no challenge to any of BPA's calculations of the value of stability reserves, nor did APAC present any contrary evidence.

The record contains no evidence of how the reservation fee and use fee contained in the General Transmission Agreement were derived. Any agreement, particularly one as significant and complex as this one, is the product of extended and complicated negotiations that inevitably include tradeoffs to reach an accommodation. It is impossible to know from this record why the parties reached the result they did, or what compromises may have been involved in reaching final agreement. The General Transmission Agreement covers the DSIs' purchase of non-Federal power for wheeling over BPA's transmission system. The purpose of the reserves valuation in the rate case is to compensate the DSIs for the reserves they provide with their Federal power. These separate sets of reserves are unrelated and cannot, without evidence, simply be assumed to be equivalent. This is especially so when, in the rate case, BPA has presented a detailed stability reserves valuation that no party has challenged.

Finally, APAC argues that BPA has predetermined this issue by signing power sales contracts with the DSIs in which BPA agreed to credit the DSI rate with the reserve valuation. APAC Initial Brief, WP/TR-96-B-PA-01, at 27. This argument assumes that the method of compensation is a rate case issue. As noted above, however, section 7(c)(3) of the Northwest Power Act states that the Administrator <u>shall</u> adjust the DSI rates to take into account the value of reserves the DSIs provide. 16 U.S.C. § 839e(c)(3). The rate case is the appropriate forum for valuing those reserves. BPA has taken care to rebut APAC's arguments. Nevertheless, the means of payment (assuming the Northwest Power Act does not require a credit) is a business and administrative matter. BPA is not compelled to determine in the rate case whether a credit is the appropriate means of payment.

<u>Decision</u>

BPA will credit the DSI power rate with the full value of the stability reserves they provide. APAC's arguments for applying a reservation fee and use fee are not persuasive.

<u>Issue 10</u>

Whether BPA should allocate the costs of the Bellingham area stability reserves to users of the Northern Intertie.

Parties' Positions

APAC argues that the costs of the Bellingham area stability reserves should be borne by users of the Northern Intertie because the reserves do not protect local load but instead support the transmission system, particularly transfers to and from British Columbia. APAC Brief, WP-96-B-PA-01, at 22. The DSIs argue that the costs of the Bellingham area stability reserves are properly borne by BPA's power users. They maintain that the Bellingham area stability reserves enable BPA to engage in storage transactions that benefit BPA's power customers. They also argue that the reserves do not benefit transmission customers importing power across the Northern Intertie. DSI Brief, WP-96-B-DS-01, at 35.

BPA's Position

BPA includes the costs of the Bellingham area stability reserves in its BPA Program Costs. Documentation for Supplemental Wholesale Power Rate Development Study, Part 1 of 2, WP-96-E-BPA-61A, at 179-183, column F, row 21. These costs are allocated to power users. *Id.* at 186. Technical studies show that Intalco load tripping is needed only for an outage of both Custer-Monroe lines when power is flowing south to north on the Northern Intertie. Kreipe, *et al.*, WP-96-E-BPA-53, at 7.

Evaluation of Positions

APAC argues that, according to BPA's rebuttal testimony, the Bellingham area stability reserves are needed to provide support for transfers "to and from" British Columbia not directly related to BPA service to native load. Wolverton, WP-96-E-PA-03, at 5. In its rebuttal testimony, however, BPA stated that the reserves are needed only for south-to-north power flows. Kreipe, *et al.*, E-BPA-53, at 7. BPA needs the Bellingham area reserves when it is in surplus hydro conditions and is storing excess power in Canada. Kreipe, *et al.*, WP-96-E-BPA-109, at 2. As the DSIs point out, BPA's power customers gain the benefit of these storage transactions. Schoenbeck, Bliven, WP-96-E-DS-12, at 7. To avoid spilling power when it is in surplus, BPA stores power in Canadian reservoirs for use at a later time. Although the Bellingham reserves are not "directly" related to service to native load, the benefits flow to native load customers. Therefore, it is appropriate to allocate the cost of the reserves to the power customers.

Decision

BPA will allocate the costs associated with the Bellingham area stability reserves to the power customers. Because the reserves are needed when BPA is storing excess power in Canada for later use, power customers are the beneficiaries of the reserves.

8.4 DSI Floor Rate Calculation

In testimony, the DSIs stated that the exclusion of delivery charges from the Industrial Firm Power (IP) rate used in the DSI floor rate test was an error, because delivery charges were included in the floor rate. The DSIs recommended that BPA either include delivery charges in the IP rate, or exclude them from the floor rate. The DSIs added that it would be more appropriate to exclude delivery charges from the floor rate since delivery charges under the proposed IP rate are not necessarily based on the amount of power purchased from BPA. Schoenbeck, *et al.*, WP-96-E-DS-08, at 9. BPA agreed that delivery charges were inadvertently excluded from the IP rate used in the DSI floor rate test. For the final rate proposal, BPA said that it would include delivery charges in the IP rate comparable to those included in the DSI floor rate. Keep, *et al.*, WP-96-E-BPA-113, at 2. The DSIs did not pursue this issue on brief. Therefore, the issue is waived. *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.13(b), 51 Fed. Reg. 7611 (1986).

Issue

Whether the DSI floor rate should be reduced by the amount of the revenue deficiency associated with sales of surplus firm power sold at less than fully allocated cost and included in the IP-83 rate.

Parties' Positions

The DSIs argue that the revenue deficiency associated with the sales of surplus firm power was included in the floor rate in the 1985 rate case because the Administrator was unable to conclude that the deficiency would decline during the 1986-87 rate period. Because BPA no longer projects a surplus firm power revenue deficiency, it should exclude the costs associated with the deficiency from the floor rate. DSI Brief, WP-96-B-DS-01, at 5.

BPA's Position

BPA concluded that, because the proposed IP rate was above the floor rate, it was unnecessary to consider adjustments to the floor rate. Keep, Revitch, WP-96-E-BPA-89, at 5.

Evaluation of Positions

Because the Industrial Firm Power (IP) rate meets the floor rate test, it is unnecessary to address adjustments to the floor rate in this rate case. Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, at 24-25. Nevertheless, the DSI proposal will be addressed briefly.

Under section 7(c)(2) of the Northwest Power Act, the Administrator bases the IP rate on the applicable wholesale rate to BPA's public body and cooperative customers and the typical margins included by such customers in their retail industrial rates. 16 U.S.C. §

839e(c)(2). In no event, however, are the rates to be less than "the rates in effect for the contract year ending on June 30, 1985." *Id.* This provision establishes the DSI floor rate.

Each rate case, a floor rate test is performed to determine whether the proposed IP rate is below the floor rate. BPA first applies the 1983 IP rate to test year DSI billing determinants to calculate revenues at the floor rate. BPA then calculates expected revenues applying the proposed IP rate to test year DSI billing determinants. If expected revenues at the proposed IP rate are less than revenues at the floor rate, the IP rate is increased so that it recovers floor rate revenues. Supplemental Wholesale Power Rate Development Study, E-BPA-61, at 24-25.

BPA established the floor rate methodology in the 1985 rate case. An issue in that case was whether BPA should make adjustments to the IP-83 rates used to calculate the floor rate. The DSIs argued that BPA should reduce the floor rate by costs included in the IP-83 rate that were not expected to recur. The Administrator noted that "it is common ratemaking practice to review historical test year events to eliminate those that are nonrecurring or extraordinary when setting future rates." *Administrator's Record of Decision, 1985 Final Rate Proposal*, WP-85-A-02, at 185 [hereinafter *1985 Rate ROD*]. Therefore, the Administrator excluded from the floor rate a deferral that was included in the IP-83 rate because the deferral was "an unusual attempt by BPA to recover in its 1983 rates the unrecovered costs from previous rate filings." *Id.* at 187. Similarly, the Administrator excluded costs associated with the phase-in of BPA's new Average System Cost methodology because the phase-in was "also an unusual event that unduly affects the average 1983 DSI rate." *Id.* at 188. The Administrator refused to exclude the revenue deficiency associated with sales of surplus firm power because there was "no certainty that unrecovered costs of surplus power will decline." *Id.* at 189.

Thus, both standard ratemaking practice and BPA precedent suggest that nonrecurring costs should be excluded from the floor rate, as they are excluded generally when setting rates. For the upcoming rate period, BPA is projecting a slight revenue deficiency associated with the sale of surplus firm power. Supplemental Wholesale Power Rate Development Study, E-BPA-61, at 21. Given the level of the deficiency, it may be appropriate to make an adjustment in the floor rate. As WPAG has noted, the deficiency was much greater in prior rate periods. Bonneville included a $64.7 million deficiency in the floor rate calculation in 1985, and experienced an annual deficiency of $137 million in the 1986-87 rate period. Beck, *et al.*, WP-96-E-WA-11, at 41-42. BPA has not made an adjustment in this rate case, however, because the floor rate test has been satisfied.

Like all of the rate directives, section 7(c)(2) establishes a ratemaking standard that the Administrator applies to set future rates. As in all other rate-setting, the floor rate test is based on load and revenue projections made in the rate case. Tr. 902. BPA does not determine after the rate case has ended whether revenues in fact exceeded floor rate revenues. *Id.* at 903. For example, in the 1985 rate case BPA decided not to exclude the revenue deficiency from the floor rate because "BPA continues to forecast that not all surplus sales will be sold at the fully allocated costs." *1985 Rate ROD* 189. In the same case, Northwest Utilities (NWU) argued that BPA should include the costs of the deferral in the floor rate because it was possible for BPA to incur a deferral in any rate period. *Id.* at 187. The Administrator rejected this argument: "NWU is correct that the potential for incurring a deferral is always present. In normal practice, however, BPA does not assume it will have a deferral at the end of a rate period that will have to be recovered in subsequent rate periods." *Id.* Thus, BPA based the floor rate on projections made in the rate case. Projections in the 1996 rate case indicate that the floor rate test will be met at the proposed IP rate even if BPA makes the maximum likely sales to the DSIs under the Firm Power Products and Services (FPS-96) rate schedule. Tr. 903; *see also* Schoenbeck, Bliven, WP-96-E-DS-08, at 12-13 and Attachment 7. Therefore, the floor rate test is satisfied even if these additional sales are included.

Finally, to the extent that BPA sells power to the DSIs under the FPS rate schedule, those sales are not subject to the section 7(c)(2) rate directives. *See infra* § 11.7. Therefore, they are not subject to the floor rate test.

Decision

BPA will not address adjustments to the floor rate in this Record of Decision. The DSIs are correct that nonrecurring costs should be excluded from future rates, including the floor rate. The evidence indicates, however, that the floor rate test will be satisfied even if BPA makes additional sales to the DSIs under the FPS rate schedule. Furthermore, the floor rate does not apply to sales made under that rate schedule.

9.0 SECTION 7(b)(2) RATE TEST

9.1 **Introduction**

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 the 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 (or 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 (or Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (or 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 section 7(i) process culminated in the section 7(b)(2) Implementation Methodology Record of Decision. 7(b)(2) ROD, b-2-84-F-02. Issues regarding interpretation of the statute were resolved in the Legal Interpretation for Section 7(b)(2). 49 Fed. Reg. 23,998 (1984).

The parties have raised numerous issues regarding the section 7(b)(2) rate test. In particular, the IOUs present a number of *ad hominem* arguments accusing BPA of manipulating numerous issues in the 1996 rate case in order to achieve a 22.6 mills/kWh Industrial Firm Power (IP) rate and to eliminate the residential exchange program. MREP Brief, WP-96-B-GE/PL/PS-01, at 1. The IOUs argue that the first of BPA's "tactics" was to exclude from the rate case record the IOUs' testimony regarding BPA's failure to recover stranded costs. *Id.* at 2. BPA's response to this issue is contained in section 14.2 of this Record of Decision. The IOUs also argue that BPA then manipulated its study of the "typical margin" by reversing a prior decision to include revenue taxes in the margin. *Id.* BPA's response to this issue is contained in section 8.2 of this Record of Decision. The IOUs then argue that BPA manipulated the section 7(b)(2) rate test by deliberately making the rate test trigger through improper assumptions. *Id.* Some of these arguments include issues that are not resolved in conducting the section 7(b)(2) rate test, but rather constitute inputs to the test. BPA's response to the IOUs' arguments regarding DSI reserve benefits is contained in section 8.3 of this Record of Decision. BPA's response to the IOUs' arguments regarding the section 7(c)(2) adjustment is contained in section 7.3 of this Record of Decision. The remaining IOU arguments regarding the section 7(b)(2) rate test are addressed in the section below. These arguments include the suggestion that BPA has an irrevocably closed mind and pre-decisional bias that deprives MREP of the impartiality and fundamental fairness required by due process. MREP Brief, B-GE/PL/PS-01, at 8.

While the parties have raised many issues regarding the section 7(b)(2) rate test in their briefs, there are a number of issues raised by the parties during the hearing that were not raised in the parties' briefs. Pursuant to section 1010.13(b) of the Procedures Governing BPA Rate Hearings, arguments not raised in parties' briefs are deemed to be waived. Such issues will be implemented based on BPA's stated position in the record.

9.2 Background of the Residential Exchange Program and the Section 7(b)(2) Rate Test

In order to understand the context of the development of BPA's rates and the implementation of the section 7(b)(2) rate test, it is helpful to review the genesis of the residential exchange program and the rate protection afforded BPA's preference customers from potential excessive costs of that program.

BPA was established by the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. 832 *et seq*. After enactment of the Project Act, BPA marketed the low cost hydropower generated by Federal dams in the Pacific Northwest. While section 4(a) of the Project Act requires BPA to "give preference and priority to public bodies and cooperatives" when selling power, 16 U.S.C. 832c(a), BPA had sufficient power for many years to serve the needs of all customers in the region. These customers include public bodies and cooperatives, known as "preference customers" because of their statutory first right to Federal power under the preference clause noted above. *Id*. These customers also included investor-owned utilities (IOUs) and direct service industrial customers (DSIs). In 1948, the increasing demand for power caused BPA to require that contracts with the DSIs must include provisions to allow the interruption of service when necessary to meet the needs of BPA's preference customers. In the 1970s, forecasts showed that preference customers soon would require all of BPA's power. Therefore, in 1973, BPA gave notice that new contracts for firm power for IOUs would not be offered and that as DSI contracts expired between 1981-1991, the contracts were not likely to be renewed. In 1976, BPA advised preference customers that BPA would not be able to satisfy preference customer load growth after 1983, and would have to determine how to allocate power among preference customers.

While Federal appropriations were used in the construction of the Federal hydrosystem, Federal taxpayers ultimately did not pay these costs. The costs of the hydrosystem are repaid with interest over time by BPA's ratepayers through BPA's wholesale power revenues. Thus, BPA's ratepayers are the parties that paid the costs of the Federal hydrosystem, not Federal taxpayers. As BPA's supply of power became unable to meet regional demand, BPA's preference customers bore more and more costs of the Federal hydrosystem.

The high cost of alternative sources of power caused BPA's non-preference customers to attempt to regain access to cheap Federal power. Many areas served by IOUs moved to establish public entities designed to qualify as preference customers and be eligible for administrative allocations of power. Because the Project Act provided no clear way of allocating power among preference customers, and because the stakes involved in buying cheap federal power had become very high, the competition for administrative allocations threatened to produce contentious litigation. The uncertainty inherent in the situation greatly complicated the efforts by all BPA customers to plan for their future power needs. In order to avoid the prospect of unproductive and endless litigation regarding access to the Federal power marketed by BPA, Congress enacted the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) in 1980. 16 U.S.C. 839 *et seq*.

The Northwest Power Act expressly reaffirmed the right of BPA's preference customers to first call on Federal power before such power could be offered to BPA's investor-owned utility or DSI customers. 16 U.S.C. 839g(c). The Act also established the residential exchange program. 16 U.S.C. 839c(c). As noted above, when BPA had insufficient Federal power to meet the needs of investor-owned utilities in the 1970s, such utilities developed their own resources, which generally were more costly than Federal hydropower. The residential exchange program provides Pacific Northwest utilities a monetary form of access to low-cost Federal power. Under the program, Pacific Northwest utilities may sell power to BPA at a rate based on the utility's average system cost (ASC) of its resources. BPA is required to purchase that power and sell, in exchange, an equivalent amount of power to the utility at BPA's Priority Firm Power (PF) rate. This is the same rate that applies to BPA's sales of power to its preference customers, although the Act expressly provides that the PF rate for the residential exchange program may be higher than the PF rate for preference customers due to the section 7(b)(2) rate ceiling described below. 16 U.S.C. 839e(b)(3). Where a utility's ASC is higher than BPA's PF rate, the difference between the rates is multiplied by the utility's jurisdictional residential load to determine an amount of money that is paid to the utility as residential exchange benefits. These benefits are passed through directly to the utility's residential consumers through lower retail rates. Marshall, Burns, WP-96-E-BPA-44, at 5. The cost of providing these benefits to exchanging utilities is borne primarily by BPA's publicly owned utility and DSI customers, subject to the rate ceiling established in section 7(b)(2) of the Northwest Power Act, which, as discussed below, protects preference customers from excessive costs of the residential exchange program.

Numerous, complex tradeoffs were necessary in order to resolve the competing claims for BPA's low-cost hydropower in the late 1970s and in order to solve the electric power planning uncertainties facing the Pacific Northwest at that time. The provisions of the Northwest Power Act reflect the give and take of those tradeoffs. While the Act established the residential exchange program to provide utilities a monetary form of access to low cost Federal power, this access, or "share in the economic benefits" of Federal power, was expressly limited by a "rate ceiling" for preference customers to ensure that "[c]ustomers of preference utilities will not suffer any adverse economic consequences as a result of this exchange . . ." H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980); *see also* H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980); S. Rep. No. 272, 96th Cong., 1st Sess. 15 (1979).

The preference customer "rate ceiling" was established in section 7(b)(2) of the Northwest Power Act. Section 7(b)(2) provides that after July 1, 1985, the rates charged for firm power sold to public body, cooperative and Federal agency customers (exclusive of amounts charged those customers for costs specified in section 7(g) of the Act) may not exceed in total, as determined by the Administrator, such customers' power costs for general requirements if specified assumptions are made. In determining public body and cooperative customers' power costs for any rate period after July 1, 1985, and the ensuing four years, the following assumptions are made:

> (A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;
>
> (B) public body, cooperative and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;
>
> (C) no purchase or sales by the Administrator as provided in section 5(c) were made during such five-year period;
>
> (D) all resources that would have been required, during such five-year period , to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were (i) purchased from such customers by the Administrator pursuant to section 6, or (ii) not committed to load pursuant to section 5(b), and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional resources were obtained at the average cost of all other new resources acquired by the Administrator; and

> (E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from (I) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and (ii) reserve benefits as a result of the Administrator's actions under this Act were not achieved.

16 U.S.C. 839e(b)(2).

The legislative history of section 7(b)(2) of the Northwest Power Act repeatedly and consistently recognizes that residential exchange benefits are subject to elimination or reduction due to the section 7(b)(2) rate ceiling. The report of the House Committee on Interior and Insular Affairs states:

> Section 5(c) of S. 885 contains provisions for a residential power "exchange". Under these provisions, any utility in the region would be entitled to sell to BPA an amount of power equal to the utility's residential and small farm load at the "average system cost" of such power and BPA would be required to sell back to each such utility an equivalent amount of power at a rate identical to what preference customers pay BPA for power to meet their "general requirements" (<u>subject to a "rate ceiling</u>").
>
> . . . This exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region. <u>Consumers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since</u>, as discussed below, the direct-service industrial customers of BPA are required to pay the costs of the exchange during its initial years while <u>a "rate ceiling" protects the customers of preference utilities during later years</u>.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980)(emphasis added). The report reiterates this point:

> As an added protection against preference utilities and their customers suffering adverse economic consequences as a result of this legislation, section 7(b)(2) establishes a "rate ceiling" which is hypothetically intended to insure that these customers' rates will be no higher than they would have

> been had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this legislation.

Id. at 36. The report emphasizes this point yet again:

> Subsection 7(b)(2) establishes a "rate ceiling" for BPA's preference customers, and specifies the method of calculating this ceiling, in order to insure such customers the cost benefits of their preference rights for sales under this subsection. Amounts not recoverable from preference customers because of this ceiling are to be recovered through supplemental rate charges for all other power sold by BPA under other provisions of section 7, as subsection 7(b)(3) specifies.

Id. at 52.

This intent that the section 7(b)(2) rate ceiling would protect preference customers from certain costs of the Act, including the costs of the residential exchange program, is also contained in the report of the House Committee on Interstate and Foreign Commerce. The report states:

> In addition, section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed in the absence of this legislation. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could pay less--but not more-- for power under the legislation than they would have in any 5-year period.

H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980). The report also notes:

> Section 7(b)(2) establishes a "rate ceiling" for preference customers that seeks to assure these customers that their rates will be no higher than they would have been had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this Act. The assumption[s] to be made by the Administrator in establishing this ceiling are specifically set forth. It is through rate ceilings that this Act provides additional protection to public bodies and cooperatives' preference customers as to the price of the sale of power by the Administrator. In the event that this rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules.

Id. at 68-69.

The establishment of a rate ceiling for preference customers is also noted in the report of the Senate Committee on Energy and Natural Resources:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater than would occur in the absence of the regional program established in S. 885.

S. Rep. No. 272, 96th Cong., 1st Sess. 20 (1979). The report also states:

> Section 7(b).--This section establishes a rate or rates for electric power sold to meet the general requirements (defined in this section) of public body cooperative and Federal agency customers and utilities under section 5(b)(2); a rate test to limit the charges that may be recovered by such rates applicable to public body, cooperative and Federal agency customers after July 1, 1985; and a supplemental rate charge to recover any costs not recovered as a result of the rate test, to be applied through rates to all other power sales of the Administrator which are not limited by the rate test. The supplemental charge in any year should be based on a prospective 5 year average of the amount which the rate without the limit would differ from that as limited by the test rate.

Id. at 32. This is reiterated in Appendix B to the Senate report. *Id.* at 56-59, 61-62. The report expressly recognizes that one item that may cause the rate test to trigger is an increase in the cost of the residential exchange program. The report states:

> The rate limit would reinstate the yardstick principle which has traditionally been used to support the multiple kind of utility ownership which exists in the Pacific Northwest today. Other areas which appear to cause the rate limit to apply are slower preference customer load growth than IOU load growth, lower DSI loads, and <u>increased IOU exchange power costs</u>.

Id. at 62 (emphasis added).

In addition to section 7(b)(2) and its legislative history, section 5(c)(4) of the Northwest Power Act establishes that Congress was well aware that section 7(b)(2) could result in reduction or complete elimination of residential exchange benefits for utilities participating in the residential exchange program. Section 5(c)(4) provides:

> An electric utility may terminate, upon reasonable terms and conditions agreed to by the Administrator and such utility prior to such termination, its purchase and sale under this subsection if the supplemental rate charge provided for in section 7(b)(3) is applied and the cost of electric power sold to such utility under this subsection exceeds, after application of the

> rate charge, the average system cost of power sold by such utility to the Administrator under this subsection.

16 U.S.C. § 839c(c)(4). *See* S. Rep. 272, 96th Cong., 1st Sess. 15 (1979). In other words, the Northwest Power Act expressly contemplates that section 7(b)(2) could completely eliminate exchange benefits for utilities whose average system cost rate was less than BPA's PF Exchange rate.

Pursuant to section 7(b)(2), BPA was required to implement the rate test for the first time in BPA's 1985 rate case. Prior to the 1985 rate case, on January 23, 1984, BPA published in the Federal Register a notice of a proposed "Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act." 49 Fed. Reg. 2911 (1984). This Legal Interpretation was intended to resolve the basic legal questions involved in the implementation of section 7(b)(2). BPA received comments and reply comments from all customers and interested parties and published a final Legal Interpretation on May 31, 1984. The Legal Interpretation has been used by BPA in every rate case since 1985 and was used in BPA's 1996 rate case.

Because of the importance and complexity of the 7(b)(2) rate test, and in order to provide customers certainty as to how section 7(b)(2) would be applied, BPA conducted a special evidentiary hearing that lasted from February 29, 1984, to August 17, 1984, to establish a Section 7(b)(2) Implementation Methodology. On March 26, 1984, BPA published in the Federal Register a notice of the "Proposed Section 7(b)(2) Implementation Methodology, Public Hearings, and Opportunities for Public Review and Comment." 49 Fed. Reg. 11,235 (1984). BPA then conducted a formal evidentiary hearing on the methodology pursuant to section 7(i) of the Northwest Power Act. All of BPA's customers (public utilities, investor-owned utilities and DSIs) intervened in the proceeding, in addition to state and Federal agencies and other interested parties. Both written and oral discovery was conducted. Direct and rebuttal testimony was filed by BPA and all parties. The hearing officer presided over two days of cross-examination. Parties filed briefs with BPA and BPA reviewed and responded to the briefs in a draft 7(b)(2) Methodology. Parties then filed reply briefs. BPA issued a Record of Decision including a final 7(b)(2) Methodology on August 17, 1984. *See* Section 7(b)(2) Implementation Methodology, b-2-84-F-02. The 7(b)(2) Methodology prescribes in detail how the 7(b)(2) test is to be conducted. The Record of Decision and the 7(b)(2) Methodology address the major issues involving the implementation of section 7(b)(2), including reserve benefits, financing benefits, natural consequences, selection of a computer model, and the rate test trigger. The 7(b)(2) Methodology has been used by BPA in every rate case since 1985 and was used in the development of BPA's 1996 rate case.

Section 7(b)(3) of the Northwest Power Act governs the allocation of costs in the event the section 7(b)(2) rate test triggers. Section 7(b)(3) provides that "Any amounts not charged to public body, cooperative and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers." 16 U.S.C. 839e(b)(3). In other words, if the rate test triggers (*i.e.*, the rate ceiling for preference customers is exceeded), the costs in excess of the ceiling must be allocated to other power sales, including sales to utilities participating in the residential exchange program. These costs increase the PF Exchange rate, which is the rate at which BPA sells power to utilities participating in the residential exchange. When the PF Exchange rate increases, the difference between that rate and the utility's average system cost rate decreases, resulting in a reduction of residential exchange benefits paid to the utility. Because each exchanging utility's average system cost rate and residential load are different from those of other utilities, exchange benefits differ by utility. A utility receives no benefits when its average system cost rate goes below BPA's PF Exchange rate.

As noted above, BPA first implemented the 7(b)(2) rate test in developing its 1985 wholesale power rates, which were effective beginning July 1, 1985. In the 1985 rate case, the 7(b)(2) rate test did not trigger. BPA next developed rates in its 1987 rate case, which were effective October 1, 1987. In that case, the 7(b)(2) rate test triggered by 0.4 mills/kWh. BPA next developed rates in its 1989 rate case, which were effective October 1, 1989. In the 1989 rate case, the parties and BPA agreed to extend BPA's existing rates, so the rate test was not performed. BPA next developed rates in 1991, which were effective October 1, 1991. In the 1991 rate case, the 7(b)(2) rate test did not trigger in BPA's initial proposal. BPA and the parties agreed to a settlement regarding rate levels and agreed as part of the settlement that the trigger would be set at 0.2 mills/kWh. BPA next developed rates in 1993, which were effective October 1, 1993. In the 1993 rate case, the 7(b)(2) rate test did not trigger. BPA next developed rates in 1995, which were effective October 1, 1995, based upon a settlement. In the 1995 rate case, the 7(b)(2) rate test did not trigger.

In summary, BPA has implemented the 7(b)(2) rate test in the 1996 rate case in the same manner as BPA always has conducted the test. BPA followed the provisions of section 7(b)(2) of the Northwest Power Act and BPA's Legal Interpretation of Section 7(b)(2), which has been in effect since 1984. BPA also has followed the 7(b)(2) Methodology, which provides detailed directions for conducting the rate test and which also has been implemented in the same manner since it was established in 1984. BPA used the same computer model adopted in the 7(b)(2) Methodology, which has remained virtually unchanged since 1984. The significant trigger resulting from the rate test in BPA's 1996 rate proposal is the result of running the test with the data used in developing that rate proposal. Clearly, as evidenced by section 5(c)(4), the Northwest Power Act made no guarantee of residential exchange benefits. Since 1981, exchange benefits have totaled nearly $2.5 billion and hundreds of millions more dollars are forecasted to be afforded over the next five years under BPA's 1996 rate proposal. While the section 7(b)(2) rate test may result in an increase in the PF Exchange rate and thus a decrease in the amount of benefits BPA provides utilities participating in the residential exchange program, failure to implement the test properly would be contrary to law and would defeat Congress's intent to establish a rate ceiling for BPA's preference customers. Issues regarding the implementation of the section 7(b)(2) rate test are addressed below.

9.3 Allegations of Closed Mind or Bias

Issue

Whether BPA's conduct in this proceeding regarding the implementation of the section 7(b)(2) rate test establishes an irrevocably closed mind and predecisional bias.

Parties' Positions

The IOUs argue that BPA's conduct in this proceeding evidences an irrevocably closed mind and predecisional bias that deprives MREP of the impartiality and fundamental fairness required by due process. MREP Brief, WP-96-B-GE/PL/PS-01, at 8; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 10-11.

BPA's Position

BPA reviews each issue in the rate case based on its merits and the rate case record. Keep, *et al*., WP-96-E-BPA-55, at 3. BPA does not have an irrevocably closed mind or predecisional bias that would deprive any party of the impartiality and fundamental fairness required by due process.

Evaluation of Positions

The IOUs argue that "BPA's conduct in this proceeding evidences an irrevocably closed mind and predecisional bias that deprives MREP of the impartiality and fundamental fairness required by due process," citing *United States v. Batson*, 782 F.2d 1307 (5th Cir. 1986), *cert. denied*, 477 U.S. 906 (1986) and *FTC v. Cement Institute*, 333 U.S. 683 (1948), *reh'g denied*, 334 U.S. 839 (1948). MREP Brief, B-GE/PL/PS-01, at 8. These allegations are unfounded. In *Batson*, the court found that there was no evidence to indicate that the hearing officer's mind was irrevocably closed nor any evidence to reasonably infer bias. *Batson*, 782 F.2d at 1315. In *Cement Institute,* the court found that the FTC was not disqualified by bias to issue a cease and desist order where its members had formed a prior opinion that a particular activity was the equivalent of a price-fixing restraint of trade. *Cement Institute* 333 U.S. at 700. Similarly, in the 1996 rate case, while the IOUs disagree with BPA on numerous technical and legal issues regarding the section 7(b)(2) rate test, these differences do not constitute an irrevocably closed mind or predecisional bias on the part of BPA. In response to the IOUs' arguments that BPA's assumptions for the section 7(b)(2) rate test were arbitrary and unreasonable, BPA's testimony stated:

> Review of the issues involved in implementing the rate test demonstrates that the initial proposal's positions on these issues were neither arbitrary nor unreasonable. While neither arbitrary nor unreasonable, however, BPA is willing to review all initial assumptions used in conducting the rate test in

> light of the parties' testimony in order to determine the proper implementation of the rate test.

Keep, *et al.*, E-BPA-55, at 3. BPA's testimony, contrary to showing a closed mind, showed BPA's willingness to review all arguments raised by the parties on every issue related to the conduct of the section 7(b)(2) rate test.

In their brief, the IOUs base their accusations regarding bias upon two primary arguments. First, the IOUs rely on the fact that, under BPA's rate proposals, BPA's rates to preference customers and DSI customers decreased while the PF Exchange rate increased. MREP Brief, B-GE/PL/PS-01, at 8-9. The fact that rates to one customer class increased under BPA's rate proposal while rates to another customer class decreased, however, provides no support for allegations of bias. When the section 7(b)(2) rate test triggers, it is to be expected that the PF Preference rate, which is protected by the rate ceiling, would decrease while the PF Exchange rate, which is one of the rates to which the costs of the trigger are allocated, would increase. As noted previously, the legislative history of the Northwest Power Act expressly recognizes that the PF Exchange rate may increase while the PF Preference rate would be protected by the section 7(b)(2) rate ceiling. 16 U.S.C. 839e(b)(3). Such increases or decreases are the result of the proper implementation of BPA's statutory and administrative rate directives. Furthermore, different rate impacts on different customer classes occur in every BPA rate case, unless there is a settlement agreement to increase all rates by the same amount. For example, in BPA's 1987 rate case, the PF rate increased 5.6 percent while the IP rate increased 18.4 percent. Indeed, unless there was a settlement under which all rates were increased by the same percentage, every BPA rate case under the Northwest Power Act has had different percentage increases in the PF and IP rates. Thus, it is not improper for a particular customer class to experience a rate increase while others receive a smaller or larger increase or a decrease. The mere fact that increases or decreases occur in the rates of different customer classes reflects the proper development of rates and does not demonstrate bias in any manner whatsoever.

The IOUs' argument that a difference in rate impacts demonstrates bias is also undermined by the IOUs' exaggeration of the rate impacts. The IOUs characterize the PF Exchange rate increase at 20.6 percent. MREP Brief, B-GE/PL/PS-01, at 9. This reiterates the manner in which the IOUs consistently exaggerated the magnitude of BPA's rate increase during the rate case. The IOUs argued that BPA's initial proposal rate for the residential exchange (the PF Exchange rate) would increase by 31.7 percent. Marshall, Burns, WP-96-E-BPA-44, at 2. The proposed increase in BPA's initial proposal was actually 15.1 percent over BPA's FY 1996 Priority Firm rate. *Id*. Because the initial proposal rates would be implemented after BPA's current rates, which are in effect for FY1996, the proper comparison to show the impact of implementing new rates would be to compare the correct initial proposal PF Exchange rate with the current PF rate. Keep, *et al.*, E-BPA-55, at 3. Instead, the IOUs compared an incorrect initial proposal PF Exchange rate, as described below, with BPA's 1993 PF rate. This improperly exaggerated the effect of BPA's initial proposal on the residential exchange program. *Id*.

BPA identified another IOU error that exaggerated the proposed rate increase. BPA noted that BPA's initial proposal included corrections that were identified by the parties and acknowledged by BPA during clarification sessions. Marshall, Burns, E-BPA-44, at 2. The IOUs had acknowledged that "BPA agreed to incorporate the results of correcting these errors into BPA's Supplemental and Final Rate Proposals." *Id*., citing Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 3. The fact that the corrections would be incorporated in BPA's supplemental and final rate proposals means that the corrections applied to BPA's initial proposal. Keep, *et al.*, E-BPA-55, at 2. Despite their knowledge of these corrections and BPA's acknowledgment that they would be incorporated in rates, the IOUs failed to reflect these corrections in their calculation of the effects of the initial proposal on exchange benefits and the PF Exchange rate, thus exaggerating the impacts described in their testimony. Marshall, Burns, E-BPA-44, at 2.

Similarly, the IOUs exaggerated the effect of BPA's initial rate proposal on forecasted residential exchange benefits. The IOUs argued that there would be an annual reduction of residential exchange benefits of about $145 million. Marshall, Burns, E-BPA-44, at 2. The IOUs' figure of approximately $145 million was calculated as the difference between a benefit level of $59 million per year (from BPA's initial proposal assuming a 2.8 mills/kWh rate test trigger) and a fictional benefit level of $202 million per year. *Id*. The $202 million level was not determined using FY 1996 exchange benefits, which would provide an appropriate comparison, but instead was based on an assumed rate test trigger of negative 0.6 mills/kWh. *Id*. Such a trigger required the uncertain assumption that the IOUs would prevail on every issue regarding the section 7(b)(2) rate test. *Id*. Thus, the $145 million reduction in exchange benefits cited by the IOUs was not well founded. *Id*. at 3. When compared to FY 1996 exchange benefits, the average annual reduction in exchange benefits from BPA's initial proposal was far less than that claimed by the IOUs, at $86.5 million. *Id*. The foregoing estimates, of course, were based on BPA's initial proposal and do not reflect the actual rates that are adopted in this Record of Decision or any potential increase in residential exchange benefits that may result from those rates. *Id*.

The IOUs' exaggerations of the increase in the PF Exchange rate were not limited to BPA's initial proposal. When BPA's supplemental proposal was released, the IOUs again exaggerated the impacts of BPA's rate proposal. The IOUs argued that the supplemental PF Exchange rate constituted an increase of 20.6 percent in the PF rate, a claim that is reiterated in their brief. MREP Brief, B-GE/PL/PS-01, at 9; Piro, *et al.*, E-GE/PL/PS-07, at 3. Again, the IOUs improperly compared the supplemental PF Exchange rate with BPA's PF-93 rate instead of BPA's current PF-95 rate, which is the proper rate for comparison. Keep, *et al.*, WP-96-E-BPA-117, at 12. By using an improper rate for comparison, the increase in the new PF Exchange rate was exaggerated. *Id*. When the proper rate is used, the supplemental PF Exchange rate is only 14.6 percent higher than BPA's PF-95 rate. *Id*. BPA's preference customers received a similar 15.7 percent rate increase in BPA's 1993 rate case.

The IOUs also argue that the amount of rate decreases to the public and DSI customers under BPA's initial proposal was approximately $165 million annually and the rate increases to exchanging utilities was approximately $145 million, meaning that BPA is funding the decreases in the former rates with increases to the latter. MREP Brief, B-GE/PL/PS-01, at 9-10. The IOUs argue that this coincidence was never explained by BPA. *Id*. at 9. To the contrary, however, this alleged "coincidence" was directly explained by BPA during the hearing. Marshall, Burns, E-BPA-44, at 7-8. First, BPA noted that the IOUs' argument was not persuasive because it used faulty logic that relied on circumstantial evidence instead of analysis and deduction. *Id*. The fact that $165 million is $20 million different than $145 million does not establish any causative relationship between the two numbers. *Id*. In any event, however, the level of decreases in the cost of the residential exchange and the level of decreases in rates to BPA's publicly owned utilities and DSIs are the result of the development of BPA's rates in accordance with applicable requirements. *Id*. For example, when the section 7(b)(2) rate test triggers, this results in a decrease in the PF Preference rate and an increase in the PF Exchange rate, which reduces residential exchange benefits. *Id*. It is no surprise that the amount of rate decreases to the public and DSI customers under BPA's initial proposal was approximately $165 million annually and the amount of rate increases to exchanging utilities was approximately $145 million, because this is the natural consequence of the proper development of the rates. There is nothing inappropriate with this result and it is certainly not a violation of law to follow the law. *Id*.

The second major argument raised by the IOUs regarding alleged bias concerns the allegation that BPA's June 1994 Draft Strategic Business Plan identified as one of BPA's "Critical Success Indicators" a target of exchange benefits consistently below a stated level. MREP Brief, B-GE/PL/PS-01, at 8. This allegation was directly rebutted during the hearing and demonstrates the self-serving purpose of the IOUs' allegations of bias. The IOUs argued that BPA's Draft Business Plan states that BPA wants to deprive the region's residential customers of the benefits of the exchange. *Id*.; Piro, *et al.*, E-GE/PL/PS-01, at 9. The IOUs, quoting BPA's Draft Business Plan, argued that the noted forecasted reductions in exchange benefits would come from "limiting net residential exchange costs to no more than $200 million per year." Piro,*et al.*, E-GE/PL/PS-01, at 9. BPA established, however, that the IOUs cited this quotation out of context. Marshall, Burns, E-BPA-44, at 8. This quotation does not mean that BPA intended to unilaterally deprive residential customers of residential exchange benefits, because the Draft Business Plan proposed cost stabilization efforts involving <u>mutual agreement</u> between BPA and the exchanging utilities. *Id*. While the Draft Business Plan proposed to "pursue alternatives to ongoing exchange transactions in order to reduce and stabilize total benefits paid through the year 2001," BPA stated that "[e]xamples of such transactions include negotiated in-lieu transactions and negotiated settlements of expected future exchange benefits." *Id*. BPA therefore did not propose to deprive customers of residential exchange benefits unilaterally, but rather only through mutual agreements with the exchanging utilities themselves. *Id*.

Contrary to the IOUs' claims, the Draft Business Plan affirmed a substantial residential exchange program. The Draft Business Plan noted that some BPA customers were seeking to develop principles to limit exchange costs in the future that might prove beneficial, but the Draft Business Plan identified several additional initiatives to improve program administration, cost-effectiveness, quality, and customer service. *Id.*, citing Draft Business Plan, at 177. The Plan then identified a number of strategic thrusts for the exchange program to achieve its goals. *Id*. at 9. The Draft Business Plan stated that each of these initiatives is "consistent with the Northwest Power Act, RPSA contracts, 1984 ASC Methodology, and other relevant legal and administrative requirements; [and] allow exchanging utilities to receive all the exchange benefits to which they are legally entitled." *Id*.

It is also worthwhile to note that the $200 million in exchange benefits mentioned in the Draft Business Plan are greater annual benefits than have been paid in most years of the residential exchange program. *Id*. The Draft Business Plan thus reflected BPA's expectation at that time to have an exchange program which provided exchange customers substantial benefits over many years. *Id*. Contrary to the IOUs' claims that the Draft Business Plan shows an intent to deprive customers of exchange benefits, it expressly states BPA's intent to "allow exchanging utilities to receive all the exchange benefits to which they are legally entitled." *Id*. In summary, the Draft Business Plan provides no support for any allegations of bias, but instead expressly demonstrates precisely the opposite: the absence of any unilateral reductions in residential exchange benefits and BPA's commitment to compliance with the RPSA, the ASC Methodology and the law.

During the 1996 rate hearing, BPA directly addressed all IOU arguments regarding any alleged bias by BPA. Arguments in addition to those above follow. In their testimony, the IOUs argued that BPA was trying to lay the blame on the residential exchange for BPA's alleged market-related and other financial woes. Piro,*et al.*, E-GE/PL/PS-01, at 8. In response, BPA noted that it was not blaming the residential exchange for any alleged market-related or other financial problems any more than BPA similarly attributes its other costs as contributing to such financial challenges. Marshall, Burns, E-BPA-44, at 6. BPA noted that the cost of the residential exchange is one of many costs that BPA must recover through its rates. *Id*. To the extent that BPA's total costs are higher, BPA's rates are higher and less competitive. *Id*. This does not mean, however, that BPA believes the cost of the exchange is the sole source of any alleged problems. *Id*. It is one of many components of BPA's cost structure. *Id*.

Similarly, the IOUs argued that BPA is trying to pay for BPA's problems with money that belongs to the IOUs' residential customers. Piro,*et al.*, E-GE/PL/PS-01, at 8. The IOUs also argued that BPA has turned to its residential exchange customers to capture costs it cannot recover because of the rate decreases to the DSIs and the preference customers and characterizes BPA's view of the exchange as a discretionary cost that can be cut arbitrarily. Piro, *et al.*, E-GE/PL/PS-07, at 3. In response to these arguments, BPA noted that, first, BPA does not view the residential exchange program as a discretionary cost that can be cut arbitrarily. Keep, *et al.*, E-BPA-117, at 12. The benefits from the residential exchange program, however, depend directly on BPA's rates and, in particular, the PF Exchange rate. *Id*. By claiming that BPA has turned to residential exchange customers to capture costs not recovered from other customers, the IOUs have mischaracterized BPA's ratemaking. *Id*. Exchange benefits for the IOUs and other exchanging utilities are determined through the comparison of the PF Exchange rate with the utilities' respective average system costs (ASCs). Marshall, Burns, E-BPA-44, at 6. The PF Exchange rate is determined through BPA's rate case process. *Id*. The level of the PF Exchange rate is determined in large part by the section 7(b)(2) rate test. *Id*., citing Initial Wholesale Power Rate Design Study, WP-96-E-BPA-05. Depending on whether the rate test triggers and on the level of the trigger, the PF Exchange rate will be higher or lower. *Id*. In BPA's initial and supplemental proposals, the rate test triggered and costs were allocated, in part, to the PF Exchange rate. *Id*. at 6-7. When the PF Exchange rate increases, exchange benefits decrease. *Id*. at 7. BPA is required to conduct the section 7(b)(2) rate test in its general rate hearings. *Id*. The technical and legal issues regarding the implementation of the section 7(b)(2) rate test are addressed in separate sections below. Therefore, BPA is not trying to "pay for BPA's problems with money that belongs to the IOUs' residential customers." *Id*. BPA simply is developing its rates in compliance with all applicable requirements. *Id*. Decisions regarding the implementation of these requirements will be made by the BPA Administrator based on the entire rate case record. *Id*. If these requirements result in a higher PF Exchange rate, exchange benefits decrease. *Id*. If these requirements result in a lower or no PF Exchange rate (although not lower than the PF Preference rate), exchange benefits increase. *Id*.

The IOUs argued that BPA intends to deprive the region's ratepayers of residential exchange benefits because the IOUs believe that the Residential Purchase and Sale Agreement (RPSA) is "the only proposed contract substantially less favorable than that agreed upon in the negotiations." Piro,*et al.*, E-GE/PL/PS-01, at 9. BPA noted that the development of new RPSAs occurs outside of BPA's ratemaking process. Marshall, Burns, E-BPA-44, at 10. The inability of BPA and exchanging utilities to reach consensus on a new RPSA was based primarily on disagreements over adjustments to contract principles. These changes were proposed by BPA to reflect dramatic changes in the market since the development of the initial principles, and were necessary to ensure that BPA could implement the residential exchange program in that market. *Id*. BPA's proposal was not aimed at depriving customers of exchange benefits. *Id*.

The IOUs argued that BPA's treatment of the residential exchange differs from BPA's treatment of its other customers because BPA offered and entered into contracts with the DSIs that obligated BPA to meet a 22.6 mill rate for the DSIs and provided that the DSIs could terminate their contracts on seven days' notice if the final rate were higher. Piro, *et al.*, E-GE/PL/PS-07, at 5. The IOUs also argued that they know of no arbitrary manipulations to artificially raise the PF rate, and BPA has not left any major issues wide open in determining the PF or IP rates. *Id*. BPA noted that the IOUs mischaracterized BPA's contracts with the DSIs. Keep,*et al.*, E-BPA-117, at 13. The contracts do not obligate BPA to meet a 22.6 mill rate. *Id*. The IP rate will be whatever is determined in the rate case based on the rate case record. *Id*. BPA's service to the DSIs differs from BPA's service to the preference customers, which differs from BPA's service to residential exchange customers. *Id*. Service to each of these groups occurs under separate contracts. *Id*. Because of different service and contracts, the treatment of the groups will differ. *Id*.

While the IOUs stated that they knew of no arbitrary manipulations to raise the PF rate, BPA noted that the IOUs had not demonstrated that BPA engaged in any arbitrary manipulations to raise the PF Exchange rate. *Id.* Also, BPA noted that preference and DSI customers might similarly argue that BPA has manipulated issues to raise the PF and IP rates arbitrarily, although BPA would similarly argue that it has not done so. *Id.* BPA stated that each issue on each rate will be decided on its merits based on the rate case record. *Id.*

The IOUs implied that BPA is treating exchanging utilities different than other customer classes because BPA had not taken firm positions on three issues in its supplemental rate proposal: (1) the post-2001 residential exchange; (2) the exclusion of Mid-Columbia resources owned and operated by public bodies and cooperatives; and (3) the exclusion of revenues from the Energy Services Business as section 7(g) costs. Therefore, the IOUs claim, these issues would be used to defeat the intent of the residential exchange program and would prevent any determinations adverse to the program from being tested in this rate proceeding. Piro, *et al.*, WP-96-E-GE/PL/PS-06, at 2; Piro, *et al.*, E-GE/PL/PS-07, at 4. Of the three issues identified by the IOUs, BPA noted that two issues rest squarely on the resolution of legal issues, not technical issues. Keep, *et al.*, E-BPA-117, at 3. The *Special Rules of Practice to Govern This Proceeding*, WP-95-O-01, WP-96-O-01, TC-96-O-01 at 7, provide that "[a]rgument and legal opinions will not be received into evidence. They are the province of the lawyer, not the witness. They should be presented in briefs or legal memoranda." *Id.* The issue of the Mid-Columbia resources rests on a legal analysis of whether such resources comply with the statutory requirements of section 7(b)(2) of the Northwest Power Act. *Id.* Similarly, the issue of Energy Services Business revenues rests on a legal analysis of section 7(b)(2) and section 7(g) of the Northwest Power Act. *Id.* BPA noted that BPA's legal analysis of issues is properly presented in its Draft Record of Decision. *Id.* Furthermore, legal issues are best determined after review of legal briefs from all parties. *Id.*

With regard to the issue of the residential exchange after 2001, BPA noted that the resolution of this issue rests on the determination of what would best reflect the in-lieu provisions of contracts implementing the exchange program in the post-2001 period. *Id.* Because there are no contracts currently governing that period, BPA filed testimony outlining two primary options. *Id.* Parties had a full opportunity to advise BPA of the proper approach to take on this issue. *Id.*

The IOUs also argued that BPA's approach prevents any determinations adverse to the residential exchange program from being tested. *Id.* This is incorrect. *Id.* at 4. While BPA noted that two of the issues are premised on legal issues and BPA identified two options for a third issue, BPA clearly identified the potential positions on each issue and filed testimony on the factual aspects of these issues. *Id.* Parties were given a full and complete opportunity to file testimony in support of any option or approach on all of these issues. *Id.* Furthermore, the IOUs are very familiar with the models used in conducting the section 7(b)(2) rate test and are capable of incorporating alternative approaches to issues and testing the effects of these approaches in their analyses. *Id.* BPA noted that it was not attempting to manipulate issues to eliminate the residential exchange but instead to address and resolve all issues in the rate case based on the development of a sound record. *Id.* BPA noted that the effect of the resolution of the foregoing issues on the residential exchange program rests with BPA's determinations based on the evidence in the record and such decisions will be consistent with BPA counsel's advice regarding the intent of the residential exchange program. *Id.* This does not mean that the residential exchange utilities are being treated improperly compared to BPA's other customers; rather, it reflects the approach the agency felt was proper for those issues.

The IOUs argued that there are signs of disparate treatment in the rate case because BPA has not explained three changes from the initial proposal: (1) the capability and cost of BPA's resources has changed significantly; (2) the amount of certain firm purchases has changed significantly; and (3) the value of reserves has changed significantly. Piro, *et al.*, E-GE/PL/PS-07, at 5-6. BPA noted that the IOUs' claim that BPA has not explained three changes from the initial proposal was puzzling. Keep, *et al.*, E-BPA-117, at 14. Obviously, the IOUs were able to identify the changes. *Id.* Therefore, the IOUs were able to ask clarifying questions and submit data requests to fully understand the noted changes. *Id.* at 14-15. Indeed, BPA even responded to informal data requests from the IOUs. *Id.* at 15. BPA did not understand how these avenues were insufficient to explain the changes to the IOUs. *Id.*

The IOUs noted changes to the capability and cost of FBS resources. Piro, *et al.*, E-GE/PL/PS-07, at 5. *See* Section 7(b)(2) Rate Test Study, WP-96-E-BPA-07A(E1), pages 51 and 52 compared to Section 7(b)(2) Rate Test Study, WP-96-E-BPA-63A, pages 48 and 49. BPA noted that it has provided an audit trail of sources used for these tables using footnotes at the bottom of the cited pages. Keep, *et al.*, E-BPA-117, at 15. These sources explain that WNP-2 O&M costs have decreased, the undistributed reduction has been distributed, and balancing purchases have decreased due to a lower DSI load forecast. *Id.* In addition, the components of the balancing purchases have changed. *Id.* In the initial proposal Section 7(b)(2) Rate Test Study Documentation Errata, WP-96-E-BPA-07A(E1), pages 51-52, additional purchase power costs and gWhs were added to reflect changes in resource acquisitions. *Id.* In the supplemental proposal, purchases included storage for May and June only and were reduced by $13.5 million for a fish implementation adjustment. *Id.*

The IOUs also noted changes to "Purchases for SP." Piro, *et al.*, E-GE/PL/PS-07, at 5. *See* Section 7(b)(2) Rate Test Study, WP-96-E-BPA-07A(E1), page 108, column C compared to Section 7(b)(2) Rate Test Study, WP-96-E-BPA-63A, page 97, column C. Column C shows the amount of economic purchases in the 7(b)(2) Case that are necessary to serve all SP contracts when the firm load/resource balance falls short in serving them. Keep, *et al.*, E-BPA-117, at 15. This procedure has been applied consistently since BPA's 1993 rate case section 7(b)(2) rate test. *Id.*, citing Section 7(b)(2) Rate Test Study, WP-93-FS-BPA-06A, page 108, Column C. The change in purchases for SP between the initial and supplemental proposals is explained by a firm load/resource balance in the supplemental proposal that serves more SP contracts, making fewer economic purchases necessary. *Id*.

With regard to the third change from the initial proposal, BPA noted that its response to the IOUs' argument regarding the value of reserves was explained in the testimony of Kreipe, *et al.*, WP-96-E-BPA-78.

The IOUs argued that BPA characterizes the residential exchange program as a subsidy, but characterizing it as a subsidy does not mean that BPA can eliminate it. Piro, *et al.*, E-GE/PL/PS-07, at 6. BPA noted that it is not using the rate case to eliminate the residential exchange program. Keep, *et al.*, E-BPA-117, at 16. The monetary benefits provided by the residential exchange program, however, legitimately can be affected by a number of factors. *Id*. For example, BPA has the authority to purchase power from a cheaper source than the utility under in-lieu transactions, which can reduce or eliminate monetary benefits under the program. *Id*. Similarly, as explained in greater detail previously, the section 7(b)(2) rate test can result in an increase in the PF Exchange rate, which can either reduce or eliminate residential exchange benefits. *Id*. Based upon BPA's initial and supplemental proposals, however, BPA's final rates will not eliminate the residential exchange program. *Id*.

Finally, the IOUs argue that during the pendency of this rate case, Congress was so concerned about BPA's apparent attempts to abuse its discretion targeted at the residential exchange that it legislated a level of residential exchange benefits of $145 million for fiscal year 1997 and directed BPA to negotiate the resolution of residential exchange issues. *Id*. at 3. While the IOUs claim that Congress was concerned about BPA's attempts to abuse its discretion targeted at the residential exchange in BPA's 1996 rate case, the IOUs fail to cite any support for this claim. BPA recognizes that the IOUs, not Congress, consistently have attempted to characterize BPA's rate proposals in pejorative terms. The rate case record, however, contains no support for the IOUs' claim of congressional conclusions of abuse. The legislation referenced by the IOUs, the Energy and Water Development Appropriations Act, P.L. 104-46, as discussed below, contains no support for this claim. Furthermore, the legislative history of the Act does not provide that BPA was abusing its discretion regarding the residential exchange or that BPA was developing its rates in any improper manner. To the contrary, the Conference Report states that "[i]n order to maintain a sound financial position, the conferees urge, to the extent practicable, BPA to take such actions as are necessary to assure the proposed rate[s] for public utilities and direct service industries are not increased from the initial proposal." H.R. Conf. Rep. No. 293, 104th Cong., 1st Sess. 95 (1995). Congress therefore affirmed the development of rates for preference and DSI customers in BPA's initial proposal, rates that were based on BPA's implementation of the section 7(b)(2) rate test. If Congress believed that BPA's initial proposal rates were improperly developed, it would not have encouraged the maintenance of the rates at such levels. Contrary to the unfounded arguments of the IOUs, however, and consistent with the foregoing legislative history, there is a simple factual explanation for the legislation.

When BPA released its initial 1996 rate proposal, the development of BPA's rates, including the implementation of the section 7(b)(2) rate test, resulted in an increase in the PF Exchange rate and therefore a potential reduction in residential exchange benefits. The reasons for this increase are explained in detail in this section of this Record of Decision. Even though BPA's initial proposal was preliminary and did not establish any final rates, and even though parties, including the IOUs, would have the opportunity to challenge the initial rates in a formal evidentiary hearing, the forecasted decrease in residential exchange benefits based on BPA's initial rate proposal was of general concern. It was the source of concern not because BPA improperly developed the rates, but rather because, having properly developed rates, it was possible that exchange benefits would be reduced when final rates were implemented. Reductions in exchange benefits mean that the monetary benefits provided to the IOUs would decrease and the IOUs' retail rates therefore would increase. The IOUs always have sought to maximize the benefits provided by BPA, which keep the IOUs' retail rates lower than they would be otherwise. In response to the concern that the proper development and implementation of BPA's rates would decrease the residential exchange benefits, Congress passed legislation that would establish a specific amount of residential exchange benefits for exchanging utilities for FY 1997 in order to avoid potential increases in exchanging utilities' retail rates. This does not mean that Congress believed that BPA was abusing its discretion, rather, Congress simply responded to the IOUs' interest in preserving a minimum amount of residential exchange benefits given the possibility that proper implementation of BPA's rates would result in reduced benefits.

The IOUs also argue that congressional concern about BPA's alleged abuse was the basis for Congress's direction to BPA to negotiate the resolution of residential exchange issues. MREP Brief, B-GE/PL/PS-01, at 3. The legislative history, however, refutes this contention. In the Conference Report on the Energy and Water Development Appropriations Act, the conferees "recognize[d] the authority of the of the Bonneville Power Administration to implement in lieu transactions, among other actions, which would effectively terminate the residential exchange after 2001. Consistent with the regional review, Bonneville and its customers should work together to gradually phase out the residential exchange program by October 1, 2001." H.R. Conf. Rep. No. 293, 104th Cong., 1st Sess. 95 (1995). Contrary to the IOUs' claim, it was not BPA's abuse but rather the proper exercise of BPA's authority that was the basis for the encouragement of all parties to phase out the residential exchange program. In summary, the IOUs' suggestion that Congress enacted the legislation due to any abuse of discretion in BPA's 1996 rate case regarding the residential exchange is both false and unfounded.

Decision

The Administrator will review each issue in the rate case based on its merits and the rate case record. The Administrator does not have an irrevocably closed mind or predecisional bias that would deprive any party of the impartiality and fundamental fairness required by due process.

9.4 Federal Base System Resources and Resource Stacks

Issue

Whether BPA has properly characterized firm power purchases to replace reductions in the capability of the Federal base system (FBS) resources as FBS resources, and whether BPA has properly included resources in the 7(b)(2) Case resource stack.

Parties' Positions

The IOUs argue that BPA incorrectly included surplus power purchases as FBS resources. MREP Brief, B-GE/PL/PS-01 at 32; MREP Ex. Brief, R-GE/PL/PS-01, at 16. The IOUs also argue that BPA incorrectly removed resources from the 7(b)(2) Case resource stack, which conflicts with the requirement to model decisions and assumptions as accurately as possible and also conflicts with the reality that once a resource is built or acquired, it cannot simply be assumed away. MREP Brief, B-GE/PL/PS-01, at 31-32; MREP Ex. Brief, R-GE/PL/PS-01, at 15-16.

WPAG argues that it is appropriate for BPA to include surplus power purchases as FBS resources. Beck, *et al.*, WP-96-E-WA-15, at 36-37. WPAG also argues that it is inappropriate to include resources in the 7(b)(2) Case resource stack merely because they had been included in prior years' rate proceedings. *Id.*

PPC argues that it is inappropriate to include resources in the 7(b)(2) Case resource stack when such resources are not needed given reductions in load. PPC Brief, WP-96-B-PP-01, at 4-6. Furthermore, the section 7(b)(2) rate test is a forward-looking estimate of costs with and without the Northwest Power Act over the rate period and the succeeding four years that is not tied to prior resources. *Id.*

BPA's Position

BPA's firm power purchases replace reductions in the capability of FBS resources and are therefore properly reflected in the section 7(b)(2) rate test as FBS resources. Keep, *et al.*, WP-96-E-BPA-117, at 4-6. The section 7(b)(2) rate test must be conducted for a prescribed time period based on the relevant rate case. Resources may change from case to case in BPA's rate proposal, the cost of the resources similarly may change from case to case, and the resource stack must be created anew with each rate case. *Id.* at 7. Since 1991, when the issue of resource additions first arose, BPA has not bound the resource additions in the 7(b)(2) Case by any previous rate case. *Id.* Pursuant to the Section 7(b)(2) Implementation Methodology, the current rate proposal period is the appropriate period to determine loads and resources for the 7(b)(2) Case, not past periods. *Id.* at 8. This test logically occurs at these specific times based on information, including resources, which is current at those times. *Id.* at 9. It makes perfect sense for the test not to be tied to resources and costs that do not reflect the time period for which the test is conducted. *Id.*

Evaluation of Positions

The IOUs note that BPA professes to conduct the section 7(b)(2) rate test objectively based on the Section 7(b)(2) Implementation Methodology and the Section 7(b)(2) Legal Interpretation. MREP Brief, B-GE/PL/PS-01, at 33. The IOUs argue that this is not what BPA did, presenting two basic arguments: (1) that surplus power purchases should not be included in the FBS and (2) that the removal of costs of resources previously assumed to be acquired from the 7(b)(2) Case resource stack is contrary to common sense, reality and prudent utility practice. *Id*. at 33-35. These arguments are reviewed below in order.

As noted above, the IOUs argue that surplus power purchases should not be included in the FBS. MREP Brief, B-GE/PL/PS-01, at 33. FBS resources are defined in section 3(10) of the Northwest Power Act as "the Federal Columbia River Power System hydroelectric projects; resources acquired by the Administrator under long-term contracts in force on the effective date of this Act; and resources acquired by the Administrator in an amount necessary to replace reductions in capability of the resources referred to in subparagraphs (A) and (B) of this paragraph." 16 U.S.C. 839a(10). FBS resources thus include the Federal hydrosystem, Washington Nuclear Project (WNP) 1, WNP-2, 70 percent of WNP-3, 30 percent of the Trojan nuclear plant, the Hanford nuclear plant, and resources acquired to replace reductions in the capability of such resources. Tr. 2070, 2080.

In BPA's initial proposal, BPA noted that balancing power purchases are quantities of power that BPA must purchase on a short-term basis during certain months of the rate test period to provide operational flexibility when total firm resources are insufficient to serve total firm power loads. Keep, *et al.*, WP-96-E-BPA-23, at 1-2. In the rate case, these purchases are made on an as-needed basis relying on power expected to be available in the short-term energy market. *Id*. at 2. In BPA's initial proposal, the 5-year average of balancing power purchases are forecasted at a level of 880 aMW. *Id*. BPA included the balancing purchase power megawatts in the FBS resources and the costs associated with these purchases are a component of the total cost of the FBS. *Id*. BPA noted that the operating flexibility of the Federal hydrosystem, which is one of the resources included in the FBS resource pool, has been constrained over the past few years as a result of operational restrictions. *Id*. Balancing purchases replace this lost flexibility. *Id*. Therefore BPA included the megawatts and the costs in the FBS totals. *Id*. Upon cross-examination, BPA clarified that BPA initially associated the balancing purchases with reductions in the capability of the hydrosystem because such reductions were the most recent reductions in the FBS. Tr. 2070. BPA acknowledged that the balancing purchases do not occur solely because of reductions in the hydro capability but rather because of reductions in the capability of FBS resources generally. *Id*.

Due to reductions in the capability of the hydrosystem from operating constraints, the failure to obtain power from WNP-1 and -3, the shutdown of the Trojan nuclear plant and the shutdown of the Hanford nuclear plant, the reductions in the capability of FBS resources are approximately 2,450 aMW. Tr. 2080. Pursuant to section 3(10) of the Northwest Power Act, BPA may acquire resources to replace these reductions in capability. Section 3(10) expressly provides that such replacement resources are FBS resources. For this reason, BPA's balancing purchases to replace reductions in the capability of the FBS resources constitute FBS resources.

Section 7(b)(2)(D) of the Northwest Power Act provides that:

> all resources that would have been required, during such five year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (<u>other than requirements met by the available Federal base system resources</u> determined under subparagraph (B) of this paragraph) were--
>
> > (i) purchased from such customers by the Administrator pursuant to section 6, or
> >
> > (ii) not committed to bad pursuant to section 5(b)
>
> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator. (Emphasis added).

Section 7(b)(2)(D) of the Northwest Power Act provides that in conducting the section 7(b)(2) rate test, BPA first uses power from the FBS to meet 7(b)(2) customers' loads in the 7(b)(2) Case. *Id*. If the FBS is insufficient to meet those loads, BPA then uses resources from the resource stack. *Id*. The Section 7(b)(2) Implementation Methodology requires that "the program case will be developed as a simulation of the BPA rate proposal results for the test year and a projection of the rates for the ensuing four years based on the test year rate proposal methodology and data. All the rate proposal determinations, decisions and assumptions for the test year regarding revenue requirements, loads, resources, cost allocation and rate design will be input or modeled as accurately as possible." *See* Section 7((b)(2) Implementation Methodology, b-2-84-F-02, 39; Keep, *et al.*, E-BPA-117, at 4. Similarly, the 7(b)(2) Methodology provides that the 7(b)(2) Case "will be modeled in the same way as the program case, except where section 7(b)(2) provides specific assumptions that modify the program case." *See* Section 7((b)(2) Implementation Methodology, b-2-84-F-02 at 41; Keep, *et al.*, E-BPA-117, at 5. The resources in BPA's 1996 rate proposal include operational power purchases which replace reductions in capability of the Federal base system resources. Keep, *et al.*, E-BPA-117, at 5; Tr. 2070. Because these power purchases replace reductions in the capability of FBS resources, BPA treats the purchases as FBS resources in its rate proposal. Keep, *et al.*, E-BPA-117, at 5. This is reflected in the Rate Analysis Model (RAM) in the Documentation for the Initial Wholesale Power Rate Development Study (WPRDS), WP-96-E-BPA-05A, at 149-153, line 43, and in the Documentation for the Supplemental WPRDS, WP-96-E-

BPA-61A, at 169-173, line 42. Because the power purchases are treated as FBS resources in the rate proposal, BPA must treat the purchases as FBS resources in the Program Case. Keep, *et al.*, E-BPA-117, at 5. Because BPA treats the power purchases as FBS resources in the Program Case, BPA must treat the purchases as FBS resources in the 7(b)(2) Case. *Id*. Because the above-noted power purchases properly are included in the section 7(b)(2) Case as FBS resources and because the FBS is larger as a result, BPA properly avoids having to use resources from the resource stack to meet 7(b)(2) customers' loads. *Id*.

BPA's inclusion of balancing purchases as FBS replacements also is supported by the fact that BPA previously has treated power purchases, such as those noted above, as FBS resources. Keep, *et al.*, E-BPA-117, at 6. For example, *see* Section 7(b)(2) Rate Test Study Documentation, WP-87-FS-BPA-05A, page 143, Column E; Keep, *et al.*, E-BPA-117, at 6.

Section 8(n) of the General Contract Provisions of BPA's power sales contracts provides that BPA will consult with its customers prior to making a decision to replace reductions in the capability of FBS resources. During cross-examination it was established that BPA has sent out a letter initiating a public consultation process for the acquisition of short-term firm power purchases as FBS replacement resources. Tr. 2082. Pursuant to section 1010.11(c) of the *Procedures Governing BPA Rate Hearings*, BPA takes official notice of the letter initiating this public process. BPA's letter dated August 31, 1996, provides as follows:

> The Bonneville Power Administration (BPA) is proposing the replacement of reductions in the capability of Federal base system (FBS) resources. FBS resources are defined in section 3(10) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) as Federal Columbia River Power System hydroelectric projects, resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act, and replacements for reductions in the capability of such resources. See 16 U.S.C. 839a(10). Long-term contracts under the foregoing definition include, for example, Washington Public Power Supply System Nuclear Project Nos. 1, 2 and 70 percent of 3, the Hanford nuclear plant, and part of the Trojan nuclear plant.
>
> Since the enactment of the Northwest Power Act in 1980, there has been a significant reduction in FBS capability. The loss in capability includes shutdown of the Trojan and Hanford nuclear plants (BPA's shares are 230 aMW and 309 aMW, respectively), failure to complete Washington Nuclear Project Nos. 1 and 3 (BPA's shares are 958 aMW and 651 aMW, respectively), and hydroelectric capability losses due to, among other things, water budget and fish augmentation operating constraints (521 aMW). BPA proposes to replace a portion of this lost capability with up to

> 1200 average annual megawatts acquired from short-term power purchases over the next 10 years (1996-2005). These purchases are the most economic purchases available to BPA.
>
> Pursuant to section 8(n) of the General Contract Provisions (Exhibit B) in BPA's Northwest Power Act power sales contracts, BPA must consult with its customers prior to making a decision to replace reductions in the capability of FBS resources. This proposal constitutes the initiation of a consultation with BPA's customers. . . .

It is clear that BPA has initiated a consultation process to acquire FBS replacement resources. Tr. 2082. It is also clear that BPA's current proposal is "to replace a portion of this lost capability with up to 1200 average annual megawatts acquired from short-term power purchases over the next 10 years (1996-2005)." While BPA has not yet completed the consultation process, BPA's proposal is the most current and best evidence of the manner in which BPA will acquire FBS replacement resources during the period from 1996-2005.

The IOUs argue that BPA's defense of the treatment of surplus power purchases as FBS resources is that "we've done it before." MREP Brief, B-GE/PL/PS-01, at 33. The IOUs state that BPA fails to mention that it "did it before" in BPA's 1995 rate case, which was settled and has no precedential value. *Id*. As is apparent from the previous discussion, however, BPA's defense of the use of surplus power purchases as FBS resources is comprised of much more than simply saying "we've done it before." In addition to the extensive legal and factual support noted above, BPA's testimony established that BPA previously had treated surplus power purchases as FBS resources. Keep, *et al.*, E-BPA-117, at 6. Contrary to the IOUs' claims, however, BPA's testimony was <u>not</u> based on BPA's 1995 rate case, but rather on BPA's 1987 rate case. *Id*.; *see* Section 7(b)(2) Rate Test Study Documentation, WP-87-FS-BPA-05A at 143, Column E. Therefore, in addition to the extensive legal and factual arguments supporting the use of surplus power purchases as FBS resources, BPA's position is also supported by BPA's past rate case practice.

The second major argument presented by the IOUs regarding resources in the section 7(b)(2) rate test is that the removal of costs of resources previously assumed to be acquired from the 7(b)(2) Case resource stack is contrary to common sense, reality and prudent utility practice. MREP Brief, B-GE/PL/PS-01, at 33-35; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 15-16. The IOUs first argue that in all prior rate cases, BPA's load and resource needs were greater than in the immediately prior case and, therefore, in any rate proceeding, in addition to new resource additions needed to serve load increases, all resources required in the prior resource stack should continue to be required in the current stack. MREP Brief, B-GE/PL/PS-01, at 31; Piro, *et al.*, E-GE/PL/PS-06, at 4. The IOUs have mischaracterized BPA's practice. Keep, *et al.*, E-BPA-117, at 6. The 7(b)(2) Methodology requires BPA's Program Case to simulate the current rate proposal. *Id*. Then, in constructing the 7(b)(2) Case, the Program Case is adjusted for the five assumptions specified in the Northwest Power Act and the 7(b)(2) Methodology. *Id*. One of these assumptions addresses the resources that are used in the Program Case. *Id*. BPA is required to build a resource stack for the 7(b)(2) Case that is made up of all the resources that BPA has or is planning to acquire from 7(b)(2) customers in the current rate case and the resources owned by 7(b)(2) customers but not dedicated to serving their loads (in the event these resources are still insufficient to meet the loads, a third type of resource may be used). *Id*. In addition, BPA must order these resources from least cost to most expensive. *Id*. The 7(b)(2) Methodology does not direct BPA to build the resource stack based on prior proposals in a rate case or upon prior rate cases. *Id*. at 6-7. Simply because the SPM selected a resource in the 7(b)(2) Case in one proceeding does not mean that the same resource will be selected again in each subsequent proceeding. *Id*. at 7. Resources may change from case to case in BPA's rate proposal, the cost of the resources may similarly change from case to case, and the resource stack must be created anew with each rate case. *Id*. In summary, since 1991, when the issue of resource additions first arose, BPA has not bound the resource additions in the 7(b)(2) Case by any previous rate case. *Id*.

The IOUs argue that with declining loads, the SPM should have retained in the 7(b)(2) Case resource stack the resources presumed acquired in the prior proceeding because, once acquired, a utility cannot simply shed itself of resources that it built to serve load -- the costs must still be paid. MREP Brief, B-GE/PL/PS-01, at 32-34; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 16; Piro, *et al.*, E-GE/PL/PS-06, at 4. This argument, however, ignores and is expressly inconsistent with BPA's Section 7(b)(2) Legal Interpretation and BPA's Section 7(b)(2) Implementation Methodology. First, it must be emphasized that no resources have disappeared from the resource stack, as the IOUs suggest. The resource stack in the 7(b)(2) Case is required to contain the same resources that previously have been acquired or are forecasted to be acquired in the Program Case ("the existing or planned resources actually acquired by BPA from the 7(b)(2) customers <u>in the relevant rate case"</u>). In summarizing BPA's Legal Interpretation, the Implementation Methodology at page 39 provides:

> Three types of resources will be assumed to be available to serve 7(b)(2) customers' loads when the Federal base system (FBS) resources are exhausted in the 7(b)(2) case: (a) the existing or planned resources actually acquired by BPA from the 7(b)(2) customers <u>in the relevant rate case</u>; (b) the existing resources owned or purchased by the 7(b)(2) customers that are not dedicated to their own regional loads; and (c) generic resources of whatever size required to serve the preference customers' remaining load, at the average cost of all existing or planned resources acquired by BPA from non-7(b)(2) customers during the relevant five-year period. The resources listed in (a) and (b) will be "stacked" in order of cost and assumed to be used <u>as needed</u> to meet loads, least cost first.

The "relevant rate case" is defined in the Methodology as "[t]he wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected." Methodology at 38. In other words, the resources used in the stack must be the same as used in the rate proposal for that particular rate case. This is exactly what BPA has done. The 7(b)(2) Methodology provides that the relevant five-year period is "[t]he test year of the relevant rate case, plus the ensuing four years." *Id.* In the 1996 initial and supplemental rate proposals, the rate test period was expanded to five years plus the ensuing four years. *Id.* The Methodology does not direct that results from a prior rate case test year or 7(b)(2) rate period must be incorporated in subsequent tests. *Id.* The current rate proposal period is the appropriate period to determine loads and resources for the 7(b)(2) Case, not past periods. *Id.*

Thus, as noted above, BPA is required to build a resource stack for the 7(b)(2) Case that is made up of all the resources that BPA has or is planning to acquire from 7(b)(2) customers and the resources owned by 7(b)(2) customers but not dedicated to serving their loads, all from the current rate case. Keep, *et al.*, WP-96-E-BPA-117, at 6. The Methodology then expressly provides that the resources must be "'stacked' in order of cost and assumed to be used <u>as needed</u> to meet loads, least cost first." Methodology at 39 (emphasis added). This is important because, after first using the FBS to meet 7(b)(2) customers' loads in the 7(b)(2) Case, additional resources from the resource stack are brought on <u>only</u> to the extent that they are <u>needed</u> to meet the 7(b)(2) customers' loads. In other words, it does not matter whether resources were used in a previous rate case in conducting the section 7(b)(2) rate test. The resources from the relevant (current) rate case must be used in constructing the stack in the order of least cost first and resources are only used to the extent needed to meet load. These are the express requirements of the Methodology. Because all resources from the relevant rate case are included in the resource stack, there are no "disappearing resources." Resources may be included in the stack but simply not used because the resources are not the least cost resources contained in the stack. This does not mean that the resources have disappeared. Furthermore, the foregoing logic also is supported by the Methodology at page 42, which provides that resources from the resource stack "will be assumed to come on-line to meet the remaining general requirements of the 7(b)(2) customers after FBS service in order of least cost first." This confirms that resources from the resource stack, and thus their costs, are used only to the extent needed to meet 7(b)(2) customers' loads in the 7(b)(2) Case. In summary, BPA's approach is consistent with BPA's statements of what it does in the rate test: model the 7(b)(2) Case rates exactly the same as the Program Case rates except for the five assumptions listed in section 7(b)(2) and using the same underlying premises and ratemaking procedures between the Program and 7(b)(2) Cases.

The IOUs' argument attempts to add a new condition for conducting the section 7(b)(2) rate test that is not provided in the 7(b)(2) Methodology or other rules governing the test. Keep, *et al.*, E-BPA-117, at 7. As noted previously, the section 7(b)(2) rate test is required to be conducted for each rate case. *Id.* In constructing the 7(b)(2) Case, the only load adjustment BPA is directed to make from the Program Case is that BPA "will not include estimates of programmatic conservation savings." *Id*.; *see* 7(b)(2) Methodology at 41. BPA is not directed to take into consideration past load forecasts, either from prior proposals within a rate case or from prior rate cases, in determining the amount of resource additions to be included in the 7(b)(2) Case. Keep, *et al.*, E-BPA-117, at 7. The loads used are from the current rate case and the resources in the stack are from the current rate case. *Id*. at 7-8. The only resources that are added in the 7(b)(2) Case are those from the stack created from the Program Case. *Id*. at 8. These resources are added only when the FBS resources are insufficient to meet 7(b)(2) customers' loads in the current rate case. *Id*.

Furthermore, as noted previously, the 7(b)(2) Methodology ROD provides that the resources "will be 'stacked' in order of cost and assumed to be used as needed to meet loads, least cost first". *Id*. Again, there is no mention that resources which came on-line in previous 7(b)(2) rate tests must come on-line before the lower cost resources in the resource stack for the current rate case. *Id*. In the likely event that resources in previous cases were more costly than more recently acquired resources, the IOU proposal would preclude BPA from complying with the statutory requirement that the resources in the stack be brought on line "least cost first." *Id*.

The IOUs argue that BPA's response to the IOUs' argument on "disappearing resources" was to move to strike it. MREP Brief, B-GE/PL/PS-01, at 34. The IOUs fail to explain, however, why BPA moved to strike the testimony. It was not because of the substance of the IOUs' argument, which is plainly at odds with the express requirements of the Section 7(b)(2) Implementation Methodology, but rather because the IOUs failed to file their testimony in a timely manner in response to BPA's initial proposal. BPA Motion, WP-96-M-54. While the IOUs claim that BPA's treatment on this issue is improper, it was not even raised by the IOUs until after BPA filed its supplemental proposal.

The IOUs argue that the elimination of the costs of 7(b)(2) Case resources that previously had been acquired is inconsistent with common sense, reality, and prudent utility practice. MREP Brief, B-GE/PL/PS-01, at 34; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 16. The IOUs argue that BPA fails to explain why it retains resources already acquired in the Program Case resource stack, and eliminates them from the 7(b)(2) Case, as though resources can be disposed of at no cost. *Id*. As noted above, however, BPA has provided a thorough explanation of its approach to this issue that is consistent with the express requirements of the Methodology. If resources are retained in the Program Case resource stack, they are retained, <u>not</u> eliminated, in the 7(b)(2) Case resource stack. However, when adding resources <u>as needed</u> to meet the 7(b)(2) customers' loads in the 7(b)(2) Case, such resources may not be among the resources that are used, least cost first, to meet such loads. If the resources are not needed to meet the loads, the costs of the resources are properly excluded. In their brief on exceptions, the IOUs argue that conservation and billing credit costs that BPA assumed existed in prior rate cases, but were "removed" by BPA, added at least $190 million to annual costs in BPA's 1993 rate case. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 16. Again, however, as required by the Methodology, BPA must use the resources from the current rate case in establishing the resource stacks. If conservation and billing credits are part of BPA's resources in the current rate case, they are not removed from the resource stack; however, such resources may not be among the resources that are used, least cost first, to meet 7(b)(2) Case loads. Therefore, if these resources are not needed to meet 7(b)(2) Case loads, the costs of the resources are properly excluded.

Furthermore, the section 7(b)(2) rate test is a unique test established by statute and implemented by administrative rule. Keep, *et al.*, E-BPA-117, at 9. As demonstrated by the debate among parties in the 7(b)(2) Implementation ROD, the section 7(b)(2) rate test contains numerous requirements that seem at odds with common sense or prudent utility practice. *Id*. Nevertheless, the rate test must be conducted according to the rules prescribed for its implementation. *Id*. These rules must govern the manner in which actual resources may be acquired and treated for operational or accounting purposes. *Id*. However, the operation of the resource stack is not illogical within the context of the section 7(b)(2) rate test. *Id*. The rate test is required to be conducted at specific times, that is, each current rate case, in order to compare two PF rates for purposes of determining whether BPA's preference customers would be financially disadvantaged under the Northwest Power Act. *Id*. This test logically occurs at these specific times based on information, including resources, which is current at those times. *Id*. If cheaper resources are available at those times to meet 7(b)(2) Case loads, it is proper that they should be used first in meeting the 7(b)(2) customers' loads. It makes perfect sense for the test not to be tied to resources and costs that do not reflect the time period for which the test is conducted. *Id*.

The IOUs argue that it is illogical for BPA to assume something that mirrors reality, such as the assumption of debt refinancings of combustion turbines used to provide reserves, and at the same time make the costs of resources disappear when they are not needed. MREP Brief, B-GE/PL/PS-01, at 35. The assumption of debt refinancing of combustion turbines used to provide reserves impacts both the Program and 7(b)(2) Cases in the section 7(b)(2) rate test because the assumption is incorporated in BPA's 1996 rate proposal. The combustion turbines, however, are not a resource within the 7(b)(2) Case resource stack, which might or might not be used in meeting 7(b)(2) customers' loads. As noted above, the Section 7(b)(2) Implementation Methodology prescribes specific rules establishing limits on the resources and thus costs that can be used to meet preference customer loads in the 7(b)(2) Case.

Decision

Balancing purchases replace reductions in the capability of FBS resources and therefore constitute FBS resources. The balancing purchases, as part of the FBS, are properly used to meet 7(b)(2) customers' loads in the 7(b)(2) Case prior to using resources from the resource stack. The resource stack for the section 7(b)(2) rate test is properly based upon the resources available for the relevant section 7(b)(2) test period in order of least cost first. The rate test properly excludes the costs of resources that are not the least cost resources which are needed to meet the 7(b)(2) customers' loads in the 7(b)(2) Case.

9.5 Mid-Columbia Resources

Issue

Whether 1312 aMW of the Mid-Columbia dams owned by preference customers but not dedicated to their loads should be included in the 7(b)(2) Case resource stack.

Parties' Positions

The IOUs argue that the 1312 aMW of Mid-Columbia resources should not be included in the 7(b)(2) Case resource stack because the power, which is sold under long-term contracts to regional IOUs, is not available for the resource stack. MREP Brief, WP-96-B-GE/PL/PS-01, at 39-40; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 17. The IOUs argue that the Northwest Power Act defines "resources" as "power" rather than generating facilities and therefore the focus should be on who owns the power. *Id.*

WPAG argues that the Northwest Power Act expressly provides that if resources are owned by preference customers but not dedicated to their loads, the resources, such as the Mid-Columbia resources, must be used in the 7(b)(2) Case resource stack. WPAG Brief, WP-96-B-WA-01, at 12-15. WPAG argues that it does not matter whether other parties actually are purchasing power from the resources because the rate test must rely on assumptions prescribed in the Northwest Power Act and ignore real world constraints. *Id.* at 15.

PPC/APAC argued that BPA has no discretion to exclude the Mid-Columbia resources from the 7(b)(2) Case resources stack because they literally satisfy the statutory requirements that resources must be owned by preference customers but not dedicated to their loads. O'Meara and Wolverton, WP-96-E-PP/PA-01, at 6.

BPA's Position

In BPA's initial proposal, BPA noted that there were 1312 aMW from Mid-Columbia dams owned by preference customers and not dedicated to their loads. Keep *et al.*, WP-96-E-BPA-34, at 8-9. BPA identified the projects and costs in its initial proposal testimony in order to receive further comment from rate case parties prior to a decision on whether to incorporate these resources in the 7(b)(2) test. *Id.* BPA noted that the central issue concerning whether the Mid-Columbia resources could be included in the 7(b)(2) Case resource stack was a legal issue that could not be determined until after reviewing the parties' legal briefs. BPA noted that the costs of these resources ranged from approximately 6.63 mills to approximately 8.05 mills per kWh for Wells, Rocky Reach, Wanapum, and Priest Rapids (7.65, 8.05, 8.01 and 6.63 mills, respectively) *Id.* The Rock Island resource cost is approximately 21 mills per kWh. *Id.* at 10.

Evaluation of Positions

In BPA's initial proposal, BPA noted that section 7(b)(2)(D)(ii) of the Northwest Power Act provides that, in addition to FBS resources, 7(b)(2) customers' loads in the 7(b)(2) Case are met with such customers' "resources not committed to load pursuant to section 5(b)." Keep, *et al.*, E-BPA-34, at 8. BPA's Legal Interpretation of Section 7(b)(2) at page 16 also refers to "resources owned or purchased by the 7(b)(2) customers, and not dedicated to their own loads." In reviewing these resources, BPA identified dams owned by 7(b)(2) customers that were not used to meet their own loads and that were omitted from previous 7(b)(2) tests. Keep, *et al.*, E-BPA-34, at 8-9. BPA identified the resources, the owners of the resources and the amount of non-dedicated out-of-region sales included in pre-1996 rate case 7(b)(2) resource stacks and again included in BPA's 1996 initial proposal. *Id.* These figures did not reflect the non-dedicated Mid-Columbia resources identified by BPA. *Id.* BPA also identified the resources, the owners of the resources, the total aMW associated with the resources, the portion of the resources dedicated to 7(b)(2) customers' loads, and the total amount of the resources that is not dedicated to 7(b)(2) customers' loads, both in-region and out-of-region. *Id.* BPA estimated the power costs for these projects using the revenues from the sale of power for each project. *Id.* This calculation yielded costs of approximately 6.63 mills to approximately 8.05 mills per kWh for Wells, Rocky Reach, Wanapum, and Priest Rapids (7.65, 8.05, 8.01 and 6.63 mills, respectively). *Id.* The Rock Island resource cost is approximately 21 mills per kWh. *Id.* While BPA identified the total aMW of these resources owned by 7(b)(2) customers but not dedicated to their own loads, BPA did not include these amounts in its 7(b)(2) test for the 1996 initial proposal. *Id.* BPA identified the projects and costs in its initial proposal testimony in order to receive further comment from rate case parties prior to a decision on whether to incorporate these resources in the 7(b)(2) test. *Id.* The factual issues regarding the Mid-Columbia resources were litigated during the rate case. The parties' legal arguments regarding the Mid-Columbias were raised in their briefs.

Section 7(b)(2) of the Northwest Power Act provides that "[a]fter 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, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, 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 assumes that --

> **§ 7(b)(2)(A)** the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are--

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

§ 7(b)(2)(B) public body, cooperative, and Federal agency customers were served, during such five year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

§7(b)(2)(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

§7(b)(2)(D) all resources that would have been required, during such five year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were--

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b)

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

§7(b)(2)(E) the quantifiable monetary savings, during such five year period, to public body, cooperative and Federal agency customers resulting from--

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this chapter were not achieved.

16 U.S.C. § 839e(b)(2) (emphasis added). As noted above, section 7(b)(2)(D) identifies three types of additional resources assumed to be acquired to meet the 7(b)(2) customers' general requirements when Federal base system (FBS) resources are exhausted. First, the

statute identifies those resources purchased by BPA from preference customers pursuant to section 6 of the Northwest Power Act. Second, the Act lists those resources not committed to load pursuant to section 5(b). These two types of resources must be the least expensive resources owned or purchased by public bodies or cooperatives. These two types of resources are stacked in order of cost and then the least expensive resource is acquired from the stack to meet 7(b)(2) customer loads. The third resource category consists of generic resources required to meet any remaining load, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) customers during the test period.

The 1312 aMW of the Mid-Columbia dams clearly satisfies the statutory requirements of section 7(b)(2) of the Northwest Power Act. The first requirement of section 7(b)(2) is that the resource is not committed to preference customer load pursuant to section 5(b) of the Northwest Power Act. Section 5(b) of the Act provides that BPA will offer to sell to preference customers electric power to meet the firm power load of such preference customers to the extent that such firm power load exceeds "the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region." 16 U.S.C. 839c(b). There is no dispute that the 1312 aMW of the Mid-Columbia resources were not used to meet preference customer loads in the year prior to enactment of the Northwest Power Act. The 1312 aMW also is not dedicated to meeting preference customer loads under the current power sales contracts. Keep, *et al.*, E-BPA-34, at 8. Under the plain meaning of the Act, the Mid-Columbia resources are "not committed to load pursuant to section 5(b)" of the Northwest Power Act.

In addition, section 7(b)(2) requires that resources in the resource stack must be the least expensive resources <u>owned or purchased</u> by preference customers. There is no dispute that the Mid-Columbia dams at issue are owned by preference customers. *Id*. As discussed in greater detail below, such resources also are among the lowest cost resources in the 7(b)(2) Case resource stack. Keep, *et al.*, E-BPA-34, at 10. Again, under the plain meaning of the Act, the Mid-Columbia resources are the least expensive resources owned or purchased by public bodies or cooperatives. In summary, under the plain meaning of the Northwest Power Act, the Mid-Columbia resources expressly satisfy each of the statutory requirements of section 7(b)(2) of the Act and properly are included in the resource stack in order of least cost first.

The IOUs argue that the Program Case and 7(b)(2) Case resource stacks are to represent power, because "the Regional Act defines 'resources' as 'electric power'", not physical generating facilities. MREP Brief, B-GE/PL/PS-01, at 39; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 17; Piro, *et al.*, E-GE/PL/PS-02, at 22; Piro, *et al.*, WP-96-E-GE/PL/PS-04, at 7. The IOUs rely on the definition of "resources" in the Northwest Power Act to argue that if power is sold from a resource, then the resource is not available for inclusion in the resource stack. The IOUs' interpretation, however, would render this provision of the Act meaningless because, while the Act expressly requires BPA to include resources in the 7(b)(2) Case resource stack that are owned by preference customers but not dedicated to their loads, there would never be an instance where this would occur under the IOUs' interpretation. The IOUs argue that if resources owned by preference customers are not dedicated to preference loads and are sold to other entities, the purchasing entities own the power and the power cannot be included in the resource stack. This construction would mean that non-dedicated resources owned by preference customers could only be included in the resource stack if they were not dedicated to preference loads and were not sold to other entities. However, where resources are owned by preference customers and not committed to their loads, such resources must be sold. Despite the fact that resources owned by preference customers and not dedicated to their loads would necessarily be sold to other entities, Congress provided that such resources are properly included in the resource stack. It is a fundamental rule of statutory construction that a reviewing court will "choose the meaning that gives full effect to all provisions of the statute." *United States v. Fields*, 783 F.2d 1382, 1384 (9th Cir. 1986); *Spiegal v. Ryan*, 946 F.2d 1435, 1438 (9th Cir. 1991). A statute should be interpreted such that meaning is given to all its provisions "so that no part will be inoperative or superfluous, void or insignificant." 2A *Sutherland Statutory Construction* § 46.06 (5th ed. 1992). *See also Boise Cascade Corp. v. U.S.E.P.A.*, 942 F.2d 1427, 1432 (9th Cir. 1991). Because the IOUs' interpretation would mean that non-dedicated preference owned resources cannot be included in the resource stack if sold to other entities, and because all non-dedicated power necessarily is sold to other entities, this element of the resources required by statute to be included in the resource stack could never occur. Such an interpretation must be rejected.

Furthermore, the Legal Interpretation directly supports the proposition that a resource properly may be included in the resource stack even though power from the resource has been sold to another party. The Legal Interpretation provides that "these two provisions result in a list of resources which were developed by 7(b)(2) customers and which <u>are assumed to be available</u> to meet regional 7(b)(2) customer needs." (Emphasis added). The Legal Interpretation thus provides that power from the resources might not be available, for example, because of a power sale to another entity, but nevertheless the resources are "assumed to be available" and are properly included in the resource stack.

Furthermore, the suggestion that "resources" should be viewed only as "power" is inconsistent with the manner in which BPA previously has conducted the section 7(b)(2) rate test. The resource stacks contain amounts of power and costs associated with physical generating assets. Keep, *et al.*, E-BPA-55, at 15. Most of these assets are named resources that exist now and are producing power now. *Id.* In some cases generic future resources are included. *Id.* In the 7(b)(2) Case, the resource stack is sorted by cost, with least expensive resources first. *Id.* The Section 7(b)(2) Implementation Methodology addresses this sorting by cost on page 42, stating: "They [the resources] will be assumed to come on-line to meet the remaining general requirements of the 7(b)(2) customers after FBS service in order of least cost first." *Id.* This language reinforces the proposition that even if power has been sold from a resource to other entities, the resource still will be "assumed" to be available for the resource stack. It is the costs of the power producing generating assets or the cost of acquiring conservation that result in the different costs per unit output that both allow and require the sorting of the 7(b)(2) Case resource stack. *Id.*

The IOUs also argue that the Mid-Columbia power is not an available resource because it is power that essentially is all committed by contract to other purchasers under contracts that expire after September 30, 2005, the last date relevant to the section 7(b)(2) rate test. MREP Brief, B-GE/PL/PS-01, at 39; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 17. The IOUs argue that regional IOUs will own the power throughout the 7(b)(2) test period. *Id.* As noted above, however, section 7(b)(2) of the Northwest Power Act includes in the resource stack "resources . . . not committed to load pursuant to section 5(b) . . . [that] were the least expensive resources owned or purchased by public bodies or cooperatives." The Mid-Columbia resources at issue are owned by preference customers. Power from the resources is sold to other parties, but this does not change the treatment of those resources for purposes of the section 7(b)(2) rate test. Congress provided that the resources owned by preference customers but not dedicated to their loads should be included in the 7(b)(2) Case resource stack regardless of whether sales are made from the resources.

During the rate hearing, the IOUs argued that in prior rate proceedings BPA properly allocated resources in the 7(b)(2) rate test based on ownership of the Mid-Columbia project output. Piro, *et al.*, E-GE/PL/PS-04, at 7. This argument is incorrect. In fact, BPA previously included Mid-Columbia resources in the resource stack despite the fact that power from the resources was sold to other entities. In past rate cases BPA included portions of the Mid-Columbia resources in the 7(b)(2) Case resource stack that were not committed to public body or cooperative loads and were the least expensive resources owned or purchased by public bodies or cooperatives. Keep, *et al.*, WP-96-E-BPA-121, at 2. As noted in BPA's rebuttal testimony, however, BPA included only a portion of the Mid-Columbia resources in the resource stack, which represented power from those resources that was sold outside the region. *See* Keep, *et al.*, E-BPA-55, at 16. BPA mistakenly treated Mid-Columbia power for purposes of the resource stack based on whether it was sold inside or outside the region. *Id.* BPA therefore did not allocate the Mid-Columbia resources in the section 7(b)(2) rate test based on "ownership" of the output, as the IOUs characterize their purchases of power from the projects, but rather on whether the sale was in-region or out-of-region. Keep, *et al.*, E-BPA-121, at 2.

More importantly, as noted above, BPA historically has included Mid-Columbia power that was sold outside the region in the resource stack. *Id.* Thus, despite the fact that entities other than regional public bodies and cooperatives who dedicated the power to their regional firm loads purchased a portion of the output of the Mid-Columbia resources, BPA's prior rate cases included such power in the resource stack. *Id.* BPA's prior rate case allocations are therefore consistent with the inclusion in the resource stack of another party's purchase of power from the Mid-Columbia resources.

The IOUs argue that the fact that BPA may have included in the resource stacks a small amount of power temporarily sold by a Mid-Columbia PUD outside the region has no bearing on the treatment to be accorded power sold to others under long-term contracts because there is no indication that such out-of-region sales extended beyond September 30, 1995. MREP Brief, B-GE/PL/PS-01, at 40. The IOUs have mischaracterized the preference customers' out-of-region sales. These sales are not simply temporary sales. These sales were reflected in BPA's 1991 rate case. *See* Documentation for Initial Section 7(b)(2) Rate Test Study, WP-91-E-BPA-06A at 123. These sales also continue at least through 2005. *See* Documentation for Supplemental Section 7(b)(2) Rate Test Study, WP-96-E-BPA-63A, at 107. Whether the sales extend beyond 2005 is irrelevant because, as the IOUs acknowledge, in conducting the section 7(b)(2) rate test the relevant period extends only through 2005. *See* MREP Brief, B-GE/PL/PS-01, at 39. Furthermore, the IOUs admit that their contract for the purchase of power from Priest Rapids Dam expires in 2005. *Id.* at 40. In any event, these sales continue for at least 14 years (1991-2005), which demonstrates that they are not "temporary" but rather long-term sales.

The IOUs also argue that BPA's estimated cost of the Mid-Columbia power is incorrect. MREP Brief, B-GE/PL/PS-01, at 41. The IOUs argued that because the power is committed to third parties, in order to acquire the power BPA would have to buy out the contractual commitments at a market price. Piro, *et al.*, E-GE/PL/PS-02, at 23. As noted above, however, the central issue concerns whether the Mid-Columbia resources should or should not be included in the 7(b)(2) Case resource stack. BPA has concluded that such resources should be included in the resource stack. The IOUs' proposal is inappropriate because the Mid-Columbias are properly included in the resource stack in spite of the existing contracts with third parties for Mid-Columbia power executed in the 1950s and 1960s. Keep, *et al.*, E-BPA-55, at 16. Because the existence of the contracts did not preclude the Mid-Columbias from being included in the resource stack, the buyout of such contracts at market value does not provide a proper basis for determining the cost of the Mid-Columbias. *Id.* The IOUs' proposal to base the cost of the Mid-Columbia resources on the cost of buying out contracts at market price also is inappropriate because such an approach would give little meaning to the requirement to use resources to meet load in the 7(b)(2) Case in the order of least cost first. *Id.* Under the IOUs' proposal, each Mid-Columbia resource would have an identical cost: the market cost of power. This would render the least cost rule superfluous for these resources. *Id.* In their brief on exceptions, the IOUs argue that a group of resources may have identical costs, which may be higher or lower than other resources in the stack. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 17. The IOUs argue that this is not inconsistent with the statute. *Id.* BPA agrees with the IOUs that certain resources might have identical costs and that this would not be inconsistent with the statute. BPA's point, however, is that BPA has always determined the cost of resources based on the cost of the resource itself, not the cost of buying the resource on the market. The use of a blanket market price to determine the cost of individual resources, which have different individual costs, would render the least cost rule superfluous for those particular resources.

The IOUs' proposal also is inconsistent with the manner in which BPA previously has determined the cost of the Mid-Columbia resources included in the 7(b)(2) Case resource stack. *Id.* BPA previously included a small amount of power from the Mid-Columbia resources in the 7(b)(2) Case resource stack. *Id*. This was power sold outside the region. *Id*. BPA mistakenly assumed that the distinction between a sale to an end-user that was inside or outside the region was relevant to the inclusion of the resources in the stack. *Id*. This small amount of power from the Mid-Columbia resources has been included at an average cost of about 2 mills/kWh. *Id*. This shows that the cost of these resources in the resource stack was determined based on the costs of operation of the resources and not the cost of buying out the contracts at market price. *Id*. The IOUs' proposal therefore would be inconsistent with the manner in which BPA previously has determined the cost of these resources. *Id*. Inasmuch as section 7(b)(2)(D) references "the least expensive resources owned . . . by public bodies or cooperatives," it is appropriate to look to the owner's resource cost as the appropriate measure of cost.

BPA proposed an appropriate manner of calculating the cost of the Mid-Columbia resources in BPA's initial proposal. *See* Keep, *et al.*, E-BPA-34, at 10. BPA proposed to use the revenues from operations as a proxy for the cost of operations for the Mid-Columbia resources. *Id*. For example, the 1994 Annual Report of Chelan County PUD, page 17, states that "[t]he cost of operating the Rock Island Production System during 1994 was reflected in the total revenues of $47.3 million." Keep, *et al.*, E-BPA-55, at 17. BPA assumes that public utilities set their revenue requirements, and hence their rates, to recover their costs of operations. *Id*.

Decision

The 1312 aMW of the Mid-Columbia resources owned by 7(b)(2) customers but not dedicated to their loads is properly included in the 7(b)(2) Case resource stack and used to meet 7(b)(2) customers' loads when the FBS is exhausted. The cost of the Mid-Columbia resources is properly based on the fixed and variable costs of the resources themselves. It is appropriate to use the revenues from operations of the resources as a proxy for the cost of the resources. This calculation provides costs of 7.65, 8.05, 8.01 and 6.63 mills/kWh, respectively, for Wells, Rocky Reach, Wanapum, and Priest Rapids Dams. The Rock Island resource cost is approximately 21 mills per kWh.

9.6 Uncontrollable Events

Issue

Whether there are costs of uncontrollable events that should be deducted from the Program Case.

Parties' Positions

The IOUs argue that increases in fish and wildlife costs due to implementation of the Endangered Species Act comprise uncontrollable events. MREP Brief, WP-96-B-GE/PL/PS-01, at 41-42; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 18-19. The IOUs also argue that prolonged years (1992-1994) with below average rainfall comprise an uncontrollable event. *Id*. The IOUs argue that a decrease in aluminum prices (1992-1994) comprises an uncontrollable event. *Id*. The IOUs also argue that the emergence of a competitive electricity market on the West Coast is an uncontrollable event. *Id*. The IOUs argue that a conservative estimate of the cost of these uncontrollable events is $150 million per year, which should be excluded from the Program Case revenue requirement. *Id*.

PPC/APAC argued that costs associated with fish and wildlife mitigation, poor aluminum markets, and poor water conditions are properly reflected in both the Program Case and the 7(b)(2) Case. O'Meara, Wolverton, WP-96-E-PP/PA-02, at 12. PPC/APAC argue that the existence of a more competitive energy market does not impose additional costs on BPA but serves as an incentive to keep BPA's costs down. *Id.*

BPA's Position

"Uncontrollable events" is a statutory term that logically refers to discrete events which differ from the continuum of changing events that occur in nature, business and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking. Keep, *et al.*, WP-96-E-BPA-55, at 13. The Northwest Power Act distinguishes fish and wildlife costs from uncontrollable events. *Id.* Because BPA has not identified any uncontrollable events subject to section 7(g) allocation in its rate proposals, it would be inappropriate to select any particular costs to be viewed as uncontrollable events only for the section 7(b)(2) rate test. *Id.* at 14. In summary, no amount should be excluded from the Program Case for the cost of uncontrollable events. Keep, *et al.*, E-BPA-55, at 14.

Evaluation of Positions

Section 7(b)(2) of the Northwest Power Act provides that:

> 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, <u>exclusive of amounts charged such customers under subsection (g) for the costs of</u> conservation, resource and conservation credits, experimental resources and <u>uncontrollable events</u>, 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 assumes that --."

16 U.S.C. 839e(b)(2)(emphasis added).

Section 7(g) of the Northwest Power Act provides that:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale or inability to sell excess electric power.

16 U.S.C. 839e(g). The analysis of whether there are costs of "uncontrollable events" that should be excluded from the Program Case must begin with an interpretation of this statutory term. The IOUs argue that the word "event" is defined as "something that happens . . ," which is not limited in any manner whatsoever and applies to any occurrence that is beyond BPA's control. MREP Brief, B-GE/PL/PS-01, at 43. This interpretation makes little sense in the context of the section 7(b)(2) rate test. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. Congress could not reasonably have intended to impose such an elusive and impractical standard upon BPA. This is confirmed by a review of the statutory context of this term. BPA must interpret the statute in a manner that is consistent with the context in which it is used, that is, the section 7(b)(2) rate test. As noted previously, the section 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that it does not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. For this reason uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business and government and are routinely reflected in rate development.

In their brief on exceptions, the IOUs argue that under BPA's definition, the eruption of Mt. St. Helens, the stock market crash of 1929 and the revolutionary overthrow of a government would not be uncontrollable events because they are a part of the continuum of nature, business and government. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 18. The IOUs have misstated BPA's position. To the contrary, these specific events would constitute uncontrollable events because they are not normal events that occur in the continuum of changing conditions but rather are significant discrete events that do not occur over time and which are not typically reflected in ratemaking. A significant eruption of Mt. St. Helens would be an uncontrollable event for purposes of section 7(b)(2). A stock market crash of the magnitude of the 1929 crash would be an uncontrollable event for purposes of section 7(b)(2). The revolutionary overthrow of a government which directly imposed costs on BPA would be an uncontrollable event for purposes of section 7(b)(2). While each of these events would qualify as uncontrollable events under BPA's interpretation of the Northwest Power Act, these events have not occurred in the context of this rate proceeding. Instead of these significant, discrete events which are not typically reflected in rates, the IOUs have cited the implementation of BPA's fish and wildlife program, changes in water conditions over a number of years, changes in aluminum prices over a number of years, and changes in the energy market over a number of years as uncontrollable events. As discussed in greater detail below, these events do not qualify as uncontrollable events for purposes of section 7(b)(2) of the Northwest Power Act.

Section 7(b)(2) of the Northwest Power Act excludes certain applicable section 7(g) costs, including the costs of uncontrollable events, from the Program Case. Section 7(b)(2) refers to "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, <u>exclusive of amounts charged such customers under subsection (g) for the costs of . . . uncontrollable events</u> . . ." The exclusion of the costs of uncontrollable events from the Program Case is tied expressly to the "amounts <u>charged</u> such [preference] customers under subsection (g) for the costs of . . . uncontrollable events." In other words, one must look to the costs of uncontrollable events that actually were "charged" to preference customers in the Program Case, which reflects BPA's rate proposal. This is confirmed by BPA's Legal Interpretation of Section 7(b)(2), which emphasizes that applicable 7(g) costs are only those "chargeable to 7(b)(2) customers." *See* Legal Interpretation at 5. BPA, however, did not identify any particular events as uncontrollable events for which costs were allocated according to section 7(g). Keep, *et al.*, E-BPA-55, at 14. Because BPA has not identified any uncontrollable events subject to section 7(g) allocation, it would be inappropriate to select any particular costs to be viewed as uncontrollable events only for the section 7(b)(2) rate test. *Id.* Therefore, no adjustment should be made to the Program Case. In their brief on exceptions, the IOUs argue that while BPA may not have specifically identified these costs as specific line items, BPA has recovered all of its costs and proposes to recover all of its costs in this proceeding. MREP Brief, WP-96-R-GE/PL/PS-01, at 19. In the event BPA had incurred costs from uncontrollable events, however, BPA would have specifically identified such costs in order to properly allocate the costs. More importantly, while there are no costs of uncontrollable events provided by line item, there are no costs of uncontrollable events whatsoever to be included in BPA's costs. The costs cited by the IOUs are not costs of uncontrollable events as that term is used in section 7(b)(2) of the Northwest Power Act but rather costs resulting from normal events that occur in the continuum of changing conditions in nature, business and government and which are typically reflected in ratemaking. As noted in greater detail below, BPA's Risk Analysis is used in BPA's rate development to account for changes of the type identified by the IOUs. Furthermore, as discussed in greater detail below, even assuming for the sake of argument that these costs were not reflected in ratemaking, the costs were incurred and paid in prior years and are not properly used for purposes of the section 7(b)(2) rate test in the current proceeding.

The IOUs argue that the exclusion of uncontrollable costs is a protection from the section 7(b)(2) rate test triggering just because of the costs of uncontrollable events so that residential consumers in the region do not pay more for power under the residential exchange than public agency utilities pay. MREP Brief, B-GE/PL/PS-01, at 41; Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 20. This rationale is not persuasive, however, because in the event that BPA incurred costs for uncontrollable events, public agencies would pay rates that included the allocation of those costs under section 7(g) and exchanging utilities would not pay more than public agencies if these costs were also reflected in the PF Exchange rate. Furthermore, neither the report of the House Committee on Interior and Insular Affairs, the report of the House Committee on Interstate and Foreign Commerce, nor the report of the Senate Committee on Energy and Natural Resources address the intent behind this provision. There is no dispute, however, that the amounts charged preference customers for the costs of uncontrollable events are to be removed from the Program Case. A rationale that makes more sense is that Congress excluded the costs of uncontrollable events as a protection from the section 7(b)(2) rate test triggering just because of the costs of discrete significant events, that is, protection from the costs of a volcanic eruption as opposed to normal variations in water conditions or aluminum prices over time.

The IOUs argue that BPA has incurred significant fish and wildlife costs from the Endangered Species Act and its implementation, which should be viewed as uncontrollable events. MREP Brief, B-GE/PL/PS-01, at 41; Piro, *et al.*, E-GE/PL/PS-02, at 21. First, as discussed in greater detail below, simply because the cost of implementing statutory responsibilities increases, this does not establish the existence of an uncontrollable event. In any event, however, the law provides that fish and wildlife costs are distinguished from, and not properly included in, the cost of uncontrollable events. Section 7(b)(2) of the Northwest Power Act provides that "[a]fter 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, <u>exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events</u>, 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 assumes that --." (Emphasis added). Section 7(g) of the Northwest Power Act provides that "[e]xcept to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, <u>all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale or inability to sell excess electric power</u>." (Emphasis added).

The foregoing provisions establish that Congress provided an express list of the costs to be removed from the Program Case in conducting the section 7(b)(2) rate test. These costs include only the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events. While Congress included other costs in section 7(g), expressly including fish and wildlife costs, Congress deliberately chose not to include those costs as applicable 7(g) costs in section 7(b)(2). It is a fundamental principle of statutory construction that "where a form of conduct, the manner of its performance and operation, and the persons and things to which it refers are designated, there is an inference that all omissions should be understood as exclusions." *Sutherland Statutory Construction*, Vol. 2A at 216 (1992), citing *Ex Parte McCardle*, 7 Wall. (74 U.S.) 506 (1868); *Stephens v. Smith*, 10 Wall (77 U.S.) 321 (1870). Thus, while Congress included fish and wildlife costs in section 7(g), Congress did not include fish and wildlife costs as applicable 7(g) costs. Fish and wildlife costs are therefore distinguished from and not properly included in the cost of uncontrollable events.

The IOUs cite testimony by BPA witnesses regarding fish and wildlife costs, but the testimony does not state that fish and wildlife costs are uncontrollable events. MREP Brief, B-GE/PL/PS-01, at 41. Instead, the testimony notes that fish and wildlife costs have increased. *Id*. Simply because costs increase, however, does not mean that costs increase because of uncontrollable events. While BPA does not have unilateral control of fish and wildlife costs resulting from the Endangered Species Act and the NMFS Biological Opinion, BPA is a Federal agency which first develops a Biological Assessment which is provided to NMFS and used in development of the Biological Opinion. Keep, *et al.*, E-BPA-55, at 13. BPA also is one of the Federal agencies that consults with NMFS in the development of NMFS's Biological Opinion. *Id*. While the Biological Opinion is a NMFS document, BPA determines whether to implement the Biological Opinion and is closely involved with development of the Biological Opinion through consultations with NMFS. *Id*. For this reason, it is inappropriate to characterize increased fish and wildlife costs as uncontrollable events. Furthermore, BPA now has control of fish and wildlife costs. As the IOUs acknowledge, BPA now may avoid such costs in excess of $435 million per year. *Id*. For this reason, fish and wildlife costs should not be viewed as costs of uncontrollable events.

The IOUs also argue that BPA has identified a number of "events" including a prolonged drought which caused an increase in expenses and decrease in revenues during the period from 1992-1994, a slump in aluminum prices during the same period, and the emergence of a competitive electricity market on the West Coast. MREP Brief, B-GE/PL/PS-01, at 42; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 18; Piro, *et al.*, E-GE/PL/PS-02, at 21-22. These arguments do not establish that these are uncontrollable events as provided by the Northwest Power Act. Uncontrollable events are logically viewed as discrete events which differ from the continuum of changing events that occur in nature, business and government and which are not typically reflected in ratemaking. Keep, *et al.*, E-BPA-55, at 13. For example, rainfall and water conditions will vary from forecasts every year, including periods of drought and periods of heavy rainfall. *Id*. Similarly, aluminum prices will vary from forecasts every year depending on the aluminum market. *Id*. at 14. In addition, the electric power market on the West Coast will vary from year to year. *Id*. These variations have occurred in every BPA rate period yet BPA and the parties never have argued that these variations constitute uncontrollable events under section 7(g) for purposes of the section 7(b)(2) rate test. *Id*. While these changes can be substantial changes, it is normal to experience substantial changes in the continuum of changing events in nature, business and government. These are not, however, significant discrete events which occur at a discrete time and which are not typically reflected in ratemaking. As discussed below, information regarding changing conditions and any effect on projected BPA costs is routinely reflected in rate development. *Id*.

In developing rates, BPA conducts a Risk Analysis. The objective of the Risk Analysis is to evaluate the impact that various economic and generation resource capability variations could have on BPA's ability to make its annual U.S. Treasury payments during the rate test period. Documentation for the WPRDS, Part 2, WP-96-E-BPA-05A, at 610. The Risk Analysis measures the financial risks BPA faces in terms of deviations in net revenues (revenues minus costs) from the revenue and expense forecast used to set rates. *Id*. The results of the Risk Analysis are used to support the amount of "Planned Net Revenues for Risk" that are included in BPA's revenue requirement. *Id*. BPA develops a number of risk models to provide input data into the Short-Term Risk Evaluation and Analysis Model (STREAM). *Id*. One of these risk models is for Pacific Northwest Hydro Production Risk. The purpose of this model is to quantify the risks associated with changes in hydro conditions. *Id*. at 611. Another model is the Aluminum Price Risk model, which captures the uncertainty in both the short-run cycle and in the long-term trend of aluminum prices. *Id.* at 615. As noted previously, Congress intended the section 7(b)(2) rate test to compare two PF rates for preference customers: one with and one without the 5 assumptions in section 7(b)(2). This fact suggests that Congress intended the comparison to be between rates that share the same basic costs but for the specific statutory exceptions. For this reason, uncontrollable events should be construed such that it does not exclude costs from the Program Case that are due to conditions that simply vary over time and which typically are reflected in rates. Because substantial variations in hydro conditions and substantial variations in aluminum prices are already reflected in developing BPA's rates, and have been incorporated in BPA ratemaking for many years, they are not properly viewed as uncontrollable events and the costs of those variations should not be subtracted from the Program Case.

With regard to the four specific alleged events cited by the IOUs, fish and wildlife costs, as discussed above, are distinguished from uncontrollable events by the express terms of the statute and are not uncontrollable in any event. The low water conditions are simply the product of variations in water levels that occur each and every year. Similarly, changes in aluminum prices are simply the product of changes in prices that occur each and every year. In developing rates, BPA routinely accounts for variations in water conditions and aluminum prices in BPA's Loads and Resources Study through the use of water forecasts and aluminum price forecasts. One cannot forecast an uncontrollable event because one can never know when it will occur. Variations in water conditions and aluminum prices, however, occur continuously and are routinely forecasted in ratemaking. These are not the types of events Congress intended to include within the term “uncontrollable events.” The IOUs also allege that costs were incurred due to low water conditions and low aluminum prices in 1992-1994. However, the costs incurred from low water conditions and low aluminum prices are incurred and paid at the time of the conditions. They are not paid again in a later rate period. When BPA establishes rates, it is required by law to set rates to recover BPA’s total revenue requirement. As noted above, part of BPA’s total revenue requirement consists of revenues for risk that cover the costs from a continuum of changing events experienced by BPA during the rate period. Furthermore, even assuming for the sake of argument that these conditions were not reflected in BPA’s rates, even though they are, these events did not establish costs that should be used in the 7(b)(2) rate test in developing BPA’s 1996 rates because they are not costs that will be incurred in the rate period. While the IOUs allege that costs for water conditions and aluminum prices were incurred in 1992, BPA established revised rates that would recover BPA’s total costs in 1993. Similarly, while the IOUs allege that such costs were incurred in 1993 and 1994, BPA established revised rates that would recover BPA’s total costs in 1995. Therefore, the costs incurred in 1992-1994 for these conditions are not properly incorporated in BPA’s 1996 rates. Finally, the IOUs argue that a more competitive market on the West Coast has affected BPA’s ability to market its power. The IOUs have not quantified any alleged cost impact on BPA resulting from this market. As noted by PPC, the existence of a more competitive energy market does not impose additional costs on BPA but serves as an incentive to keep BPA’s costs down. O’Meara, Wolverton, WP-96-E-PP/PA-02, at 12. Also, the energy market, like water conditions and aluminum prices, varies from year to year and is not a discrete “uncontrollable event” within the meaning of the statute.

The IOUs argue that a conservative amount that should be excluded from the Program Case for uncontrollable events is $150 million per year. MREP Brief, B-GE/PL/PS-01, at 42; Piro, *et al.*, E-GE/PL/PS-02, at 22. This argument is not well-founded. The $150 million proposal is based upon recent fish and wildlife costs incurred by BPA. Keep, *et al.*, E-BPA-55, at 14. As noted above, fish and wildlife costs are not properly included as costs of uncontrollable events and this amount therefore is inappropriate. *Id.* The additional events identified by the IOUs also are not properly viewed as uncontrollable events. *Id.* Furthermore, even assuming for the sake of argument that such items were uncontrollable events, there has been no demonstration that even if there were costs associated with low water levels and aluminum prices during 1992-1994, that these costs would affect the development of BPA’s 1996 rates. There also has been no demonstration or estimate of costs resulting from the changing energy market. In summary, no amount should be excluded from the Program Case for the cost of uncontrollable events. *Id.*

Decision

No amount should be excluded from the Program Case for the cost of uncontrollable events.

9.7 Energy Services Business

Issue

Whether the cost of conservation excluded from the Program Case as an applicable cost under section 7(g) of the Northwest Power Act should reflect the actual conservation costs charged 7(b)(2) customers by crediting conservation revenues against conservation costs.

Parties' Positions

The IOUs argue that section 7(b)(2) of the Northwest Power Act provides that the Program Case is adjusted only for conservation costs, while section 7(g) refers to both costs and benefits, and therefore BPA should remove conservation costs from the Program Case without regard to any offsetting conservation revenues. MREP Brief, WP-96-B-GE/PL/PS-01, at 46-47; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 19.

PPC argues that section 7(g) of the Northwest Power Act refers to both costs and benefits, which requires that BPA should offset conservation costs with conservation revenues. PPC Brief, WP-96-B-PP-01, at 20-21; PPC Ex. Brief, WP-96-R-PP-02, at 2. PPC/APAC argued that both the costs and revenues from the Energy Services business be eliminated altogether from the calculation of the section 7(b)(2) rate test. O'Meara, Wolverton, WP-96-PP/PA-01, at 8-9.

BPA's Position

For the initial proposal, the estimated revenues from BPA's Energy Services business were assigned as credits against administrative and general costs. Keep, *et al.*, WP-96-E-BPA-34, at 10-11. In this way these revenues reduced the rates of all rate pools. *Id.* BPA's initial proposal identified other ways of treating BPA's Energy Services business costs and conservation costs, including the separation of the Energy Services business costs and revenues from applicable 7(g) costs or the inclusion of Energy Services business costs and revenues in applicable 7(g) costs. *Id.* BPA noted that this issue rested substantially on a legal issue regarding whether conservation costs charged to preference customers under section 7(b)(2) should reflect conservation revenues and that BPA would review the parties' briefs prior to making a determination. Keep, *et al.*, WP-96-E-BPA-55, at 11.

Evaluation of Positions

BPA recently developed an Energy Services business, which provides conservation services to BPA's customers apart from BPA's existing conservation projects. Keep, *et al.*, E-BPA-34, at 10. The costs associated with the Energy Services business are subsumed within the conservation costs in the revenue requirement data provided by BPA's Financial Services Group. *Id.* In BPA's initial proposal, the division of the total cost of conservation between existing programs and Energy Service programs was not specified and therefore all costs were assigned to conservation. *Id*. In addition to the cost of conservation, BPA's Energy Services business generates revenues. *Id*. For the initial proposal, the estimated revenues from the Energy Services business were assigned as credits against administrative and general costs. *Id*. In this way these revenues reduced the rates of all rate pools. *Id*.

BPA's initial proposal identified other ways of treating BPA's Energy Services business costs and conservation costs. *Id*. at 11. BPA noted that assigning the Energy Services business costs as applicable 7(g) costs when there are Energy Services business revenues to offset the costs may be inappropriate. *Id*. BPA noted that a logical approach would be to separate the Energy Services business costs and revenues from applicable 7(g) costs. *Id*. This would be appropriate because the Energy Services business generates revenues which support its costs and therefore these costs are not expected to be borne by BPA's ratepayers. *Id*. Another alternative would be to include Energy Services business costs and revenues in applicable 7(g) costs. *Id*. This approach also would reflect the revenues that offset Energy Services business costs. *Id*.

The IOUs support BPA's exclusion of Energy Services revenues from the calculation of applicable section 7(g) costs in the initial proposal. MREP Brief, B-GE/PL/PS-01, at 46-47; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 19; Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 19. The IOUs argue that the section 7(b)(2) rate test requires the exclusion of certain section 7(g) costs, including conservation costs, from the Program Case. *Id*. The IOUs then note that section 7(g) of the Act refers to both costs and benefits from conservation. *Id*. The IOUs view revenues from Energy Services as a benefit. The exclusion in section 7(b)(2), they argue, is limited to 7(g) costs. *Id*. Therefore, the IOUs argue that Energy Services Business revenues are irrelevant and should not affect the calculation of applicable section 7(g) costs. *Id*. While this argument has initial appeal, it is not dispositive upon detailed review.

Section 7(b)(2) of the Northwest Power Act provides that:

> 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, <u>exclusive of amounts charged such customers under subsection (g) for the costs of conservation</u>, resource and conservation credits, experimental resources and uncontrollable events, 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 assumes that --."

(Emphasis added).

Section 7(g) of the Northwest Power Act provides that:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the cost of credits granted pursuant to section 6, operating services, and the sale or inability to sell excess electric power.

Section 7(b)(2) of the Northwest Power Act excludes certain applicable section 7(g) costs, including conservation, from the Program Case. Section 7(b)(2) refers to "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, <u>exclusive of amounts charged such customers under subsection (g) for the costs of conservation</u>. . ." The exclusion of conservation costs from the Program Case is tied to the "amounts [of conservation costs] <u>charged</u> such [preference] customers under subsection (g) for the costs of conservation." In other words, one must look to the conservation costs that were actually "charged" to preference customers in the Program Case, which reflects BPA's rate proposal. This is supported by BPA's Legal Interpretation of Section 7(b)(2), which emphasizes that applicable 7(g) costs are only those "chargeable to 7(b)(2) customers." *See* Legal Interpretation at 5. In BPA's rate proposal and Program Case, BPA only "charged" preference customers the net cost of conservation, that is, total costs less Energy Services Business revenues. *See* Documentation for Supplemental Wholesale Power Rate Design Study, Part 1, WP-96-E-BPA-61A, at 179-184, Table COSA 06.

PPC and APAC argued that BPA should eliminate both the costs and benefits of the Energy Services Business from the calculation of the rate test in both the Program and 7(b)(2) Cases. O'Meara, *et al.*, WP-96-E-PP/PA-01, at 9. However, the costs of BPA's Energy Services Business are included in BPA's revenue requirement. Keep, *et al.*, E-BPA-55, at 12. BPA establishes rates to recover its costs. *Id*. BPA cannot arbitrarily eliminate Energy Services Business costs from the rate setting process. *Id*.

<u>Decision</u>

As demonstrated by the foregoing discussion, the question of whether Energy Services business revenues should be credited against Energy Services business costs is a difficult legal issue. BPA does not adopt a formal legal position on this issue at this time. BPA has only recently developed the Energy Services business and therefore has no previous experience regarding forecasted Energy Services business costs or revenues. BPA will continue BPA's initial proposal treatment of crediting Energy Services business revenues *against administrative and general costs. In this way, the revenues reduce the costs of all rate pools.*

9.8 Quantification of Reserve Benefits

Issue

Whether BPA has quantified reserve benefits in the 7(b)(2) Case using the same analysis as used in BPA's current rate case.

Parties' Positions

The IOUs argue that BPA has improperly conducted the section 7(b)(2) rate test by causing resources used in the value of reserves analysis to disappear in the 7(b)(2) Case. MREP Brief, WP-96-B-GE/PL/PS-01, at 37-38; MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 19. The IOUs also argue BPA has said that it "will quantify reserve benefits in the 7(b)(2) Case by using the same analysis that is used in the relevant rate case," but that BPA has not done so. MREP Brief, WP-96-B-GE/PL/PS-01, at 38.

BPA's Position

BPA has quantified reserve benefits in the 7(b)(2) Case using the same analysis that is used in the current rate case. Documentation for Initial Section 7(b)(2) Rate Test Study, WP-96-E-BPA-07A, at 121; Documentation for Supplemental Section 7(b)(2) Rate Test Study, WP-96-E-BPA-63A, at 109.

Evaluation of Positions

The IOUs argue that BPA said it would "quantify reserve benefits in the 7(b)(2) case by using the same analysis that is used in the relevant rate case," but it has not done so. MREP Brief, B-GE/PL/PS-01, at 38. To the contrary, BPA has quantified reserve benefits in the 7(b)(2) Case in the same manner as in the relevant rate case and also in accordance with the requirements of section 7(b)(2) of the Northwest Power Act and the Section 7(b)(2) Implementation Methodology, b-2-84-F-02. The Section 7(b)(2) Implementation Methodology Record of Decision, b-2-84-F-02 at 9, provides:

> BPA will quantify reserve benefits in the 7(b)(2) case by using the same analysis as is used in the relevant rate case. The full value (not the credit) attributed to the restriction rights by that analysis will be the quantity of reserve benefits in the 7(b)(2) case. A financing benefits analysis of the reserve margins required in the 7(b)(2) case will be reflected in the reserve benefits determination; this analysis will be performed by the outside financial analyst.

The Methodology ROD also provides that "[t]he quantification of reserves as calculated in the relevant rate case will be adjusted in the 7(b)(2) case for the actual amount of "within or adjacent" DSI loads assumed to be served by 7(b)(2) customers." *Id*. at 11.

In both BPA's initial and supplemental rate proposals, BPA used the full value of reserves from the relevant rate case and adjusted the value by a reduction for the financing benefits and by a reduction for "within or adjacent" DSI loads assumed not to be served by 7(b)(2) customers. Documentation for Initial Section 7(b)(2) Rate Test Study, E-BPA-07A, at 121; Documentation for Supplemental Section 7(b)(2) Rate Test Study, E-BPA-63A, at 109. The IOUs' suggestion that BPA is not using the same analysis is therefore incorrect.

The IOUs also apparently argue that the hypothetical CTs used to value the reserves provided by the DSIs are in fact actual resource additions and the full cost of those CTs should be included in the development of the 7(b)(2) Case rates. As noted above, however, the Section 7(b)(2) Implementation Methodology prescribes specific rules for determining reserve benefits in the 7(b)(2) Case. These rules do not instruct BPA to include the total costs of hypothetical CTs in the development of the 7(b)(2) Case rates. The rules only require BPA to use the quantification of the reserves as provided in the relevant rate case as adjusted for financing benefits and "within and adjacent" DSI loads.

The hypothetical CTs are only used to determine a value for the DSI reserves. The actual acquisition of resources in the 7(b)(2) Case is governed by separate directives of section 7(b)(2) and the Section 7(b)(2) Implementation Methodology. These directives require BPA to first use Federal base system resources in meeting 7(b)(2) Case loads. If the FBS is insufficient to meet those loads, BPA uses specified types of resources from the relevant rate case in the order of least cost first. The hypothetical CTs are not resources that are included in the 7(b)(2) Case resource stack.

In summary, BPA is determining reserve benefits in the 7(b)(2) Case in accordance with section 7(b)(2) of the Northwest Power Act and the Section 7(b)(2) Implementation Methodology. In addition, BPA is treating the costs of resources in the 7(b)(2) Case in accordance with the directives that govern such costs.

Decision

BPA has properly quantified reserve benefits in the 7(b)(2) Case by using the same analysis used in the current rate case.

10.0 REVENUE FORECAST AND SHORT-TERM PURCHASES

10.1 Introduction

The Revenue Forecast projects revenues given specified rates and loads. For the 1996 rates, two revenue forecasts are prepared. First, BPA forecasts revenues under existing rates (1995 rates) for the fiscal years (FY) 1996, 1997, 1998, 1999, 2000, and 2001. Wedlund, Reilly, WP-96-E-BPA-81, at 2. Projected revenues in FY 1996 are used to determine BPA's cash balance at the beginning of the rate period. *Id.* The FY 1997 through FY 2001 forecasts at current rates are used to determine the adequacy, or demonstrate the inadequacy, of current rates to meet BPA's revenue requirement. *Id.* The forecasts of FY 1997 through FY 2001 revenues at revised rates are used in the revised revenue test to demonstrate that the revised rates are adequate to meet BPA's revenue requirement. *Id.*

Most of BPA's revenues are expected from firm power sales to its preference and direct service industrial customers. Wholesale Power Rate Development Study, WP-96-FS-BPA-05, at 62. However, BPA also receives revenues from other sources. For instance, BPA receives revenue from power sales where the rates are based on formulas specified by contract. *Id.* In addition, BPA expects to receive revenues from sales resulting from variations in water conditions from critical water levels and from other types of short-term transactions. *Id.* The revenue forecast also projects revenues BPA expects to receive during the test period from these other sources.

Expected water conditions not only affect the amount of revenues BPA expects to receive but the amount of power purchases BPA expects to make during the test period. BPA expects to purchase power to meet monthly firm load deficits, provide operational flexibility, displace higher-cost purchases, and provide for certain fish mitigation measures. *Id.* at 14. BPA estimates the need for power purchases based on critical water conditions, but the amount of power BPA expects to purchase varies under different water conditions. For ratemaking purposes, expected power purchases are projected under each of the 50 water conditions and then averaged. *Id.* at 61. The result of this approach is that the amount of expected power purchases is just enough to meet firm loads under average water conditions.

10.1.1 Revenues from Excess Federal Power

As part of the Energy and Water Development Appropriation Act of 1996, Congress included a provision that provides new marketing authority to BPA. Public Law 104-46. Congress recognized that current BPA authorizing legislation limits the agency's flexibility to market Federal power. To increase BPA's revenues and competitiveness, Congress enacted legislation that removes some of BPA's legislative restrictions from certain Federal power sales. H.R. 1905, Conf. Rep. No. 293, 104th Cong., 1st Sess. 94 (1995). Under the Energy and Water Development Appropriation Act of 1996, BPA can market a category of surplus power called "excess Federal power" without certain statutory restrictions. Public Law 104-46. The excess Federal power that BPA can sell without the "sale for resale" prohibition and the 60-day "call-back provision" for energy and the 60-month "call-back provision" for capacity is power freed up as a result of reduced firm power loads or as a result of fisheries operations. *Id.* BPA expects the legislation will increase revenues by increasing the price BPA can obtain for surplus power compared to the price BPA would have received had the restrictions been attached to these sales, and by expanding the market for this power. Wedlund, Reilly, E-BPA-81, at 7; Tr. 1572. In setting its 1996 rates, BPA included additional revenues of about $16 million per year in its forecast as a result of the new legislation.

For ratemaking purposes, BPA assumed that BPA would directly market some of the excess Federal power and that some would be sold to IOUs, brokers, or power marketing firms, and these entities would remarket to others in the surplus bulk power market. Wedlund, Reilly, E-BPA-81, at 7. The $16 million represents the additional revenues BPA could expect from additional sales and other sales that are currently forecasted to be made at nonfirm energy prices. *Id.* at 8. No party challenged BPA's estimate of the $16 million in additional revenues. BPA believes that the $16 million is a conservative and modest estimate of the additional revenues that BPA may receive without these restrictions on its ability to market excess Federal power. *Id.* at 7. A more moderate estimate would be higher. For the final proposal, BPA increased its estimate of the additional revenue benefits from the new legislation by about $10 million above the modest estimate included in the supplemental proposal, resulting in expected revenues from power due to reductions in firm load or power generated for fish and wildlife of about $26 million per year. *See* the WPRDS, WP-96-FS-BPA-05, at 65.

10.1.2 <u>Purchased Power Pricing</u>

In the 1996 initial proposal, the purchase power cost formula was revised from the formula used in past rate cases to reflect BPA's recent experience buying and selling power in the short-term market. Wedlund, Reilly, WP-96-E-BPA-26, at 7. The result was lower projected prices for power BPA expected to purchase during the test period. *Id.* Even though the expected prices for power purchases were more in line with BPA's recent experience in the short-term market, the prices that BPA expected to pay for power in the short-term market were significantly above the prices at which BPA expected to sell power in the same market in the later years of the test period. As such, the revised purchased power price formula produced results that were counter-intuitive. Wedlund, Reilly, E-BPA-81, at 11. In the supplemental proposal, BPA proposed a temporary solution to this problem and based its projections of purchase power costs on the spot market burner tip forecast of natural gas prices in California. *Id.* BPA witnesses testified that this proposal was a temporary solution and had problems as well. *Id.* Although using the spot market burner tip price of gas in California solved the problem of power purchase costs diverging significantly from the average price for BPA's nonfirm sales prices, it created a different problem--the price BPA expected to pay for power did not vary with the amount of power purchased. *Id.* BPA witnesses later proposed using an algorithm developed from PMDAM data which was between the higher level in the initial proposal and the lower level in the supplemental proposal. Bolden, *et al.*, WP-96-E-BPA-106, at 20-21. No party took issue with using an algorithm based on PMDAM data to estimate the expected costs to BPA of purchasing short-term power during the rate period.

10.2 Expected Revenues from Nonfirm Energy Sales

As part of its supplemental proposal, BPA proposed to revise its forecast of the Pacific Northwest (PNW) thermal displacement market. Conger, Rohe, WP-96-E-BPA-82, at 1. The PNW thermal displacement market consists of the output from gas-fired, coal-fired and wood-fired plants that potentially can be displaced by short-term power purchases. *Id.* at 2. In theory, a company will operate a plant when its variable costs are lower than the price for spot market power, and will use spot-market energy to displace the output from a plant when the price of spot market power is lower than its variable costs. *Id.* Based on new information BPA was able to obtain, BPA proposed to update the variable costs of displaceable PNW thermal plants using plant specific costs. *Id.* at 3. The revision was a partial revision, focusing mainly on the decremental costs, which had not been updated recently, of the various thermal resources. The update on the amount of output from each plant that could be displaced with BPA's nonfirm energy was incomplete at the time BPA's supplemental proposal was prepared; however, some resources were removed from the market because there was no evidence that they had ever been displaced with economy energy. Conger, *et al.*, WP-96-E-BPA-112, at 6.

The DSIs initially argued that BPA understated the amount by which PNW thermal resources can be displaced with BPA's nonfirm energy, thereby understating revenues from nonfirm sales and overcharging firm power customers. Schoenbeck, Bliven, WP-96-E-DS-09, at 4-5. They claimed that BPA inappropriately removed resources from its estimate of the PNW thermal displacement market, and understated the displaceable portion of other resources. *Id.* at 5-8. The DSIs argued that BPA should increase the size of the PNW thermal displacement market by including all resources relied on by utilities to meet firm regional load, which they allege is consistent with past practice. A larger displacement market such as the DSIs proposed would be significantly larger than the PNW thermal displacement market currently represented in the Revenue Forecast Model and significantly larger than the PNW thermal displacement market represented in other models used in this rate filing. While some of the plant-specific information on the amount of power that can be displaced is out of date, the overall size of the PNW thermal displacement market contained in BPA's forecast is more consistent with other market estimates than the size recommended by the DSIs. Tr.1771. However, BPA agrees with the DSIs that the Cogentrix combined-cycle combustion turbine unit should be included the PNW thermal displacement market. Conger, *et al.*, E-BPA-112, at 7. Accordingly, in the final rate proposal, Cogentrix will be included in the PNW thermal displacement market at an assumed heat rate of 7,300 Btu/kWh and variable O&M costs of 0.4 mills/kWh. The DSIs did not pursue this issue in their briefs, and thus they are deemed to take no position on the size of the PNW thermal displacement market.

10.3 Expected Revenues from Computed Requirements Customers

Issue

Whether BPA should assume, in developing its rates and revenue forecasts that all customers will purchase under the new 1996 Power Sales Contracts for the rate period.

Parties' Positions

APAC and PGP state that PGP members will not sign the 1996 Power Sales Contract, based on their understanding of December 6, 1996, contract draft. Leone-Woods, *et al.*, WP-96-E-PA/PG-03, at 4; Smith, *et al.*, WP-96-E-PA/PG-05, at 2. Thus, PGP and APAC urge BPA to set its 1996 rates based on the assumption that the utilities will continue to purchase power under the terms of their existing 1981 Power Sales Contract. *Id.*

BPA's Position

In developing its rates, BPA assumed that all of its customers, preference utilities and DSIs, would sign new 1996 Power Sales Contracts. Kitchen, Moorman, WP-96-E-BPA-98, at 7; Keep, Revitch, WP-96-E-BPA-23, at 6.

Evaluation of Positions

BPA and its customers devoted a lot of time and effort to reach agreement on the principles guiding the new 1996 Power Sales Contracts (hereinafter the 1996 Power contracts). Kitchen, Moorman, E-BPA-98, at 7. The principles and the 1996 Power contracts were developed after nearly three years of negotiations between BPA and its customers. The 1996 Power contracts reflect conditions in the 1990s, instead of the late 1970s when the 1981 Power Sales Contracts (1981 Power contracts) were negotiated. The 1996 Power contracts allow customers to pick which products and services they want to purchase. In effect, with the 1996 Power contracts, each customer can create a unique contract with BPA, tailored to its needs and the new competitive environment. Kitchen, Moorman, WP-96-E-BPA-11, at 3. In contrast, under the 1981 Power contracts, most customers receive basically the same products and services regardless of whether they need or even use all those products or services. For purposes of developing its rates, BPA assumed that all of its customers, both utilities and DSIs, would choose to purchase power under the terms of the 1996 Power contracts, due to the added flexibility in terms of product choice that is included in these new contracts. Kitchen, Moorman, E-BPA-98, at 7; Keep, Revitch, E-BPA-23, at 6.

Some DSIs have signed new 1996 Power contracts. Tr. 450. BPA's utility customers, however, have not yet signed new contracts. APAC and PGP state that PGP members will not sign the 1996 Power contract, based on their understanding of the December 6, 1996, contract draft. Leone-Woods, *et al.*, E-PA/PG-03, at 4. PGP claims that PGP utilities have not yet made a final decision about whether to execute a new contract or retain their existing contract. Nevertheless, PGP states that in general PGP utilities prefer to retain their existing 1981 Power contract. Smith, *et al.*, E-PG-05, at 2. Thus, APAC and PGP urge BPA to set its 1996 rates based on the assumption that the utilities will continue to purchase power under the terms of their existing 1981 Power contracts. Leone-Woods, *et al.*, E-PA/PG-03, at 4. BPA agrees that some utilities may not sign new 1996 Power contracts. In fact, some customers may simply choose to waive some of their existing contractual rights and thereby amend their existing contracts instead of signing a 1996 Power contract. However, some utility customers may choose to change their purchase relationship with BPA and move to the relationship in the 1996 Power contracts. Currently, BPA does not have sufficient information on the record to determine which utilities will continue to purchase under the existing contract and which will move to the new contract. Moreover, the parties did not provide any information that would allow BPA to identify which utilities would sign new 1996 Power contracts and which utilities would continue to purchase power under the 1981 Power contracts. Arnold, *et al.,* WP-96-E-BPA-45, at 6. Since none of the utility customers has signed a new contract, BPA agrees with APAC and PGP that absent better information, for ratemaking purposes, BPA should assume that the utilities will continue to purchase under the terms of their existing 1981 Power contracts.

Changing the assumption of under what contract the utilities will purchase primarily affects the expected loads from Computed Requirements Customers. Under the 1981 Power contract, these customers have a contract right to displace their purchases from BPA. Metcalf, *et al.*, WP-96-E-BPA-105, at 3. In comparison, the new 1996 Power contracts do not contain a right to displace unless a customer purchases products which mitigate or allow displacement. Absent any product for displacement, the 1996 Power Contracts impose a "take-or-pay" obligation on the customer. *Id.* at 4.

Decision

Absent better information, BPA will develop its rates and revenue forecasts assuming that all customers continue to purchase under the 1981 Power contracts, as amended. BPA will not assume that its purchase relationship with its utility customers includes a "take-or-pay" obligation.

10.4 Section 4(h)(10)(C)

10.4.1 Section 4(h)(10)(C) Credits

Issue

Whether foregone revenues should be included in the costs allocated to non-power purposes pursuant to section 4(h)(10)(C) of the Northwest Power Act.

Parties' Positions

The DSIs argue that foregone revenues should be included in the costs allocated to non-power purposes pursuant to section 4(h)(10)(C) of the Northwest Power Act. They argue that Congress intended that power customers bear only those fish and wildlife mitigation costs related to the operation of electric power facilities. DSI Brief, WP-96-B-DS-01, at 38-41.

BPA's Position

BPA testified that section 4(h)(10)(A) of the Northwest Power Act requires the Administrator to make expenditures from the Bonneville Power Administration fund for fish and wildlife measures, and that section 4(h)(10)(C) requires the Administrator to allocate those expenditures to the various projects and project purposes. Because foregone revenues are not expenditures from the BPA fund, they are not reallocated to non-power purposes. DeWolf, *et al.*, WP-96-E-BPA-101, at 2.

Evaluation of Positions

Under section 4(h)(10)(C) of the Northwest Power Act, the Administrator allocates expenditures for fish and wildlife mitigation to the various hydroelectric projects and to the various project purposes. 16 U.S.C. § 839b(h)(10)(C). The DSIs argue that the Administrator should also allocate foregone revenues. DSI Brief, B-DS-01, at 38-41. Foregone revenues are revenues BPA does not earn because water is used for fish and wildlife mitigation measures instead of being used to generate electricity.

The DSIs rely on two provisions of the Northwest Power Act. Section 4(h)(8)(B) provides that "[c]onsumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only." 16 U.S.C. § 839b(h)(8)(B). Section 4(h)(8)(D) provides that "[m]onetary costs and electric power losses resulting from the implementation of the program shall be allocated by the Administrator consistent with individual project impacts and system-wide objectives of this subsection." *Id.* § 839b(h)(8)(D).

The DSIs have cited these provisions out of context, ignoring the structure of section 4 of the Northwest Power Act. Section 4 establishes the Pacific Northwest Electric Power and Conservation Planning Council, and charges it with establishing a regional conservation and electric power plan and a program to protect, mitigate, and enhance fish and wildlife. *Id.* § 839b(a)(1). Sections 4(d) and (e) of the Act set out the components of the plan and procedures for its adoption. *Id.* §§ 839b(d) & (e). Section 4(h)(1) sets forth the Council's responsibility to develop the program. *Id.* § 839b(h)(1)(A) ("The Council shall promptly develop and adopt, pursuant to this subsection, a program to protect, mitigate, and enhance fish and wildlife . . . on the Columbia River and its tributaries.")

Sections 4(h)(2) through 4(h)(9) set forth standards for the Council's development of the program. For example, section 4(h)(2) provides that the Council shall solicit recommendations for the program from fish and wildlife agencies and Indian tribes. *Id.* § 839b(4)(h)(2). Section 4(h)(4) establishes procedures for the Council to obtain public comment on the recommendations. *Id.* § 839b(4)(h)(4). Sections 4(h)(5) through (7) charge the Council with adopting the program on the basis of the recommendations and other factors, and with providing explanations in those cases in which it fails to adopt a recommendation. *Id.* §§ 839b(4)(h)(5) to (7).

Sections 4(h)(1) through 4(h)(7), therefore, concern the responsibility of the Power Planning Council to adopt a fish and wildlife mitigation program. Section 4(h)(8) sets forth principles for the Council to consider in the program's adoption. Unlike the previous sections, it does not establish explicit mandates. Sections 4(h)(8)(A) and (D) provide as follows:

> 4(h)(8) <u>The Council shall consider</u>, in developing and adopting a program pursuant to this subsection, the following principles:
>
> . . . .
>
> 4(h)(8)(B) Consumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only.
>
> . . . .
>
> 4(h)(8)(D) Monetary costs and electric power losses resulting from the implementation of the program shall be allocated by the Administrator consistent with individual project impacts and system-wide objectives of this subsection.

Id. §§ 839b(h)(8)(B) and (D) (emphasis added).

The Administrator's responsibilities are set forth in section 4(h)(10). Section 4(h)(10(A) provides that

> [t]he Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under this Act and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries in a manner consistent with the plan, if in existence, the program adopted by the Council under this subsection, and the purposes of this Act.

Id. § 839b(h)(10)(A).

Section 4(h)(10)(B) provides that "[t]he Administrator may make expenditures from such fund which shall be included in the annual or supplementary budgets submitted to the Congress pursuant to the Federal Columbia Transmission System Act." *Id.* § 839b(h)(10)(B) (emphasis added). Finally, section 4(h)(10)(C) sets forth the Administrator's responsibility to allocate expenditures to power and non-power purposes:

> The amounts expended by the Administrator for each activity pursuant to this subsection shall be allocated as appropriate by the Administrator . . . among the various hydroelectric projects of the Federal Columbia River Power System. Amounts so allocated shall be allocated to the various project purposes in accordance with existing accounting procedures for the Federal Columbia River Power System.

Id. § 839b(h)(10)(C) (emphasis added).

Section 4(h)(10) differs from the previous sections in three respects. First, it concerns not the Council's responsibilities but the Administrator's. Sections 4(h)(1) through 4(h)(9) all concern the Council's adoption of its fish and wildlife program. Section 4(h)(10) then sets forth the Administrator's responsibility to act in a manner consistent with the plan and the program. This responsibility includes making and allocating expenditures from the BPA fund for fish and wildlife measures.

Second, unlike section 4(h)(8), section 4(h)(10) is mandatory. Section 4(h)(8) sets forth principles for the Council to "consider." The reference in section 4(h)(8)(D) to the Administrator's allocation of monetary costs and electric power losses is simply one such principle. The introductory language of section 4(h)(8) belies the conclusion that Congress intended this language to bind the Administrator. By contrast, section 4(h)(10) provides that the Administrator "shall" use the Bonneville Power Administration fund and "shall" allocate expenditures among the various projects and project purposes. It contains no reference to the Council nor any introductory language indicating that its provisions are discretionary.

Third, section 4(h)(10)(C) applies only to "amounts expended" by the Administrator. The DSIs suggest that it is not clear whether foregone revenues are "expenditures" under section 4(h)(10). DSI Initial Brief, WP-96-B-DS-01, at 40. They argue that foregone revenues are "known and measurable costs associated with BPA's fish mitigation efforts." *Id.* Section 4(h)(10), however, refers to "expenditures" and "amounts expended," not to "costs." Section 4(h)(8)(D) references allocation of "[m]onetary costs and electric power losses." Significantly, Congress omitted this language from section 4(h)(10). Had Congress intended that the Administrator allocate foregone revenues under section 4(h)(10)(C), it could have retained this language in that section. Its failure to do so suggests that this was not Congress's intent.

Under section 4(h)(10)(C), therefore, the Administrator allocates actual expenditures to the various project purposes. The Act contains no direction to the Administrator to allocate foregone revenues.

When section 4(h) is read in its entirety, it becomes clear that it contains two distinct parts. The first part guides the Council in the adoption of its fish and wildlife program. The second part applies to the Administrator, and directs him to use the Bonneville Power Administration Fund to protect fish and wildlife in a manner consistent with the Council's program, and to allocate expenditures to the various projects and project purposes. The DSIs' argument relies on the first part only. It is the second, however, that controls the allocation. Congress did not include foregone revenues in this part of the statute.

Decision

Foregone revenues will not be included in the calculation of the credit pursuant to section 4(h)(10)(C) of the Northwest Power Act. That section directs the Administrator to allocate actual expenditures among the various projects and project purposes. It contains no reference to electric power losses or to foregone revenues.

10.4.2 Access to Fish Cost Contingency Fund

The letter of October 24, 1995, from Office of Management and Budget Director Alice Rivlin to Senator Mark Hatfield (DeWolf, *et al.*, WP-96-E-BPA-69, Attachment 1) reflects an agreement between the Administration and members of the Congressional delegation to establish a BPA Fish Cost Contingency Fund. The Fund was formed for BPA to take credit for the part of BPA's fish and wildlife mitigation expenditures allocable to non-power purposes which had accrued, but had not yet been taken, from the date of enactment of the Northwest Power Act to the present pursuant to 4(h)(10)(C) of the Act. The estimated amount of that fund as of September 30, 1995, was $325 million. The exact amount is to be certified by BPA to the Secretary of the Treasury. According to the agreement, BPA may use credits from the Fund for fish and water-related costs during fiscal years 1996 through 2001 in two circumstances: (1) for additional costs resulting from court-ordered fish and wildlife actions if the costs of those actions exceed the target spending levels in the BPA fish budget; and (2) for shortfalls in nonfirm power revenues or increases in power purchase costs due to adverse hydro conditions in any of the six years of the covered period. In any of those years, if the total of any such shortfall and increase exceeds a threshold level determined in the final rate filing that is predicted to make this funding available 25 to 30 percent of the time during the six year period, BPA may draw on the Fund for the excess. *Id.*; Arnold, *et al.*, WP-96-E-BPA-69, at 8-10. Because BPA expects the credits to be available 25 to 30 percent of the time due to the nonfirm revenue shortfall and excess power purchase cost contingency, BPA will show an average expected credit over 50 water years as additional revenues in each year of the rate period. The amount will be detailed in the Revenue Forecast in the final Wholesale Power Rate Development Study. *See generally* Supplemental Revenue Requirement Study, WP-96-E-BPA-58, at 113-116.

Issue

Whether the Fish Cost Contingency Fund arrangement represents a reasonable exercise of the Administrator's discretion to take credit for expenditures in excess of power generation's appropriately allocated share.

Party's Position

BPA should either reduce its revenue requirement by the amount of the Fish Cost Contingency Fund, plus foregone revenues of $100 million, to reduce rates to its customers, or refund the money directly to customers from whom it was taken. DSI Pr. Brief, WP-96-P-DS-01, at 31-32; DSI Brief, WP-96-B-DS-01/TC-96-B-DS-01, at 38-41.

BPA's Position

The Administrator acted within his discretion in deciding to apply the $325 million credit under the circumstances outlined in the OMB arrangement. This is a prudent cash management decision that reasonably balances BPA's competitive and funding needs. BPA is not claiming credits for lost revenues under section 4(h)(10)(C). *See* ROD section 10.4.1., *supra*. BPA's decision not to reduce rates or provide a refund by the full amount of the Fish Cost Contingency Fund is an issue not properly litigated in the rate case.

Evaluation of Positions

In its review of BPA's 1982 rates, the Federal Energy Regulatory Commission (FERC) stated, "[i]t thus appears that losses of sales and revenues could have been reasonably anticipated and reflected in the Project Repayment Study. As a result of Bonneville's over-optimistic projections, Bonneville's estimates of sales were unduly excessive." *U.S. Dept. of Energy--Bonneville Power Admin.*, 23 F.E.R.C. ¶ 61,378, at 61,797 (1983). Partly as a result of FERC's comment, BPA began incorporating assumptions recognizing the possibility of load underruns or low streamflows in its 1985 rates to better assure Treasury payment. 1985 Administrator's Record of Decision (ROD), WP-85-A-02, at 16-30; *U.S. Dept. of Energy--Bonneville Power Admin.*, 39 F.E.R.C. ¶ 61,078, at 61,207-61,208 (1983). BPA continued to focus on and improve its risk management in subsequent rate cases. *See, e.g.*, 1987 ROD, WP-87-A-02, at 21-72; 1993 ROD, WP-93-A-02, at 57-95.

As part of its efforts, BPA developed a 10-Year Financial Plan under which a

> key objective is to design financial policies that will ensure BPA's ability to make its annual U.S. Treasury payments in full and on time, while also providing increased rate predictability. . . .

> In order to meet this key objective, the primary focus of this first Financial Plan has been to determine the amount of financial reserves necessary to meet the uncertainties that exist in BPA's operating environment.

Bonneville Power Administration, 10-Year Financial Plan 2 (Jan. 1993); *see* Supplemental Revenue Requirement Study, WP-96-E-BPA-58, at 20. The 10-Year Financial Plan established a policy of setting rates at a level sufficient to assure a 95 percent probability of BPA meeting its Treasury payments in full and on time. *Id.* In the 1993 rate case, BPA decided that it would adopt the 95 percent probability policy in the 1993 rate case and for future rate cases, absent a determination by the Administrator that the policy should be modified to meet BPA's changing operating environment. 1993 ROD, WP-93-A-02, at 68. In the 1993 rate case, due to competitive pressures, the Administrator determined that rates in that case would have to be set to meet a lower repayment probability. *Id.* at 76.

Because of increasing costs and declining revenues in recent years, BPA's financial reserves were largely depleted as BPA began the 1996 rate case. Moorman, Evans, WP-96-E-BPA-09, at 9. As of September 30, 1995, BPA had financial reserves of $196 million, after a decline from $877 million at the beginning of 1992, due to a series of years of persistent drought, low aluminum prices, and escalating fish and wildlife costs. Bonneville Power Administration, 1995 Annual Report, at 21 (Feb. 1996).

BPA's deteriorating financial condition has troubled Congress. The Senate Appropriations Committee report accompanying the FY 1995 Energy and Water Development Appropriation Bill, S.Rep. No. 291, 103d Cong, 2d Sess. 197 (1994), attached to DeWolf, *et al.*, WP-96-E-BPA-69, Attachment 4, p. 5, states

> A recently released General Accounting Office [GAO] report on the financial health of BPA . . . notes that BPA's current financial difficulties are caused by uncontrollable circumstances, principally consecutive low water years, low aluminum prices and salmon recovery costs. The report also acknowledges that BPA is taking steps to meet its financial challenges through refinancing debt at lower interest rates, deferring capital programs, increasing rates and cutting costs.
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> . . . .
>
> Notwithstanding BPA's efforts to reduce controllable costs, actions that would change the financing of capital programs and the level of reserves may be necessary. This situation creates a dilemma for BPA since these efforts to improve flexibility would cause increases in rates and would further narrow the gap between BPA's rates and the cost of alternative energy sources.

The report notes both BPA's lack of reserves and the narrowing gap between BPA's rates and the market. The GAO report also described these problems:

> In the short term, BPA's low financial reserves provide little flexibility to respond to further operating losses, increasing the possibility that BPA would be unable to make its annual payment to Treasury. In the longer term, BPA's financial viability could also be jeopardized if the gap between BPA rates and the cost of alternative energy sources continues to narrow. Such a scenario could cause some BPA customers to meet their energy needs elsewhere, leaving a dwindling pool of ratepayers to pay off the substantial debt accumulated from previous years.

U.S. General Accounting Office, Briefing Report, Bonneville Power Administration Borrowing Practices and Financial Condition 2 (April 1994), attached to DeWolf, *et al.*, E-BPA-69, Attachment 4, p. 13.

As described in BPA's competitiveness testimony, a very troubling threat to BPA's competitiveness and, hence, its ability to meet costs and fulfill its responsibilities has been the specter of uncontrollable fish and wildlife costs:

> In the context of this emerging market, customers realistically can demand, and obtain, competitive, stable, and predictable prices. A particular source of significant competitive risk to BPA is recent increases in its fish-related costs. Many customers perceive that BPA will be unable to control these additional costs, making BPA a risky supplier in their estimation. Annual fish and wildlife expenditures grew from $20 million in 1981 to $146 million in 1990. By 1994, expenditures more than doubled to roughly $350 million. Recently, the National Marine Fisheries Service (NMFS) developed additional fish mitigation measures that are projected in this proposal to increase BPA's fish-related costs to more than $500 million per year. See Revenue Requirement Study Documentation, Volume 1, WP-96-E-BPA-02A. Using a rough rule of thumb that every $100 million increase in BPA's revenue requirement will increase the preference rate by approximately 4 percent, customers view these cost increases and the uncertainty they entail as proof that BPA should not be relied upon as a supplier of competitively priced power. As a consequence, customers are beginning, at a minimum, to diversify their resource portfolios.

Moorman, Evans, E-BPA-09, at 3. Bonneville's competitiveness problems as they related to fish and wildlife costs, in particular, received increasing attention within the Administration and Congress.

On March 15, 1995, Office of Management and Budget (OMB) director Alice Rivlin announced to the Energy and Water Subcommittee of the Senate Appropriations Committee that "the Administration has devoted significant time and resources to reach consensus" among "many people in the several Federal agencies involved in this issue in the Northwest" on an arrangement "to assist the region" in meeting annual costs of fish mitigation under the Northwest Power Act and the Endangered Species Act. Documentation for Supplemental Revenue Requirement Study, WP-96-E-BPA-58A, at 526 and 531 [hereinafter "Rev. Doc."]. Director Rivlin stated that "[t]hrough its customers, BPA is paying about $200 million a year -- not counting purchase power and foregone revenues resulting from reduced water availability. When these latter are included, the total cost to BPA and its ratepayers is over $300 million. This represents about 11 percent of Bonneville's estimated 1996 operating outlays." *Id.* at 529. The arrangement announced by Director Rivlin included annual credits against BPA's cash transfers to Treasury under section 4(h)(10)(C) of the Northwest Power Act, and, to the extent necessary, reduction of BPA's accumulation of cash reserves, thus reducing the probability of BPA meeting its annual payments to the Treasury, and BPA cost cutting of $30-40 million per year. DeWolf, *et al.*, WP-96-E-BPA-14, at 2. Director Rivlin informed the Subcommittee that "[b]ased on these actions, BPA believes the incremental costs of the 1995 Biological Opinion can be covered without a further increase in its recently announced five percent rate increase." Rev. Doc., E-BPA-58A, at 531. After Director Rivlin's testimony, BPA engaged in numerous discussions with the National Marine Fisheries Service (NMFS) and the Northwest Power Planning Council (NPPC), and consulted with the Corps of Engineers (COE), to arrive at a more refined estimate of the types and timing of investments which would fulfill the objectives of the 1995 Biological Opinion. *Id.* at 519. The revised investment projections were incorporated into the October 24, 1995, revision to the arrangement, which is described below. *Id.*

Although BPA expected that the arrangement announced March 15, 1995, would enable BPA to avoid increasing rates more than 5 percent for the 1996 Fiscal Year, *id.* at 531, Director Rivlin testified that there would be more costs to implement the Endangered Species Act over the next several years. *Id.* BPA's 1995 Annual Report described the context:

> BPA's fish and wildlife obligations nearly tripled in four years from $150 million in 1991 to $400 million in 1995. As the year opened, projections of future additional fish obligations ranged from an added $300 million to $600 million a year. In January, the Northwest's senate delegation wrote the President expressing concern about BPA's ability to fund these potential added fish costs. Fear of future fish costs ranked high on BPA customers' lists of reasons to consider switching to other suppliers.

Bonneville Power Administration, 1995 Annual Report, at 11 (Feb. 1996).

On October 24, 1995, against a background of mounting Congressional concerns with BPA's fish and wildlife costs, Director Rivlin wrote to Senator Hatfield, Chairman of the Senate Appropriations Committee:

> In more recent months, the Northwest delegation and others in the region, such as the Northwest Power Council, have cooperated to develop solutions that provide greater financial certainty to BPA and its customers relating to its fish and wildlife obligations, while simultaneously assuring that the 1995 Biological Opinion and the Northwest Power Council's Fish and Wildlife Program will be implemented in a way which helps assure recovery of the dwindling salmon runs. As a result of these discussions, the delegation and the Administration have developed a program which we believe will accomplish these twin objectives.
>
> . . . The objective of the program is to provide a clear technical plan ("Plan") with a stable, multi-year budget for BPA to finance the implementation of its fish and wildlife obligations under the Northwest Power Act and the Endangered Species Act, based upon the draft plan of the BPA, the National Marine Fisheries Service (NMFS), and the Chairman of the Northwest Power Planning Council (NPPC) dated September 19, 1995. The final Plan will be developed as an interagency agreement among the affected agencies: BPA, NMFS, Corps of Engineers, and the Department of the Interior, in consultation with the NPCC*[sic]* and the Tribes.

Rev. Doc., E-BPA-58A, at 534-535. Referring to a Fish Cost Contingency Fund, the letter states that "in lieu of [Endangered Species Act and Northwest Power Act] sufficiency language, the Administration has reached agreement with you and other key Members of Congress to provide a source of emergency fish recovery funding, in the event that BPA's $435 million average annual budget is not adequate to meet the needs of the fish recovery program." *Id.* at 537.

To provide greater financial certainty to BPA and its customers, the letter described "a BPA Fish Cost Contigency Fund consisting of credits to be used by BPA against fish and wildlife costs under certain conditions. The beginning credit balance in this fund shall be the amount of all reimbursements available, but not used, under provision 4(h)(10)(C) of the Northwest Power Act of 1980 from the date of enactment to the present." *Id.* at 535. One of the purposes the credits can be used for is "to defray fish and other water-related costs . . . for the amount by which additional power purchases and shortfalls in non-firm power revenues, combined, exceed a percentage of the sum of those two projected annual levels for 1996-2001 in BPA's final rate case. The specific threshold levels will be determined in a manner that will be predicted to make this funding available 25 to 30 percent of the time during the . . . period . . . ." *Id.* at 535-536.

As just indicated, the Fish Cost Contingency Fund is funded through "the amount of all reimbursements available, but not used, under provision 4(h)(10)(C) of the Northwest Power Act of 1980 from the date of enactment to the present." The statutory authority for these reimbursements is founded on Northwest Power Act section 4(h)(10)(C), which states:

> The amounts expended by the Administrator for each activity pursuant to this subsection shall be allocated as appropriate by the Administrator, in consultation with the Corps of Engineers and the Water and Power Resources Service, among the various hydroelectric projects of the Federal Columbia River Power System. Amounts so allocated shall be allocated to the various project purposes in accordance with existing accounting procedures for the Federal Columbia River Power System.

[Emphasis added.] Section 4(h)(8) states, in part

> **4.(h)(8)** The Council shall consider, in developing a program pursuant to this subsection, the following principles:
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> . . . .
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> **4.(h)(8)(B)** Consumers of electric power shall bear the cost of measures designed to deal with adverse impacts caused by the development and operation of electric power facilities and programs only.
>
> . . . .
>
> **4.(h)(8)(D)** Monetary costs and electric power losses resulting from the implementation of the program shall be allocated by the Administrator consistent with individual project impacts and system-wide objectives of this subsection.

[Emphasis added.] Although the statute clearly intends that BPA should allocate fish and wildlife costs among project purposes, the emphasized language in 4(h)(10)(C) demonstrates that the Administrator has some discretion whether and when to make the allocation for any particular expenditure. The emphasized language in section 4(h)(8) is addressed to the Northwest Power Planning Council.

As part of the arrangement announced by Director Rivlin on March 15, 1995, *supra*, it was determined that "to the extent necessary, BPA will reduce its build-up of cash reserves. This may make it more likely that BPA will have to reschedule a portion of its annual Treasury payment in future years." Rev. Doc., E-BPA-58A, at 532; Bonneville Power Administration Newsbreaker, "Fed offer help for fish costs" (3/14/95); *see* Moorman, Evans, E-BPA-09, at 28. BPA's supplemental rate proposal included a projected 80 percent probability of meeting BPA's Treasury payment obligation during the 5-year rate period, which is less than the percentage required to meet the 5-year probability indicated by the 10-Year Financial Plan. Arnold, *et al.*, E-BPA-71, at 11.

Nevertheless, BPA is not proposing to abrogate its 10-Year Financial Plan, only to reduce Treasury payment probability by reducing the amount of net revenues for risk in the revenue requirement in light of changed circumstances. *See* Bonneville Power Administration, 1995 Business Plan, at 36 (August 1995). FERC's concerns about cost recovery remain valid. The Fish Cost Contingency Fund is "an effective risk mitigation tool that . . . increases the probability that BPA will make all of its Treasury payments on time and in full." Rev. Doc., E-BPA-58A, at 506. Availability of the fund as a risk mitigation tool is consistent with the Business Plan mitigation objective of transferring costs. U.S. Dept. of Energy, Bonneville Power Administration, Record of Decision, Business Plan Final Environmental Impact Statement, at 13-14 (August 1995). The Fund is available for fish and water-related costs due to adverse water conditions and if BPA incurs additional fish mitigation costs above those budgeted for in the draft agreement between BPA, NMFS, USFWS, COE and USBR because of a court decision. Arnold, *et al.*, E-BPA-71, at 9. BPA is unable to model or assess the risk of such a court decision nor to quantitatively determine how much BPA's repayment risk is reduced by that contingency, although the contingency does indeed reduce BPA's risk. Rev. Doc., E-BPA-58A, at 505-506. However, BPA can and has modeled the reduction in payment risk due to the low water contingency. *Id.* at 506. The availability of the Fish Cost Contingency Fund for the low water contingency increases BPA's probability of making its annual Treasury payment during the upcoming rate period by 10 to 15 percent. Arnold, *et al.*, WP-96-E-BPA-71, at 10.

The DSIs argue BPA should either reduce its revenue requirement by the full amount of the Fish Cost Contingency Fund, plus foregone revenues of $100 million, to reduce rates to its customers now, or refund the money directly to customers from whom, they assert, it was taken. DSI Pr. Brief, P-DS-01, at 31-32; DSI Brief, WP-96-B-DS-01/TC-96-B-DS-01, at 38-41. However, based on the facts detailed above, and as explained below, (a) the Fish Cost Contingency Fund is a reasonable and prudent means of recognizing past fish and wildlife expenditures that exceeded the power purposes' appropriate share of fish and wildlife costs, (b) utilization of the excess expenditures in the "refund" manner advocated by the DSIs is not supported by the facts in this case, and (c) the DSIs, having chosen not to challenge the creation of the Fish Cost Contingency Fund, are now precluded from doing so.

The Fish Cost Contingency Fund reflects the non-power share of BPA's costs for fish and wildlife mitigation expenditures from passage of the Northwest Power Act through Fiscal Year 1994. As stated in the legislative history of section 4(h)(10)(C), "All expenditures by BPA are to be made on a reimbursable basis vis-a-vis other project purposes, although BPA will have the flexibility to treat expenditures in excess of its allocated share as being payments for other project costs for which BPA is responsible under existing law." H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2, at 45 (1980). The language from the Report does not say when or in what form BPA must seek reimbursement, and the statement that BPA has "flexibility" to exercise the credit process gives BPA an amount of discretion concerning if, how, or when that flexibility is exercised.

The Fish Cost Contingency Fund arrangement represents a reasonable exercise of the flexibility afforded by section 4(h)(10)(C). As indicated earlier, BPA needs to maintain a healthy financial reserve. The Fund operates as a reserve to fund designated costs. BPA is reducing the generation costs to be recovered through rates during the rate period by $118 million, based on its expected use of the Fund as a financial resource. If the conditions in the Fish Cost Contingency Fund arrangement trigger, BPA will reduce its year-end cash transfer to Treasury by the amount called for under the arrangement. Amounts so credited are no longer the responsibility of the ratepayers. The ratepayers receive a significant benefit from the arrangement due to the rate case assumption of expected use under the terms of the arrangement. The estimated $118 million over the 5-year rate period is about $23 million a year, which is about 7 percent each year of the $325 million fund.

Moreover, because of the fund, BPA and its ratepayers have an insurance policy against higher costs of fish mitigation due to Endangered Species Act and Northwest Power Act compliance costs. One of the customers' major concerns about BPA as a competitive supplier is the possibility of increased fish costs. Congress also is concerned about the possibility that BPA will be unable to pay Treasury because of increasing fish costs. This Fund responds to those concerns by providing BPA a financial cushion. In addition, the Fund is part of a comprehensive budgetary and risk management package, as described by Director Rivlin in her October 24 letter. Rev. Doc., E-BPA-58A, at 534-37. If BPA were to have insisted on taking the full credit immediately, that insurance policy would not be available, and if mitigation costs significantly increased, BPA would have to increase rates, reduce programs, or miss Treasury payments. While the competitive pressures on BPA might have counseled that the full amount of the past over-expenditures be credited against rates over the next five years, a reasonable balance has been struck among the various short- and long-run competing needs for the funds. The balance is well in accord with the requirement of Northwest Power Act section 7(a) that the Administrator establish and revise rates to recover costs "in accordance with sound business principles," and the dictate of section 9(b) that the Administrator implement the Northwest Power Act in "a sound and businesslike manner." 16 U.S.C. §§ 839e(a)(1), 839f(b).

The DSIs' argument that BPA simply refund the past over-expenditures in a lump sum flies in the face of reality, and would clearly contravene sound business principles. Under the competitive circumstances faced by BPA in this rate case, refunding the amounts in a lump sum as if customers had previously overpaid for them would cause BPA to have to increase its revenue requirements. To do so could cause BPA to underrecover its costs, given that its rates are already at or, as some would argue, above the market. Such an underrecovery is inconsistent with the section 7(a) requirement to set rates at a level sufficient to recover costs.

If, and to the degree, that the DSIs' argument is founded on some as-yet unexplained claim of entitlement, they are grossly mistaken. First, as the DSIs well know from their participation in past BPA rate cases, BPA has previously based past rates in part on a legislative judgment by the Administrator as to how high the rate increases should be.

E.g., 1993 ROD, WP-93-A-02, 23-25, at 76; 1987 ROD, WP-87-A-02, at 47. Lowering the probability of repaying the U.S. Treasury provided a means of lowering the revenue requirement and thereby providing lower rates. Given that sustainable rate level determination, additional net revenues for risk might well have been included in rates had fish and wildlife expenditures not been included, assuming they were. See 1993 ROD, WP-93-A-02, at 76; 1987 ROD, WP-87-A-02, at 47. In other cases--the 1989, 1991, and 1995 rate cases--there were settlement agreements whereby parties assented to the overall level of the rate increases. It cannot, therefore, be said that there was a past "overpayment" of costs by customers.

Second, there is no record evidence that all of the past fish and wildlife expenditures were in fact previously included in revenue requirements used to set past rates. What is forecast in rate cases may often diverge considerably from what actually happens. Third, and with regard to what actually has happened, the evidence in the record of this case indicates that, in fact, the DSIs have "underpaid" costs, were one to accept the DSIs' retroactive true-up line of reasoning: "For the 3-year period 1992 to 1994, revenues from the aluminum industry were approximately $500 million less than projected in the 1991 rate case." Moorman, Evans, E-BPA-09, at 8. While BPA subsequently increased its rates, it did so not to retroactively collect underpayments, but on a prospective basis to ensure that it would recover sufficient revenues to recover costs and provide a reasonable probability of repaying the U.S. Treasury. That is precisely what BPA is doing in this case, and the Fish Cost Contingency Fund is an essential component of that effort. BPA's approach comports with the doctrine against retroactive ratemaking:

> Under this doctrine, the Commission is prohibited from adjusting current rates to make up for previous over- or undercollections of costs in prior periods . . . . The Commission may not disinter the past merely because experience has belied projections, whether the advantage went to customers or the utility; bygones are bygones.

Associated Gas Distributors v. FERC, 898 F.2d 809 (D.C. Cir. 1990); *see also Public Service Company of New Hampshire v. Federal Energy Regulatory Commission*, 600 F.2d 944, 957-958 (D.C. Cir. 1979); *Alabama Power Co. v. I.C.C.*, 852 F.2d 1361, 1373 (D.C. Cir. 1988).

Finally, after the Fish Cost Contingency Fund arrangement had been announced as a decision, the DSIs did not challenge it. To the extent that the Fish Cost Contingency Fund may be viewed as constituting a Federal fiscal and budgetary issue, the DSIs' complaints are out of time. BPA has been consistent in its position that Northwest Power Act section 7 does not allow litigation of program issues, program levels, and budgets in the rate case. 1993 ROD, WP-93-A-02, at 319-329; *1996 Proposed Wholesale Power Rate and Transmission Rate Adjustment*, 60 Fed. Reg. 36464, at 36465 (1995). The Administrator must be free to discuss Federal fiscal and budgetary matters with members of the Congressional delegation, the Administration, and others, and to enter into arrangements regarding BPA's Treasury payment obligation that he considers to be in the interests of BPA and its ratepayers. The Administrator could not perform those activities if he had to make decisions regarding them on the rate case record. 1993 ROD, WP-93-A-02, at 326. Since all BPA activities potentially are reflected in the budget and, eventually, in rates, such a precedent could lead to any of BPA's decisions being litigated in the rate case. OMB Director Rivlin obviously considered the Fish Cost Contingency Fund a Federal fiscal and budgetary issue. BPA also included a description of the fund in its FY 1997 budget submission to Congress. Bonneville Power Administration, FY 1997 Budget Submission, at 32 (March 1996).

Decision

BPA will not reduce rates or provide a refund for the full amount of the $325 million Fish Cost Contingency Fund. BPA will show expected revenues over the rate period from use of the fund in accordance with the conditions outlined by OMB Director Rivlin on October 24, 1995.

11.0 WHOLESALE POWER RATE SCHEDULES

11.1 Introduction

In the 1996 rate case, BPA proposed major changes in the design of its 1996 wholesale rates. Wholesale Power Rate Development Study (WPRDS), WP-96-FS-BPA-05, at 4-5. BPA's proposed 1996 rate schedules have been revised in format and content to reflect BPA's marketing strategy, which is BPA's response to the changing and increasingly competitive market for power. *See*, *generally*, Buchanan, *et al.*, WP-96-E-BPA-11. BPA is repositioning its products by unbundling power products; offering rate schedules for periods longer than two years; and pricing products to make them competitive in the market. *Id.* at 3. BPA also is unbundling its power and transmission rates. Power users are now charged for transmission separately, instead of rolling transmission costs into the power rate demand. WPRDS, FS-BPA-05, at 5. BPA is offering five-year rate schedules for requirements power purchases. *Id.* BPA also is proposing the Firm Power Products and Services (FPS-96) rate schedule, which can support purchases for the next 10 years. *Id.* at 91. Five-year rates are addressed in ROD section 2.7, and the FPS-96 rate schedule is addressed in section 11.7. In addition, BPA is proposing a Flexible Rate Option under the PF and NR rate schedules. *See* section 11.2.8.

BPA is proposing energy and demand billing factors in its power rate schedule that are designed to reflect the purchase relationship described in the 1996 Contract, the new products BPA is proposing, and BPA's intention to make the billing factors for 1981 and 1996 Contract purchasers as consistent as possible. WPRDS, FS-BPA-05, at 47, 48. Billing factors are addressed in ROD section 11.3.1. Besides charging power customers for demand and energy, BPA is offering several unbundled load shaping products in its requirements rate schedules. *See* section 11.2.1. The Availability Charge and the Power Demand Reservation Charge are charges that reimburse BPA for standing ready to serve the contractual entitlements of customers that are able to displace their energy or capacity purchases from BPA. Metcalf, *et al.*, WP-96-E-BPA-18, at 7; Metcalf, *et al.*, WP-96-E-BPA-74, at 12. The Availability Charge is addressed in section 11.3.3, and the Power Demand Reservation Charge is addressed in section 11.3.2.

BPA recognizes that some customers, particularly small utilities, may want a simplified power bill. To respond to the needs of its small customers, BPA has proposed a composite rate available under the PF-96 rate schedule that rebundles certain power products for Full and Metered Requirements customers that have annual retail loads of 25 aMW or less and agree to purchase all their power from BPA for five years under the PF-96 rate schedule. WPRDS, FS-BPA-05, at 51. The composite rate is addressed in ROD section 11.3.4. BPA also recognizes that some of the changes in its rates, specifically the unbundling of its power products and unbundling of transmission, would cause some customers' rates to increase compared to the rate they would have paid with bundled rates. To mitigate the impacts of the changes in rate design on some of its customers, BPA proposed a Phase-In Mitigation for eligible Full and Metered

Requirements customers, the effect of which is to limit the monthly increase in the customer's bill. *Id.* at 54. *See* section 11.3.5.

This chapter is organized by rate schedule except section 11.2, Major Rate Design Proposals Affecting More Than One Rate Schedule. Section 11.3 covers issues related to the Priority Firm Power (PF) rate. Section 11.4 covers the Industrial Firm Power (IP) rate, section 11.5 covers the Industrial Power Spot Gas rate, and section 11.6 covers the Variable Industrial Power rate. Section 11.7 covers issues related to the FPS rate. Section 11.8 covers other power rates. Transmission rates are discussed in chapter 12.0.

11.2 Major Rate Design Proposals Affecting More Than One Rate Schedule

11.2.1 Load Shaping

11.2.1.1 Introduction

Load Shaping shifts the planning risk to BPA for meeting the difference between the customer's actual and forecasted retail loads. BPA is proposing rates for four Load Shaping products: (1) Full Load Shaping, (2) Full Load Shaping with Industrial Exemption, (3) Partial Load Shaping, and (4) DSI Load Shaping. Lamb, *et al.*, WP-96-E-BPA-19. Details of the individual products and rate case considerations and issues are discussed below.

11.2.1.2 Full Load Shaping; Utility Factor

Full Load Shaping shifts the planning risk to BPA for all variations between actual and forecasted retail loads above the level of the customer's resources. With Full Load Shaping, BPA will deliver additional power at the PF or NR rate to meet variations in retail load above forecast and will reduce PF or NR deliveries for variations in retail load below forecast. This product is available to utility customers under both the 1981 and 1996 Contracts with the exception of Planned and Contracted Computed Requirements customers under the 1981 Contract. Lamb, *et al.*, E-BPA-19, at 3.

For 1981 Contract customers, the Full Load Shaping charge will be multiplied by a Utility Factor, which increases the Full Load Shaping charge by the ratio of the customer's total retail load to its BPA deliveries, in the case of Metered Requirements customers, or to its BPA energy entitlement (Computed Energy Maximum), in the case of Actual Computed Requirements customers. Lamb, *et al.*, WP-96-E-BPA-19, at 8-10; Bolden, *et al.*, WP-96-E-BPA-106, at 10-12. Because BPA's energy delivery obligation is the billing factor for the Full Load Shaping charge, the Utility Factor adjustment makes the charge proportionate to the amount of load shaping BPA makes available, which is related to the amount of the customer's retail load. Lamb, *et al.*, E-BPA-19, at 8-9; Kitchen, *et al.*, WP-96-E-BPA-49, at 17. Customers that serve nearly all their retail load with non-BPA generation would receive very high Utility Factors. To avoid unreasonably large Utility Factors for those customers, BPA proposes to cap the Utility Factor at 6. Kitchen, *et al.*, WP-96-E-BPA-75, at 2-3. BPA also proposes to exclude New Large Single Loads served with dedicated resources, and Industrial Exemption loads, in calculating the Utility Factor for Full Load Shaping. *Id.* at 3-4.

A Utility Factor of 6 equates to a customer serving 83 percent of its load with its own firm resources, while BPA would serve 17 percent. In BPA's Load Shaping analysis, BPA assumes an expected maximum variation from forecast retail load of about 15 percent. Wholesale Power Rate Development Study Documentation, WP-96-FS-BPA-05A, section 7.7. Because BPA service to 15 percent of a customer's load would result in an uncapped Utility Factor of 6.7, customers receiving less than 17 percent service from BPA receive a discount with the capped Utility Factor. Bolden,*et al.*, E-BPA-106, 9. As the percentage of BPA service declines further below 15 percent, the customer's already-discounted load shaping costs continue to decline in proportion to the reduction in BPA deliveries. The built-in discount is not eliminated until the customer's percentage of BPA service reaches zero.

BPA also will apply the Utility Factor to the PF and NR Load Regulation charges, because the amount of Load Regulation BPA provides also is related to the amount of the customer's retail load. Lamb, *et al.*, E-BPA-19, at 8-9. Because New Large Single Loads served with dedicated resources and Industrial Exemption load are customer retail loads within BPA's control area, BPA will not exclude those loads in calculating the Utility Factor for Load Regulation. Kitchen, *et al.*, E-BPA-75, at 3-4.

BPA proposes to set the Full Load Shaping charge based on the marginal costs of serving variations in load. Kitchen, *et al.*, E-BPA-49, at 2-3. BPA assumes that it must buy generation on the spot market to serve load in excess of forecast and that it sells generation on the nonfirm market equal to the difference between forecast loads and variations in load below forecast. *Id.* The difference between PF rate revenues, the cost of spot market purchases, and expected revenues from sales at the nonfirm energy rate is the marginal cost of the load shaping product. *See* Documentation for the Wholesale Power Rate Development Study, WP-96-FS-BPA-05A, section 7.7.

PGP, APAC, and WPAG filed testimony asserting that BPA's load shaping charges violate the 1981 Contract, because they impose penalties on customers for having acquired resources, Smith, *et al.*, WP/TC-96-E-PG-01, at 7-8; because they charge customers for service that the customers are obligated to provide under the 1981 Contract, *Id.* at 2; Smith, *et al.*, WP/TC-96-E-PG-05, at 4; Leone-Woods, *et al.*, WP/TC-96-E-PG/AP-02, at 2-3; Beck, *et al.*, WP-96-E-WA-13, at 28; or because the proposed Utility Factor imposes a penalty on customers that made use of a contract right to displace in a previous year. Beck, *et al.*, E-WA-13, at 29.

In response to the contention that the load shaping charges violate the 1981 Contract because they impose penalties on customers that have diversified, or charge those customers for BPA serving load served by the customers' resources, Load Shaping does not impose a penalty on customers that have acquired resources. It sends a marginal cost price signal of the cost of serving variations in the customers' retail loads, a service which BPA is contractually obligated to provide. Kitchen, *et al.*, E-BPA-49, at 2-3; Kitchen, Moorman, WP-96-E-BPA-41, at 5-6; Kitchen, Moorman, WP-96-E-BPA-98, at 5. Furthermore, under the 1981 Contract, BPA is obligated to serve variations in Actual Computed Requirements customers' retail loads above the level of their firm resources, and to continue to stand ready to provide service to any increases in load even when their loads fall below the level of their resources. Bolden, *et al.*, E-BPA-106, at 8-9. PGP and APAC admit that the amount of public utility load variation from forecast shown in BPA's Risk Analysis accurately reflects the amount of variation BPA must serve. Leone-Woods, *et al.*, E-PG/AP-02, at 6-7. BPA used the Risk Analysis public utility load variations to determine load shaping charges. Wholesale Power Rate Development Study Documentation, WP-96-FS-BPA-05A, at section 7.7. The Utility Factor is intended to cause the level of the Full Load Shaping charge to be related to the amount of Full Load Shaping provided by BPA, which is related to the size of the customer's retail load. Lamb, *et al.*, E-BPA-19, at 8-9.

PGP and APAC testified that charges for Full Load Shaping would become unreasonable when customers serve a very large percentage of their own load. Smith, *et al.*, WP-96-E-PG-01, 2; Leone-Woods, *et al.*, E-PG/AP-02, 22. However, capping the Utility Factor at six results in a discount in Full Load Shaping charges for customers with capped Utility Factors. Bolden, *et al.*, E-BPA-106, at 9.

BPA initially proposed to use BPA purchases as the denominator in calculating the Utility Factor for Actual Computed Requirements customers. Lamb, *et al.*, E-BPA-19, at 8-10. WPAG and others pointed out that because Actual Computed Requirements customers exercise a contract right to displace BPA service when cheap energy is temporarily available, using actual purchases in a given calendar year to determine the Utility Factor for a later fiscal year could cause the Utility Factor, and therefore the Full Load Shaping charge, to be higher than would be justified if the customer did not displace as much in the fiscal year. Bolden, *et al.*, E-BPA-106, at 10-12. In response to those concerns, BPA proposes to modify how the Utility Factor would be calculated for Actual Computed Requirements customers so that the denominator would be the amount of energy a customer could have bought from BPA, thus ignoring displacement. BPA proposes that the denominator in calculating the Utility Factor for Actual Computed Requirements customers be the Computed Energy Maximum. *Id.*

In initial briefs and briefs on exceptions, the parties did not raise any issues about whether Load Shaping charges are consistent with the 1981 Contract, including the issues discussed above, and so have waived those issues *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611, § 1010.13(b) (1986) (hereinafter "Procedures").

PGP and APAC testified that the Full and Partial Load Shaping charges were excessive because (1) they were based on costs that exceeded the costs of meeting variations in load determined by using BPA's STREAM model from BPA's Risk Analysis; (2) the amount of the total utility loads that would be subject to Load Shaping is overstated in BPA's load shaping analysis; and (3) BPA erroneously assumed that the risks placed on BPA by the retail load fluctuations of those utilities who operate their own resources are identical to the risks imposed by retail load fluctuations of utilities who do not operate their own resources. Leone-Woods, *et al.*, E-PG/AP-02, at 4. BPA testified that the Risk Analysis assumes use of nonfirm energy from BPA's system before making purchases on the market to meet load variations, while the Load Shaping analysis assumes that BPA must buy energy on the market to supply loads above forecast and must sell energy on the spot market that is freed up from loads below forecast. Thus, the Load Shaping analysis provides a better estimate of the marginal costs of meeting variations in load. *See* Kitchen, *et al.*, E-BPA-49, at 2-3. As BPA stated in the Supplemental Marginal Cost Analysis Study, WP-96-E-BPA-60, at 2,

> The [marginal cost price] signal is appropriate because the price the customer faces will just cover the cost of resources necessary to produce the product. If the customer has a cheaper alternative, pricing the product at its marginal cost will cause the firm to avoid incurring additional costs for output which its customers could obtain elsewhere for less and will lead to an efficient allocation of society's scarce resources.

BPA may provide marginal cost price signals within the PF rate. Pacific Northwest Electric Power Planning and Conservation Act, § 7(e), 16 U.S.C. § 839e(e) (hereinafter Northwest Power Act). Because the forecast revenues from Load Shaping reduce the PF energy charge, Load Shaping customers pay a rate that recovers the cost of resources used to provide the service, pursuant to Northwest Power Act, § 7(b). Arnold, *et al.*, WP-96-E-BPA-45, at 5; Kitchen, *et al.*, E-BPA-49, at 6.

Regarding PGP's contentions that BPA overstated loads subject to Load Shaping, BPA acknowledged the PGP and APAC point that Tacoma's loads should not and would not be included in the loads for which BPA is obligated to provide Load Shaping in the Load Shaping analysis. Kitchen, *et al.*, E-BPA-49, at 6-7.

PGP and APAC also testified that loads placed on BPA by generating customers tend to be more stable in the face of weather fluctuations than do the loads of non-generating utilities and that there should be an adjustment either in the load shaping charge or the billing determinant to reflect that difference. Leone-Woods, *et al.*, E-PG/AP-02, at 13-14. BPA testified that the PGP and APAC testimony failed to consider whether the PGP utilities placed variations between forecast and actual loads on BPA, which is the service for which the Full Load Shaping charge was designed. Kitchen, *et al.*, E-BPA-49, at 10-11. BPA demonstrated that PGP utilities who are Actual Computed Requirements customers do use the Full Load Shaping product in accordance with their contract rights. *Id.* Because PGP and APAC failed to correctly address whether PGP customers use Full Load Shaping, they also failed to demonstrate that they use Full Load Shaping less than non-generating customers.

Because no party raised issues concerning whether the proposed load shaping charges are excessive in its initial brief and brief on exceptions, the foregoing issues have been waived. Procedures, *supra*, § 1010.13(b).

11.2.1.3 <u>Industrial Exemption</u>

Industrial Exemption was developed to allow customers the option to "exempt any single industrial load of 5 aMW or larger from Full Load Shaping. . . ." Lamb, *et al.*, WP-96-E-BPA-19, at 5. BPA offered Industrial Exemption because loads that are highly predictable place less costs on BPA. *Cf.* Kitchen, *et al.*, E-BPA-49, at 25. BPA also wanted to ensure that Full Load Shaping does not provide an undesirable price signal for large loads that are truly predictable by forcing their serving utilities to pay for services that they do not use. Kitchen, *et al.*, WP-96-E-BPA-75, at 5. Customers with qualifying Industrial Exemption loads would be required to submit a monthly forecast of monthly heavy load hour and light load hour energy for each load. *Id.* at 6-7. The customer will be billed an Industrial Exemption charge for deviations from the forecast. *Id.* The monthly forecast also will be used to determine whether the load is predictable enough to retain its Industrial Exemption. Bolden, *et al.*, E-BPA-106 (Addendum). This was a change from BPA's initial proposal to require an hourly forecast to support an hourly predictability test. *Id.* Under the monthly predictability test, if the load deviates by more than +1/-5 percent from forecast more than one month in any six-month period, the load will lose its exemption. The customer could apply to re-qualify the load. Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, at 30.

The initial Industrial Exemption proposal assessed an unauthorized deviation charge if the customer's exempt load varied from forecast. Lamb, *et al.*, E-BPA-19, at 5. To avoid the unauthorized deviation charges associated with variations, the customer had to purchase Industrial Curtailment as well, which provided the customer with the ability to decrease its Industrial Exemption load forecast up to the amount of Industrial Curtailment the customer had nominated. *Id.* at 6. In addition, Industrial Exemption and Industrial Curtailment were available only to customers purchasing under the 1996 Contract. *Id.* at 5.

WPAG proposed that BPA eliminate Industrial Exemption or, if kept, that it be made available to any stable load regardless of type or size and that the product require monthly, weekly, daily, and hourly load forecasts. Beck, *et al.*, WP-96-E-WA-01, at 43-44. PGP and APAC requested that exempt industrial loads simultaneously be given access to the energy market, that the minimum size requirement be changed to 1 aMW, that the circumstances in which unauthorized increase could occur be limited to after BPA offered spot market energy to the customer to cover the overrun, and that the product be available to 1981 Contract purchasers. Leone-Woods, *et al.*, WP-96-E-PG/AP-02, at 27-28. PGP and APAC requested a smaller time lag between the forecast and operations, asked that the predictability test be removed, requested that customers be able to use their own resources to provide load shaping, and again requested market access. Leone-Woods, *et al.*, WP-96-E-PA/PG-03, at 32-35. PGP and APAC also testified that BPA's apparent exemption of the DSIs from any charges for eccentric loads in the Block Sale contract but requiring a predictability test for utility industrial exemption load was unduly discriminatory. *Id.* at 34. BPA responded that it had not proposed to establish a separate charge for any eccentric loads. Bolden, *et al.*, WP-96-E-BPA-106, at 5. BPA also modified the predictability test. *Id.* Addendum, at 2.

In response to the parties' testimony regarding Industrial Exemption, BPA made the following modifications to its proposal:

1) BPA made Industrial Exemption available under both the 1981 and the 1996 Contracts. Kitchen, *et al.*, E-BPA-49, at 25.

2) BPA simplified the forecasting process by deleting the hourly forecast requirement and reduced the time between submission of the forecast and deliveries. Originally BPA proposed to require submission of the monthly forecasts on February 14 for the following August through July period. BPA now proposes to require the single monthly forecast 2 months prior to the billing month. Bolden, *et al.*, E-BPA-106, at 3 and Addendum.

3) The customer will be billed for the facilities' actual use of load shaping based on the difference between the HLH forecast and actual HLH energy use and the difference between the LLH forecast and actual LLH energy use, using the Industrial Exemption Rate. Kitchen, *et al.*, E-BPA-75, at 5-6. Overruns will not be charged at the unauthorized deviation rate.

4) The 5 aMW minimum load size for qualification was relaxed to become a general guideline. Bolden, *et al.*, E-BPA-106, at 2.

BPA does not propose to allow customers access to the market to serve variations in Industrial Exemption loads, because the exemption is available only to Full Load Shaping purchasers who have chosen to place all variations from forecast retail load on BPA. *Id.* at 5. BPA has instead modified the Industrial Exemption so that BPA supplies service for variations from forecast in an economic manner.

Because no party raised issues concerning Industrial Exemption in their initial briefs or briefs on exceptions, the issues identified above are waived, pursuant to *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611, § 1010.13(b) (1986).

11.2.1.4 Partial Load Shaping

Partial Load Shaping, a product initially proposed to be offered only to Partial Requirements Customers under the 1996 Contract, provides customers with the option to purchase a specific amount of Load Shaping from BPA. With Partial Load Shaping, BPA will adjust deliveries for positive or negative variations between a utility customer's forecasted and actual retail loads up to the amount of Load Shaping purchased. When actual load is greater than forecast, BPA provides additional power up to the amount of Partial Load Shaping purchased, and when actual load is less than forecast, BPA relieves the customer of its power purchase obligation up to the amount of Partial Load Shaping purchased. Lamb, *et al.*, E-BPA-19, at 4.

Issue

Whether Partial Load Shaping should be made available under the 1981 Contract to Computed Requirements customers.

Parties' Positions

PGP urges BPA to recognize the operational and business needs of Computed Requirements customers by making Partial Load Shaping available to Actual Computed Requirements customers. PGP Brief, B-PG-01, at 9; PGP Ex. Brief, WP/TC-96-R-PG-01, at 15-17.

BPA's Position

BPA originally proposed not to make Partial Load Shaping available under the 1981 Contract and to require all Actual Computed Requirements customers to buy Full Load Shaping. Lamb, *et al.*, E-BPA-19, at 3-5.

Since the initial rate proposal, BPA has proposed to make Partial Load Shaping available to Planned Computed Requirements customers purchasing under the 1981 Contract. Tr. 2348-2350; WP-96-E-BPA-126. BPA continues to propose not to make Partial Load Shaping available to Actual Computed Requirements customers under the 1981 Contract. Tr. 704-706.

Evaluation of Positions

PGP, APAC, and WPAG, throughout the rate case, have asked that Partial Load Shaping be made available to customers under the 1981 Contract. PGP and APAC requested Partial Load Shaping for Actual and Planned Computed Requirements customers, and requested that those customers be able to elect BPA service for different amounts of positive and negative variations from forecast each month. Leone-Woods, *et al.*, E-PG/AP-02, at 29. WPAG requested that BPA give Actual Computed Requirements customers under the 1981 Contract the same right to purchase Partial Load Shaping as Partial Requirements customers under the 1996 Contract. Beck, *et al.*, E-WA-01, at 39; WPAG Pr. Brief, WP-96-P-WA-01, at 19.

Because Partial Load Shaping allows a customer to vary its BPA deliveries from forecast purchase amounts, the customer must establish a forecast against which to measure the variations. Under the 1981 Contract, Planned Computed Requirements customers submit forecasts of their retail monthly peak and energy load, and the amount of capacity and energy that their resources will be obligated to provide each month (Assured Peak and Energy Capability of their Firm Resources) to serve their retail load. 1981 Contract, sections 16 and 17(a); Bolden, *et al.*, E-BPA-106, at 15. The balance is the forecast of BPA peak and energy purchases, which is binding on Planned Computed Requirements customers. *Id.* Thus, the forecasts required of Planned Computed Requirements customers serve to establish BPA's delivery obligation and thus provide a benchmark from which those customers may buy Partial Load Shaping to meet variations between forecast and actual retail load. With the Partial Load Shaping product, a Planned Computed Requirements customer may vary from its forecast of BPA purchases to the extent its retail load varies from forecast, up to the amount of Partial Load Shaping purchased. *See* WP-96-E-BPA-126.

Under the 1996 Contract, a customer may obtain a service similar to the 1981 Contract Planned Computed Requirements service. Bolden,*et al.*, E-BPA-106, at 17. The customer then may choose the amount of Partial Load Shaping it wants, and its PF or NR power purchases may vary from forecast up to the amount of Partial Load Shaping purchased to meet variations from forecast in the customer's retail load.

Actual Computed Requirements customers under the 1981 Contract submit binding forecasts of the monthly Assured Peak and Energy Capabilities of their Firm Resources, but they do not submit binding forecasts of their retail loads. 1981 Contract, sections 16 and 17(c); Bolden, *et al.*, E-BPA-106, at 15. BPA is obligated to serve the difference between those customers' Firm Resources' Assured Capabilities and the customers' retail loads, whatever those retail loads turn out to be. *Id.*

BPA originally proposed not to make Partial Load Shaping available under the 1981 Contract. Lamb, *et al.*, E-BPA-19, at 4-5. Because BPA is obligated to stand ready to serve all variations between customers' forecasted and actual retail loads of Actual Computed Requirements customers under the 1981 Contract, BPA believes that a contract amendment would be required to limit that contractual obligation. Kitchen, *et al.*, E-BPA-49, at 23. BPA is not proposing to design a Load Shaping charge that would require an amendment to the 1981 Contract. *Id.* Customers wanting Partial Load Shaping have the option of choosing to buy Partial Load Shaping by becoming a Partial Requirements customer under the 1996 Contract. Kitchen,*et al.*, E-BPA-49, at 20. Furthermore, BPA does not provide load shaping service under the 1981 Contract to Planned Computed Requirements customers. *Id.* at 21. However, because of requests from WPAG, PGP, and APAC as discussed above, and because staff believes that BPA can make Partial Load Shaping available to Planned Computed Requirements customers with minimal administrative burden, BPA now proposes to do so. *See* Tr. 2348-2350; WP-96-E-BPA-126.

If BPA were to make Partial Load Shaping available to Actual Computed Requirements customers, necessary contract changes would include: (1) limiting BPA's obligation to serve all variations between forecast and actual retail load; (2) requiring binding forecasts of energy and peak loads, to provide a benchmark against which to measure Partial Load

Shaping; and (3) changing the contractual mechanism under which Actual Computed Requirements customers can re-shape the Assured Energy Capability of their Firm Resources among months to meet variations between forecast and actual retail load (Flexibility Account). Tr. 706; 1981 Contract, section 17(d). Such changes fundamentally alter key aspects of Actual Computed Requirements service. The contract amendments that would be required to implement such changes are so extensive that BPA would not be establishing a rate for an existing contract, and it would be more appropriate to try to design that type of business relationship under a new contract. Tr. 705.

PGP asserts that BPA's proposal to require Actual Computed Requirements customers to become Planned Computed Requirements customers in order to receive Partial Load Shaping requires them to relinquish rights under the 1981 Contract. PGP Ex Brief, R-PG-01, at 4. PGP, in its initial brief, argued that BPA's contractual arrangements must recognize the operational and business needs of customers and that offering Partial Load Shaping only to Planned Computed Requirements customers does not recognize the way an Actual Computed Requirements customer operates, plans, and schedules. WP/TC-96-B-PG-01, at 9. BPA desires to offer products that recognize customers' operations; however, Actual Computed Requirements customers' 1981 Contracts enable them to choose to place the full difference between their firm loads and their firm resource obligation on BPA, while BPA must stand by to serve the full difference even if the customer chooses not to put the full difference on BPA. Kitchen, *et al.*, E-BPA-49, at 14-16 and 18. Because BPA is contractually obligated to provide Full Load Shaping service, but not Partial Load Shaping service, to Actual Computed Requirements customers, making Partial Load Shaping service available only to Planned Computed Requirements customers has no effect on Actual Computed Requirements Customers' ability to operate, plan, and schedule, nor does it require them to relinquish rights under the 1981 Contract.

PGP and APAC requested the ability to specify different amounts of upside and downside Partial Load Shaping service each month. The Partial Load Shaping product allows a customer to choose separate amounts of load shaping each month, but those amounts would allow the customer either positive or negative variations from forecast. BPA does not propose to develop separate charges for positive and negative variations from forecast.

An additional option available to Actual Computed Requirements customers to obtain customized load shaping services, or other types of shaping services such as resource shaping services, is to purchase them from BPA using the proposed FPS rate. Kitchen, *et al.*, E-BPA-49, at 21-24; Bolden, *et al.*, E-BPA-106, at 14. Services that are not available to a particular type of customer under its 1981 Contract may be available from BPA under separate contracts under other rates. *Id.* PGP stated that it was ludicrous to assert that these customers could buy Partial Load Shaping service under the FPS rate, because BPA has asserted many times that FPS arrangements are not available to replace requirements service unless BPA is convinced that it will lose the load. PGP Ex Brief, R-PG-01, at 17. However, BPA testified that customized load shaping services not available under the 1981 Contract may be negotiated using the proposed FPS rate. Bolden, *et al.*, E-BPA-106, at 14. Those services would not replace requirements service, but may be available to meet special needs not met by the provisions of the 1981 Contract. Kitchen, *et al.*, E-BPA-49, at 22.

Decision

BPA will offer Partial Load Shaping to Planned Computed Requirements customers under the 1981 Contract. Full Load Shaping will remain as a required component of service for Actual Computed Requirements customers.

11.2.1.5 DSI Load Shaping

DSI Load Shaping, offered only under the 1996 Contract, shifts a portion of the DSI's planning risk to BPA by providing coverage for up to 15 percent variation between the customer's actual and subscription load. Lamb, *et al.*, E-BPA-19, at 7. DSI Load Shaping remains unchanged from BPA's supplemental rate proposal. In the supplemental rate proposal, BPA proposed several modifications to DSI Load Shaping from the initial rate proposal. First, BPA proposed adding a capacity component in the costing of DSI Load Shaping. Kitchen, *et al.*, E-BPA-75, at 9. In addition, BPA proposed to determine the Calculated Energy Capacity (CEC) billing factor based on the amount of energy a DSI would consume when its facility was operating at full capacity, to review CECs annually, and to revise them as needed to reflect any changes in plant capacity or technology. *Id.*

The DSIs testified that BPA should change the positive deviation bandwidth to two percent. Schoenbeck, Bliven, WP-96-E-DS-08, at 13. However, BPA has entered into a contract with a DSI to provide the ±15 percent bandwidth product. Tr. 2185. As a result, BPA will retain the ±15 percent bandwidth. DSIs desiring to purchase products that are not available under their power sales contracts may contact BPA to discuss other products that may be available under the FPS rate schedule. Because no party raised the issue addressed by the Schoenbeck and Bliven testimony in its initial brief or brief on exceptions, the issue is waived pursuant to *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg 7611, § 1010.13(b) (1986).

11.2.2 Load Regulation

Issue

Whether BPA should unbundle the rate for Load Regulation in the PF, IP and NR rate schedules.

Parties' Positions

The Public Agency and Large Industrial Customers separately and jointly oppose BPA's draft decision provided in the Draft ROD to bundle Load Regulation in the PF, IP and NR rate schedules. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01; DSIs' Ex. Brief, WP-96-R-DS-01; PGP's Ex. Brief. WP-96-R-PG-01, at 6-9; PPC's Ex. Brief, WP-96-R-PP-01, at 11; RCC's Ex. Brief, WP-96-R-RC-01, at 2. Clark County PUD (Clark) and City of Tacoma (Tacoma) also oppose the draft decision to bundle Load Regulation into the power rates. Clark's Ex. Brief, WP-96-R-CP-01, at 12-14; Tacoma's Ex. Brief, WP-96-E-TU-01, at 2-3.

BPA's Position

In the Draft ROD BPA proposed to bundle the Load Regulation Charge in the PF, NR and IP rate schedules. Draft ROD, WP-96-A-01, at 265-266.

Evaluation of Positions

BPA's initial proposal proposed to unbundle the charge for Load Regulation in the PF, IR, and NR rate schedules in response to both the competitive environment and the FERC notice of proposed rule (NOPR) for open transmission access,. Dinsmore, *et al.*, WP-96-E-BPA-22; WP-96-E-BPA-22(E1). The FERC NOPR proposed to require public utilities to unbundle their wholesale power services, and to offer separate transmission and ancillary services at separately stated rates. Dinsmore, *et al.*, WP-96-E-BPA-22, at 2. The NOPR, however, proposed to apply the functional unbundling requirement only to the public utility's new wholesale power sales and purchases. *Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking*, 67 Fed. Reg. 17,662, 17,681 (1995). In rebuttal testimony, PGP generally complained that BPA's proposals to unbundle rates and charges modified existing power sales contracts and would adversely affect the PGP members' system operational flexibility. Smith, *et al.*, WP-96-E-PG-01, at 5, 7. PGP claimed that BPA's unbundling proposal dramatically increased the charges assessed under the 1981 power sales contracts and would make the contracts more complex and allow less flexibility in utility operations. Smith, *et al.*, WP-96-E-PG-05, at 7. PGP also claimed that customers would be charged twice for some services. LeoneWoods, *et al.*, WP-96-E-PA/PG-03, at 2. In addition, PGP opposed BPA's proposed Utility Factor adjustment which would be applied to the unbundled rates for Load Shaping and Load Regulation under the PF rate. *Id.* WPAG also opposed BPA's proposal for multiple unbundled products. Beck, *et al.*, WP-96-E-WA-13, at 24. WPAG argued that BPA's proposal imposed restrictive operating requirements. *Id.* In supplemental testimony, BPA acknowledged that the 1996rate case was the first time it had developed rates for Load Regulation and other ancillary services, and explained that there was no utility standard to follow. BPA notified its customers that it would continue to monitor how utilities filing open access tariffs with FERC developed rates for load regulation, and explained that it may modify its proposal subject to those findings. Dinsmore, *et al.*, WP-96-E-BPA-77, at 7-8. In the Draft Record of Decision, BPA proposed to bundle the Load Regulation charge into the power rates in response to customer concerns. Draft Record of Decision, 1996 Rate Proposal, WP-96-A-01, at 265-267.

BPA's power customers, however, jointly and separately objected to the draft decision in their briefs on exceptions. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01; DSIs' Ex. Brief, WP-96-R-DS-01; PGP's Ex. Brief. WP-96-R-PG-01, at 6-9; PPC's Ex. Brief, WP-96-R-PP-01, at 11; RCC's Ex. Brief, WP-96-R-RC-01, at 2; Clark's Ex. Brief, WP-96-R-CP-01, at 12-14; and Tacoma's Ex. Brief, WP-96-E-TU-01, 2-3. The customers generally argue that BPA's draft decision is inconsistent with BPA's business direction to charge customers for what they use. PGP's Ex. Brief. WP-96-R-PG-01, at 7. The customers assert that bundling is anti-competitive and would prevent a market in load regulation from developing, but fail to produce any record evidence to support their assertion. PPC Ex. Brief, WP-96-R-PP-01, at 11, PGP's Ex. Brief. WP-96-R-PG-01, at 7; Clark Ex. Brief, WP-96-R-CP-01, at 13. In contrast, in its supplemental proposal, BPA witnesses explained that, in the preliminary stages of open access, BPA's competitors were making fixed price offers for delivered power to customers in the Northwest. By "delivered power," BPA meant that power suppliers competing with BPA for sales agreed to sell power to Northwest customers, and the Northwest customers agreed to buy power from such suppliers, with transmission and other services included at bundled prices. Metcalf, *et al.*, WP-96-E-BPA-84, at 2. Prior to BPA's supplemental testimony, Northwest utilities represented to FERC that there was a vigorous competitive market for ancillary services in the Pacific Northwest, including load following services. Dinsmore, *et al.*, WP-96-E-BPA-22, Attachment 1, at 3-6. Notably, the competition in this market evolved in an environment of bundled power sales.

The DSIs also argue that bundling Load Regulation into the IP rate is inconsistent with BPA's contractual commitments to DSI companies under the 1996 Block Sales agreements. DSI Ex. Brief, WP-96-R-DS-01, at 2-3. The DSIs rely on section 19 of the 1996 Block Sale agreements to argue that a company has a contractual right to move out of BPA's control area and discontinue purchasing load regulation from BPA. Wolverton, WP-96-E-PA-03, Attachment 1, Section 19(b). BPA agrees that the 1996 Block Sale agreements permit DSI companies purchasing power under the agreements to discontinue purchasing load regulation from BPA if they move out of BPA's control area.

The customers' principal argument opposing BPA's draft decision to bundle Load Regulation in the power rates, however, rests on their claim that the draft decision undermines the Settlement Agreements, and is inconsistent with FERC's Order 888. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01, at 2; DSI Ex. Brief, WP-96-R-PG-01, at 2; PGP Ex. Brief, WP-96-R-PG-01, at 7; and Tacoma Ex. Brief, WP-96-R-TU-01, at 2-3. In addition, the DSIs also claim that BPA's draft decision violates the procedural requirements of section 7(i) of the Northwest Power Act. DSI Ex. Brief, WP-96-R-DS-01, at 3-5.

Neither the Transmission Settlement Agreement nor the Power Settlement Agreement settled the rate levels or any rate design features of the rates for any ancillary services, as the parties admit. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01, at 3. Furthermore, neither the Transmission Settlement Agreement nor the Power Settlement Agreement settled the rate design treatment for Load Regulation in BPA's power rate schedules for requirements service.

In fact, the Power Settlement Agreement recognizes that power rate design not specifically covered by the agreement was not included in the settlement. Power Settlement Agreement, Appendix B, ¶ Right to Contest. While the Settlement Agreements are not dispositive of this issue, as a matter of policy, BPA agrees it is reasonable to afford the customers the opportunity to choose the products and services BPA so vigorously promoted during the rate case. This choice better promotes competitive markets, and can be accomplished without compromising BPA's cost recovery requirements. Also, BPA understands that over the course of this unusually lengthy rate case, customers may have made arrangements based on BPA's long-held proposal to unbundle Load Regulation in its requirements power rates.

In light of the decision to unbundle Load Regulation, BPA addresses the requirements of Order 888 below only to begin a dialogue with its customers on this issue. Because BPA has decided to unbundle Load Regulation as a matter of policy, however, it is unnecessary to address issues regarding the procedural requirements of section 7(i).

The parties assert that the Load Regulation component included in BPA's power rates for requirements service is a transmission service subject to the unbundling requirement for non-discriminatory open access transmission tariffs. The parties also claim that BPA committed to subject itself to the same comparability standards applicable to other transmitting utilities under the Federal Power Act. Therefore, the parties argue that FERC's standards for non-discriminatory transmission service must be applied to BPA's draft decision to unbundle Load Regulation in its power rates. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01, at 3-5.

Order 888 provides that functional unbundling requires public utilities to establish separate rates for wholesale generation, transmission and ancillary services. *Promoting Wholesale competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 61 Fed. Reg. 21,540, 21,552 (1996), FERC Stats. & Regs. ¶ 31,036 (1996) [hereinafter Order 888]. However, Order 888 also states that the functional unbundling requirement applies only to a public utility's <u>new</u> wholesale services and does not apply to service under the utility's existing requirements contracts. *Id.* at 21,558. FERC further explains that the open access requirements apply only to the utility's new wholesale power sales or purchases executed after July 9, 1996. In addition, the utility must take transmission service for all of its new wholesale requirements sales and wholesale purchases executed after July 9, 1996, under the open access tariffs. Order 888 expressly provides that the open access requirements do not apply to the utility's requirements service agreements executed on or before July 9, 1996. *Id.* at 21,694. All of BPA's power sales contracts examined in this rate case were executed before July 9, 1996. See section 10.3 of this Record of Decision for more information. Order 888, therefore, does not apply to either the Block Sale agreements, or any other power sales agreements executed with any DSI or utility customer prior to July 9, 1996.

Order 888 defines a requirements service agreement to mean "a contract or *rate schedule* under which the public utility provides any portion of a customer's *bundled* wholesale power requirements." Order 888, at 21,694 (emphasis added). Thus, even though Order 888 directs a public utility to develop separately stated rates for generation, transmission and ancillary services for new wholesale power sales, BPA understands that Order 888 also permits public utilities to sell bundled requirements service so long as the utility takes transmission service for the new wholesale sales and purchases under the open access tariffs. Furthermore, the utility's obligation to offer customers the option to purchase certain ancillary services, including load regulation service, from the utility, provide the service to itself or acquire the service from third parties, only arises when the customer takes transmission service under the utility's open access tariffs. Order 888, Proforma Tariffs, at 21,709.

In addition to the issues raised with Order 888, the parties also allege that the Energy Policy Act of 1992 authorizes FERC to order BPA to provide wheeling services, and subjects BPA's rates for transmission service to FERC's just and reasonable and not unduly discriminatory or preferential standard. Public Agency and Large Industrial Customers' Ex. Brief, WP-96-R-PP/DS/PA/PG/RC/WA-01, at 3. In making this assertion, the parties incorrectly imply that all of BPA's rates for transmission service are subject to the ratemaking provisions of the Energy Policy Act standards. The Energy Policy Act grants FERC the authority to order BPA to provide transmission service. If FERC orders transmission service on the FCRTS, then FERC must also assure that

> the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law, and not be any provision of section 210, section 211, this section [212] and section 213, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(1)(B)(ii). FERC has held that the Energy Policy Act standards apply only to BPA's transmission service ordered by FERC under section 211. *U.S. Dep't of Energy--Bonneville Power Admin.*, 67 F.E.R.C. ¶ 61,351 (1994).

Finally, because BPA will unbundle Load Regulation in the power rates, BPA needs also to consider PGP's request not to charge a utility for Load Regulation under both the PF power rate and a separate transmission rate through the APS-96 rate. PGP Ex. Brief, WP-96-R-PG-01, at 7-8. BPA recognizes that it has proposed several rates that would permit it to impose charges for Load Regulation. *See, e.g.*, PF-96; IP-96; FPT-96.1; IR-96; NT-96; PTP-96; and APS-96, Wholesale Power and Transmission Rate Schedules, WP-96-A-02, Appendix. Thus, if a customer is taking Load Regulation service under multiple rate schedules, the customer will only be required to pay BPA for Load Regulation under one rate schedule during the billing period.

Decision

BPA will include an unbundled rate for Load Regulation in the PF, IP or NR rate schedules.

11.2.3 Irrigation Discount

Issue 1

Whether BPA should eliminate the Irrigation Discount.

Parties' Positions

Northwest Irrigation Utilities (NIU) does not oppose elimination of the Irrigation Discount, in return for PF rate seasonality as BPA proposed in the initial proposal, and a BPA offer of a surplus firm product to serve summer-only irrigation loads. NIU Brief, WP-96-B-NI-01, at 2.

BPA's Position

The Irrigation Discount should be eliminated. Craig, *et al.*, WP-96-E-BPA-20, at 11.

Evaluation of Positions

NIU is willing to accept elimination of the Irrigation Discount as long as BPA sustains the level of seasonality proposed in the initial PF rate proposal, and offers flexibly priced products for summer period users. Olsen, WP-96-P-NI-01, at 2. BPA is undergoing dramatic changes to become more competitive. Moorman, Evans, WP-96-E-BPA-09, at 27. BPA's 1996 proposed rates include unbundling products and services to offer our customers more choice in the type of services BPA provides. Craig, *et al.*, E-BPA-20, at 11. As part of that effort, a new Summer Seasonal Product (SSP) is under development. The SSP will be cost-based and would take advantage of excess energy on the Federal system in the spring and summer months. Irrigation loads represent the majority of the expected load that will utilize this product. Buchanan, *et al.*, WP-96-E-BPA-11, at 11.

Elimination of the Irrigation Discount is consistent with BPA's 1993 Marketing Plan and Draft Business Plan, as well as the intent expressed in BPA's 1993 rate case Record of Decision to consider modification to or elimination of the discount in the context of a more comprehensive examination of BPA's rate designs. Craig, *et al.*, E-BPA-20, at 11.

BPA's proposed PF rates are based on a marginal cost analysis that differentiates seasonal and diurnal energy costs. Craig, *et al.*, E-BPA-20, at 11. For the final rate proposal, BPA is revising its marginal cost studies. The results of the studies will lower heavy load hour energy costs in the month of August. Because BPA is proposing to offer low PF prices in the summer, plus additional flexibility in pricing and product choices, which provide the correct price signals, BPA proposes elimination of the Irrigation Discount. *Id*.

Decision

BPA will eliminate the Irrigation Discount.

11.2.4 Low Density Discount

BPA proposes to revise the current LDD methodology to provide an appropriate discount to BPA's customers with low system densities. Under the current methodology, a customer receives the *greatest* discount for which the customer qualifies based on either of the two applicable criteria: K/I (kilowatthours of total electric energy requirements during the previous calendar year over investment, which is the purchaser's depreciated electric plant (excluding generation plant) at the end of such calendar year) or C/M (average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding the average number of consumers associated with separately billed services for water heating, electric space heating, and security lights) during the previous calendar year divided by the average number of pole miles of distribution line for such year). Taken together, these criteria would ensure that only customers with high distribution costs resulting from sparsely populated service areas receive the discount; individually, however, these criteria do not ensure that only such customers qualify for the LDD. For example, currently a customer may qualify for the LDD simply because it has a high ratio of annual energy purchases to its electric plant excluding generation (the K/I component). Craig, *et al.*, WP-96-E-BPA-20, at 3-4. Such a customer might not have a low system density and high distribution costs resulting from a sparsely populated service area. BPA reviewed the proportion of benefits given to customers under the current LDD under each of the two criteria. BPA determined that more LDD dollars were going to the customers who qualified based on the K/I ratio than to customers who qualified based on the C/M ratio. *Id.* at 4. The majority of those customers qualifying under the K/I ratio received maximum discounts of 7 percent solely on the basis of having a costly distribution system. *Id.* As noted above, this is contrary to the intent of the discount because it does not ensure that LDD benefits are being provided to customers with low system densities. *Id.*; Craig, *et al.*, WP-96-E-BPA-107, at 6.

Furthermore, LDD benefits have been growing by approximately $1 million annually. Craig, *et al.*, E-BPA-20, at 3-4. The growth in the LDD costs has been caused primarily by load growth of LDD utilities and increases in the PF rate. Inflation is also a small contributor. However, because of the disproportionate benefits provided to customers that qualify based on the K/I ratio, a larger percentage of the increasing cost of the LDD is attributable to such customers. *Id.*

For the foregoing reasons, the current methodology must be revised to re-establish the goal of providing assistance to low system density customers with high distribution costs resulting from sparsely populated service areas, and to control and reduce LDD costs. *Id.*

Instead of allowing the greatest discount determined from applying the two criteria, BPA proposes to revise the methodology so that the purchaser receives the sum of the discounts resulting from applying each of the two criteria, but not in excess of 7 percent. If the revised discount varies from the current discount by more than one-half of one percent, BPA proposes to progressively phase in the revised discount in annual increments each fiscal year of one-half of one percent until the customer receives its then-final revised discount. *Id.* at 6-7. The applicable percentage discount is applied each month to the charges for all power (excluding transmission) purchased under the PF and NR rate schedules from BPA. *Id.* at 5-6. BPA also proposes to include nonfirm sales to nonfirm loads in the "K" portion of the K/I ratio, except for the current amount of such sales. *Id.* at 8. BPA also proposed including a very low density discount of an additional one-half of one percent for those utilities with a C/M ratio of 3 or less, a K/I ratio of 25 or less, and whose discount without considering the very low density discount adjustment is below 7 percent. Craig, *et al.*, E-BPA-76, at 3-4. As noted in Issue 5, *infra*, NIU suggests BPA should raise the maximum K/I ratio criterion applicable to the proposed very low density discount from 25 to 26. NIU Ex. Brief, WP-96-R-NI-01. Furthermore, for inter-regional utilities, BPA proposes to apply the qualification criteria separately to the customer's system within the Pacific Northwest and to its entire system inside and outside the Pacific Northwest. The customer would qualify for the lowest level of discount for its Pacific Northwest or combined system. WP-96- E-BPA-127; Tr. 2343-2346.

WPAG testified that the intent of the LDD is to assist rural and cost disadvantaged systems, not just low density rural systems. Beck, *et al.*, WP-96-E-WA-01, at 59-60. WPAG asserts that BPA should not change the LDD methodology to give more weight to the consumer per mile ratio. *Id.* at 61. WPAG also testified that BPA's very low density discount proposal was "consistent with Bonneville's redefined intent of the LDD. This approach again is creating winners and losers under the new LDD, rather than a more equitable approach." Beck, *et al.*, WP-96-E-WA-13, at 90-91. PacifiCorp states that the LDD benefits retail ratepayers of BPA's customers that have relatively high electric plant investment compared to low population density. Stamper, Brattebo, WP-96-E-PL-01, at 1. PacifiCorp makes no assertions about whether BPA's proposed methodology is consistent with the intent of section 7(d)(1) of the Northwest Power Act. RCC states that the reason for the LDD is reflected in the wording of section 7(d)(1) of the Northwest Power Act, that "'the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for' 'customers with low system densities' 'to avoid adverse impacts on retail rates. . .'" Sher, WP-96-E-RC-03, at 2. RCC is willing to accept, for this rate case, BPA's proposal to equalize the weight between the sales to investment and consumer per mile criteria, but argues that because the need for a discount is as great as ever, the amount of BPA's proposed overall reduction in LDD benefits is inconsistent with section 7(d)(1) of the Northwest Power Act. *Id.* at 2-3. PPC, not including Clallam County PUD, Lewis County PUD No. 1, and Mason County PUDs Nos. 1 and 3, testifies that the purpose of the LDD is to avoid adverse impacts to systems with low system densities. Carr, *et al.*, WP-96-E-PP-05, at 1-2.

BPA acknowledges WPAG's assertion that there are other factors besides low system densities that could cause a utility's distribution costs to be high, such as heavily wooded areas in high wind zones, difficult terrain, and seasonal customers. Craig, *et al.*, E-BPA-50, at 4. However, contrary to WPAG's contention, BPA believes the LDD was not intended to benefit customers that have high electric plant investment but do not have low system densities. While these other cost factors may adversely impact LDD customers, those factors in themselves are not exclusive to low density customers. *Id.* at 4-5.

Section 7(d)(1) of the Northwest Power Act provides:

> In 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 of such customers.

Section 7(d)(1) of the Northwest Power Act clearly states that the discount applies to "customers with low system densities." The legislative history to section 7(d)(1) of the Northwest Power Act supports BPA's understanding of the intent of section 7(d)(1). The Report of the House Interior and Insular Affairs Committee, H.R. Rep. 976, Part II, 96th Cong., 2d Sess. 52 (1980), states:

> Section 7(d)(1) permits BPA to offer rate discounts to customers with low system densities such as rural electric cooperatives with high distribution costs resulting from sparsely populated service areas.

The Report of the House Interstate and Foreign Commerce Committee, H.R. Rep. 976, Part I, 96th Cong., 2d Sess. 69 (1980), states:

> Section 7(d) permits the Administrator to apply constraints to the rates of <u>customers with low system densities</u>. This is intended to afford greater equity to consumers of small rural co-ops which have high distribution costs due to difficult terrain, remote service areas, or other factors.

(Emphasis added.) The quote from the House Interstate and Foreign Commerce Committee report demonstrates that the primary intent of section 7(d)(1) of the Northwest Power Act was to assist customers with low system densities, and that the Committee understood that various factors would contribute to high costs.

In rebutting RCC testimony, WPAG testified that the intent of the LDD is best summarized by the following statement of Shirley Melton, then Director of BPA's Division of Rates, dated December 22, 1986, summarizing the results of the LDD review process required by section 8(g) of the General Contract Provisions to the 1981 Contract:

> This discount was implemented to reduce adverse impacts on retail rates of utilities with low system densities, and to assist rural customers who have

> high costs due to low system density, difficult terrain, remote service areas, or other factors.

In other testimony, WPAG implied that the LDD was intended to benefit not just low density systems, but any rural system that is "cost disadvantaged." Beck, *et al.*, E-WA-01, at 58-60. WPAG apparently quotes Shirley Melton to support its understanding of the intent of the LDD because arguably the "and" in the Melton statement is used disjunctively. However, the better interpretation of the Melton statement, because it is consistent with the wording of the statute and with the legislative history, is to read the "and" conjunctively with the preceding statement so that the clause after the "and" merely explains the circumstances that would apply to low density customers. Furthermore, the Melton statement is not a BPA decision document, but merely a summary of study results by a BPA staff member. WPAG also testified that in the 1981 initial rate proposal BPA proposed to apply a discount based only on system investment costs (the K/I ratio) and added a system density criterion (the C/M ratio) later, and that that demonstrates BPA considered the system cost criterion of primary importance. *Id.* at 59. WPAG's understanding is not consistent with the record of the 1981 rate case. In the 1981 rate case, BPA initially proposed to include both system investment cost and system density criteria, and proposed to add another system density criterion as a result of customer comments during the course of the rate case. Craig, *et al.*, E-BPA-50, at 3-4. The 1981 rate proceeding does not support WPAG's understanding.

WPAG overlooked a previous BPA decision document that supports BPA's understanding of the intent of the LDD. The 1981 BPA rate case Record of Decision states:

> A low density discount (LDD) is included in the PF-1 Priority Firm Power Rate Schedule pursuant to Section 7(d)(1) of the Regional Act. This discount has been instituted to aid <u>customers with low system densities</u> in avoiding adverse impacts on retail rates. . . . I have determined that LDD's [sic] are appropriate to avoid adverse impacts on . . . customers of <u>utilities with low system densities</u>.

Administrator's Record of Decision, 1981 Transmission and Wholesale Power Rate Proposals IX-9-10 (June 1981) (emphasis added).

The RCC, PPC, and PacifiCorp testimonies cited above all support the intent of the LDD as being to aid customers with low system densities.

RCC argues that the need for the LDD is as great as, or greater than, ever, and that the amount of BPA's reduction of LDD benefits under current circumstances is inconsistent with section 7(d)(1) of the Northwest Power Act. Sher, E-RC-03, at 2. The extent to which a low density discount benefit should be offered is within the discretion of the Administrator. As stated in section 7(d)(1) of the Northwest Power Act, "the Administrator shall, <u>to the extent appropriate</u>, apply discounts. . . ." (Emphasis added.)

Where, as here, BPA demonstrates: (1) a need to control and reduce LDD costs, Craig, *et al.*, E-BPA-20, at 4; Craig, *et al.*, E-BPA-107, at 6, Tr. 746, 751, 761, 773; (2) that benefits are most often provided to systems based on the ratio of requirements to investment (K/I) rather than on consumers per mile (C/M), Craig, *et al.*, E-BPA-20, at 4, Tr. 761-763; and (3) since the overall level of BPA's rates to LDD customers will decline notwithstanding the reduction in LDD benefits, Craig, *et al.*, E-BPA-50, at 8-11; the LDD proposal in this rate case is well within the discretion of the Administrator.

Because no party raised the issue of whether BPA's LDD proposal is consistent with section 7(d)(1) of the Northwest Power Act in its initial brief or brief on exceptions, the issue is waived. *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg 7611, § 1010.13(b) (1986)(hereinafter "Procedures").

PacifiCorp testified that BPA's proposal to clarify application of the LDD ratios in the General Rate Schedule Provisions (GRSPs) to the "utility's entire system in the Pacific Northwest, regardless of whether the utility has service areas in more than one state or whether the utility is participating in the residential exchange program in more than one jurisdiction" was intended to have the effect of disqualifying Utah Power & Light (UP&L) as a LDD recipient under the Residential Purchase and Sale agreement (RPSA), and that such disqualification would be contrary to UP&L's rights under the RPSA. Brattebo, Stamper, WP-96-E-PL-01, at 4-5. BPA responded that PacifiCorp, rather than UP&L, was the utility that incorrectly filed for the LDD based only on the portion of its system associated with the southern Idaho jurisdiction of its Utah division, Craig, *et al.*, E-BPA-50, at 15-16, and that BPA had mistakenly made payment. *Id.* at 20-22. BPA testified that the RPSA executed with UP&L does not reference the LDD, except insofar as the LDD is referenced in the PF rate schedule and GRSPs, which are exhibits to the RPSA. *Id.* at 25. PacifiCorp responded that it acted in good faith in applying for LDD benefits for UP&L, based on the conduct of the parties. Brattebo, Stamper, WP/TC-96-E-PL-05. BPA subsequently proposed to delete the language that would clarify application of the LDD criteria to the "utility's entire system in the Pacific Northwest, regardless of whether the utility has service areas in more than one state or whether the utility is participating in the residential exchange program in more than one jurisdiction." Tr. 2346. PacifiCorp stated in its initial brief that as a consequence of BPA's withdrawal of the foregoing language and its replacement with the new eligibility test noted in Issue 1, *infra*, the contractual dispute regarding the proper construction and interpretation of UP&L's RPSA is no longer an issue in the rate case, although PacifiCorp continued to contend that UP&L should be considered a separate customer from PP&L for purposes of power sales under the RPSA. PacifiCorp Brief, WP-96-B-PL-01, at 9 n.4.

Issue 1

Whether BPA should allow the phase-in adjustment to a utility that no longer is eligible for the LDD due to BPA's proposal to apply the LDD eligibility criteria separately to an inter-regional customer's system in the Pacific Northwest and to its total system inside and outside the Pacific Northwest.

Parties' Positions

PacifiCorp advocates allowing the LDD Phase-In Adjustment for any LDD utility that is disqualified due to BPA's proposal to apply the LDD eligibility criteria separately to the utility's system inside the Pacific Northwest and to the utility's entire system inside and outside the Northwest. PacifiCorp Brief, B-PL-01, at 10; PacifiCorp Ex. Brief, R-PL-01, at 6-8. No other party has taken a position on this issue.

BPA's Position

BPA does not propose to make the LDD Phase-In Adjustment available to utilities that are no longer qualified to receive the LDD. *See* General Rate Schedule Provisions, WP-96-E-BPA-64, Section II.J.4.

Evaluation of Positions

During cross-examination of BPA witnesses, PacifiCorp asked if BPA had considered applying the phase-in adjustment to a utility that no longer is eligible for the LDD if BPA adopts the proposal to apply the eligibility criteria separately to the in-region and total systems of utilities with service areas inside and outside the Pacific Northwest. Tr. 2346. BPA had not considered phasing out the discount to utilities no longer eligible due to the proposal for applying the eligibility criteria to inter-regional utilities. *Id.* at 2347. BPA proposes to make the phase-in adjustment available only to purchasers who first satisfy all five of the eligibility criteria. Craig, *et al.*, E-BPA-20, 5-6. PacifiCorp states that because Utah Power and Light's residential and small farm customers in southern Idaho will experience substantial rate increases due to BPA's LDD proposal, changes in the residential exchange, and changes in rate design affecting irrigators, BPA should offer a phase-in adjustment to customers that received the discount in prior rate periods but no longer qualify due to higher system-wide densities. PacifiCorp Brief, B-PL-01, at 10-11. PacifiCorp states that equity supports extending the phase-in adjustment for reductions in LDD benefits to UP&L's residential and small farm consumers. PacifiCorp Ex. Brief, R-PL-01, at 7-8. PacifiCorp has determined that its southern Idaho UP&L jurisdiction would be unlikely to qualify for the LDD. PacifiCorp Brief, B-PL-01, at 9. PacifiCorp does not contest the criteria BPA has proposed to determine whether a utility qualifies for the LDD; PacifiCorp only contests whether its southern Idaho UP&L jurisdiction should be allowed a phase-in of elimination of benefits. Although the changes in BPA's rate design may impose added costs on PacifiCorp and its UP&L division, the LDD is designed to assist customers with low system densities. If a utility no longer qualifies for the LDD, equity does not favor continuing to grant the utility a discount. It would be inappropriate for BPA to extend the Phase-In Adjustment to utilities that are disqualified from receiving the LDD. While BPA is sympathetic to the plight of consumers resulting from the elimination of this rate discount, BPA believes remediation of that problem is best achieved by PacifiCorp and its customers reviewing its southern Idaho UP&L jurisdiction rate structure.

Decision

The Phase-In adjustment applies only to purchasers that meet the five eligibility criteria. It will not be available to purchasers who no longer meet the criteria.

Issue 2

Whether BPA should include nonfirm sales to nonfirm retail loads in the calculation of "K" in the requirements over investment (K/I) LDD eligibility criterion.

Parties' Positions

The Requirements Customer Coalition (RCC) states that nonfirm sales to nonfirm retail loads should not be considered in determining the K/I criteria. RCC Brief, WP/TC-96-B-RC-01, at 9.

BPA's Position

BPA proposes to include nonfirm sales to nonfirm loads in the calculation of "K" in the requirements over investment (K/I) eligibility criterion. Craig, *et al.*, E-BPA-20, at 8. However, beginning in calendar year 1997, BPA proposes to exclude an amount of nonfirm sales to nonfirm loads equal to the amount of such sales made by the utility in calendar year 1996 from the calculation of each utility's requirements in the requirements over investment (K/I) ratio. Craig, *et al.*, E-BPA-76, at 5.

Evaluation of Positions

PacifiCorp states it has excluded amounts of transmission plant allocated to nonfirm sales from its southern Idaho jurisdiction LDD filings, and that BPA's proposal to include nonfirm sales to nonfirm loads in the requirements portion of the requirements over investment (K/I) criterion would be inconsistent with the investment portion of the criterion unless investment for nonfirm loads also were allowed. *See* Craig, *et al.*, E-BPA-50, at 14-15, Attachment E; Brattebo, Stamper, E-PL-01, at 3. Under the current LDD criteria, PacifiCorp could have included facilities dedicated to nonfirm loads in its submittals. Craig, *et al.*, E-BPA-50, at 15. The fact that it chose not to do so does not make BPA's proposal inconsistent. PacifiCorp failed to raise this issue in its initial brief and brief on exceptions, and thus has waived it. Procedures, *supra*, § 1010.13(b).

RCC argues that BPA decided to exclude nonfirm sales in the requirements calculation in a previous rate case and that BPA has not demonstrated what has changed, or that any LDD utilities would gain additional net revenues from unstable and unpredictable sales. McConkey, E-RC-04, at 2-3. RCC states that nonfirm service which the utility could interrupt or which the retail load could interrupt does not provide a significant contribution to the margins of these utilities and would not reduce the high distribution costs. McConkey, WP-96-E-RC-08, at 2. Therefore, RCC argues that nonfirm sales appropriately should be excluded from the calculation of the LDD. *Id.* In response to a data request, RCC provided information that Flathead Electric Cooperative had entered into a transaction that would be considered a nonfirm sale for purposes of the proposed LDD criterion. Craig, *et al.*, E-BPA-50, at 11, and Attachment D. The data response indicates that the "Waiver and Release" transaction would be delivered to Flathead for delivery to Columbia Falls Aluminum Co. *Id.*, at Attachment D, p. D-4. The amount of the Waiver and Release schedule for a single month appears to be 39 aMW. *Id.*, at Attachment D, p. D-2. The data response stated that "[t]he attached documents describe the expected size of the transaction as it would affect the K/I transaction." *Id.*, at Attachment D, p. D-1. Thus, it appears that the expected size of the transaction is 39 aMW. Flathead's forecast load for the rate period ranges between 18 and 20 aMW. Loads and Resources Study Documentation, WP-96-FS-BPA-01A, at 88*et seq.* (customer number 339). The expected amount of the nonfirm transaction is double Flathead's forecast firm load. The Flathead nonfirm sale, forecast to be 39 aMW, appears not to be unstable and unpredictable; therefore any additional Flathead revenues from the sale should be stable and predictable. RCC also testified that:

> [e]ven if there were additional net revenues, since those revenues come from nonfirm sales, they would still be "unstable and unpredictable" as Bonneville characterized them in previous testimony. Like additional revenues from an extremely cold winter, these are not revenues that a utility can plan to apply to its costs.

Id. at 3. Again, the witness relied on BPA testimony from an earlier rate case to make his point. However, it is hard to understand how an expected nonfirm load that is twice the size of the rest of a utility's load can be characterized as the equivalent of "revenues from an extremely cold winter." The data response indicates the nonfirm load is expected, while an extremely cold winter is not. The RCC witness, McConkey, is Flathead's manager. RCC Qualification Statement, WP-96-Q-RC-04. Thus, McConkey's testimony that "<u>Bonneville</u> presents no evidence that any more utilities will begin making nonfirm sales to nonfirm retail loads. . . ," McConkey, E-RC-04, at 2 (emphasis added), avoids denying that such sales would happen, and the facts presented in response to the data request show they do happen. There is other evidence in the record supporting BPA's position that substantial amounts of nonfirm loads could be included in the calculation of a utility's requirements. PacifiCorp stated in a data response that "[i]n southern Idaho, PacifiCorp provides a substantial amount of nonfirm sales to nonfirm retail loads (approximately 40% of southern Idaho retail sales)." Craig, *et al.*, E-BPA-50, at Attachment E.

BPA proposed to include nonfirm sales to nonfirm retail loads, because as more utilities enter a very competitive marketplace, BPA believes that utilities will make nonfirm sales to nonfirm retail loads or assist others (such as power brokers or marketers) in serving a nonfirm load by first purchasing the energy from the broker/marketer and delivering the energy to a third party beneficiary. Craig, *et al.*, E-BPA-20, at 8. BPA's expert witnesses are qualified to state such an opinion. *See* Craig, WP-96-Q-BPA-26; Itami, WP-96-Q-BPA-27; Hoffman, WP-96-Q-BPA-28. That is exactly what happened with the Columbia Falls Aluminum Company load and Flathead. PacifiCorp and a marketer, Hinson Power Company, entered into a transaction to provide power to a BPA direct-service industrial customer through Flathead. The data response indicates that Hinson would execute "BPA's standard power marketer enabling agreement." Craig, *et al.*, E-BPA-50, at Attachment D, p. D-4.

BPA notes that although RCC raised the foregoing issue in its initial brief, RCC Brief, WP/TC-96-B-RC-01, at 9, it did not do so in its brief on exceptions. Instead, the RCC brief on exceptions states only that

> The RCC takes exception to the preliminary decisions in the DROD with regard to the following issues:
>
> 1. Low Density Discount. . . .
>
> The RCC endorses the position and argument presented in the Brief on Exceptions of the Public Power Council with regard to the [Low Density Discount]. RCC adopts each of those positions and arguments as if set forth herein.

RCC Ex. Brief, R-RC-01, at 2. The only LDD issue raised by the PPC brief on exceptions referenced by the RCC was whether BPA should adopt the PPC LDD proposal. Procedures § 1010.13(d) states that "[a]lleged errors not raised in briefs on exceptions shall be deemed waived." Further, Procedures § 1010.13(b) states that "[p]arties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. Arguments not raised are deemed to be waived." Because RCC did not specifically take exception to BPA's draft decision on this issue, they did not "raise and fully develop their position" and have waived the issue, pursuant to the Procedures.

It is not BPA's intent to adversely impact past agreements that may include nonfirm sales to nonfirm loads. Craig, *et al.*, E-BPA-76, at 5. Therefore, BPA proposes that utilities include nonfirm sales to nonfirm loads in their K/I ratio data submittals to BPA for the period January 1, 1996, through December 31, 1996. *Id.* That amount of nonfirm sales will not be included in calculations of the utilities' K/I for the 5-year rate period. *Id.* Beginning January 1, 1997, the purchaser will include any amount of nonfirm sales to nonfirm retail loads that is in addition to the amount of such sales in calendar year (CY) 1996 to calculate the purchaser's K/I. *Id.*

WPAG suggests nonfirm sales should be included in the K/I calculation in CY 1996 to prevent LDD customers from artificially increasing their nonfirm sales. WPAG contends that utilities may manipulate their nonfirm sales in CY 1996 to receive a larger benefit for the remaining 4 years. Beck, *et al.*, WP-96-P-WA-15, at 20. WPAG further suggests BPA would be better served by simply including all nonfirm transactions in the K/I calculation starting in 1997. *Id.* at 20. BPA does not want to reduce a customer's LDD due to existing transactions. Furthermore, because of BPA's proposed definition of nonfirm load, *infra*, BPA does not expect customers to be able to artificially increase their nonfirm sales in calendar year 1996. Because WPAG did not raise these issues in its initial brief and brief on exceptions, it has waived them. Procedures, *supra*, § 1010.13(b).

Decision

BPA will include nonfirm sales to nonfirm retail loads in calculating the K/I ratio. Utilities will submit nonfirm sales to nonfirm loads for the calendar year beginning January 1, 1996. The amount of nonfirm sales to nonfirm loads for 1996 will not be included in the calculation of a utility's K/I ratio for the 5-year rate period, but in subsequent calendar years, nonfirm sales to nonfirm loads above the 1996 level will be included in calculations of the K/I ratio for the remainder of the 5-year rate period.

Issue 3

Whether BPA's proposed definition of nonfirm load to be included in the K/I ratio criterion is correct.

Parties' Positions

The RCC suggests the nonfirm load definition should be "'[n]onfirm sales to nonfirm loads' shall mean service which, pursuant to contract or statutory right, either the Purchaser may interrupt or the retail load may curtail on short notice." McConkey, E-RC-08, at 2; RCC Brief, B-RC-01, at 9.

BPA's Position

BPA proposes that the definition of nonfirm load be "nonfirm energy load is electric load that is subject to interruptions or curtailment on short notice at any time for any condition, including economic and physical conditions like power shortage and transmission limitations." General Rate Schedule Provisions, WP-96-E-BPA-64, at 148.

Evaluation of Positions

WPAG agrees with BPA's definition of nonfirm energy. WPAG states BPA's definition of nonfirm energy is the traditional utility definition of this product, and it is not unclear. Beck, *et al.*, E-WA-15, at 19. RCC contends BPA's proposed definition of nonfirm energy is unclear and an inappropriate limitation on what constitutes nonfirm energy load for purposes of determining a utility's LDD. McConkey, E-RC-08, at 2.

Excluding calendar year 1996 nonfirm loads that are truly firm would reduce the "K" component of the K/I ratio and potentially increase the LDD percentage level, Craig, *et al.*, E-BPA-107, at 9, and therefore increase BPA's LDD costs. BPA is concerned that

RCC's proposed definition might allow calendar year 1996 firm loads to be considered nonfirm. *Id.* As stated by WPAG:

> [t]he definition offered by [RCC] . . . defines nonfirm as power which is subject to interruption by the purchaser or end user. Taken literally, this definition would allow all power to be classified as nonfirm, since the purchaser or end user always has the right to decline to take power.

Beck, *et al.*, E-WA-15, at 22. Clearly, the RCC's proposed definition would result in the exclusion of firm load from the calculation of a utility's requirements in the determination of its LDD. As with Issue 2, *supra*, RCC did not except to BPA's draft decision on this issue and has therefore waived it.

Decision

BPA will adopt the following definition of "nonfirm energy load" for determining nonfirm sales to nonfirm load in calculating the K/I ratio for determining LDD eligibility: "'nonfirm energy load' is electric load that is subject to interruptions or curtailment on short notice at any time for any condition, including economic and physical conditions such as power shortages and transmission limitations."

Issue 4

Whether BPA should adopt the LDD proposal offered by the PPC in Carr, et al., WP-96-E-PP-08.

Parties' Positions

BPA should adopt the LDD proposal offered by the PPC in Carr, *et al.*, E-PP-08. PPC Brief, WP/TR-96-B-PP-01, at 24; PPC Ex. Brief, WP/TC-96-R-PP-01, 2-4. RCC supports the proposal. RCC Brief, B-RC-01, at 9; RCC Ex. Brief, R-RC-01, at 2. In initial direct testimony, the RCC submitted another alternative proposal, Sher, WP-96-E-RC-03, which PPC supported. Carr, *et al.*, WP-96-E-PP-05. Because neither RCC nor PPC raised the earlier RCC proposal in its initial brief and brief on exceptions, that proposal is waived. Procedures, *supra*, § 1010.13(b).

BPA's Position

BPA does not propose to adopt the PPC proposal.

Evaluation of Positions

BPA's intent in proposing the modification to the LDD was to re-establish both the original intent of the LDD and to reduce and control LDD program costs. Craig, *et al.*, E-BPA-107, at 4 and 6; *see also* Tr. 746, 751, 761, 773. The PPC proposal increases

LDD costs over BPA's proposal by approximately $18 million. Craig, *et al.*, E-BPA-76(E1), Attachment C; Craig, *et al.*, E-BPA-107, at 4 and 6; *see also* Tr. 783. Because increasing the cost of the LDD by $18 million over the rate period could result in increased rates for other customers, BPA does not support PPC's proposal. Tr. 775.

PPC erroneously uses BPA's 1996 supplemental rate proposal, Wholesale Power Rate Development Study Documentation (WPRDS), WP-96-E-BPA-61A, Part 1 of 2, Revenue Forecast at BPA's current 1995 PF rates to attack the credibility of BPA's analysis. PPC Brief, B-PP-01, at 23. PPC argues that BPA's revenue forecast shows LDD costs declining under the current LDD methodology at current 1995 PF rates and that BPA's analysis in supplemental testimony shows increasing LDD costs under "the same assumptions." *Id.* at 22. PPC goes on to state that BPA's analysis in supplemental testimony failed "to correctly forecast the trend in discount levels using current 1995 PF rates and current LDD methodology. . . ." *Id.* at 23.

If PPC's conclusion were correct, then BPA's proposal not to adopt the PPC alternative would be based on a faulty analysis. But PPC's conclusion is incorrect because of PPC's faulty analysis. The figures PPC extracts from the supplemental WPRDS Documentation, E-BPA-61A, are part of the forecast of revenues at*current 1995 PF rates*, which reflect a 4 percent increase over 1993 PF rates, and use BPA's proposed sliding scale LDD percentage methodology. They do not, as the PPC brief states, use the current 3, 5, 7 percent LDD methodology. In the supplemental proposal, projected revenues at current 1995 PF rates were on average $520 million per year lower than revenues at proposed 1996 PF rates. This is because market conditions and other factors would cause BPA substantial load reductions in response to the higher current 1995 PF rates. Wedlund, Reilly, WP-96-E-BPA-81, at 4-5. For the final proposal, forecast revenues under current 1995 rates are approximately $218 million per year lower than forecast revenues under the proposed rates. WPRDS Documentation, WP-96-FS-BPA-05A, Section 3.6 (proposed 1996 rates revenue forecast) and Section 3.7 (current 1995 rates revenue forecast). As noted in the final WPRDS, "[t]he expected firm loads at current rates for generating and non-generating publics and DSIs are lower than expected firm loads at proposed rates." WPRDS, WP-96-FS-BPA-05, Section 5.3.

BPA's alternative analysis cited in PPC's Brief, B-PP-01, at 23, is based on the 1997 through 2001 load forecast at proposed PF rates from BPA's initial 1996 rate proposal, and assumes the current LDD methodology of 3, 5, and 7 percent is applied to both power purchases and transmission. Craig, *et al.*, E-BPA-107, at 5. The load forecast used in the BPA alternative analysis shows increasing BPA loads over the rate period. *See* Lee, *et al.*, WP-96-E-BPA-12, at 13. The PPC brief erroneously compares different loads (the load forecast at PF-95 rates in the WPRDS Documentation and the load forecast under proposed rates in the BPA alternative analysis), different PF rates (PF-95 rates in the WPRDS Documentation and PF-96 initial proposal rates in the BPA alternative analysis), and different LDD percentages (proposed new methodology in the WPRDS Documentation and current methodology in the BPA alternative analysis). Each variable is different.

In its brief on exceptions, PPC cited the foregoing comparison from its initial brief and an earlier comparison from Carr, *et al.*, E-PP-08, Attachment 2, in support of the conclusion that their analysis "is based on verifiable data from the utilities that is contained in documentation for the Supplemental Proposal." PPC Ex. Brief, R-PP-01, at 3. The PPC's reliance on the comparison in Carr, *et al.*, E-PP-08, Attachment 2, is also misplaced because that analysis also includes more variables than just the different LDD percentages under the different proposals. *See* Craig, *et al.*, E-BPA-119, at 2-3.

The PPC's brief on exceptions refers to tables presented in Carr, *et al.*, E-PP-08, Attachment 2, and PPC Brief, B-PP-01, at 23, to support its position of providing "verifiable data" from LDD-receiving utilities. The two tables created by the PPC (replicated below) provide expected LDD costs under different scenarios. Under each PPC table is a table prepared by BPA describing the assumptions in the preceding PPC table.

From Carr, *et al.*, E-PP-08, Attachment 2
"LDD Benefits for Public Agencies"

	1997	**1998**	**1999**	**2000**	**2001**	**Total**	**Avg**
Current Rates	$22,088	$21,586	$21,322	$21,149	$20,686	$106,831	$21,386
PPC proposal	$19,869	$19,235	$18,689	$18,225	$17,818	$ 93,837	$18,767
Proposed Rates	$15,832	$15,468	$15,275	$15,160	$14,813	$ 76,548	$15,310
Sources:							
Current rates (WP-96-BPA-E-BPA-05A, p.246ff)							
Proposed rates (WP-96-BPA-E-BPA-05A, p.196ff)							

Assumptions behind Carr, *et al.*, E-PP-08, Attachment 2 "LDD Benefits for Public Agencies"	
Current Rates	***Assumes:*** ⇒ Load: Forecasted load under proposed rates. ⇒ Rate: BPA's PF-95 rates, including transmission. ⇒ LDD percentage: BPA's proposed sliding scale LDD percentage methodology. Applied to power purchases only.
PPC proposal	***Assumes:*** ⇒ Load: 1993 actual load for LDD-receiving utilities held constant through 5 year rate period. Craig, *et al.*, E-BPA-119, at 2. ⇒ Rate: BPA's PF-96 rates. Does not include transmission. ⇒ LDD percentage: Applies PPC-RCC proposed LDD percentage methodology. Applied to power purchases only.
Proposed Rates	***Assumes:*** ⇒ Load: Energy and demand load forecasted in BPA rate case for FY 1997-2001 for non-generating utilities under proposed rates. ⇒ Rate: BPA's PF-96 rates. Does not include transmission. ⇒ LDD percentage: Applies BPA's proposed sliding scale LDD methodology. Applied to power purchases only.

From PPC Brief, B-PP-01, at 23 "Table 1"					
	1997	**1998**	**1999**	**2000**	**2001**
WPRDS	$20,695	$20,238	$19,987	$19,760	$19,225
ALTERNATE	$20,043	$20,369	$20,591	$20,846	$20,893
Sources:					
WPRDS: WP-96-BPA-E-BPA-61A, lines 33 and 40, pages 327, 337, 347, 357, 368					
Alternate: WP-96-BPA-E-BPA-76, p.C-1					

Assumptions behind PPC "Table 1" From PPC Brief, B-PP-01, at 23	
WPRDS	***Assumes:*** ⇒ Load: Reduced BPA 1997-2001 energy and demand load forecast for small and non-generating utilities at current PF-95 rates. *See* Wedlund and Reilly, WP-96-E-BPA-81, at 4-5. ⇒ Rate: BPA's PF-95 rates, including transmission. ⇒ LDD percentage: BPA's proposed sliding scale LDD percentage methodology. Applied to power purchases only.
Alternate	***Assumes:*** ⇒ Load: Energy and demand load forecasted in BPA rate case for FY 1997-2001 for non-generating utilities at proposed PF-96 rates. ⇒ Rate: BPA's PF-96 rates. ⇒ LDD percentage: Applies BPA's current 3-5-7 percent LDD methodology. Applied to power and transmission purchases.

As demonstrated by the tables titled "Assumptions behind" above, the PPC errs by increasing the number of variables instead of establishing a base case and adjusting only the LDD percentages to examine the cost impacts of various proposals. A valid comparison would vary only the different LDD percentages in the different proposals to determine the relative cost impacts of the different percentages; introducing other variables skews the results because of factors not related to the LDD that cause differences in costs. *Cf* .Craig. *et al.*, E-BPA-119, at 2-3. As pointed out above, both the comparison in PPC's initial brief and in Carr, *et al.*, E-PP-08, Attachment 2, include cost impacts caused by unrelated factors.

To compare the different proposed LDD methodologies, BPA analyzed four alternative methodologies in Craig, *et al.*, E-BPA-76, Attachments B and C. The first scenario is BPA's current 3, 5, and 7 percent LDD methodology applied to PF power purchases and transmission. Scenario two is BPA's proposed summed percentage sliding scale methodology capped at 7percent with a phase-in of one-half of one percent increments applied to PF power purchases only. The third scenario is RCC's initial proposal with the cap removed and phased in in six-tenths of one percent increments applied to PF power purchases only. The fourth scenario is the joint PPC-RCC methodology (referred to by the PCC as the consensus proposal) that is capped at 8.5 percent and is phased in in six-tenths of one percent increments, also applied to PF power purchases only. All four scenarios use the same 1997-2001 load forecast, and all four use the initial proposal 1996 PF rate. *Id.* at 7. By using the same load and rate projection and changing only one variable--the proposed LDD percentage--BPA was able to develop a fair comparison of the differences between the alternative proposals. Craig, *et al.*, E-BPA 107, at 5. Because BPA's analysis did not attempt to "forecast the trend in discount levels using current 1995 PF rates," as asserted by the PPC in their brief, B-PP-01, at 23, PPC's conclusion that BPA's analysis lacks credibility has no basis. Indeed, there is no reason to "forecast the trend in discount levels using current 1995 PF rates" because the current 1995 PF rates expire in October 1996. Expiration of the 1995 surcharged rates was a condition of the 1995 rate case settlement executed by the PPC and others. The surcharged rates were to be non-precedential. 1995 ROD, WP-95-A-01, at 2-3. Furthermore, BPA's analysis is intended only to test the various LDD methodologies and estimate LDD costs. Craig, *et al.*, E-BPA-107, at 5; *see also* Tr. 776.

PPC argues that the reasons supporting BPA's draft decision to adopt BPA's LDD proposal would also support adopting the PPC LDD proposal. *Id.* at 3. PPC argues that if BPA sets the average PF rate at 24.4 mills in accordance with the Settlement Agreement, the PF rate would not be affected by the increased costs resulting from adoption of their proposal. *Id.* BPA is struggling to cut costs to remain competitive. Moorman, Evans, WP-96-E-BPA-09, at 27-28. In the face of BPA's need to recover costs with revenues generated from rates set at the level stated in the Settlement Agreement, PPC's argument is baseless, because it would add $18 million to BPA's costs without BPA being able to increase the PF rates to recover those costs.

BPA testified that the BPA proposal met the competitive needs of BPA to keep rates low for all customers, including those receiving the LDD. As BPA testified in rebuttal to concerns about reduced LDD benefits under BPA's proposal:

> BPA's rate proposal must be examined in its entirety. Many of BPA's customers who receive LDD benefits will realize *<u>double-digit decreases</u>* from their 1993 PF rates because of BPA's 1996 rate proposal. Most LDD recipient utilities see a reduction in their overall power and transmission rates. Based on rate impact results, non-generating utilities, on average, will see an approximate rate reduction of 12 percent from their PF-93 rates. Some utilities approach 19 percent. . . . This reduction includes power and transmission rates and considers BPA's proposed LDD changes. . . . [I]t appears that most LDD customers will receive overall rate reductions even though the LDD will not apply to transmission rates.
>
> . . . .
>
> . . . We recently performed a sensitivity analysis on all LDD recipient utilities. The results show an overall LDD benefit reduction of 11 percent over the 5-year period using the proposed methodology compared to the current LDD methodology. The analysis applied the current methodology's LDD percentage discounts to both the proposed power and transmission rates. The analysis applied the proposed methodology only to the proposed power rate. . . . These same utilities, however, would likely

> see a reduction in their total BPA bill over the same period and are better off when the entire rate proposal is considered.
>
> . . . .
>
> While we agree that customers compete through their retail rates, and that the LDD provides additional dollars to keep retail rates lower, increasing the LDD as suggested. . . would reduce BPA's competitive position because it would necessitate raising rates to other customers to offset the LDD increases.

Craig, *et al.*, E-BPA-50, at 9-11 (emphasis in original). BPA must keep rates low to compete. One way to do that is by cutting costs. Increasing BPA's costs by adopting the PPC proposal would not be in the best interests of BPA or its LDD customers. *Id.*

<u>Decision</u>

BPA's LDD proposal is consistent with the intent of the LDD and controls and reduces BPA's costs. Furthermore, while the BPA proposal reduces LDD benefits, in the context of BPA's entire rate proposal, the power and transmission costs of most LDD utilities will go down in comparison to costs under the PF-93 rate. Adopting the PPC proposal would unnecessarily increase BPA's costs to be recovered in rates. BPA will adopt the proposal of BPA staff and not the PPC proposal.

<u>Issue 5</u>

Whether BPA should raise to 26 the maximum K/I ratio criterion applicable to the proposed very low density discount.

<u>Parties Positions</u>

BPA should raise from 25 to 26 the maximum K/I ratio criterion applicable to the proposed very low density discount. NIU Ex. Brief, WP-96-R-NI-01.

<u>BPA's Position</u>

Because this issue has not previously been raised, BPA has stated no position.

<u>Evaluation of Positions</u>

In the supplemental proposal, BPA proposed a very low density discount for customers with a consumers per mile ratio of 3 or less, a kilowatthour per investment ratio of 25 or less, and that have a LDD discount percentage, without considering the very low density discount, of less than 7 percent. Craig, *et al.*, E-BPA-76, at 3. BPA proposed this additional discount in response to comments from Big Bend Electric Cooperative at the Pasco Field Hearing. *Id.* at 2. Big Bend had a consumer per mile ratio of 2, making it one of the least dense systems served by BPA. F.H. Tr. 40 (Pasco, WA.). One purpose of

BPA's proposed new LDD methodology was to ensure that LDD benefits go to customers with low density systems. Craig, *et al.*, E-BPA-76, at 2. However, under the proposal, Big Bend, a customer with a very low density system, faces a declining LDD percentage. *Id.* To help meet the objective that customers with the least dense systems receive the discount, BPA proposed the additional discount for very low density systems, such as Big Bend. *Id.* at 2-3.

Big Bend's recent LDD data submittal revealed that Big Bend might not qualify for the very low density discount. NIU Ex. Brief, R-NI-01, at 2. In selecting 25 as the maximum K/I ratio to qualify for the very low density discount, BPA wanted to ensure that utilities deserving of the added discount could qualify. It appears that one such utility would not qualify, and that utility has asked that BPA raise the maximum qualifying K/I ratio to 26. No other parties have taken positions in their briefs on the very low density discount. NIU's brief indicates that this information became available recently and that Big Bend's qualification for the very low density discount with a maximum K/I of 25 could depend on changes in weather from year to year. *Id.* BPA does not wish to disqualify deserving utilities from receiving the very low density discount because of changes in weather from year to year. While NIU raised this matter late, no party objected. BPA previously determined that the cost of providing Big Bend with the very low density discount was negligible. Craig, *et al.*, E-BPA-76, at 4. BPA should raise the maximum qualifying K/I ratio criterion for the very low density discount to 26.

Decision

BPA will increase the maximum qualifying kilowatthour per investment (K/I) ratio criterion for the very low density discount to 26.

11.2.5 Unauthorized Increase Charge

BPA's proposed Unauthorized Increase Charge, which also is the charge for positive unauthorized deviations, has two components. The demand charge is based on the applicable demand charge for purchases by the customer. The energy charge is 100 mills per kilowatthour. Wholesale Power and Transmission Rate Schedules (Rate Schedules), WP-96-E-BPA-08, at 187; Metcalf, *et al.*, WP-96-E-BPA-18, at 9; Metcalf, *et al.*, WP-96-E-BPA-48, at 4. PGP/APAC and WPAG argued that the Unauthorized Increase Charge should be cost-based. Leone-Woods, *et al.*, WP-96-E-PG/AP-02, at 30-34; Beck, *et al.*, WP-96-E-WA-13, at 49; APAC Prehearing Brief, WP-96-P-PA-01, at 7.

PGP has been making similar arguments regarding the Unauthorized Increase Charge for many years. *See* 1983 Final Rate Proposal Administrator's Record of Decision, WP-83-A-02, at 187-188, and 1993 Final Rate Proposal Administrator's Record of Decision, WP-93-A-02, at 166-171. The current PGP/APAC proposal would turn unauthorized overruns into another energy product, one available at the purchaser's discretion and at the spot market price for energy. Leone-Woods, *et al.*, E-PG/AP-02, at 32. From BPA's point of view, this is a much less efficient price signal than BPA's proposed charge, in combination with the rest of BPA's available products and prices. The Unauthorized Increase Charge BPA has proposed is designed to encourage customers to choose the products they wish to purchase rather than using unauthorized overruns as an alternative "product." Metcalf, *et al.*, E-BPA-48, at 6. Since its inception, the Unauthorized Increase Charge has been developed to be a penalty and not a cost-based rate. 1993 Final Rate Proposal Administrator's Record of Decision, WP-93-A-02, at 166-171. Encouraging customers to choose individual products rather than relying on unauthorized overruns is consistent with BPA's efforts to be a competitive business partner and to unbundle its products. Metcalf, *et al.*, E-BPA-48, at 6; Tr. 2041. Because no party raised the issue of the level of the Unauthorized Increase Charge on brief, this issue is withdrawn in accordance with section 1010.3 of the *Procedures Governing Bonneville Power Admin. Rate Hearings*, 51 Fed. Reg. 7611 (1986).

In addition, APAC stated that BPA's proposed Unauthorized Increase Charge is "arbitrary because it is ... sufficiently vague as to cause billing disputes." APAC Prehearing Brief, P-PA-01, at 7. PGP and APAC stated that the GRSP description of the Unauthorized Increase Charge is "vague, because it refers to the customer's 'contractual entitlement.' [PGP/APAC] recommend that the GRSP be amended to ensure that the exercise of rights under section 17(d) of the 1981 power sales contract, also known as the 'flexibility account,' will <u>not</u> lead to an Unauthorized Increase charge being assessed." [Emphasis in original.] Leone-Woods, *et al.*, E-PG/AP-02, at 32. The language BPA has used in the rate schedule document regarding the Unauthorized Increase Charge has been the same for the last 15 years. Metcalf, *et al.*, E-BPA-48, at 9. In addition, the definitions of Measured Demand and Measured Energy include a statement: "Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Rate Schedules, WP-96-E-BPA-08, at 204 and 205. PGP and APAC did not specify any particular or additional language that would make the GRSPs less "vague" for them.

BPA met with the parties in a workshop on September 19, 1995, to discuss the Deviation Adjustment and to attempt to understand the parties' concerns. Metcalf, *et al.*, E-BPA-48, at 11. Even though the parties did not raise this issue in later testimony, BPA revised the GRSP descriptions of the Deviation Adjustment and Unauthorized Increase Charge for the supplemental proposal with the hope of clarification and increased understanding. Metcalf, *et al.*, E-BPA-48, at 11. Because no party raised the issue of the level of the Unauthorized Increase Charge on brief, this issue is withdrawn in accordance with section 1010.3 of the *Procedures Governing Bonneville Power Admin. Rate Hearings*, 51 Fed. Reg. 7611 (1986).

11.2.6 <u>Firm Capacity without Energy and Energy Return Surcharge</u>

Under certain conditions, customers may purchase firm capacity under their 1981 Contracts. The basic structure of a firm capacity sale, as distinguished from a power sale, is that BPA provides the purchaser energy during heavy load hours and the purchaser returns that same amount of energy to BPA in the light load hours. The rate for firm capacity reflects the relative difference between the costs of providing energy during heavy load hours and the costs of providing energy during light load hours. Firm Capacity without Energy also is available under the FPS-96 rate schedule, at negotiated prices and terms that may vary from those in the PF-96 and NR-96 rate schedules.

The Firm Capacity without Energy rates in the PF-96 and NR-96 rate schedules have been modified to incorporate BPA's proposal to charge for transmission separately from its charge for power and to diurnally differentiate energy charges. To calculate the firm capacity rate for PF capacity sales, the difference between the PF-96 HLH and LLH energy charges is first converted to a dollars per megawatt charge and then added to the PF demand charge. The same approach was used to set the NR-96 capacity rate in the initial and supplemental proposal. *See* Section 7.1 of the WPRDS Documentation, WP-96-E-BPA-61A. For the final proposal rates, the NR-96 energy charges are set equal to the PF energy charges. However, for purposes of calculating the NR capacity rate, the cost difference between providing heavy and light load hour energy will continue to be based on the fully allocated cost of providing NR service. *See* Section 7.1 of the Final WPRDS Documentation, WP-96-FS-BPA-05A. Using this approach for calculating the PF and NR capacity rates reflects BPA's costs of delivering PF or NR energy to a purchaser on peak, which the purchaser then returns to BPA off peak. Customers purchasing capacity under the PF and NR rate schedules are required to purchase transmission under the applicable transmission rate schedule. No party raised issues with regard to the design or calculation of the Firm Capacity without Energy rates.

The methodology used to determine the Energy Return Surcharge is unchanged from past rate cases. However, the calculation of the Energy Return Surcharge has been changed to reflect the unbundling of BPA's transmission costs and BPA's time of day energy charges.. One of the components of the Energy Return Surcharge is the cost of capacity delivered under the PF rate. In the 1995 rates, the PF and NR demand charges bundled the allocated costs of capacity with the allocated costs of transmission costs, and BPA's energy charge were the same in all hours of the day. In the 1995 rates, the cost of capacity was equal to the PF demand charge. With the unbundling of BPA's transmission costs and BPA's time of day energy charges, the cost of capacity is no longer equal to the PF demand charge, but must be constructed from the various unbundled components. To derive the cost of capacity the difference between the PF heavy and light load hour energy charges, expressed in dollars per megawatt, is added to the PF demand charge. This amount is then added to the Network Integration transmission rate. In this way the calculation uses the unbundled rates but produces an energy return surcharge that is consistent with the previous methodology. No party raised issues with regard to BPA's Energy Return Surcharge.

11.2.7 Billing Procedures

All of BPA's 1996 rate schedules state that for sales under each rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures. *See* Wholesale Power and Transmission Rate Schedules, WP-96-A-02, Appendix. In the 1996 initial proposal, BPA explained that certain material had been deleted from the General Rate Schedule Provisions (GRSPs) as they appeared in previous rate proposals. Metcalf, *et al.*, WP-96-E-BPA-18, at 14. Provisions previously included in the GRSPs and certain contractual provisions, including administrative matters such as billing, will be published in BPA's Billing Procedures. *Id.* The Billing Procedures document will implement the rates proposed in the current proposal and thus will be available after the end of the hearing process. *Id.*

In its brief on exceptions, PGP stated concern "that disputes over billings under the new rate schedules are likely." PGP, Ex. Brief, WP-96-R-PG-01, at 8. PGP "asserts its contract right to accurate billing statements and advises the Administrator that the billing procedures documents cannot limit any rights in that regard." *Id.* at 17. PGP urges BPA "to work with the customers to develop the Billing Procedures in a mutually satisfactory fashion." *Id.* BPA intends to continue its practice of accurate and understandable billing. The rate schedules were revised several times during the 1996 rate proceeding in aid of customer understanding. Metcalf, *et al.*, WP-96-E-BPA-48, at 11; Metcalf, *et al.*, WP-96-E-BPA-105, at 27; *see also* Draft PF, NR, and IP Rate Schedules, May 21, 1996. The Billing Procedures will implement the rate schedules and thus will be developed in final form after the 1996 final rate proposal. Metcalf, *et al.*, E-BPA-18, at 14. The Billing Procedures document is outside the scope of the 1996 rate case, but BPA does intend to involve the customers in its development. *Id.* After the 1996 final rate proposal is complete, BPA will distribute the final draft Billing Procedures document for comment from the customers. *Id.* Upon the end of the comment period, BPA will complete the final Billing Procedures.

11.2.8 <u>Flexible Rate Option for Sales of Priority Firm Power and New Resources Power</u>

BPA needs rates that are competitive to rates being offered by other suppliers. In the 1996 supplemental proposal, BPA advanced the option of a flexible Priority Firm Power (PF) rate that allows BPA to tailor the rate for individual customers, while receiving the same overall revenues BPA would have received if the posted PF rates had been directly applied. Norman, WP-96-E-BPA-92, at 1-9. BPA proposed the PF flexible rate, in part, to give BPA the ability to offer customers products and rate designs similar to what is being offered by BPA's competitors. Some of BPA's competitors are offering very simple rate designs, such as a single annual millage rate for energy. *Id.* at 2. Competitors also are offering blocks of take-or-pay power (without load shaping or load regulation). *Id.* A flexible PF rate option improves BPA's ability to offer comparable products and rate designs to its PF customers. The flexible PF rate also gives BPA a tool to use in the future if seasonal and diurnal price relationships in the market change such that BPA's posted rates are out of line with the market. *Id.* With the flexible PF rate, BPA can change the seasonal and hourly shape of customers' rates, if necessary, to more closely track the relationships in the market while still assuring BPA of the same overall revenues as the posted rates. *Id.* Because the same reasons for offering a flexible PF rate option for PF sales also apply to sales under the New Resources (NR) rate, BPA included the same flexibility option in the NR rate schedule. Norman, WP-96-E-BPA-100, at 2.

The flexible PF and NR rate options are discretionary. Norman, E-BPA-92, at 4. Because the flexible rate options are discretionary, BPA intends to offer the rate only when it makes business sense to do so. *Id.* BPA intends to offer this option only to customers who make a purchase commitment either through a new power sales contract or through an amendment to the 1981Contract. *Id.*

The flexible PF and NR rate options afford BPA wide discretion as to the structure of the rate as long as the revenues under the flexible option are comparable to the revenues BPA would have received under the respective posted rates. *Id.* at 6. To ensure and demonstrate comparability, BPA initially proposed three revenue tests that must be met under the flexible options. The first test is that the revenues for each specific agreement must be the same, or greater, on a net present value (NPV) basis as the revenues expected under the posted rates (NPV Revenue Test). *Id.* The second test is that BPA must receive at least the same amount of projected nominal revenues during the rate period under the flexible rate option as the revenues projected by applying the posted rates (Nominal Revenue Test). *Id.* And the third test is that the design of the flexible rate option not create an annual (year-to-year) cash flow problem for BPA (Cash Flow Test). *Id.* Upon further reflection, BPA believes that the Nominal Revenue Test is duplicative and unnecessary. The Nominal Revenue Test does not provide any additional revenue protection that is not already provided through the NPV Revenue Test and the Cash Flow Test. In the final rates, BPA proposes to include the NPV Revenue Test and the Cash Flow Test as the two revenue tests that must be satisfied before offering the flexible PF and NR rate options. The Nominal Revenue Test will be eliminated from the rate schedule.

To conduct these tests, BPA will forecast revenues expected at the posted rates and revenues expected with the flexible rate option. The NPV Revenue Test looks only at expected revenues from the individual transaction. *Id.* In conducting the NPV Revenue Test, BPA will apply a discount rate that recognizes both BPA's cost of capital and the availability of capital funds at the time the deal is offered. Norman, E-BPA-100, at 2. The Cash Flow Test looks at BPA's total expected nominal revenues from all sales under the flexible rate options. Norman, E-BPA-92, at 6. In conducting the Cash Flow Test, BPA adds the total nominal revenues for each year of the transaction to expected revenues from other flexible rate transactions for the same years to ensure that in any given year the total revenues from these sales are not significantly less than the revenues expected under the posted rate. *Id.* In effect, this test limits the amount of revenues that can be shifted between years so that BPA's cash flow is not impaired.

Generally, most of BPA's public agency customers support the flexible rate options included in the PF and NR rates. NIU, WP-96-E-NI-03, at 15; RCC Brief, B-RC-01, at 4 ("BPA must be given freer opportunity to compete for load with other potential wholesale power suppliers by offering a 'Flexible' PF rate."). No party opposed the flexible rate option concept. Norman, E-BPA-100, at 2.

Issue

Whether BPA should allow groups of utilities to jointly negotiate with BPA to develop combined billing determinants under the flexible rate options in the PF and NR rate schedules.

Parties' Positions

NIU urges BPA to expand the flexible rate options to allow groups of utilities that place all of their load on BPA to negotiate combined billing determinants based on their cumulative loads. Olsen, Saven, WP-96-E-NI-03, at 15; NIU Brief, B-NI-01, at 4. NIU states that the combined billing determinant should be allowed, especially for small utilities with limited resources. NIU Brief, B-NI-01, at 4.

BPA's Position

Whether BPA will allow utilities to combine their purchases for billing purposes (combined billing determinants) is a policy and contract issue. Norman, E-BPA-100, at 2. BPA's rate schedules in general, and the flexible PF and NR rates in particular, neither support nor prohibit a group of utilities from negotiating to be billed as a single purchaser. *Id*.

Evaluation of Positions

NIU urges BPA to allow groups of utilities, especially small utilities with limited resources, to negotiate combined billing determinants under the flexible rate options. Olsen, Saven, E-NI-03, at 15; NIU Brief, B-NI-01, at 4. NIU claims that the flexible PF rate favors utility-specific arrangements with BPA and makes combinations of utilities less feasible because of the potential for the rate to move costs between years. Olsen, Saven, E-NI-03, at 15.

The 1996 power rates in general, and the flexible rate options in particular, are intended to be neutral as to the business relationship between BPA and its customers. Norman, E-BPA-100, at 3. Whether utilities can negotiate to combine their energy purchases or their billing determinants under the flexible rate options is a fundamental issue related to the business relationship between BPA and its customers. *Id*. Combining utilities' purchases of Federal power for billing purposes has broader implications and ramifications than developing rates or billing determinants. NIU's recommendation raises statutory considerations regarding sales of Federal power by BPA to its customers on an individual customer basis as stated in the Bonneville Project Act and the Northwest Power Act. 16 U.S.C. § 832c(c); 16 U.S.C. § 839c(b). In addition, NIU's recommendation raises contractual considerations and issues. While the 1981 Contract addresses multiple points of delivery for a single customer, it does not provide for multiple customers combining their points of delivery. Section 17, 1981 Power Sales Contract. Under the 1981 Contract, each customer is obligated to pay for Federal power delivered to that customer's points of delivery. Section 14(a), 1981 Power Sales Contract. Thus, regardless of the customer's share of the combined purchases, the customer is contractually obligated to pay BPA for the power delivered to its points of delivery.

BPA is unwilling to decide fundamental contractual and business relationship issues as part of its ratemaking process. The type of business relationship that BPA agrees to create with its customers is not a rate case issue. Currently BPA and its customers are involved in negotiating new power sales contracts (1996 Contracts) and amendments to the 1981 Contracts. These issues are more properly resolved in these ongoing contract negotiations than through the 7(i) process. Whatever the outcome of the negotiations, BPA believes that its rates accommodate the business relationship under the 1981 Contracts, and also will accommodate future relationships. Norman, E-BPA-100, at 3.

Decision

Whether BPA will allow groups of utilities to combine their BPA purchases for billing purposes under the flexible rate options in the PF and NR rate schedules is not addressed as part of the 1996 rate case. Allowing groups of customers to combine their BPA purchases is not a rate case issue, but a contractual and business relationship issue. BPA believes that all its rates, including the flexible PF/NR option, are designed to accommodate whatever business relationship may be established in the new 1996 Contracts or through amendments to existing 1981 Contracts.

11.3 Priority Firm Power (PF) Rate

11.3.1 Billing Factors

Issue

Whether BPA should bill generation demand at the time of BPA's generation peak or at the time of the customer's peak load on BPA.

Parties' Positions

APAC and PGP urge BPA to continue to bill for demand at the time of the customer's peak load on BPA, instead of billing for demand at the time of BPA's generation system peak. Leone-Woods, *et al.*, WP-96-E-PA/PG-03, at 32. PGP also recommends that BPA adopt the same power and transmission billing factors for Actual and Planned Computed Requirements customers under the 1981 Power Sales contracts. PGP Brief, B-PG-01, at 9-10; Or. Tr. 2423. WPAG agrees, and recommends that the billing factors in the Transmission Rates and Terms and Conditions Settlement Agreement for service under the NTP be extended to PF power demand purchased by Computed Requirements customers under 1981 contracts. WPAG Brief, B-WA-01, at 6-8; Or. Tr. 2432.

BPA's Position

Initially BPA proposed to measure a customer's demand in the same hour as the monthly transmission peak load. Metcalf, *et al*., WP-96-E-BPA-18, at 7. Using the same hour for measuring customers' power demand as the hour for measuring customers' transmission use under the Network Integration rate would simplify the administration of BPA's rates for both BPA and the customer, and maintain consistency between the power and transmission rates. *Id*. In addition, measuring a customer's power demand coincident with the time of BPA's transmission peak better reflects customers' contributions to BPA's peak. *Id*. As such, customers will recover their proportional contribution to BPA's peak. In this way, the design better reflects the principles of cost-causation than measuring customers' demand on a non-coincidental basis. *Id*.

In the supplemental proposal, BPA changed the time when the power demand billing would be measured to the hour of the generation peak load. Metcalf, *et al*., WP-96-E-BPA-74, at 9-10. Measuring a customer's contribution to BPA's generation peak provides customers with a better price signal as to their relative share of BPA's generation costs associated with meeting peak load than measuring a customer's peak load at the time of the transmission system peak. *Id*.

Evaluation of Positions

In the supplemental proposal, BPA proposed to measure a customer's demand at the time of the peak load on the Federal generation system (referred to as coincident peak in that the customer's monthly peak load is measured coincident with BPA's monthly generation peak period hour). Metcalf, *et al*., E-BPA-74, at 9-10. The time of the Monthly Federal System Peak Load is defined as "the peak load on the Federal System during a customer's billing month determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control sources." Supplemental Wholesale Power and Transmission Rate Schedules WP-96-E-BPA-64, at 190. The generation system peak consists of all loads served by Federal generation, both firm and nonfirm, and imports needed to meet those loads. Metcalf, *et al*., WP-96-E-BPA-105, at 23. More precisely, the Monthly Federal System Peak Load is the peak load on the Federal system during the billing month determined by the largest hourly integrated demand produced from the system generation plants in BPA's control area and scheduled imports for BPA's account from other control areas. Metcalf, *et al*., E-BPA-74, at 8. Under this approach, a customer will pay for its peak demand in portion to its contribution to the generation system peak.

APAC and PGP assert that BPA can manipulate the time of the Federal system peak load. Leone-Woods, *et al*., E-BPA-03, at 30. They therefore conclude that BPA will have an incentive to manipulate its generation to trigger payment of a demand charge by its customers. *Id.* APAC and PGP go on to make the incredible claim that BPA can control the time of the Federal system peak through off-system transactions, such as sales, storage, and exchanges. *Id.* *See also*, Smith, *et al.*, WP-96-E-PG-05, at 6. As such, they suggest BPA should exclude off-system transactions from its determination of the hour of the peak load on the Federal system. *Id.* at 31.

Realistically, BPA cannot control the timing or the size of its generation system peak. Metcalf, *et al.*, E-BPA-105, at 24. Control over the time and the size of the Federal generation system peak primarily is in the hands of BPA's customers. *Id.* The system peak is most heavily influenced by the demands of BPA's customers, and BPA cannot control the demands of its customers. *Id.* In fact, Computed Requirements customers have a number of tools available under the 1981 Contracts to control the amount of load they place of BPA, including running their own resources, using their own nonfirm energy to serve their load, and buying from other suppliers. Metcalf, *et al.*, E-BPA-48, at 8. Off-system sales also depend on the purchasers' needs or demands. Moreover, sales of nonfirm energy depend on purchasers' demands, as well as the availability and price in the market. *Id.* BPA cannot control these factors. *Id.* Contrary to APAC and PGP's assertion, BPA has neither the means nor the incentive to manipulate sales for purposes of increasing the amount of dollars paid by a particular customer or customer class for demand. *Id.*

PGP claims that the hour of the generation system peak cannot be identified in advance of making scheduling decisions. Smith, *et al.*, E-PG-05, at 6. APAC and PGP argue that this proposal will make it very difficult for BPA's existing customers to control and manage their wholesale power costs. Leone-Woods, *et al.*, E-BPA-03, at 30. While it may be more difficult to determine when the Federal system peak will occur, sophisticated wholesale customers such as PGP members should be able determine with a fair degree of accuracy when the peak will occur based on historical information and real time information available to PGP members. Tr. 2037. Nevertheless, BPA agrees that utilities cannot precisely identify in advance the Federal system's peak generation hour. Metcalf, *et al.*, E-BPA-74, at 10. But neither can BPA. *Id.* The peak generation hour will not be known to either BPA or the customer until after the end of the customer's billing month. *Id.* But this is the case even when BPA bills for generation demand at the time of a customer's peak load on BPA. The time of a customer's peak on BPA is determined after the fact. *Id.* In that sense, using the time of the generation system peak is not that different from earlier methods. *Id.* Moreover, "even if customers cannot accurately predict their peaks, this is no reason not to bill them more accurately for the service they take." *New England Power Company*, 52 FERC §61,090, at 61,337 (1990) *aff'g sub nom. Town of Norwood Mass. v. F.E.R.C.*, 962 F.2d 20 (1992).

Moreover, even if customers cannot accurately predict the time of the Federal generation system peak, they are no worse off and may be better off if billed for demand at the hour of the Federal system peak. Metcalf, *et al.*, E-BPA-74, at 10. By definition, the customer's monthly coincident peak is always equal to or less than its maximum peak load placed on BPA. *Id.*; Tr. 2059. For customers who do not own or operate their own resources, billing for demand at the hour of the Federal system peak most likely will reduce their bill for demand.

APAC and PGP argue that billing on the hour of the Federal generation system peak will encourage customers to maintain their own generation at the highest possible level and reduce their off-system sales to support their retail loads. *Id*. at 31. From this, they leap to the conclusion that billing on a coincidental peak basis is anti-competitive because they will have less energy to sell in the bulk power market. *Id*. Providing customers with an economic incentive to operate their resources in an efficient manner and thereby reduce their take from BPA at the time of the peak hour is not an anti-competitive action, but a rate design firmly grounded on a long-established ratemaking principle: customers should recover their share of the costs they impose on BPA's system. This type of rate design ensures that a customer cannot routinely get a "free ride" by escaping a portion of its demand charge. Billing customers for their peak load coincident with BPA's peak hour does not force customers out of the market or erect barriers for their access to the market. Rather, the charge provides customers with the information they need to make an economic choice whether to use the output from their own resources to meet their loads or sell the output in the market.

Billing on a coincidental basis is supported by economic theory and by FERC and the courts. Recently FERC reviewed a request by a wholesale supplier to switch from billing on a non-coincidental basis to a coincidental basis. The request was filed by the New England Power Company and was set for a full hearing. The ALJ and ultimately the Commission and the courts approved the request for coincidental billing. As stated succinctly by the ALJ in that case, " [I]t is beyond question now that a wholesale customer's usage at the time of system peak is what imposes capacity costs on the utility that serves the customer. True, noncoincident peak usage [referring to the maximum demand the customer places on the supplying utility during the month, whether or not that demand coincides with the monthly system peak] is more likely to controllable by the customer than its coincident peak demand. . . . [However] one of the objectives of an optimum rate design is to reflect that costs that each customer's usage places on the system." *New England Power Company*, 49 FERC §63,007, at 65,035. (1989). The ALJ found that "[t]he interests of efficiency and cost-minimization would best be served if [wholesale customers] . . . can reduce their usage at the time of [the supplying utility's] system peak. Use of coincidental peaks for billing purposes provides this kind of salutary incentive to . . . customers." *Id*. For these reasons the ALJ applauded the switch from using non-coincident peak billing determinants to coincident peak billing determinants. *Id*. ("The switch from the use of non-coincident peak billing determinants to coincident peak billing determinants for purposes of calculating each customer's demand charge is clearly an appropriate step.")

The Commission affirmed the ALJ's decision, noting "[t]he Commission believes that is it each customer's proportion of consumption at the [supplying utility's] system peak that measures the share of peak load capacity cost for which each customer is causally responsible. Under a coincident demand peak billing, the customer's incentive is to reduce its demand at the time of the [supplying utility's] system peak either through conservation or by shifting demand to off-peak periods, thereby conserving the [supplying utility's] peak capacity need. Thus, the use of coincident peak demand billing should facilitate the rate design goal of setting prices to more accurately track costs" *New England Power Company*, 52 FERC §61,090, at 61,337 (1990) (emphasis added), *aff'g sub nom. Town of Norwood Mass. v. F.E.R.C.*, 962 F.2d 20 (1992).

In their briefs, PGP and WPAG suggest carving out an exception to billing for demand on a coincidental basis. PGP recommends that BPA adopt the same power and transmission billing factors for Actual and Planned Computed Requirements customers under the 1981 power sales contracts. PGP Brief, B-PG-01, at 9-10; Or. Tr. 2423. WPAG agrees, and recommends that the billing factors in the Transmission Rates and Terms and Conditions Settlement Agreement for service under the NTP be extended to PF power demand purchased by Computed Requirements customers under 1981 Contracts. WPAG Brief, B-WA-01, 6-8; Or. Tr. 2432. That is, they urge BPA to bill Computed Requirements customers' demand purchases under the 1981 Contract at the hour of the purchaser's highest monthly power delivery from BPA. PGP Brief, B-PG-01, at 9-10; WPAG Brief, B-WA-01, at 7.

As WPAG points out, this billing factor is comparable to the demand billing factor in previous PF rates. Oral Tr. 2423. Thus, WPAG suggests that the customers know how to manage their resources effectively and efficiently in response to this billing factor. *Id*. WPAG claims that a non-coincident peak billing factor provides Computed Requirements customers a clear price signal. *Id*. Computed Requirements customers can respond to this price signal, according to WPAG, because they know how their systems operate, they know when they peak, and hence they can manage their resources and their purchases to be responsive to that rate design. WPAG Brief, B-WA-01, at 7. Because customers know how to respond, WPAG states that customers will have the opportunity to smooth their purchases on BPA and help BPA in its power management tasks. *Id*. As WPAG correctly notes, Computed Requirements customers are required to plan and operate their resources to minimize their energy and capacity loads on BPA. *Id*. However, PGP claims that with all the rate design changes proposed by BPA, utility operation will be more difficult. Smith, *et al*., E-BPA-05, at 6. To illustrate the complexities and difficulties facing Computed Requirements customers, APAC and PGP note that under BPA's proposed transmission and power rates each customer must attempt to track four quantities in real time: (1) the Monthly Federal System Peak Load; (2) the monthly Transmission Peak Load; (3) the customer's highest Measured Demand on BPA; and (4) the customer's Measured Demand at the time of the Monthly Transmission Peak Load. Leone-Woods, *et al*., E-PA/PG-03, at 30. WPAG notes that the requirements of unbundling and comparability have inevitably resulted in rates that are extremely complex. WPAG Brief, B-WA-01, at 7.

BPA agrees that the requirements of unbundling and comparability have introduced new rate complexities. In fact, that was one of the reasons BPA initially proposed to use the same basis for measuring a customer's power and transmission demand to simplify BPA's rates. Metcalf, *et al*., E-BPA-18, at 7. As WPAG points out, a return to non-coincident peak billing for both power and transmission would provide benefits of understandability, administrative ease, and simplicity for both BPA and its customers. Or. Tr. 2423. Another important factor is customer acceptance. BPA's Computed Requirements customers prefer this approach. Given the other rate design complexities introduced in BPA's 1996 rates and Computed Requirements customers' overwhelming preference for non-coincidental peak billing, BPA believes that carving out a narrow exception to coincidental peak billing for Computed Requirements customers purchasing under the 1981 Contract is attractive.

Decision

For Computed Requirements customers, both Actual and Planned, purchasing power under the 1981 Contracts on an other than contract demand basis, BPA will measure their demand at the hour of the customer's peak load on BPA, non-coincidental peak demand, instead of measuring demand at the time of BPA's generation system peak, coincidental peak demand. In effect, BPA adopts the same power and transmission billing factors for Actual and Planned Computed Requirements customers under the 1981 Contracts. This change in the time when demand will be measured also will be reflected in the Power Demand Reservation Charge. The Power Demand Reservation Charge is calculated by subtracting a purchaser's Measured Demand from the purchaser's Computed Maximum Requirement. As such, the amount of measured demand subtracted will be determined based the hour of the customer's peak load on BPA. Otherwise, the Power Demand Reservation Charge is not affected by the change in when demand is measured.

For all other customers, Metered Requirements customers under the 1981 Contracts, and all customers purchasing under the 1996 Contract, BPA will bill for power demand at the hour of the Monthly Federal System Peak Load (Federal generation system peak). The Federal generation system peak will be defined by the peak load on the Federal system during the billing month determined by the largest hourly integrated demand produced from the system generation plants in BPA's control area and scheduled imports for BPA's account from other control areas. Using a coincident peak billing factor may result in lower demand payments from Metered Requirements customers compared to using non-coincidental peak billing. In addition, billing for demand on a coincidental peak basis sends a better price signal and more accurately tracks costs, in that each customer recovers its proportional share of peak load capacity costs for which that customer is causally responsible.

11.3.2 Power Demand Reservation Charge

In the 1996 rate proposal, BPA did not include the Demand Ratchet, which had been included in BPA's rate schedules since passage of the Northwest Power Act and even before then. As a replacement for the demand ratchet, BPA proposed a Power Demand Reservation Charge. Metcalf, *et al*., E-BPA-74, at 11. The Power Demand Reservation

Charge compensates BPA for its obligation to serve Computed Requirements customers' heavy load hour contractual entitlements. *Id.* Under the 1981 Contracts, these customers are entitled by contract to purchase, on heavy load hours, the greater of their Computed Peak Requirement or Computed Average Energy Requirement (the greater of these two terms is call Computed Maximum Requirement or CMR). *Id.* In effect, the Power Demand Reservation Charge compensates BPA for standing ready to serve loads that Computed Requirements customers are entitled to place on BPA during heavy load hours but do not. Metcalf, *et al.*, WP-96-E-BPA-105, at 18. Because the Power Demand Reservation Charge applies to the difference between what a customer actually took (measured demand) and what they were entitled to take (CMR), if a customer takes its full entitlement it will not pay the Power Demand Reservation Charge. *Id.* at 20. If, on the other hand, a customer does not take its full entitlement or displaces its peak purchases from BPA, then the Power Demand Reservation Charge compensates BPA for having stood ready to serve their peak load. *Id.*

Historically, Computed Requirements customers have displaced their peak purchases from BPA. For example, in the past few years, three Computed Requirements customers displaced their peak purchases from BPA in virtually each month of the year. *Id.* at 20. For these customers, the amount of peak displacement was 3,680MW, resulting in revenue lost of almost $1.7 million per year. Some customers that are entitled to take energy during the heavy load hours manage to buy all their power from BPA during light load hours. Tr. 2060. Because some customers do not need all their contractual entitlement during heavy load hours, BPA proposed to allow customers to waive a portion of their contractual entitlement on heavy load hours, their CMR, as a way to avoid the Power Demand Reservation Charge. Metcalf, *et al.*, E-BPA-74, at 8. In this way customers would not be penalized simply because their contractual entitlement, which was part of the contract negotiation in the late 1970s, was greater than they really need.

The Power Demand Reservation Charge has two cost components. The first cost component is the cost to BPA of holding capacity resources in reserve (reserve cost component). The second is the cost to BPA of losing revenues when Computed Requirements customers displace their purchases from BPA (displacement cost component). Metcalf, *et al.*, E-BPA-74, at 13. The reserve cost component recovers the cost of holding power in reserve to meet peak load. To approximate this cost, BPA assumes that 15 percent of the cost of demand is associated with the costs of holding power in reserve. Metcalf, *et al.*, E-BPA-105, at 22. The displacement cost component recovers foregone revenues from the demand charge that BPA would have received from these customers had the displacement not occurred. Metcalf, *et al.*, E-BPA-74, at 13. In effect, BPA is shifting some of the revenue underrecovery that in the past BPA had collected from the Availability Charge to the Power Demand Reservation Charge. The Availability Charge is discussed in section 11.3.3. When a customer displaces its hourly peak load, there is no real market for that demand in that hour. Tr. 2028. When a customer displaces its PF energy purchases from BPA, BPA can usually resell that energy in the spot market and recover some of its cost. When a customer displaces its peak demand, BPA recovers very little of those costs. *Id.*

APAC and PGP initially argued that the Power Demand Reservation Charge double counts the cost to BPA of operational displacement and recovers costs that are already recovered from the demand charge. Leone-Woods, *et al.*, E-PA/PG-03, at 23. As BPA explained, the costs of operational displacement are not counted twice, but instead are shifted from the Availability Charge to the Power Demand Reservation Charge. Metcalf, *et al.*, E-BPA-105, at 17. In other words, some of the costs of displacement that would have been recovered in the Availability Charge are being recovered through the Power Demand Reservation Charge. As for double counting costs in the demand charge, the demand charge recovers BPA's costs of meeting peak load actually placed on BPA. *Id.* The Power Demand Reservation Charge, on the other hand, compensates BPA for standing ready to serve peak loads Computed Requirements customers are entitled to place on BPA but do not. *Id.* These customers did not raise these issues associated with the Power Demand Reservation Charge in their briefs, and, as such, the issue is not discussed further here.

APAC and PGP also initially argued that the Power Demand Reservation Charge was unnecessary given BPA's proposal to bill for demand on the hour of BPA's system peak. Leone-Woods, *et al.*, E-PA/PG-03, 28. Given the draft decision to bill for demand on the hour of the customer's maximum load on BPA, their argument is no longer relevant. *See* discussion of demand billing factors in section 11.3.1.

Issue #1

Whether BPA should adopt a proposal as part of this rate case which addresses how the Computed Maximum Requirement (CMR) waivers will be implemented.

Parties' Positions

APAC and PGP argue that customers cannot rely on BPA's offer of a process for waiving or adjusting their CMR without additional information on how the waiver process would work. Leone-Woods, *et al.*, E-PA/PG-03, at 24-25. Without more information, APAC and PGP claim that PGP members cannot determine whether they should exercise the waiver or not. *Id.* PGP urges BPA to adopt a proposal as part of this rate case that addresses how the CMR waivers will be implemented. PGP Brief, B-PG-01, at 7.

BPA's Position

Waiver of a customer's CMR requires a contract amendment. Metcalf, *et al.*, E-BPA-105, at 18. Issues associated with amending provisions of the 1981 power sales contracts will be resolved through negotiations with the customers outside of the rate case. *Id.* Contract amendment issues are not rate case issues and as such, are not properly resolved through the rate case process. *Id.*

Evaluation of Positions

APAC and PGP argue that without additional information related to the specific changes in the 1981 Contract provisions, PGP members are unable to assess the likelihood that they will be able to exercise the CMR waiver. Leone-Woods, *et al.*, E-PA/PG-03, at 24. They state that section 17(g) of the 1981 Contract governs scheduling rights during all heavy load hours and is subject to limits imposed by BPA on the customer's scheduling rights. *Id.* Section 17(g) permits BPA to reduce Computed Requirements customers' scheduling rights in the heavy load hours to "enable Bonneville to meet loads which Bonneville serves from firm load carrying capability as defined in the Coordination Agreement." *Id.*, *citing* Section 17(g)(1)(C)(1) of the 1981 Power Sales Contract. APAC and PGP claim that section 17(g) of the 1981 Contract gives BPA a unilateral right to impose reductions in their heavy load hour scheduling rights. *Id.* With recent legislation permitting BPA to make longer-term sales of excess Federal power, APAC and PGP raised concerns that BPA could sign a new long-term contract that requires energy deliveries in the heavy load hours, and thus reduce PGP utilities' scheduling rights under 17(g)(1) of the 1981 Power Sales Contracts. *Id.* The recent legislation referenced by PGP is discussed in section 10.1.1. Given these concerns, APAC and PGP state that PGP members are hesitant to execute these waivers and reduce their scheduling rights unless BPA gives up its right to impose reductions on their scheduling rights. *Id.* At the very least, APAC and PGP claim, PGP members need a limit on the duration of the waiver. *Id.* They suggest that the waiver should be for only one operating year at a time and that the waiver in any month should not affect scheduling rights in the same month in any subsequent operating year. *Id.*

BPA does not view the CMR waiver as an opportunity for customers to reduce their purchases from BPA; rather, the CMR waiver allows customers to bring their contractual entitlement in line with their needs. It is not clear why the heavy load hour scheduling provisions in the 1981 Contacts would need to be amended to accomplish this. However, if changes in the contract provisions for heavy load hour scheduling are needed, these issues should be resolved in negotiations with the customers. Metcalf, *et al.*, E-BPA-105, at 18. Scheduling issues are complex, and in some cases are customer-specific. Scheduling should be resolved through negotiations with customers, not through the 7(i) process. Moreover, scheduling rights are not rate issues, but power supply issues. BPA is unwilling to redefine the scheduling provisions in Computed Requirements customers' existing contracts through a 7(i) rulemaking process.

As BPA witnesses testified, the conditions facing each customer differ. *Id.* Some customers historically take almost all of their contractual peak requirements. BPA does not expect these customers will find the waiver attractive or necessary to avoid the Power Demand Reservation Charge. *Id.* By definition, because the Power Demand Reservation Charge applies to the difference between what a customer actually takes (measured demand) and what they are entitled to take (CMR), if a customer takes its full entitlement it will not pay the Power Demand Reservation Charge. *Id.* at 20. Some customers have sufficient peak resources to serve their load, but not enough to meet their firm energy loads. *Id*. For these customers, their Computed Peak Requirement is less than their Computed Energy Maximum, and so their CMR is based on the Computed Energy Maximum. Some of these customers' CMR is significantly higher than they really need. These customers could waive a significant portion of their CMR and still take all the energy that they need on peak. Tr. 2033. BPA expects that these customers would be the ones looking at waiving some of their onpeak scheduling rights. Tr. 2032. In addition, some of these customers may be able to waive some of their CMR and purchase all their firm energy during light load hours. Metcalf, *et al*., E-BPA-105, at 18.

PGP continues to urge BPA to adopt a proposal as part of the rate process to address how the CMR waivers will be implemented. PGP Brief, B-PG-01, at 7. As previously stated, BPA will implement the CMR waiver through a contract amendment. Metcalf, *et al*., E-BPA-105, at 18. The details of the CMR contract amendment will be resolved through negotiations with the customers outside of the rate case. *Id*. Currently BPA and its public utility customers are negotiating amendments to the 1981 power sales contracts. The CMR waiver can and should be discussed in these ongoing negotiations. BPA expects that the negotiations would resolve when the customer would elect the waiver, the duration of the waiver, and the amount the customer elects to waive. Tr2030.

<u>Decision</u>

Each customer's Computed Maximum Requirement (CMR) is defined in the customer's 1981 power sales contract. To waive a portion of a customer's CMR requires a contract amendment. Contract amendment issues are not rate case issues, and as such are not properly resolved through the rate case process. Issues associated with amending provisions of the 1981 Contracts will be resolved through negotiations with the customers outside of the rate case. BPA expects that the negotiations would, at a minimum, resolve when the customer would elect the waiver, the duration of the waiver, and the amount the customer elects to waive. Given that BPA expects that the contract amendments would specify the timing issues related to the CMR waivers, any reference to when the waiver must be made is removed from BPA's rate schedules or General Rate Schedule Provisions, consistent with the terms of the Power Settlement Agreement. Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128.

<u>Issue #2</u>

Whether the Power Demand Reservation Charge is supportable on a cost basis.

<u>Parties' Position</u>

PPC argues that the Power Demand Reservation Charge should be supported on a cost basis. PPC Ex. Brief, R-PP-01, at 9. In addition, PPC takes exception to the Power Demand Reservation Charge level and methodology. *Id*.

BPA's Position

The Power Demand Reservation Charge has two cost components. The first cost component is the cost to BPA of holding capacity resources in reserve (reserve cost component). The second is the cost to BPA of losing revenues when Computed Requirements customers displace their purchases from BPA (displacement cost component). Metcalf, *et al.*, E-BPA-74, at 13.

Evaluation of Positions

For the first time in the case, the PPC in its final brief objects to the method BPA used to calculate the Power Demand Reservation Charge. PPC Ex. Brief, R-PP-01, 9. PPC does not point to any specific part of the method it finds offensive other than a general objection to the overall increase in the Power Demand Reservation Charge between BPA's supplemental proposal and the Draft Record of Decision. *Id.* PPC then goes on to argue that the charge should be supportable on a cost basis. *Id.*

The overall increase in the Power Demand Reservation Charge between BPA's supplemental proposal and the Draft Record of Decision is due to the increase in the power demand charge. In the Draft Record of Decision, BPA proposed to add the transmission costs assigned to all power users to the generation cost of capacity. Previously BPA recovered these transmission costs through the energy charge or through its transmission rates. *See* section 7.2. of the ROD, which discusses recovering transmission costs through the power demand charge.

Regarding PPC's assertion that the Power Demand Reservation Charge is not supportable on a cost basis, BPA witnesses explained that the Power Demand Reservation Charge has two cost components. The first cost component is the cost to BPA of holding capacity resources in reserve (reserve cost component). The second is the cost to BPA of losing revenues when Computed Requirements customers displace their purchases from BPA (displacement cost component). Metcalf, *et al.*, E-BPA-74, at 13. The reserve cost component recovers the cost of holding power in reserve to meet peak load. To approximate this cost, BPA assumes that 15 percent of the cost of demand is associated with the costs of holding power in reserve. Metcalf, *et al.*, E-BPA-105, at 22. The displacement cost component recovers foregone revenues from the demand charge that BPA would have received from these customers had the displacement not occurred. Metcalf, *et al.*, E-BPA-74, at 13. In effect the foundation and the starting point for the level of the Power Demand Reservation Charge is the embedded cost of capacity and transmission allocated to PF customers. The Power Demand Reservation Charge, like the Availability Charge, attempts recover a portion of BPA's embedded costs from those customers who caused BPA to incur the costs. Metcalf, *et al.*, E-BPA-105, at 5. PPC's assertion that Demand Reservation Charge must be supported by costs is misplaced. The Power Demand Reservation Charge is a rate design mechanism to collect the demand costs allocated to PF customers.

Even though the Power Demand Reservation Charge is based on BPA's embedded cost, the Northwest Power Act does not preclude BPA from taking into account other factors besides costs in designing its rate. *See* section 13.3.

Decision

The Power Demand Reservation Charge is based on BPA's cost of capacity and transmission and as such, is supportable on a cost basis.

11.3.3 Availability Charge

The Availability Charge, historically, has not been a charge in the sense of a mills per kilowatthour charge or a dollars per megawatt charge. Metcalf, *et at.*, E-BPA-105, at 2. Rather, the Availability Charge refers to the light load hour billing factor for Computed Requirements customers. *Id*. For Computed Requirements customers, the light load hour billing factor is a weighted average of the purchaser's Measured Energy and its Computed Energy Maximum (CEM). *Id*. The Availability Charge is established so that the portion of the rate that varies with energy actually taken is equal to the marginal revenue BPA expects to receive from an alternative nonfirm energy sale of the displaced energy. *Id*. The portion of the rate that does not vary with energy actually taken is referred to as the Availability Charge. *Id*. As long as BPA has the contractual obligation to serve its customers' load, and the customers have the contractual right not to take their full contractual entitlement, BPA needs some mechanism to mitigate the revenue loss that BPA experiences when these customers purchase less power than BPA is obligated to provide and to protect its other customers who do not have this right. *Id*. at 5. Currently the Availability Charge is one mechanism that provides some revenue mitigation.

The Availability Charge was designed to recover the costs that BPA already has incurred at the time that the customer's displacement occurs, through critical water planning to meet the loads of these customers. Metcalf, *et al.*, E-BPA-105, at 5. Absent the Availability Charge, other customers would bear a disproportionate amount of these costs. The Availability Charge attempts to more equitably recover BPA's embedded costs by charging those customers who caused BPA to incur the costs. *Id*. The Availability Charge never was intended to eliminate totally any possibility that Computed Requirements customers might purchase less power than that to which they are contractually entitled. Even with the Availability Charge, Computed Requirements customers still will find it economic, in some conditions, to purchase less power from BPA than BPA is obligated to provide. *Id*. What the Availability Charge does attempt to do is mitigate the impacts on other customers who do not have the same resources or flexibility that Computed Requirements customers have in choosing how much power to buy from BPA.

There may be other mechanisms that also could mitigate the revenue loss that BPA faces when customers purchase less than the amount of power that BPA is obligated to provide. BPA is willing to explore alternative revenue mitigation measures with customers who elect to purchase under the 1996 Contracts and have the right to take less than their full contractual entitlement. These measures must compensate BPA for the costs it incurs to provide firm service and must provide at least the same amount of revenue mitigation as the Availability Charge.

BPA first adopted the Availability Charge in 1983, and has retained essentially the same structure in every rate proposal since then. *Id*. To implement the Power Settlement Agreement, in response to customers' request for rate simplification, BPA agrees to express the Availability Charge in the 1996 PF rate schedule as a mills per kilowatthour charge. Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128. Expressing the Availability Charge in mills per kilowatthour is straightforward and a simpler approach to structuring the charge, and eliminates some of the billing complexities associated with the previous structure for both BPA and its customers.

One of the components of the Power Settlement Agreement is the level of the Availability Charge for the months September through March. The Power Settlement Agreement calls for an Availability Charge of 7.0 mills per kilowatthour for the months September through December and 8.0 mills per kilowatthour for the months January through March. Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128.

In its supplemental proposal, BPA expressed alarm at the amount and pace at which Computed Requirements customers displaced their PF power purchases with their own nonfirm energy or energy from other sources during FY1995. Metcalf, *et al*., E-BPA-74, at 6. As BPA witnesses testified, during FY 1995, Computed Requirements customers displaced about 403 aMW of power that BPA was required contractually to provide. BPA proposed to set the Availability Charge at a level that would provide BPA with greater revenue protection than the 1995Availability Charge provided with the actual water and market conditions that prevailed in FY1995. *Id*.

The average Availability Charge for the period September through March in the Power Settlement Agreement (7.4 mills per kilowatthour), is greater than the average charge proposed for the same period in BPA's initial proposal. The average Availability Charge in the Power Settlement Agreement also is greater than the charge proposed using FY 1995 water and market conditions. Under FY 1995 water and market conditions, the Availability Charge for the period September through March averaged 6.99 mills per kilowatthour. As such, the Availability Charge in the Power Settlement Agreement meets BPA's concerns about water and market conditions in FY1995 recurring. In addition, the level of the Availability Charge in the Power Settlement Agreement is high enough to provide an economic disincentive for customers to purchase less than their contractual entitlement under conditions of low gas prices. *See* Final WPRDS Documentation, WP-96-FS-BPA-05A, section 7.8.

The level of the Availability Charge in the Power Settlement Agreement for the months September through March strikes a balance between mitigating the impacts on other customers, but does not entirely eliminate the possibility that Computed Requirements customers may purchase less power than that to which they are entitled contractually. In addition, at the level of the Availability Charge in the Power Settlement Agreement for the months September through March, Computed Requirements customers still will find it economic, in some conditions, to purchase less power from BPA than BPA is obligated to provide under the expected water and market conditions over the next five years. In fact, absent the parties' Power Settlement Agreement and the Administrator's adoption of it, or in the event the settlement agreement is not adhered to, the Availability Charge calculated using an average of 50 historical water years and expected market conditions would be much higher. The Availability Charge based on an average of 50 years and expected marketed conditions would be 9.24mills per kilowatthour for the months September through December; 11.32 mills per kilowatthour in the months January through March; 12.36 mills per kilowatthour for April; 4.99 mills per kilowatthour in the months of May through June; 4.60 mills per kilowatthour for July; and 7.71 mills per kilowatthour for August. *See* Final WPRDS Documentation, FS-BPA-05A, section 7.8.

Nevertheless, given customers' acceptance and support of the Power Settlement Agreement, the level of the Availability Charge in the Power Settlement Agreement provides an acceptable level of revenue protection. For the period September through March, BPA adopts the Availability Charge level contained in the Power Settlement Agreement.

The Power Settlement Agreement does not address the level of the Availability Charge in the other five months, April through August. Instead, the Power Settlement Agreement states that BPA will calculate the charge using one of the two methods discussed in BPA's supplemental proposal: FY 1995 water, or the average of 50 years of historical water. Power and Transmission Partial Settlement Agreement, WP-96-E-BPA-128.

Issue

How should the Availability Charge be calculated for the months April through August?

Parties' Positions

WPAG, PPC, PGP and the City of Tacoma claim that using 50 water years of record and an updated gas price forecast to calculate the Availability Charge for the months April through August results in an increase in the Availability Charge that was not anticipated in the Power Settlement Agreement. WPAG Ex. Brief, R-WA-01, at 9; PPC Ex. Brief, R-PP-01, at 4; PGP Ex. Brief, R-PG-01, at 18; Tacoma Ex. Brief, R-TU-01, at 1. WPAG urges BPA to remove the updated gas price forecast from the Availability Charge calculation. WPAG Ex. Brief, R-WA-01, at 11. PGP urges BPA to set the level of Availability Charge in the five spring to summer months within the range of 4.5 to 4.7 mills per kilowatthour. PGP Ex. Brief, R-PG-01, at 19. PPC argues that the Availability Charge should be established to reflect the cost of supplying operational rights based on the market price of options to purchase energy. PPC Ex. Brief, R-PP-01, at 5. The City of Tacoma urges BPA to set the Availability Charge in the months April through August at the level presented in the supplemental proposal. Tacoma Ex. Brief, R-TU-01, at 2.

BPA's Position

The Power Settlement Agreement does not specify the level of the Availability Charge in the months April through August. Draft Record of Decision, WP-96-A-01, at 296. Rather, the Power Settlement Agreement gives BPA a choice between two methods for determining the level of the Availability Charge in these months. The Power Settlement Agreement states that BPA will calculate the charge using one of the two methods discussed in BPA's supplemental proposal: FY 1995 water conditions, or the average of 50 years of historical water conditions. Power and Transmission Partial Settlement Agreement, E-BPA-128. The agreement does not preclude BPA from updating data used as inputs to the calculation.

Evaluation of Positions

As part of the Power Settlement Agreement, BPA and the parties agreed to a specific level for the Availability Charge in the months September through December. The Power Settlement Agreement provides that "[t]he Administrator should establish an Availability Charge . . . which applies to computed requirements customers under the 1981 Power Sales Contracts, of 7 mills per kilowatthour for the months September through December, and 8 mills per kilowatthour for the months January through March." Power and Transmission Partial Settlement Agreement, E-BPA-128. For the months April through August, the Power Settlement Agreement did not specify the level for the Availability Charge, but prescribed the approach BPA was to use in calculating the Availability Charge. The Power Settlement Agreement states that BPA will establish the level of the Availability Charge in the months April through August following one of the two methods for calculating the charge that BPA advanced in its supplement proposal. "The level of the Availability Charge in all other months [April through August] will be established following one of the two methods (use of '95 water or an average of 50 water years) described in Bonneville's Supplemental Proposal, including any errata and subsequent record revisions thereto." *Id.*

In the Draft Record of Decision, BPA proposed to use the 50 water years method to establish the level of the Availability Charge in the months April through August, with market conditions based on updated forecasts of natural gas prices. BPA selected this method for a number of reasons. Draft ROD, WP-96-A-01, at 297. First, this is the method that BPA has used consistently since the Availability Charge was first adopted in its 1983 rates. In every rate case since 1983, the level of the Availability Charge has been established based on the difference between revenues expected from sales at the PF rate and the revenues BPA could expect if this same energy was sold at expected nonfirm energy prices during the test period. Metcalf, *et al.*, E-BPA-105, at 2. For purposes of calculating the Availability Charge, in every rate case since 1983, BPA projected nonfirm energy revenues based on expected market conditions, which in turn are a function of projected prices of natural gas used as fuel in certain generating facilities, averaged over 50 different water years. Second, the revised future gas prices provide a better indicator of market conditions that will exist in the next five years than historical prices based on a single year such as FY 1995. Thus the average of 50 water years with the updated gas price projections better reflects BPA's estimate of nonfirm energy market conditions over the next five years than the prices in FY 1995 alone. Draft ROD, WP-96-A-01, at 297.

WPAG, PPC, PGP and the City of Tacoma claim that using 50 water years of record with an updated gas price forecast to calculate the Availability Charge for the months April through August results in an increase in the Availability Charge that was not anticipated in the Power Settlement Agreement. WPAG Ex. Brief, R-WA-01, at 9; PPC Ex. Brief, R-PP-01, at 4; PGP Ex. Brief, R-PG-01, at 18; Tacoma Ex. Brief, R-TU-01, at 1. PGP asserts that the customers agreed to the Availability Charge in the Power Settlement Agreement based on an explicit assumption that the level of Availability Charge in the months April to August would be comparable to the levels contained in BPA's supplemental proposal, between 4.5 and 4.7 mills per kilowatthour. PGP Ex. Brief, R-PG-01, at 18. PPC claims that the parties to the Power Settlement Agreement believed that BPA would select one of the methodologies stated in the Power Settlement Agreement, and then use the same inputs as were used in the supplemental proposal to calculate the Availability Charge. PPC Ex. Brief, R-PP-01, at 5. PPC states that it did not contemplate a choice of Availability Charge methods coupled with revised inputs such as the revised gas forecast. *Id*. at n. 1. WPAG notes that the parties recognized that the Availability Charge in the months not covered by the Power Settlement Agreement might change. WPAG Ex. Brief, R-WA-01, at 10. However WPAG also claims that the parties did not contemplate that BPA would change its gas price forecast such that the Availability Charge numbers relied on during the settlement negotiation would be irrelevant. *Id*.

Notwithstanding the parties' expectations about the level of the Availability Charge in April through August, the Power Settlement Agreement states that BPA will establish the Availability Charge for April through August following one of two methods, 95 water or an average of 50 water years. The Power Settlement Agreement does not state that the level of the Availability Charge in April through August will be approximately the same as the levels presented in BPA's supplemental proposal. Nor does the Power Settlement Agreement state that the level of the Availability Charge will be based on an average of 50 water years and market conditions assumed in BPA's supplemental proposal. While the parties may have had expectations about the level of the Availability Charges in the months April through August, these expectations were not incorporated in the language of the Power Settlement Agreement.

PPC accuses BPA of reducing its natural gas forecast in order to manipulate the level of the Availability Charge in April through August. PPC Ex. Brief, R-PP-01, at 5. PPC's accusation is unsupported and untrue. BPA did not revise its gas forecast to achieve a certain level of the Availability Charge in April through August. Several parties had suggested that the gas price forecast BPA was using in the rate case was too high. In response to these suggestions BPA reviewed its gas price projections and determined that its forecast in the supplemental proposal should be revised downward. *See* section 3.3 of the ROD, which describes the reason for the lower gas price projection. Several of BPA's rates and thus revenues from the sale of these products are based on BPA's gas price forecast. A lower gas price forecast means lower revenues from the sale of these products. Given the other provisions of the Power Settlement Agreement, a lower gas price forecast meant that BPA would have to find more cost savings than it had anticipated at the time of the settlement discussions in order to reduce its average PF rate to 24.4 mills per kilowatthour. Despite the fact that a lower gas price forecast would lower BPA's projected revenues, the Administrator decided that the revised forecast provides a more accurate projection of future gas prices and thus a more accurate projection of BPA's revenues and expenses.

PPC argues that establishing the Availability Charge to recover the revenue loss that BPA faces when Computed Requirement customers purchase less power than BPA is obligated to provide is at odds with BPA' business interest. PPC Ex. Brief, R-PP-01, at 5. PPC argues that the Availability Charge should be established to reflect the cost of supplying operational rights based on the market price of options to purchase energy. *Id*. PPC's proposal is curious. On the one hand PPC objects to BPA's decision to use an average of 50 water years and updated gas prices to calculate the Availability Charge in April and August as being inconsistent with the Power Settlement Agreement. PPC then turns around and advances an entirely different approach for establishing the Availability Charge that is not based on either 50 water years or FY 1995 water conditions. As the PPC recognizes, the Power Settlement Agreement specifies the level of the Availability Charge for the fall and winter months. That level is 7 mills per kilowatthour for the months September through December, and 8mills per kilowatthour for the months January through March. For the other months, the level of the Availability Charge is based on one of the two methods BPA advanced in its supplemental proposal. Both of these methods are based on recovering the revenue loss that BPA faces when Computed Requirement customers purchase less power from BPA than it is obligated to provide. Neither of these methods is based on the cost of supplying operational rights based on the market price of options to purchase energy. The PPC proposal is at odds with any notion of consistency with the Power Settlement Agreement.

WPAG urges BPA to remove the updated gas price forecast from the Availability Charge calculation. WPAG Ex. Brief, R-WA-01, at 11. PGP urges BPA to set the level of Availability Charge in the five spring to summer months within the range of 4.5 to 4.7 mills per kilowatthour. PGP Ex. Brief, R-PG-01, at 19. The City of Tacoma urges BPA to set the Availability Charge in the months April through August at the level presented in the supplemental proposal. Tacoma Ex. Brief, R-TU-01, at 2 BPA executed the Power Settlement Agreement based on its assessment that the level of the Availability Charge in the months September through March would protect BPA's revenues from low gas prices, even though it would not necessarily provide protection from water conditions. BPA was not relying on the expected gas prices in its supplemental proposal, but on prices very similar to the prices in its revised gas forecast. The revised future gas prices are a better indicator of market conditions that will exist in the next five years than historical prices based a single year such as FY 1995 or the gas prices used in BPA's supplemental proposal. BPA intended to calculate the Availability Charge using the same market assumptions that are used to develop BPA's other power rates and its revenue forecasts.

Nevertheless, while BPA believes its proposed revision for April through August were entirely consistent with the letter of the Power Settlement Agreement and at least BPA's intent, BPA recognizes the parties' genuine concern with the level of the change in these months. BPA wants to preserve the spirit of compromise that enabled the parties to come together on a common proposal. Therefore, BPA will set the Availability Charge level in April through August at a level between the level that the parties claim was contemplated in the Settlement Agreement and the level in the draft rate schedules that BPA released on May 21, 1996, which reflected the decisions in the Draft Record of Decision. For the months April and August, the Availability Charge will be capped at the levels specified in the Power Settlement Agreement for the adjacent months. Thus, April is capped at 8 mills per kilowatthour, and August is capped at 7 mills per kilowatthour. The cap effectively results in an annual average Availability Charge that is about one-half mill lower than the level released on May 21, 1996, and about one-half mill higher than the level in BPA's supplemental proposal, about half way between the level the parties claim was contemplated in the Power Settlement Agreement and the level reflected in the Draft Record of Decision.

The Administrator remains willing to adopt the Power Settlement Agreement even with this compromise to BPA's understanding of it. BPA hopes that the parties will view the compromise in the spirit in which it is offered to keep the settlement intact and enjoy the benefits it confers on both BPA and the parties. Agreement with BPA's customers is valuable to BPA, and the customers benefit from lower Availability Charges than would otherwise be the case.

Decision

For the months April through August, the Availability Charge calculation will assume revenues from nonfirm sales based on an average of 50 water years and updated gas prices; however, the level of the Availability Charge in April will be limited to 8 mills per kilowatthour, and the level of the Availability Charge in August will be limited to 7 mills per kilowatthour.

11.3.4 Composite Rate

The composite rate is a weighted average Priority Firm rate that bundles into a single energy charge the various rate components included in the PF-96 rate schedule. The composite rate is based on the weighted expected revenues from eligible customers' purchases of firm power (including demand and energy components) and Load Shaping, excluding eligible customers that primarily serve irrigation load. Customers will be billed for transmission service for their Federal power deliveries, assessed under the appropriate transmission rate schedule. Eligible customers include Full Requirements preference customers under the 1996 Contract and Metered Requirements preference customers under the 1981 Contract that are expected to have an annual retail load of 25 aMW or less each year of the rate period and who agree to purchase their entire requirements from BPA for the rate period.

PPC filed initial direct testimony stating that the composite rate was higher than any qualifying customer would pay under the PF rate, for two reasons. The first reason was that BPA initially miscalculated heavy load hour energy during the September through December period. Carr, *et al.*, WP-96-E-PP-02, at 3. BPA corrected that error in the supplemental proposal. Craig, *et al.*, WP-96-E-BPA-76, at 8. The second reason for the higher composite rate was due to rate design. Carr, *et al.*, E-PP-02, at 4. In response, BPA testified that in designing the composite rate, BPA excluded eligible irrigating utilities in calculating the composite rate because those utilities are not expected to buy under the composite rate. To include their lower-priced spring and summer loads in the calculation of the composite rate would improperly benefit other customers. Craig, *et al.*, WP-96-E-BPA-50, at 27. The PPC did not raise in its initial brief or brief on exceptions the issues identified in its testimony concerning the composite rate, thereby waiving those issues. *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611, § 1010.13(b) (1986).

11.3.5 Phase-In Mitigation

BPA proposes to offer Phase-In Mitigation for qualifying Full Requirements preference customers under the 1996 Contract and Metered Requirements preference customers under the 1981 Contract who commit to purchase all of their power from BPA for the entire rate period. Whether a customer is eligible for Phase-In Mitigation will be determined by a formula that compares two amounts for each customer. The first amount is the customer's expected costs of power calculated by applying 1993 PF rates to the customer's FY 97 expected BPA purchases, as forecasted in the 1996 rate case by BPA. The second amount is the customer's expected costs of power calculated by applying all applicable 1996 rate schedules, including applicable transmission rate schedules, to the customer's FY 97 expected BPA purchases, as forecasted in the 1996 rate case by BPA. If the second amount is more than 9 percent greater than the first amount, rounded to the nearest tenth of a percent, the customer may notify BPA to phase in the 1996-97 rate increase. To receive the Phase-In Mitigation, the customer must notify BPA by September 1, 1996.

The September 1, 1996, notification provides BPA 1 month to coordinate with BPA's Billing Operations to prepare the customer's billing to accommodate the necessary adjustments and comparisons between the 1993 rate schedules and 1996 rate schedules. Purchasers may not apply for mitigation after that date. If a customer does qualify and does notify BPA to phase in, during each month of the rate period BPA will compare, for the billing period, what the customer's bill would have been applying the 1993 PF rates to all BPA purchases and what the customer's bill would be applying all applicable 1996 rates to all BPA purchases.

If the increase over the 1993 rates is greater than 9 percent in any month during the first year, greater than 18 percent in any month during the second year, greater than 27 percent in any month during the third year, greater than 36 percent in any month during the fourth year, and greater than 45 percent in any month during the fifth year, then BPA will reduce PF generation charges to a level that results in an increase for a month over the 1993 rates of 9, 18, 27, 36, and 45 percent for each respective year. Phase-In Mitigation is available only to Full or Metered Requirements preference customers because of their commitment to BPA to purchase their entire load from BPA for a 5-year period, and because many of these customers have limited ability to choose suppliers. Many of BPA's other customers have more choices, are buying and selling power in the market, and can mitigate the rate increase by optimizing their resource operation against their purchases from BPA. Since no parties have taken positions on Phase-In Mitigation, BPA will adopt the proposal as described.

11.4 **Industrial Firm Power (IP) Rate**

11.4.1 **Fixed Curtailment Fee**

In testimony, the Western Public Agencies Group (WPAG) argued that the Fixed Curtailment Fee should be 8.2 mills per kilowatthour (kWh). WPAG argued that BPA's analysis inappropriately assumed that BPA would be able to sell some of the curtailed power as firm power. Beck, *et al.*, WP-96-E-WA-13, at 64-65. In rebuttal, BPA testified that given the circumstances necessary for curtailment of aluminum smelter operations, BPA would likely be able to resell some of the curtailed power at surplus firm prices. Bolden, *et al.*, WP-96-E-BPA-111, at 4-5. WPAG did not pursue this issue on brief. Therefore, the issue is deemed to be waived. *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.13(b), 51 Fed. Reg. 7611 (1986).

Issue

Whether BPA should assume that each year of the rate period it will resell 40 percent of curtailed power as surplus firm power.

Parties' Positions

The parties have taken no position on this issue. Because BPA is proposing to change the methodology in its supplemental proposal, it is being addressed as an issue.

BPA's Position

BPA proposes an assumption that each year during the rate period it will resell 40 percent of the curtailed power as surplus firm power.

Evaluation of Positions

The fixed curtailment fee gives a DSI purchasing take-or-pay energy under a 1996 contract the right to curtail its plant load below the sum of its take-or-pay obligation plus any amount of non-Federal service the DSI identifies when it elects this product. The DSI then pays BPA a fixed curtailment fee in mills per kilowatthour for the curtailed amounts.

In pricing the fixed curtailment fee, BPA assumed that 1,000 MW of DSI load would subscribe to either the fixed curtailment fee or the non take-or-pay product. BPA further assumed that the probability of plant curtailment was zero percent in the first year, increasing by 5 percent each year until it reached 20 percent in the last year of the rate period. BPA assumed that during the second year of the rate period it would resell 10 percent of the curtailed energy as surplus firm energy and the rest as nonfirm energy. Finally, BPA assumed that the amount sold as surplus firm energy would increase by 10 percent each year, reaching 40 percent in the last year of the rate period. Bolden, *et al.*, WP-96-E-BPA-80, at 2-4.

Curtailments of DSI load are likely to occur only when aluminum prices are depressed. In addition, because of the high costs of shutting down and restarting, the DSIs are unlikely to curtail unless the expected the curtailment to be long-term. *Id.* at 3. Therefore, BPA reasonably assumed that it would be able to resell a portion of the curtailed power as surplus firm power. BPA assumed, however, that its ability to resell curtailed power as surplus firm power would increase during the rate period. Based on additional evidence, BPA now proposes to assume that each year of the rate period it will resell 40 percent of the curtailed power as surplus firm energy.

This assumption is justified. First, the DSIs agreed that, given the nature of aluminum smelter operations, any shutdown of aluminum potlines would usually be long-term. The DSIs noted that they already coordinate with BPA when aluminum potlines are started, so that BPA will have adequate notice when curtailed energy will no longer be available for resale. The DSIs concluded that each year during the rate period BPA would be able to resell the same percentage of the curtailed energy as surplus firm power. They suggested that this percentage should be 20 to 30 percent. Schoenbeck, Bliven, WP-96-E-DS-12, at 10-11.

It is reasonable to conclude that BPA will be able to resell a fixed percentage of the curtailed energy as surplus firm power. For the reasons stated in both BPA's and the DSIs' testimony, any curtailment of DSI load is likely to be long-term. Therefore, even if the DSIs curtail production during the first year of the rate period, BPA can expect the curtailment to be long-term, and can have reasonable assurance that it will have surplus power to sell. The DSIs noted that they coordinate with BPA regarding the resumption of operations. In addition, because of BPA's forecast of aluminum prices, BPA itself can estimate when the DSIs will resume operations. Bolden, *et al.*, WP-96-E-BPA-111, at 5.

Therefore, whenever the DSIs shut down production, BPA should be in the same position as far as its ability to resell the power as surplus firm.

BPA assumed that the amount sold as surplus firm power would reach 40 percent in the last year of the rate period. Bolden, *et al.*, E-BPA-80, at 4. This amount should be assumed throughout the rate period. First, as noted, BPA should have an equal ability to resell the power as surplus firm power in the first year of the rate period as in the last year of the rate period. Second, BPA will be including an updated natural gas forecast in its Final Proposal. *See supra* § 6.4. The updated gas forecast is lower than the forecast contained in BPA's Supplemental Proposal. The gas forecast in turn results in forecasts of significantly lower prices for excess energy, including surplus firm energy. Therefore, purchasers of energy will be in a better position to purchase surplus firm energy for its certainty, and are more likely to do so.

Third, the Energy and Water Development Appropriations Act of 1996 removed certain obstacles to BPA's ability to sell excess power. This Act eliminated the "sale for resale" requirement and relaxed the call-back provisions. Wedlund, Reilly, WP-96-E-BPA-81, at 7. The Act should increase the price BPA can obtain for surplus power and expand the market for BPA's power. *Id.* In its supplemental case, BPA assumed that the legislation would result in an increase in revenues of $16 million per year. *Id.* at 8. BPA is now assuming an annual revenue increase of $26 million. *See supra* § 10.1.1. BPA did not take this legislation into account in calculating the fixed curtailment fee. Based on this legislation as well as the updated gas forecast, BPA can expect greater revenues from the resale of curtailed power than it assumed in its supplemental case. An assumption that each year BPA will resell 40 percent of the curtailed power as surplus firm power captures these revenues and is consistent with the most up-to-date information.

<u>Decision</u>

BPA will assume that each year of the rate period it will resell 40 percent of the curtailed power as surplus firm energy. This assumption is consistent with the nature of DSI operations, the updated natural gas forecast, and the anticipated effects of the Energy and Water Development Appropriations Act of 1996.

11.5 <u>Industrial Power Spot Gas Rate</u>

In testimony, the DSIs stated that BPA should allow up to 50 percent of the load committed under the block sale agreements to convert to the spot gas rate. The DSIs argued that broadening the eligibility could only enhance BPA's net revenues. Schoenbeck, *et al.*, WP-96-E-DS-08, at 11. In rebuttal, BPA testified that the most effective way to limit its risk was to limit the amount of load eligible to be served at the spot gas rate. By limiting the eligibility for the spot gas rate to incremental load above the block sale, BPA should enhance its revenues over alternative sales in the spot electric market. Under the DSI proposal, the spot gas rate becomes an alternative to sales at the IP rate with a potential for reduced revenues. Bolden, *et al.*, WP-96-E-BPA-111, at 3-4.

The DSIs did not pursue this issue on brief. Therefore, it is deemed waived. *Procedures Governing Bonneville Power Administration Rate Hearings § 1010.13(b),* 51 Fed. Reg. 7611 (1986).

Issue 1

Whether BPA should guarantee to hedge its risk under the Spot Gas Rate.

Parties' Positions

The PPC argues that, in order to eliminate risk, BPA should base the spot gas rate on the cost of hedging it on natural gas futures markets instead of on the BPA natural gas price forecast. PPC Brief, WP-96/TR-96-B-PP-01, at 21.

BPA's Position

BPA argues that its risk under the spot gas rate is minimal, and that the decision whether to hedge is an internal management decision for BPA. Bolden, *et al*., WP-96-E-BPA-111, at 2.

Evaluation of Positions

The spot gas rate ties a portion of the customer's power charge to the spot market price of natural gas. The rate consists of a fixed readiness charge plus a charge equal to the average spot market gas price, in $/MMBtu, for the previous twelve months multiplied by an energy multiplier. The rate is designed to recover the same revenues that BPA would recover under the flat IP rate. Bolden, *et al*., WP-96-E-BPA-80, at 7-8.

For two reasons, BPA's risk in offering the spot gas rate is minimal. First, BPA is offering the spot gas rate only for incremental DSI load; that is, load above the amount the DSIs committed to place on BPA in the block sale contracts that were signed in September 1995. *Id.* at 11. In negotiating the block sale, BPA signed up as much DSI load at the flat IP rate as it could. Chang, Cocks, WP-96-E-BPA-110, at 4. The spot gas rate is being offered for load BPA would not otherwise expect to serve. Bolden, *et al*., E-BPA-80, at 11. Therefore, the alternative to power sales under the spot gas rate is power sales on the spot electric market. *Id.*

Second, the price of electricity in the spot electric market is driven by the marginal cost of the marginal resource on the west coast. Most of the time the marginal resource is gas-fired generation. Therefore, as gas prices, and hence the spot gas rate, rise, the variable cost of gas-fired electric generation and the price of electricity on the spot market also rise. *Id*. at 14. As gas prices and the spot gas rate fall, the price of electricity on the spot market also falls. In almost all cases, however, the spot gas rate should exceed the price of electricity in the spot electric market. *Id.* at 11, 14-15; Tr. 1165.

Two conclusions follow from this analysis. First, if BPA does not offer the spot gas rate, the power it would have sold at the spot gas rate will be sold on the spot electric market. Therefore, the spot gas rate will enhance BPA's revenues so long as it exceeds the price BPA can obtain in the spot electric market. Second, the spot gas rate should exceed the price on the spot electric market. Therefore, BPA's revenues should be enhanced by offering the spot gas rate, regardless of whether BPA's natural gas forecast is accurate. If BPA's forecast is too high, BPA will recover less revenue under the spot gas rate than it has projected. However, lower natural gas prices mean lower prices in the spot electric market. Therefore, the revenues BPA would have recovered in the spot electric market will also be less. Since the spot gas rate should exceed the price in the spot electric market, BPA still will have gained by offering the spot gas rate.

Nevertheless, the PPC argues that BPA is taking financial risk by relying on its natural gas forecast. *See* Carr, *et al*., WP-96-E-PP/PA-03, at 22. The PPC notes that BPA is offering a variable rate based on hedging aluminum, yet is taking risk by not hedging the spot gas rate. *Id.* at 23. This analogy is misplaced. The aluminum variable rate is available for any amount of load a DSI wishes to place on it; the DSI customer has a choice between the flat IP rate and the aluminum variable rate. Therefore, the alternative to sales at the aluminum variable rate is sales at the IP rate. Bolden, *et al*., E-BPA-111, at 3. The alternative to sales at the spot gas rate is sales in the spot electric market. Under the spot gas rate, BPA's revenue position will be enhanced so long as it recovers more than it would have recovered in the spot electric market.

Moreover, as established above, the risk under the spot gas rate is minimal because the rate is tied to the price of natural gas, which varies with the price of electricity on the spot market. *Id.* at 2-3; Bolden, *et al*., E-BPA-80, at 11-15. Thus, except in unusual cases, the spot gas rate will exceed the price available in the alternative market. Tr. 1165-66.

Finally, BPA must be in position to manage its risk prudently in a business-like manner. Guaranteeing to hedge a rate does not allow BPA the flexibility it needs in a dynamic environment to prudently manage risk while seeking to enhance its revenues. Thus, even under the aluminum variable rate BPA is not guaranteeing to hedge under all circumstances. *See infra* § 11.6. Given the minimal risk under the spot gas rate, retention of this flexibility is even more appropriate in this case.

Decision

BPA should not guarantee to hedge its risk under the spot gas rate. Because the rate is available only for incremental load, the alternative to sales at the spot gas rate is sales in the spot electric market. Because natural gas prices and spot electric market prices move together, BPA's risk is minimal. In addition, BPA must retain the flexibility to manage its risk so that the agency can seek to enhance its revenues when prudence dictates such a course.

11.6 Variable Industrial Power Rate

Issue

Whether BPA should fully hedge its risk under the Variable Industrial Rate under all circumstances.

Parties' Positions

The PPC argues that, in order to eliminate risk, BPA should guarantee that it will fully hedge the Variable Industrial Rate under all circumstances. PPC Brief, WP-96/TR-96-B-PP-01, at 21.

BPA's Position

BPA states that under most circumstances it intends to fully hedge the rate. BPA believes, however, that it must retain flexibility in order to prudently manage risk and to maximize revenues. Ross, *et al*., WP-96-E-BPA-56, at 2.

Evaluation of Positions

In addition to arguing that BPA should fully hedge the variable rate, the PPC argues that BPA should publicly disclose the terms of any hedge, and that a participating DSI must agree to pay the costs of providing the hedge and must commit to a take-or-pay relationship with BPA for the term of the hedge. PPC Brief, B-PP-01, at 21. BPA has already agreed with these recommendations. *See* Ross, *et al*., WP-96-E-BPA-35, at 3, 10; Ross, *et al*., E-BPA-56, at 2. Therefore, they are not at issue.

Under the existing variable rate, which has been in place since 1986, the rate charged the DSI aluminum smelters varies with the price of aluminum. The rate expires September 30, 1996, and BPA has proposed a successor variable rate. BPA expects to fully hedge the risk associated with the new rate. Ross, *et al*., E-BPA-35, at 15-16. The PPC and APAC argue that BPA should guarantee to fully hedge the rate, thereby essentially eliminating risk. Carr, *et al*., WP-96-E-PP-04, at 5; Carr, *et al*., WP-96-E-PP/PA-03, at 21. They further argue that BPA does not have the expertise to make profits trading on the aluminum futures market. *Id*.

BPA testified that, although it expects to fully hedge each variable rate, it would be imprudent to leave itself no flexibility to take advantage of market movements that could increase its revenues. Ross, *et al*., E-BPA-35, at 16; Tr. 1200. BPA anticipates that it will fully hedge the variable rate at the beginning of the rate period, but that it might need to adjust the hedge over time in response to market changes. Ross, *et al*., E-BPA-35, at 16; Tr. 1190, 1203-04.

In managing the hedge, BPA intends to engage in prudent risk management. Ross, *et al*., BPA-35, at 17. The parties' insistence that BPA avoid <u>all</u> risk is not reasonable. Avoidance of all risk is not a sound business principle; indeed, few if any businesses operate on such a principle. Under the existing variable rate, BPA has assumed all risk of aluminum price fluctuations. The proposed Variable Industrial Rate mitigates this risk substantially by providing for the potential to hedge, a course BPA intends to follow in most, and perhaps all, circumstances.

If BPA is to operate its power business prudently and in accord with sound business principles, however, it should not guarantee to eliminate all risk. BPA intends to maintain a less-than-fully-hedged position only when it concludes that this course results in a probability of higher revenues. Tr. 1206. For example, BPA might be in a position to buy back a call (the purchaser of a call has the right to buy the seller's asset at a pre-determined price; hence, by buying back the call, BPA would not have to pay the counterparty financial institution when the price of aluminum rises) and potentially increase revenues without taking the risk of falling aluminum prices. *Id*. at 1193, 1204. In this situation, the financial institution would still be required to pay BPA under the terms of the hedge if the price of aluminum falls.

The parties' suggestion that BPA lacks the expertise to "make profits trading on the aluminum futures market" is misplaced. *See* Carr, *et al*., E-PP/PA-03, at 21. Managing risk and making profits are not the same thing. Under BPA's Interim Hedging Policy, "speculating" is defined as "trading in financial instruments, such as derivatives, with the objective of achieving profits through successful anticipation of price movements." Ross, *et al*., E-BPA-56, Attachment A, at A-3. Section 5 of the Interim Hedging Policy provides as follows:

> <u>Section 5. Speculative Transactions Prohibited</u>
>
> (a) It is BPA policy not to speculate on commodity prices.
>
> (b) Speculative transactions have no place in BPA's risk management program and are prohibited by this Interim Policy.

Id. at A-4.

In its testimony, BPA also explained the difference between speculation, or "[t]rading with the objective of achieving profits through the successful anticipation of price movements," and hedging, which is employed to mitigate risk. *Id*. at 8. In retaining flexibility, BPA is managing risk; it is not trading on the aluminum markets to make profits.

Moreover, for ten years BPA has had in place a successful variable industrial rate under which BPA assumed all the risk of aluminum price fluctuations. This rate was based on BPA's projection of aluminum prices in the 1986 Variable Industrial Rate Case. In every rate case since 1986 BPA has made a projection of aluminum prices. BPA's experts developed an aluminum price forecast for this rate case as well. *See* Supplemental Loads and Resources Study, WP-96-E-BPA-57A, at 10-11; Ross, *et al.*, E-BPA-35, at 18-20. Because the DSI aluminum smelters are a substantial segment of BPA's load, BPA has had a long-standing interest and expertise in aluminum prices.

As is evident from the testimony, BPA has also spent considerable effort developing a hedging strategy, including issuing multiple drafts for review. *See* Ross, *et al.*, E-BPA-35, Attachment A and Ross, *et al.*, E-BPA-56, Attachment A. BPA has developed a prudent strategy for managing risk while leaving itself the flexibility to maximize revenues. According to BPA's hedging policy, BPA's "competitive success will depend on its ability to manage business and financial risks associated with its commercial operations in a changing competitive environment." Ross, *et al.*, E-BPA-56, Attachment A, at A-1. BPA adopted the policy to ensure that "its decisions to manage various price risks be conducted in an intelligent, business-like manner." *Id.* at A-2. Under the policy, one element BPA will consider in comparing hedging alternatives is "the liquidity of the hedge instrument should future circumstances dictate restructuring or unwinding the hedge." *Id.* at A-5. Thus, BPA's agency-wide policy contemplates flexibility in all its hedging transactions.

BPA is not approaching its risk management decisions in a haphazard fashion. It has developed a detailed policy, and intends to take prudent actions to assure cost recovery while maximizing revenues in a dynamic environment. In such an environment, it would be imprudent to eliminate options for the entire five-year rate period.

Decision

BPA must maintain flexibility in the dynamic electricity market in order to minimize risk while maintaining the ability to maximize revenues. Therefore, BPA should not guarantee to fully hedge the risk of the Variable Industrial Rate in all circumstances.

11.7 FPS Schedule

11.7.1 Structure and Limitations

Issue

Whether the Firm Power Products and Services (FPS-96) rate schedule exposes BPA's customers and Federal taxpayers to cost underrecovery risk and should therefore be further structured to contain limitations that will govern prospective sales.

Parties' Positions

The investor-owned utilities (IOUs) argue that the FPS-96 rate schedule is totally unstructured and exposes BPA's customers and Federal taxpayers to unnecessary risk. IOU Brief, WP-96-B-GE/PL/PS-02, at 8. They state that the FPS schedule does not meet the standards set by FERC for approval of BPA's long-term rates, and that the

Commission has approved such rates only where the rate was sufficiently structured and contained adequate safeguards to ensure cost recovery and the future adequacy of BPA's revenues. *Id*. at 12. Specifically, the IOUs note that: 1) there is no floor or ceiling rate as provided for in several past BPA long-term rates; 2) there is no limit on the quantity of power available for sale under the FPS schedule; 3) BPA may acquire any amount of resources for resale under the FPS schedule; 4) there are no specified rate escalators; and 5) there is no costing methodology required as a basis for setting prices, such as BPA has proposed in its flexible PF schedule. *Id*. at 9-10. The IOUs maintain that FPS-96 gives BPA so much discretion as to what rate it will actually charge any particular customer that FERC will be unable to evaluate whether BPA's power rates proposal in this proceeding meet the cost recovery and repayment requirements of section 7(a)(2) of the Northwest Power Act. *Id*. at 16.

In their brief on exceptions the IOUs argue that the Draft ROD dismisses the argument that the FPS schedule fails to meet the standards for long-term rates set by FERC in connection with prior rate filings by BPA. IOU Ex. Brief, WP-96-R-GE/PL/PS-02, at 7. They state that the Draft ROD wrongly implied that the IOUs were suggesting that the FPS schedule contain each and every condition traditionally applied by FERC to longer-term rates, and that they believe some combination will be sufficient to protect BPA's cost recovery and mitigate BPA's risks under the FPS schedule. *Id*. at 10-11.

Clark asserts in its initial brief that the lack of structure or limits in the proposed FPS-96 schedule raises the likelihood of serious, substantial and sustained revenue underrecoveries. Clark Brief, WP-96-B-CP-01, at 27. It contends that such underrecoveries will expose other BPA customers to the risk of cost shifts to cover these underrecoveries. *Id*.

The Full Meal Deal Utilities (FMD) argue that putting strict limits on BPA's authority to market surplus power under the proposed FPS-96 rate schedule would cripple BPA's efforts to retain its load and to be successful in today's unregulated market, and would give a one-sided and unfair advantage to BPA's competitors. Wagner,*et al*., WP-96-E-FM-02, at 9. They argue that the flexibility of the FPS-96 schedule will benefit both BPA and its existing customers. *Id*. at 12. FMD utilities note the competition that BPA has been facing from wholesale power marketers and argue that the restrictions recommended by the IOUs would only serve to put BPA at a disadvantage in its efforts to retain load and secure needed revenue. FMD Pr. Brief, WP-96-P-FM-01, at 7.

NIU opposes the IOUs' proposals to restrict BPA's ability to market power under FPS-96, and argues that such limitations are unwarranted and would only serve to inhibit BPA and give the IOUs a competitive advantage. NIU Pr. Brief, WP-96-E-NI-01, at 4-5. NIU states that the only parties "safeguarded" by the adoption of the limits recommended by the IOUs are the IOUs themselves. Saven, WP-96-E-NI-02, at 9. They state that changed circumstances, including fish flow requirements which increase non-firm resources, and the changed federal laws and regulations governing electric industry competition fully justify BPA's proposal to offer competitively priced surplus power products under FPS-96. NIU Pr. Brief, WP-96-E-NI-01, at 6. NIU argues that the greatest risk of cost underrecovery is posed by BPA's inability to flexibly respond to market conditions, and that the IOUs' recommendations to add structure and safeguards would significantly increase the chance of BPA experiencing underrecovery, not reduce it. Saven, E-NI-02, at 13. NIU argues that the caps proposed by the IOUs on sales of energy and capacity under FPS-96 are artificial limits designed to tie BPA's hands. *Id*. at 15. They note that while competition has made FPS-96 necessary there is ample historical precedent for BPA to propose unique products and flexible rates to develop or retain load. *Id*. at 9-10.

The PPC argues that the term and pricing flexibility proposed by BPA in the FPS-96 schedule is appropriate. Carr, *et al*., WP-96-E-PP-08, at 3. They state that that cap proposed by the IOUs on the amounts of energy and capacity available under FPS-96 may unduly and arbitrarily limit BPA's ability to make FPS-96 sales. *Id*.

WPAG argues that any resource acquisition and sale poses some risk that costs will not be collected, and that BPA's customers face this risk now. Beck,*et al*., WP-96-E-WA-11, at 26. They state the flexibility of the FPS-96 schedule is essential if BPA is to compete effectively. *Id*.

<u>BPA's Position</u>

The FPS-96 rate schedule is a market-based rate that will apply to power sales derived from a mix of power purchases and surplus resources. Hill, *et al*., WP-96-E-BPA-51, at 15. The FPS-96 rate schedule is flexible to allow BPA to meet individual customers' product needs and provide BPA with pricing flexibility to respond to changing market conditions, thereby improving BPA's ability to maximize net revenues for long-term business stability. Moorman, Evans, WP-96-E-BPA-09, at 30. In a fully competitive market, with the bulk of BPA's sales vulnerable to being served by other parties, BPA faces greater challenges in recovering the revenues it needs to meet its costs and meet its Treasury repayment obligations. Hill, *et al*., E-BPA-51, at 7. BPA's experience with other long-term flexible schedules, however, shows that efforts to assure FERC that BPA would recover its fully allocated costs, by including in the schedule the kind of structure and limitations proposed by the IOUs, only helped assure that it would not. *Id*. at 13.

Contrary to the IOUs' assertion in their brief on exceptions, BPA has not ignored the conditions placed on longer-term rates in the past by FERC. The Draft ROD in its evaluation of the parties' positions presents a detailed discussion of each of the conditions noted by the IOUs. That evaluation is carried over into this Final ROD.

<u>Evaluation of Positions</u>

The IOUs fail to adequately recognize or evaluate in either their testimony or briefs the competitive environment that justifies BPA's proposal to adopt the flexible FPS-96 schedule. Taken in the context of yesterday's highly regulated market, when BPA was both the low cost provider and a dominant market force, the IOUs' arguments are more persuasive. Taken in the context of today's vigorously competitive wholesale power market, however, the IOUs' arguments have little or no merit. BPA has undertaken considerable redesign of its power products and prices to ensure that its rate schedules contain competitive rates. *See generally* Buchanan, *et al.*, WP-96-E-BPA-11. The majority of BPA's proposed rate schedules contain fixed rates designed to recover BPA's costs. *See generally* Supplemental Rate Proposal - Wholesale Power and Transmission Rate Schedules, WP-96-E-BPA-64, at 1-75 (hereafter cited as "Rate Schedules"). In fact, it is under these rate schedules that BPA has provided, and will continue to provide, service to the majority of its customers.

Competition for BPA's historical loads has intensified in recent years, due to several factors, including large West Coast surpluses, low gas prices, rising BPA costs and market deregulation. Moorman, Evans, E-BPA-09, at 12. Such competition, primarily from IOUs, their affiliates and marketers, has resulted in significant load loss from BPA's requirements and direct-service industry customers. Hill, *et al.*, E-BPA-51, at 3; *see generally* Norman, Oliver, WP-96-E-BPA-10. This competition has been flavored by BPA's limited ability to respond with terms and conditions that match the competition. Some competitors have made open-ended offers to BPA customers with prices that will beat BPA's requirements rate, whatever that rate turns out to be. Norman, Oliver, E-BPA-10, at 10. Customers have stated that if BPA cannot begin to offer unique products and services as needed to compete head-to-head with other sellers, including the IOUs, it places its customer base at risk. Saven, E-NI-02, at 6-7.

FPS-96 is a market-based rate intended to provide BPA sufficient rate flexibility to respond to market needs either on a contractual basis or in the spot market. Dinsmore, *et al.*, WP-96-E-BPA-21, at 4. It allows for both short- and long-term sales of varying types of firm energy and capacity products and at various load factors. *Id*. A diversity of products, sold with a diverse set of terms and conditions such as contract duration, will help support BPA's revenues in a competitive market. *Id*. As long as BPA must offer its requirements service at a fixed, published rate, BPA's competitors know exactly what price they have to beat to make an attractive offer. Hill, *et al.*, E-BPA-51, at 7. In the event BPA cannot retain a customer under its fixed rate schedules, BPA must be allowed the flexibility to staunch its losses. BPA seeks maximum flexibility in its FPS-96 rate schedule to keep lost sales and lost revenues to a minimum. Hill, *et al.*, E-BPA-51, at 7.

The IOUs argue that BPA should not seek approval for the proposed FPS-96 schedule without adopting safeguards sufficient to protect the agency's cost-recovery and revenue adequacy. IOU Brief, B-GE/PL/PS-02, at 19. In testimony they specifically recommend that the total sales under the FPS schedule should be subject to a cap of 575 average megawatts of energy (including BPA's existing surplus firm sales) and 1,350 megawatts of capacity (including existing sales). Brattebo, *et al*, WP-96-E-GE/PL/PS-03, at 16-17. In addition, the IOUs imply in their initial brief that each of the conditions required by FERC prior to its approval of past long-term rates proposed by BPA should be included in the schedule. In their brief on exceptions the IOUs state that they do not contend that each and every safeguard applied in the past must be applied to the FPS schedule. IOU Ex. Brief, R-GE/PL/PS-02, 10. They state that only "some combination" of these safeguards are needed. *Id*. at 11. Nevertheless, because BPA believes none of the limitations are appropriate to include in the schedule, each one raised by the IOUs is addressed here, or in other issues addressed in this section 11.7.

The IOUs go to great lengths in their initial brief to compare the FPS-96 schedule with prior long-term rates proposed by BPA and reviewed by FERC. They assert that BPA's proposed FPS schedule does not meet the standards set by FERC for approval of BPA's long-term rates. IOU Brief, B-GE/PL/PS-02, at 12. They state that there were several "key features common to those rates" that have been approved. *Id*. These included caps on the quantity of power available for sale under the rate, automatic adjustment clauses, and floors and ceilings. They argue that because the FPS-96 schedule does not contain these same key features, that it is not sufficiently structured and lacks the safeguards required by FERC. *Id*. Additionally, the IOUs argue that the FPS-96 schedule is defective in that it lacks a specified costing methodology. *Id*. at 10.

The IOUs' argument that the FPS schedule must contain these safeguards is supported chiefly by their heavy reliance on FERC's treatment of BPA's long-term schedules during the late 1980's, and for that reason is unpersuasive. Since that time, the intensity of competition has increased enormously, as the industry evolves toward a less regulated generation sector and comparable transmission access. Dinsmore, *et al*., E-BPA-21, at 5; *see generally* Moorman, Evans, E-BPA-09; Norman, Oliver, E-BPA-10. Passage of the Energy Policy Act and subsequent rulemakings have increased the risk of doing business for everyone concerned. Hill, *et al*., E-BPA-51, 7. At the same time, BPA's costs have increased, due in large part to a loss of resources from additional nonpower constraints. Dinsmore, *et al*., E-BPA-21, at 5-6. With its loads and revenues no longer secure, BPA must have the flexibility that FPS provides in order to compete successfully to retain load and sustain its revenue base. The market-based FPS rate schedule is designed to reduce BPA's overall revenue risk by diversifying it. Dinsmore, *et al*., E-BPA-21, at 8. Wholesale utilities cannot simply design schedules that lack substantial flexibility, or that set their rate at fully allocated costs and expect to retain their customers. Hill, *et al*., E-BPA-51, at 13-14. Any comparisons with FERC's treatment of past long-term rates must be made in light of this new competitive environment.

The IOUs note that the FPS-96 schedule has no floors or ceilings, and state that the SL-87 rate was not initially approved by FERC because it contained an inadequate description of a floor and ceiling. Brattebo *et al*., WP-96-E-GE/PL/PS-03, at 7, 13; Brattebo, WP-96-E-PL-04, at 3. Under SL-87 the floor, which could not fall below BPA's priority firm (PF) or preference rate, was designed to assure that BPA would not sell its power under this schedule below the fully allocated cost of preference power. Hill, *et al*., E-BPA-51, at 15. The ceiling, which was the fully allocated cost of BPA's highest cost resource, was designed to assure that BPA would not extract excessive profits from an inefficient market. *Id*. Other than making this comparison to past treatment by FERC and noting that FERC required the floor to help safeguard revenue recovery, the IOUs present no evidence for why a floor or ceiling remains an appropriate part of a rate schedule in a competitive power market. Today's competitive market provides the appropriate ceiling on FPS sales, so a rate ceiling was not included. Dinsmore, *et al.*, WP-96-E-BPA-21, at 3. Furthermore, a rate ceiling would be impracticable because if market prices rise, so could the cost to BPA of purchasing power to meet its contractual obligations to FPS customers. Hill, *et al.*, E-BPA-51, at 15. Regarding the floor, BPA's opportunity cost plus some small margin will be its floor, which will sometimes approach its variable cost, sometimes the value of the next best use of its resources, and sometimes the cost of purchased power. *Id.* Because the floor will vary significantly with each transaction, it would be meaningless and impractical to insert one in the rate schedule. *Id.* In addition, BPA has presented substantial evidence that its customers are receiving offers for firm power at or below BPA's proposed rates. *See generally* Norman, Oliver, E-BPA-10. Competitive pressures require BPA to have the downward flexibility to follow the market below any artificially imposed floor, where it would be prudent to do so. Upward flexibility allows BPA to offset, if possible, sales at less than fully allocated costs.

The IOUs note that there is no limit on the quantity of power available for sale under the FPS schedule. Brattebo, *et al*, E-GE/PL/PS-03, at 5. They argue that the FPS schedule should be subject to a cap of 575 average megawatts of energy (including BPA's existing surplus firm sales) and 1,350 megawatts of capacity (including existing sales). *Id.* at 16. As support they cite the fact that FERC has required BPA to limit the quantity of power available under past long-term rates in order to mitigate the down-side risk to BPA's ability to recover its costs. IOU Br., B-GE/PL/PS-02, at 12-15. The IOUs have provided no record support for the quantities they propose for the caps, other than to note that these were the caps under the modified SL-87 rate. Brattebo, WP-96-E-PL-04, at 3. The IOUs proposal is unreasonable, however, inasmuch as BPA's existing surplus firm sales presently exceed the proposed cap - thereby effectively capping FPS-96 sales at zero. Hill, *et al.*, E-BPA-51, at 10. The PPC stated in testimony that the caps proposed by the IOUs "may unduly and arbitrarily limit BPA's ability to make FPS sales." Carr, *et al.*, E-PP-08, at 3. BPA concurs with the PPC characterization, and believes it would be counterproductive to set any cap in the rate schedule. With a substantial proportion of BPA's firm sales at risk in the market, BPA may need to resell unforeseen amounts of surplus power under the FPS schedule. *Id.* Market forces affecting price and supply, and fish mitigation measures affecting BPA's load-resource balance, will dictate the opportunities and viability of additional sales under the FPS schedule. *Id.* Caps set in the schedule will decrease BPA's ability to take full advantage of market opportunities. *Id.*

The IOUs note that the FPS schedule contains no rate escalators, such as previously contained in BPA long-term rate proposals approved by FERC. IOU Br., B-GE/PL/PS-02, at 10. They cite several FERC opinions for the proposition that the inclusion of such rate escalators in BPA's long-term schedules is a necessary precondition to FERC approval. *Id.* at 12. They state in testimony that the SP-93 rate schedule, which the FPS-96 schedule would succeed, was subject to various automatic adjustments, including the interim rate adjustment (IRA). Brattebo, *et al.*, E-GE/PL/PS-03, at 5. SP-93 was subject to the IRA, but did not contain any other automatic rate adjustment clause. Hill, *et al.*, E-

BPA-51, 15. BPA, however, has proposed to eliminate the interim rate adjustment from all its rate schedules, not just the FPS-96 rate. Hill, *et al*., E-BPA-51, at 14. The IRA was designed to protect BPA from unforeseen cost increases that may occur in the middle of a rate period, and to enhance BPA's probability of meeting its repayment obligations. *Id*. BPA's proposed elimination of the IRA is engendered by the pressures of the competitive wholesale power market. BPA's customers desire rate stability and are finding competitors who will offer it. Moorman, Evans, WP-96-E-BPA-09, at 10-11. An IRA implies the possibility of unplanned rate increases within a rate period, damaging BPA's ability to compete; as such it is a risk mitigation strategy that will no longer meet BPA's needs and, in fact, runs counter to BPA's needs. Arnold *et al*., WP-96-E-BPA-15, at 4-5. A generic escalation clause in the schedule will only serve to weaken BPA's position to compete in the market and reduce its ability to recover costs and meet its repayment obligations. While BPA intends to negotiate escalators with prospective customers where appropriate, it would run counter to sound business principles to design the FPS schedule with escalators that may run counter to market demands. In a competitive market BPA needs the flexibility to design escalators on a case-by-case basis.

Other criteria for approval of BPA long-term rates used by FERC in the past and discussed in the opinions cited by the IOUs are addressed in this section 11.7 under the issue addressing the proposed 10-year term of the FPS schedule.

The IOUs state in their brief that BPA asserted at cross-examination that it retained "complete discretion" to make FPS offers to its preference and DSI customers, and that BPA could substitute sales of FPS power for sales of priority firm (PF) or industrial firm (IP) power. IOU Brief, B-GE/PL/PS-02, at 10. The IOUs conclude this will encourage load shedding by BPA's customers, *i.e*., reducing their load on BPA, and makes it likely that BPA will recover less than forecasted revenues. *Id*. First, the IOUs have mischaracterized the witnesses' testimony, and ignored testimony regarding BPA's intent. In fact, the witness responded to opposing counsel's assertion that BPA's intent was to seek "complete discretion":

> I hesitate at the word "complete," but yeah, we're trying to maintain discretion to make offers to these [preference] customers.

Tr. 830. BPA's witness later testified that

> I think there are certain things which prevent us from making FPS offers to public and IP [DSI] customers, that being any customer who requests or wants requirements service, we are obligated to provide it. We cannot offer FPS to a customer who wants requirement service.

Tr. 836. In fact, BPA has made clear its intent to displace PF sales to preference customers under the FPS schedule only when it will otherwise lose the load. Hill, *et al*., E-BPA-51, at 8. Often that load loss will be occasioned by the same IOUs that are now arguing for constraints on the FPS schedule. As is made clear in the FPS schedule, BPA is under no obligation to make power or energy available under the FPS schedule if such power or energy would displace sales under the PF, IP, NR or VI rate schedules. Rates Schedules, E-BPA-64, at 59. The retention of customers, however, is essential to keeping BPA's rates at the lowest possible levels and meeting its cost recovery and Treasury repayment obligations, and BPA will use the FPS schedule where it would otherwise lose sales, when such action is otherwise a good business deal for BPA.

Nor did BPA's witness testify that BPA retained "complete discretion" to make FPS offers to the DSIs. Rather, BPA's witness merely answered in the affirmative when asked by counsel if BPA reserved to itself the right to make offers to DSIs and to negotiate a price for those offers. Tr. 831. The phrase "complete discretion" was not part of the question or the answer.

Second, the IOUs' argument that the FPS rate will encourage load shedding also has no merit. They argue in testimony that by announcing that it wants flexibility to offer lower prices to customers threatening to drop load from it, BPA has invited its customers to treat the PF and IP rate as a price lid while searching for a third-party offer in an effort to generate a BPA offer below the established rate. Brattebo,*et al*., E-GE/PL/PS-03, at 14. In fact, the PF and IP rates are a price lid on the market today, with or without the FPS schedule. Hill, *et al*., E-BPA-51, at 8. Those rates are the only fixed points in a very fluid market. *Id*. The IOUs suggest that while they and other marketers actively court BPA's sales with below-PF and IP offers, BPA should send out a resolute signal that it will not compete and that under no circumstances will it lower its prices below those rates. This approach poses a much greater threat of encouraging load shedding than an approach that allows BPA to meet market prices. *Id*.

The IOUs also note that the FPS schedule contains no costing methodology. IOU Brief, B-GE/PL/PS-02, at 10. They state in testimony that because BPA has not included in the schedule a methodology to determine whether sales are beneficial, BPA is essentially proposing a "Trust Me" approach to ratemaking. Brattebo,*et al*., E-GE/PL/PS-03, at 15. BPA has not proposed a generic costing methodology to be included in the schedule since no single methodology will work for all the various combinations of resources BPA may utilize for sales under the FPS schedule. Hill, *et al*., E-BPA-51, at 11. BPA's costs are probabilistic in nature because BPA has limited control over the use of its resources, and the market value and availability of those resources fluctuates considerably. *Id*. As a consequence, a costing methodology in the rate schedule would be either too vague to be meaningful or too restrictive to be useful in making competitive offers. *Id*. BPA has, however, outlined in detail the costing methodology that it will use to determine the viability of any transaction on a case-by-case basis. *Id*., Attachment G. Each transaction that is negotiated under the FPS-96 rate schedule, whatever the duration, will provide the structure and safeguards needed to provide BPA a reasonable assurance of overall cost recovery. Hill, *et al*., E-BPA-51, at 16

Nevertheless, the IOUs argue in their initial brief that the FPS schedule gives BPA so much discretion as to what rate it will actually charge any particular customer that FERC will not be able to evaluate whether BPA's power rates meet the requirements of section 7(a)(2) of the Northwest Power Act. IOU Brief, B-GE/PL/PS-02, at 16; 16 U.S.C. § 839e(a)(2). They argue that the Commission must reject rates where the record provides insufficient information to evaluate the long-term effect of a rate schedule on BPA's overall revenues. IOU Brief, B-GE/PL/PS-02, 16. However, FERC review of BPA's rates focuses on the overall cost/revenue relationship of BPA's rate schedules in the aggregate, rather than solely on the merits of each individual rate schedule. *United States Department of Energy - Bonneville Power Administration*, 36 FERC ¶61,350, at 61,849 (1986). The FPS rate is a marketing tool that BPA must have if it is to position itself to assure cost recovery. The IOUs also state that BPA's witness on cross examination suggested that FPS sales would not be made at a level that would fully recover costs, but this conclusion is not supported by the cited text. IOU Brief, B-GE/PL/PS-02, at 16-17 (citing Tr. 838, lines 2-7). The cited portion of the transcript states:

> Q. Thank you. Now, in fact then, isn't it true that there's no way to know today how much power will be sold in the upcoming five-year rate period under the PF and IP rates as compared to power sold under different rates using the FPS schedule?
>
> A. That's fair to say at this moment.

How this exchange can be viewed to be a suggestion by the witness that BPA did not expect to fully recover costs under the FPS schedule is not apparent. BPA does expect to recover its costs associated with the FPS schedule, and has so stated in testimony. Dinsmore, *et al.*, E-BPA-21, at 14; Hill, *et al.*, E-BPA-51, at 6-7. Moreover, BPA has presented substantial evidence indicating that BPA faces the prospect of significant loss of sales as customers seek to further diversify their resource portfolio. *See generally* Moorman, Evans, E-BPA-09, and E-BPA-65; Norman, Oliver, E-BPA-10. In light of the clear competitive pressures it faces, the risk of revenue underrecovery is greater without the FPS schedule than with it. Buchanan, *et al.*, WP-96-E-BPA-11, at 13; Saven, WP-96-E-NI-02, at 14-15. Additionally, while the Administrator's discretion to enter into contracts to sell power under the FPS schedule is substantial, including making purchases to support such sales, it is not completely without limits. Most importantly, the Administrator must act consistent with sound business principles. In a competitive market, BPA's customers have indicated in their testimony they will not respond to either above-market prices or suppliers offering inflexible rate terms and conditions. *See e.g.*, Beck, *et al.*, E-WA-11, at 26; Wagner, *et al.*, E-FM-02, at 9; Saven, E-NI-02, at 6. This fact in and of itself is strong evidence for the proposition that the flexible FPS schedule is required for BPA to compete to retain sales and revenues. In sum, the record contains evidence sufficient for FERC to conclude that BPA's rate schedules in the aggregate, including the FPS-96 schedule, meet the requirements of section 7(a)(2) of the Northwest Power Act.

BPA is not unmindful that the use of the flexible FPS schedule presents issues of cost recovery, as the IOUs have gone to great lengths pointing out. The IOUs' testimony, however, nowhere acknowledges the impact of a deregulated, fiercely competitive market on BPA's ability to recover its costs and meet its repayment obligations. BPA has stated that before entering into a transaction under the FPS-96 rate schedule it "would have to have a fairly high level of confidence that the transaction we were entering into would be a profitable one." Tr. 842. This is no different from the essential business criteria BPA currently applies to sales under the SP-93 schedule, which is also a market-based rate. The criteria for assessing that profitability would include BPA's costs, the market prices over the period and product availability. These limits are not built into the rate schedule but they have been articulated by BPA on the rate case record. *See e.g.*, Hill, *et al.*, E-BPA-51, Attachment G; Tr. 843, line 19 to 844, line 11.

Rapidly changing market conditions militate against including these criteria in the schedule itself. Limitations that are not subject to change during the rate period deny the Administrator the ability to effectively apply his business judgment to evolving market conditions, and thereby render the rate schedule inflexible and unresponsive to market conditions. It is this inflexibility that puts BPA's ability to recover costs at risk. Saven, E-NI-02; and Hill, *et al*., E-BPA-51, at 16.

BPA's witness on re-direct examination summarized why such flexibility is so important to BPA, and the manner in which BPA intended to use the schedule:

> Q. What is your opinion as to what Bonneville's competitive ability or position would be were it unable to offer flexibility inherent in the FPS rate schedule?
>
> A. Currently the prices in the market are pretty low and I think we would have a difficult time selling any surplus power we have at the contract rate under the FPS rate schedule. We need the flexible rate to sell power that is not sold under the requirement service or any of our other rate schedules.

Tr. 916.

The IOUs also argue that section 7(f) of the Northwest Power Act effectively caps the price for in-Region sales of firm power under FPS-96 at BPA's "fully embedded cost" of service. IOU Brief, B-GE/PL/PS-02, at 17. Section 7(f) states that

> Rates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be *based upon the cost* of the portions of Federal base system resources, purchases of power under section [5(c)] of this title and additional resources *which, in the determination of the Administrator, are applicable to such sales.*

16 U.S.C. § 839e(f) (emphasis added). The IOUs argue that BPA should modify the FPS schedule to comport with their view of the section 7(f) standard to the extent that FPS sales are made for customers for use within the Region. IOU Brief, B-GE/PL/PS-02, at 17. The IOUs state that this cap on the Administrator's discretion is based on the "plain

language" of section 7(f). The provision, however, clearly gives the Administrator ample discretion in its application, and BPA has never interpreted section 7(f) in a manner that required the agency to calculate a cap for any sales based on BPA's fully embedded cost. For example, BPA established and FERC approved the SP-93 rate schedule, which permitted BPA to price sales above its fully embedded costs. The IOUs' argument, if accepted, would also frustrate BPA's ability to recover its costs under the FPS schedule, an issue on which the IOUs have expressed great concern.

The Northwest Power Act, however, grants the Administrator discretion in the design of rates. This broad discretion is found in section 7(e) of the Act, 16 U.S.C. § 839e(e), which provides:

> Nothing in this Act prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

The legislative history of the Act confirms the Administrator's discretion. H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 1, at 69 (1980); H.R. Rep. No. 976, 96th Cong., 2nd Sess., pt. 2, at 53, *reprinted in* 1980 U.S. Code Cong. & Admin. News 6023, 6051. The Ninth Circuit has recognized this authority, finding that "the statute does not require BPA to impose any particular type of rate on its customers. Rather it restricts BPA only to 'sound business principles' in setting rates to meet its revenue requirements." *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987). Thus, the Administrator's primary rate setting authority and obligation is to set rates to meet BPA's revenue requirements, consistent with sound business principles. *See* 16 U.S.C. § 839e (a)(1).

Section 7(f) does not curtail that authority, and does not require that Regional sales of surplus firm power must be capped at BPA's fully embedded cost. Rather, the provision requires the Administrator to price such sales "based upon" the cost of the resources which in his determination are applicable to such sales. Language in other BPA rate directives similar to that in section 7(f) have been held not to limit the Administrator's broad discretion to set rates. In *Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D. Or. 1980), plaintiffs contended that section 7 of the Bonneville Project Act, which requires in part that rates shall be set "having regard to the recovery of the cost of producing" the power sold, and be "based upon an allocation of costs," imposed a cost of service standard for BPA's nonfirm energy rate. 16 U.S.C. § 832f. The court rejected this claim:

> Despite all the references to cost, the two quoted passages do not support an inference that cost is the <u>only</u> basis upon which rates may be computed. The qualifying phrases "having regard to," "may include," and "to the maximum extent practicable," indicate that the discretion granted in 16 U.S.C. §§ 825s, 832e, 838g . . . were not significantly altered by the requirement to <u>consider</u> costs in calculating rates.

Id. at 683 (emphasis in original).

The Administrator is granted similar discretion in designing rates by the language of section 7(f), which requires only that rates for such power be "based upon" the costs of the resources that "in the determination of the Administrator" are used to service the sale. BPA has never interpreted the "based upon" language in section 7(f) to require that the price be capped at BPA's fully embedded cost, in part because BPA's fully embedded cost for any given sale is not susceptible to rote calculation, and in part because the amount of recovery is dictated by market conditions. In some cases, market conditions will permit BPA to recover only a portion of its fully embedded costs. Nevertheless, that recovery absolves BPA's other customers from having to shoulder those fixed costs. Capping sales at BPA's fully allocated cost would deny BPA potential opportunities to offset market-dictated below cost sales with above market sales. The IOUs interpretation therefore works to frustrate the Administrator's section 7(a) cost recovery obligations, and conflict with BPA's obligations to establish rates consistent with sound business principles. 16 U.S.C. § 839e (a)(1).

NIU views the IOUs' positions regarding the FPS schedule as a "thinly disguised" effort to gain a near term competitive advantage over BPA in the wholesale power markets. Saven, WP-96-E-NI-02, at 1. NIU presents evidence demonstrating that the IOUs are beleaguering BPA for its intentions to market surplus firm power in ways the IOUs themselves are using to raid BPA's customer base and protect their own. *Id*. at 8-9. Indeed, FERC has recognized pricing flexibility should improve competition:

> A competitive market simply cannot function unless the participants can make their own pricing decisions and put them into practice to take advantage of fast changing market conditions. At times, a seller needs the flexibility to reduce prices quickly to make or retain a sale, even though its profits may be small. At times when demand is high, prices need to be raised quickly to allocate scarce resources to those customers who value them the most. Without competitive pricing flexibility, competitive markets cannot function efficiently.

<u>Pacific Gas and Electric Company</u>, 38 FERC ¶ 61,242, at 61,790 (1987).

Counsel for Pacificorp in oral argument maintained that the IOUs object to FPS-96 as concerned customers, and not competitors of BPA. Or. Tr. 2475. The relevant fact remains, however, that limiting BPA's flexibility to design products which meet the competition hurts BPA and BPA's customers, in particular its public agency customers. *See e.g*., Wagner, *et al*., WP-96-E-FM-02, at 9; NIU Brief, WP-96-B-NI-01; Or. Tr. 2425. For example, BPA's public and cooperative utility customers are under tremendous pressure from their retail industrial customers to tailor services, unbundle products and reduce rates. Hill, *et al*., E-BPA-51, at 5. They are looking to BPA for assistance in tailoring products for their industrial customers, at a competitive wholesale price *Id*. The FPS-96 schedule is a key tool to enabling not only BPA, but also its customers, to retain sales.

Decision

The structure and limitations proposed by the IOUs are inappropriate in a competitive wholesale power market, and would increase, not decrease, the risk that BPA will be unable to recover its costs and meet its Treasury repayment obligations.

11.7.2 10-Year Term

Issue

Whether BPA's proposed FPS-96 rate schedule should have a 10-year term.

Parties' Positions

The investor-owned utilities (IOUs) argue that the proposed FPS schedule does not meet the standards set by FERC for approval of BPA's long-term rates. IOU Brief, WP-96-B-GE/PL/PS-02, at 12. They argue FERC requires that BPA's long-term rates over 5 years in duration should be limited, structured and supported by sufficient and reliable cost information. Brattebo, *et al.*, WP-96-E-GE/PL/PS-03, at 5; IOU Pr. Brief., WP-96-P-GE/PL/PS-02, at 4. They contend that the FPS-96 rate schedule does not meet this criteria, and note that the proposed schedule does not provide for any further section 7(i) or FERC review of rates negotiated under the schedule. *Id*. at 7. As a consequence of these alleged deficiencies they recommend that sales under FPS-96 be limited to five years. *Id*. at 16. By way of comparison the IOUs' testimony includes examples of longer term BPA rates that FERC has both approved and disapproved, and note that FERC approved such rates only where BPA demonstrated that the risk of underrecovery of its revenue requirement was minimal. *Id*. at 9. The IOUs contend there is substantial risk that revenues over the 10-year rate period would not recover the costs of firm power products and services sold, and that BPA would seek to recoup such an underrecovery in part from the IOUs. Brattebo, *et al*., E-GE/PL/PS-03, at 3.

PPC testifies that a 5-year limitation would unnecessarily restrict BPA's discretion in applying the FPS-96 rate. Carr, *et al*., WP-96-E-PP-08, at 4; PPC Br., WP-96/TR-96-P-PP-01, at 6. They note that BPA has financial obligations that extend past 2001, and argue that if BPA has sales contracts in place that recover some of these costs, BPA and its customers will face less uncertainty. Carr, *et al*., E-PP-08, at 4. PPC also testified that one of the principal concerns of BPA's customers is rate stability over time. Eldridge, *et al*., WP-96-E-PP-01, at 7. They state that BPA's competition is proposing long-term rates at competitive prices and that BPA's customers are "finding these proposals attractive." *Id*.

NIU argues that there is a market for 10-year surplus sales. Saven, WP-96-E-NI-02, at 14. They state that the IOUs are currently making proposals to some of BPA's wholesale customers for 10-year or longer sales. *Id*. NIU rejects the IOUs' argument that the 10-year term increases the risk of underrecovery. They state the greater risk of underrecovery is that BPA will not have the competitive mechanisms to respond to its marketplace competitors, and that BPA's proposed net economic benefit analysis of any 10-year sale will adequately protect against the risk of underrecovery. *Id*. at 14-15.

BPA's Position

The proposed 10-year term for the FPS-96 schedule is intended to provide BPA sufficient flexibility to meet the portion of the market that seeks longer-term rate stability. Dinsmore, *et al*., WP-96-E-BPA-21, at 4. While BPA believes that the majority of FPS-96 sales will be at terms less than 10 years, BPA must be able to offer a longer term product to compete with the offers being made to its customers by its competitors. *Id*. at 13. If BPA is not able to compete, it will lose loads to competitors at longer-term firm power prices and have to resort to less valuable shorter-term firm and nonfirm sales, thus reducing BPA's ability to recover revenue. Buchanan, *et al*., WP-96-E-BPA-11, at 13. Furthermore, each transaction that is negotiated under the FPS-96 rate schedule, whatever the duration, will provide the structure and safeguards needed to provide BPA a reasonable assurance of overall cost recovery. Hill, *et al*., WP-96-E-BPA-51, at 16. Re-opening any rate negotiated under the FPS-96 schedule for additional 7(i) or FERC review is unnecessary. *Id*. FERC has approved other BPA long-term market-based rate schedules that allowed flexible rates that could not be ascertained until particular contracts were executed, and which did not require further rate proceedings or FERC review. *Id*. at 12. However, the restrictions that FERC required be built into the rate in exchange for approval of a term longer than 5-years, to better ensure cost recovery, made the rate unattractive to potential customers. *Id*.

Evaluation of Positions

The IOUs' argument that the 10-year term of FPS-96 schedule means it must have attributes similar to those required by FERC in the past is misplaced. The IOUs cite to the 20-year capacity sale to Pacificorp (PL-91) as support for their position that any BPA rate with a term of greater than 5 years must contain features similar to those in that rate. Brattebo, *et al*., E-GE/PL/PS-03, at 9. But the PL-91 rate was first negotiated and then later subjected to a section 7(i) proceeding and FERC review, so that negotiations over the rate were not checked by the kind of fixed constraints the IOUs propose for the more generic FPS-96 schedule. Hill, *et al*., E-BPA-51, at 13. The IOUs likewise point to the conditions FERC placed on BPA's 20-year SL-87 rate schedule as a model against which the FPS-96 rate should be judged. Brattebo, *et al*., E-GE/PL/PS-03, at 12-13. They note that SL-87 was approved only after modifications, including: 1) a floor and a ceiling; 2) a penalty on purchasers for early termination; 3) a limit on sales to within the Pacific Northwest Region; 4) caps on the amounts of energy and capacity to be sold under the rate; and 5) a minimum escalation factor. Brattebo, WP-96-E-PL-04, at 3. Indeed, FERC did require that the SL-87 rate be modified to better satisfy its concerns regarding cost recovery, in exchange for a waiver of FERC's regulations which limit approval of BPA's rates to a maximum of 5 years, absent good cause shown. *See United States Department of Energy - Bonneville Power Administration*, 45 FERC ¶ 61,358 (1988); 18 C.F.R. §

300.1(b)(6) (1995). Nevertheless, market deregulation make comparisons between the proposed FPS-96 schedule and either the PL-91 or modified SL-87 schedules largely inapposite. Both PL-91 and SL-87 were cost-based rates, proposed during a period when the industry was highly regulated, when cost recovery was largely a matter of identifying costs and designing proper rates, and when FERC looked askance at utilities that sought rates based on something other than embedded costs. Hill, *et al*., E-BPA-51, at 13.

Comparing rate schedules proposed in today's competitive electricity industry to those reviewed by FERC prior to the initiation of deregulation is like comparing apples to oranges. The generation side of the industry is highly competitive, negotiated rates are becoming the norm, and access to transmission is available pursuant to comparable terms and conditions. *See* Moorman, Evans, WP-96-E-BPA-09; Norman, Oliver, WP-96-E-BPA-10; Buchanan, *et al*., E-BPA-11. Wholesale utilities cannot simply design schedules that lack substantial flexibility, or that set their rate at fully allocated costs and expect to retain their customers even where that utility has some of the lowest cost-based rates in the nation. Hill, *et al*., E-BPA-51, at 13-14. As NIU notes in its testimony, the IOUs' have made proposals to BPA's customers for terms of 10 or more years. Saven, E-NI-02, at 14; *see also* Norman, Oliver, E-BPA-10, Attachment B. The fact that BPA's customers, with the exception of the IOUs and Clark, unanimously support the proposed 10-year term in itself is evidence that there is a market for longer-term rates. Discussion at oral argument concerning BPA's competitive need to reform the section 7(i) process made clear that customers will not respond favorably to a schedule that significantly inhibits BPA's ability to put together rate deals that meet the specific needs of individual customers. Or. Tr. 2374, 2425. This, however, is the natural consequence of the IOUs' proposals to limit the FPS schedule, especially when other competitors are not likewise restricted.

No party argues that FERC may not waive the 5-year limitations set forth in sections 300.1 (b)(6) or 300.21 (e)(1) of FERC's regulations. 18 C.F.R. §§ 300.1 (b)(1); 300.21 (e)(1) (1995). As noted above, FERC has approved BPA rates for terms in excess of 5 years, and has specifically held that its decision to waive the 5-year regulation is a policy decision by the Commission, as opposed to any statutory limitation. *United States Department of Energy - Bonneville Power Administration*, 37 FERC ¶ 61, 345, at 62,041 (1986).

FERC has reviewed such requests by BPA in the past in light of its concerns that the total system revenues collected by BPA over the term of the proposed rate might not be adequate to meet annual expenses and to repay the Federal investment. *See, e.g., United States Department of Energy - Bonneville Power Administration*, 43 FERC ¶ 61,032 (1988) (SL-87 rate); 37 FERC ¶ 61,345 (1986) (FERC review of 20-year SC-86 rate to Southern California Edison.) While comparisons to past long-term proposals is a dubious undertaking, for the reasons noted above, the FPS-96 schedule meets the primary criteria articulated in the past by FERC, when such comparisons are made in light of the new competitive environment.

For example, FERC approved BPA's application for approval of the 20-year SC-86 rate because a number of elements were present. FERC noted that BPA's general rate filings for its other rates would continue to occur at intervals no less frequent than every 5 years, thereby allowing the Commission an opportunity to review BPA's rates in total to determine whether BPA was recovering its costs and repaying the Federal investment. 37 FERC ¶ 61,345, 62, 041. BPA's proposed Priority Firm Power (PF-96), Industrial Firm Power (IP-96), and New Resources Firm Power (NR-96) rates, which together constitute BPA's primary rates, are for maximum 5-year terms. Metcalf, *et al*., WP-96-E-BPA-74, at 2-3. BPA is not proposing any other rate that exceeds a 5-year term, other than the FPS-96 rate schedule. Furthermore, BPA will not displace sales under those schedule with an FPS sale unless it believes it would otherwise lose the sale altogether. Hill,*et al*., E-BPA-51, at 8.

The Commission also concluded that approval of the SC-86 rate allowed BPA to market surplus power at higher rates than it might otherwise receive, thereby enhancing its ability to meet its repayment obligations. 37 FERC ¶ 61,345, at 62, 041. The record in this proceeding contains substantial evidence that BPA is losing sales in the region as its customers seek to diversify their power contracts, including through contracts of a longer duration. *See* Moorman, Evans, E-BPA-09, and E-BPA-65; Norman, Oliver, WP-96-E-BPA-10, at 14-18; Lee, *et al*., WP-96-E-BPA-67; Beck, *et al*., WP-96-E-WA-13, at 10-11. Longer-term contracts benefit both BPA and its customers. Customers get an assured supply of power at an assured cost. BPA will benefit from firm power sales at higher prices than short-term sales. The 10-year option under the FPS-96 schedule will allow customers to diversify their resource contract mix via a longer-term sale from BPA; BPA will benefit from the retained sales and from having contracts with a greater diversity of termination dates, meaning a revenue stream that extends beyond 2001, when its other rates expire. Dinsmore, *et al*., E-BPA-21, at 13; Carr, *et al*., E-PP-08, at 4. The IOUs are concerned about the cost underrecovery implications of BPA making long-term sales under a schedule with as much flexibility as is provided in the FPS-96 schedule. Since the IOUs have contracts with BPA that are escalating according to BPA's costs, this concern is not unjustified. Tr. 877-78. But as NIU points out, it is BPA's full requirements customers that are most at risk from BPA's inability to recover its costs. Saven, E-NI-02, at 13.

Finally, FERC noted that SC-86 contained annual escalation factors. 37 FERC ¶ 61,345, at 62, 041. BPA intends to negotiate escalators where appropriate. While building generic escalators into rate schedules was logical when BPA enjoyed a distinct competitive advantage in price, that logic no longer holds in today's competitive market. Hill,*et al*., E-BPA-51, at 14. BPA needs the flexibility to design escalators on a case-by-case basis.

Decision

In order to accommodate a variety of transactions and enhance revenues, the FPS-96 rate schedule should have a 10-year term.

11.7.3 <u>Purchasing Strategy</u>

Issue

Whether BPA lacks the statutory authority to purchase power for the purpose of creating firm power for resale, and whether such a proposal is beyond its proper role as a Federal power marketing agency.

Parties' Positions

The investor-owned utilities (IOUs) object to BPA acquiring resources for the sole purpose of resale. IOU Brief, WP-96-B-GE/PL/PS-02, at 18. They contend that BPA may not enter into contracts for the sale of firm power without resources to back the sale, and that BPA may not purchase power unless it is needed for its section 4(h) or 5(b)-(d) obligations under the Northwest Power Act. *Id.* at 19; Northwest Power Act, 16 U.S.C. §§ 839b(h) and 839c(b)-(d). They argue that BPA's proposal to purchase for resale would unwisely allow BPA to "become a gambler on the power market" with Treasury funds. IOU Brief, B-GE/PL/PS-02, 11. In support of this position the IOUs argue that BPA's proper role as a federal power marketing agency is to dispose of federally-generated power, and not to commit to the purchase of future power beyond the amounts necessary to meet its statutory obligations. Brattebo, *et al.*, WP-96-E-GE/PL/PS-03, at 5, 15. The IOUs allege that the proposed FPS-96 schedule would permit BPA to subrogate its proper role to that of an "unfettered speculator on the market." *Id.* They recommend that BPA should not be permitted to make long-term sales based on future market speculation and to acquire resources for the purpose of creating a surplus under the FPS-96 schedule. *Id.* at 16-17; IOU Pr. Brief., WP-96-P-GE/PL/PS-02, at 5. Pacificorp separately notes that, absent limitations in the FPS-96 schedule, it opposes BPA entering into the purchase-for-resale market. Brattebo, WP-96-E-PL-04, at 5; Pacificorp Pr. Brief., WP-96-P-PL-01, at 21.

In their brief on exceptions, the IOUs argue that the Draft ROD's adoption of BPA's proposal to create a valuable firm product by supplementing existing surplus resources with purchases ignores market changes of recent years, as explained by counsel at oral argument. IOU Ex. Brief, WP-96-R-GE/PL/PS-02, at 9. They argue that these market conditions will permit BPA to advantageously sell its federal power, without the need to increase the value of that power through supplementary purchases. They reason that so long as there is vigorous competition to market packaged power between private power marketers, BPA's surplus will be a valuable commodity. *Id.* The IOUs conclude that because it is not necessary for BPA to purchase power to enhance the value of its existing surplus resources, that the only reason for doing so would be to purchase power for resale at a profit. *Id.* at 10. They assert this constitutes "mission creep" and that BPA has offered no explanation for why it should be permitted to purchase solely for resale. *Id* at 8, fn 5.

The Northwest Irrigation Utilities (NIU) reject the IOUs' argument that BPA's proposed use of the FPS-96 schedule would exceed its proper role. They argue that limitations on BPA's ability to acquire power for the purposes of firming its existing resources would preclude BPA from maximizing the value of its resources, and relegate BPA to the status of an auctioneer and not a competitor. Saven, WP-96-E-NI-02, at 5. NIU argues that restricting BPA's ability to participate in the purchase-for-resale market would be a "crushing blow" to BPA's prospects for becoming competitive and retaining its existing customer base *Id.* at 2. NIU concludes that the IOUs' recommendations will deny BPA the revenues it needs to remain competitive and meet its statutory obligations, including its Treasury repayment obligation. *Id.* at 5-6.

Full Meal Deal Utilities (FMD) state that the limitations proposed by the IOUs would hurt BPA's public agency customers and give an unfair advantage to BPA's competitors. Wagner, *et al.*, WP-96-E-FM-02, at 9. They echo NIU's argument that BPA needs the flexibility inherent in the FPS-96 schedule to help it retain its customers, and that the IOU recommendations would "artificially limit" that flexibility. *Id.* at 12. The Public Power Council (PPC) states that the FPS-96 schedule does not confer undue flexibility upon BPA. Carr, *et al.*, WP-96-E-PP-08, at 3.

BPA's Position

BPA's proposal to purchase power to either supplement or firm-up existing Federal Base System resources to support short and long-term firm power sales under the FPS-96 schedule is within the Administrator's statutory authority, and is consistent with BPA's role as a federal power marketer and its statutory obligations. Hill, *et al.*, WP-96-E-BPA-51, at 6. The core of BPA's role as a federal power marketer include its statutory mandates to encourage the widest possible diversified use of electricity at the lowest possible cost consistent with sound business principles, and to recover its costs and meet its repayment obligations. *Id.* Deregulation of the electric utility industry and the concomitant evolution of intense competition in the West Coast power market present BPA with a new challenge in fulfilling this role. *See* Moorman, Evans, WP-96-E-BPA-09; Norman, Oliver, WP-96-E-BPA-10. In addition, BPA's resources are increasingly constrained by non-power requirements that reduce its ability to market firm power, even as BPA's need to compete for revenue in surplus markets increases. Dinsmore, *et al.*, WP-96-E-BPA-21, at 5.

By strategically purchasing power to supplement existing resources - including both purchasing to firm-up nonfirm resources, and purchasing where necessary to meet contractual obligations - BPA will be better able to market power during periods of high market demand, and will provide a better quality, *i.e.*, firmer, product to compete for that demand. *Id.* at 7. BPA believes this strategy will enable it to effectively compete to maximize its net revenues and better assure its ability to recover its costs, including meeting its repayment obligation to the Treasury. *Id.* at 8; Hill, *et al.*, E-BPA-51, at 6, 14; Moorman, Evans, E-BPA-09, at 30.

Contrary to the IOUs' assertion in their brief on exceptions, BPA has not ignored the market theories presented by counsel at oral argument. Counsel's theory, however, and the example used to illustrate the point of the theory, are fundamentally flawed. Although counsel's specific example at oral argument was not addressed in the Draft ROD, BPA did present extensive testimony, which was cited and reiterated in the Draft ROD, discussing the benefits of purchasing power to firm-up its nonfirm resources for sale under the FPS schedule. Notwithstanding the fact that counsel's argument was not presented or developed by the IOUs in their testimony or initial brief, it is addressed below.

Evaluation of Positions

The IOUs argue in testimony that BPA's proposal to purchase power to support firm power sales under the FPS-96 schedule is outside its proper role. Brattebo, *et al.*, E-GE/PL/PS-03, at 15. They contend that BPA will become a "gambler on the power market with Treasury funds" if permitted to enter the purchase-for-resale market. *Id.* They state that this is not appropriate, and that BPA is risking its ability to recover its costs and meet its repayment obligations in an attempt to make a "profit." *Id.* IOU counsel at oral argument argued that BPA's proposal to purchase for resale was not intended to enhance its ability to sell federal power, but to become more like a private sector power marketer. Or. Tr. 2480. Counsel described this as "mission creep." *Id.* The gist of their argument in testimony is that the acquisition of additional resources to support FPS firm power sales absent limitations in the schedule presents unacceptable risks of cost recovery and extends BPA's marketing activities beyond its proper role. Brattebo, *et al.*, E-GE/PL/PS-03, at 13-15. Additionally, the IOUs argue in their initial brief that the Administrator lacks the statutory authority to purchase power for resale in the manner contemplated to support sales under the FPS schedule. IOU Brief, B-GE/PL/PS-02, at 18.

Allegations that BPA seeks to make a "profit," that it intends to "gamble" with Treasury funds and become a "speculator" on the power market misconstrue the purpose of the FPS-96 schedule, and the manner in which BPA has stated it will implement the schedule. Hill, *et al.*, E-BPA-51, at 9-10; and E-BPA-51, Attachment G. The IOUs' position also fails to recognize the predicament BPA faces from the twin challenges of competition and a hydro-system increasingly constrained by non-power uses. Dinsmore, *et al.*, E-BPA-21, at 5. Passage of the Energy Policy Act in 1992 and the follow-on-rulemakings implementing that legislation have created intense competition in the wholesale electricity markets. Hill, *et al.*, E-BPA-51, 2; Moorman, Evans, E-BPA-09; Norman, Oliver, E-BPA-10. Parties representing every segment of BPA's customer base , including the IOUs, acknowledge this fact in their testimony. Brattebo, E-GE/PL/PS-03, at 2; *see also e.g.*, Schoenbeck, Bliven, WP-96-E-DS-01, at 3; Piper, WP-96-E-RC-05, at 2-3; Eldridge, *et al.*, WP-96-E-PP-01, at 1-3; Beck, *et al.*, WP-96 -E-WA-01, at 6-11; Carr, *et al.*, WP-96-E-PP/PA-03, at 4.

As a strictly wholesale marketer of electricity, BPA has been a focal point of this enhanced competition in the Pacific Northwest. Hill, *et al.*, E-BPA-51, at 3. Consequently, in order to retain existing load and capture new load where appropriate, BPA is under tremendous pressure to offer products, services and prices that are competitive in the market. Moorman, Evans, E-BPA-09, at 26. Failure to meet the competitive challenge will make it increasingly difficult for BPA to comply with its statutory mission, or role. BPA believes it can significantly enhance its ability to fulfill its role by mitigating the erosion of its firm resources. Hill, *et al*., E-BPA-51, at 6.

The Federal Columbia River Power System (FCRPS) serves multiple purposes, including recreation, navigation, irrigation, fisheries and wildlife, as well as electric power interests. Dinsmore, *et al*., E-BPA-21, at 6. These competing demands, in particular the effort to operate the river in a manner to mitigate the loss of anadromous fish stocks, have increasingly infringed on BPA's ability to market power. *Id*. The erosion of BPA's firm resources is due in general to the shifting of large amounts of water releases out of the fall and winter months, when BPA experiences its peak loads, into the spring months when BPA already has large amounts of surplus energy. Hill, *et al*., E-BPA-51, at 6. This means that BPA is required to store water in the winter when its loads are highest and release water in the spring and early summer when its loads are lowest, resulting in the loss of a significant portion of BPA's firm hydroelectric resources. Dinsmore, *et al*., E-BPA-21, at 6; Misley, *et al*., WP-96-E-BPA-13. As a consequence firm energy is lost or devalued into a nonfirm product. Hill, *et al*., E-BPA-51, at 6. By firming-up this nonfirm energy through purchases and marketing the resulting firm product by means such as the FPS-96 schedule, BPA will enhance its ability to meet its many statutory obligations, including its cost recovery and Treasury repayment obligations. *Id*.

Some of these purchases would be in support of firm power sales for non-requirements service, meaning sales of firm power that is surplus to the Administrator's obligations under section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). The IOUs object to BPA creating valuable firm surplus energy from less valuable nonfirm energy through purchases. Brattebo, *et al*., E-GE/PL/PS-03, 5, at 16. They argue that firm energy offered for sale under the FPS-96 rate schedule should be limited to surplus power available as a result of the four circumstances adopted by BPA in the 1993 rate proceeding. *Id*. at 6. These are when: 1) BPA's allocation under the Pacific Northwest Coordination Agreement (PNCA) planning process exceeds its planned firm load; 2) energy purchases are acquired too late to be included in the PNCA planning process and are excess to BPA's planned firm loads; 3) BPA's actual loads underrun its planned firm loads; and 4) firm power is purchased to cover future risks, which then dissipate. *Id*. BPA believes that limiting its marketing under the FPS-96 schedule to the existing definition of surplus power will deny it the ability to offer higher quality firm products and effectively prevent it from earning additional revenues. Hill, *et al*., E-BPA-51, at 9.

The IOUs assert that if BPA is permitted to use the FPS-96 schedule in this manner, that it could make long-term firm sales without sufficient resources to back up the sales and then speculate on the futures market to acquire the necessary resources. Brattebo, *et al*., E-GE/PL/PS-03, at 8. The IOUs' statements concerning BPA becoming a "gambler" with Treasury funds and an "unfettered speculator" in the market is a red-herring. The following colloquy from cross-examination of BPA's witnesses shows the IOUs' use of extreme examples as a means to attack the absence of specific purchasing criteria in the FPS-96 schedule and to imply that BPA will be operating outside the scope of its proper role.

> Q. Now, could you make this hypothetical sale, say, it's 2000 megawatts, starting five years from now ending ten years from now, and determine that you would acquire no resources to cover that 2000 megawatts for the first five years and anticipate just buying market power starting in the year the sale begins, under the rate schedule would that be permitted?
>
> A. If I understand your question correctly, no, we would not do that. That's not in line with the philosophy that we've expressed in our testimony, which is we approach these deals from a business standpoint. We look at the profitability of the transaction. We look at the market, the supply alternatives as we find them, whether they're physical or financial, and we base the decision to do the deal or not on the likelihood that the deal is going to be profitable. What you described would have a low likelihood of profitability.
>
> Q. <u>*The gist of my question was could you, not would you*</u>. Could the FPS schedule permit you to do that?
>
> A. I'd say the FPS may not address that, but the statutes that we operate under require us to operate pursuant to sound business principles so, therefore, we could not do that without violating the statute.
>
> *******
>
> Q. <u>*Is it fair to summarize what you've told me by saying that the FPS rate schedule would not prevent Bonneville from making an offer of 10,000 megawatts for ten years at ten mills*</u>, but that you believe the statutory obligations Bonneville has would prevent you?
>
> A. I believe that it would be very unprofitable to do that and that we would not do that.
>
> Q. Is that to say that you believe both the rate schedule and the law would permit you to do it?
>
> A. <u>*I don't think we would be operating under sound business principles to do such a thing, and whether the statute was there or not, we wouldn't do it, but it is there.*</u>

Tr. 843-46 (emphasis added).

Far from speculating or gambling in the power market, as made clear in this excerpt BPA intends to augment when necessary its current hydro and nuclear resource base with a prudent portfolio of purchases to support firm power sales under the FPS-96 schedule. Hill, *et al*., E-BPA-51, at 9. BPA well understands that this strategy is not risk-free. In general, however, the market will dictate the opportunities, the quantities, and the cost of any purchase made by BPA. *Id*. BPA generally will be purchasing when there is a high level of certainty that the energy will be sold later at a higher price. *Id*. BPA describes its criteria for acquiring additional resources to support FPS-96 firm power sales in its testimony. Hill, *et al*., E-BPA-51, Attachment G. BPA's purchasing policy includes employing hedging tools with the aim of diversifying and thus reducing BPA's risk. *Id*.; and E-BPA-51, Attachment D (BPA Interim Resource Strategy) at 4. Supporting sales with existing resources augmented by purchases, together with a prudent hedging strategy, has become industry practice in the competitive wholesale power market. Hill,*et al*., E-BPA-51, at 10, and E-BPA-51 Attachment E. As noted by NIU, the IOUs employ this strategy. Saven, E-NI-02, at 3-4. It is no secret that the IOUs have proposed and consummated a number of long-term, flexible power deals with BPA's public and direct-service industry customers akin to the type of deals BPA proposes to make under the FPS-96 schedule. Hill, *et al.*, E-BPA-51, at 3; Norman, Oliver, E-BPA-10. Unless BPA can develop product choices that meet the market it may lose its ability to remain the supplier of choice of its full requirements customer. Saven, E-NI-02, at 6. Failure to do so places BPA's customer base at risk. *Id*. at 7. BPA seeks maximum flexibility in its FPS-96 rate schedule to keep lost sales and lost revenues to a minimum. Hill,*et al*., E-BPA-51, at 7. Firming available non-firm energy with purchases, and purchasing for resale when necessary to meet contractual obligations, will enhance BPA's ability to achieve these goals.

In their brief on exceptions the IOUs allege that in today's more competitive market, BPA's surplus, including spill energy, will be priced "most advantageously" whether or not BPA packages its surplus with nonfederal options. IOU Ex. Brief, WP-96-R-GE/PL/PS-02, at 9. The implication is that BPA will get the same price for its surplus energy whether it does its own firming up or lets others do it instead. In a simplistic and confused example, which the IOUs also applied in cross examination and presented in oral arguments, they display a lack of understanding of the market risks that BPA is facing. *See* Tr. 884-889; Or. Tr. 2477-2480. They state that

> [s]imply put, if the market price for Bonneville spill combined with a nonfederal option is 30 mills and the price of the nonfederal option is 15 mills, then in a truly competitive market Bonneville should be able to demandclose to 15 mills for its spill energy from competing third-party marketers. Without purchasing the nonfederal option and reselling the package itself, Bonneville should extract the market value from its surplus in the new competitive market. (In the example given above, the market value of Bonneville's spill is close to 15 mills.)

IOU Ex. Brief, R-GE/PL/PS-02, at 9 (parenthetical in original).

The fact is the market for BPA's nonfirm energy is not 15 mills but ranges between zero and 15 mills depending on how much nonfirm energy BPA is forced to put on the market at any given time. Since BPA cannot predict when it will have nonfirm on the market or how much nonfirm it will have available, it cannot sell the energy except on the spot market. When nonfirm energy becomes available in large amounts, competitors and customers know it is coming, know that BPA can do very little about controlling it, and know that BPA's market clearing price will necessarily be extremely low. Tr. 887-88.

A marketer or IOU can use cheap BPA "spill energy" to periodically displace its more expensive resources or to replace them entirely in the spring. In looking at the viability of making a sale, a marketer or IOU will anticipate the presence of BPA nonfirm spill energy on the market and reduce its costs associated with making this deal accordingly. Tr. 889. In the IOUs' example, where the market price is fixed at 30 mills, the consumer does not benefit from these reduced costs through lower prices. The marketer or IOU instead increases its profits.

BPA, in the meantime, has sold its spill energy at some price between zero and 15 mills. As detailed above, the hydro system has multiple purposes and numerous nonpower constraints, and BPA's firm resources have been declining in recent years, due to a reshaping of the hydro system for fish purposes. As its firm resource declines, its surplus or spill energy is on the increase. To the extent that BPA must forego a firm annual sale at fully allocated cost and replace it with a nonfirm sale in the spring at extremely low market prices, BPA's financial stability is threatened.

If BPA can sustain its ability to sell firm power through making strategic purchases, it can reduce the amount of spill energy it puts on the market. In this way, it not only increases the value of the nonfirm energy that has been firmed up, but it enhances the value of the spill energy, which has been reduced in amount at any given point in time. By reducing the amount of spill energy on the market, BPA can sustain a higher price for those sales. Not only will BPA be able to maintain its market share by replacing its lost firm resources, and not only will BPA enhance the value of its remaining nonfirm energy, but by being able to compete with marketers and IOUs, it will lower market prices to consumers. Counsel for the IOUs claimed to welcome such competition at oral argument. Or. Tr. 2474.

The IOUs' proposal, however, evidences a desire to maintain the status quo. BPA today assumes the financial risk of selling its spill energy to IOUs and marketers, while they reap the benefits of the firmed up power, displacing the thermal generation they have already sold to others at higher prices. BPA today proposes joint ventures with these same utilities to combine their firm resources with BPA's nonfirm energy. Unfortunately, there is not a robust market for such products. Hill, *et al.*, E-BPA-51, at 17. IOUs have little desire to joint venture for a product they can acquire from the same source on the open market at a cheaper price.

BPA's FPS proposal is an attempt to enhance its revenue while reducing its overall risk in a competitive wholesale market that has already taken a large bite out of BPA's firm loads. Norman, Oliver, E-BPA-10; Hill, *et al*., E-BPA-51, at 17. It does so by giving BPA the flexibility it needs to provide customers with the products they want, and by increasing the market value of BPA's existing nonfirm energy resources. *Id*.

The entities who stand to benefit most from BPA being forced to market surplus power at nonfirm prices are the very IOUs who express concern over BPA's potential inability to recover costs. The IOUs' proposal would effectively eliminate the positive net benefits BPA can gain by making strategic purchases to firm up its surplus energy and creating a higher value product.

The IOUs also argue that the Administrator lacks the statutory authority to purchase power solely for resale. IOU Brief, B-GE/PL/PS-02, at 18; IOU Ex. Brief, R-GE/PL/PS-02, at 11. The IOUs contend that the Administrator is authorized to purchase power under section 6 of the Northwest Power Act only to meet BPA's contractual obligations to its section 5(b), (c), and (d) customers, and to assist in meeting BPA's fish and wildlife obligations under section 4(h). IOU Brief, B-GE/PL/PS-02, at 18; 16 U.S.C. § 839d(a)(2). They note that the Administrator is also authorized by the Pacific Northwest Federal Transmission System Act to purchase power on a short-term basis, but only to meet temporary deficiencies in electric power which the Administrator is obligated by existing contract to supply or to meet fish and wildlife obligations. *Id*. at 19; Transmission System Act, § 11(b)(6), 16 U.S.C. § 838i(b)(6). The IOUs reason that

> Because Bonneville may only sell power to its preference, residential exchange, or DSI customers pursuant to section 5(b)-(d) of the Northwest Power Act or power that is surplus to those obligations, Bonneville may not enter into contracts to sell power (other than pursuant to Section 5(b)-(d) of the [Northwest Power Act]) for which it lacks resources to support the sale. (Section 5(f) of the [Northwest Power Act], 16 USC § 839c(f), (1980).)

IOU Brief, B-GE/PL/PS-02, at 19. They conclude from this that BPA may not enter into contracts for the sale of firm power without resources to back the sale, and it may not purchase power unless needed for its Northwest Power Act section 4(h) or 5(b)-(d) obligations, meaning it may not purchase simply for resale to others. *Id*.

The IOUs misread the scope of the Administrator's authorities, and ignore the circumstances that make BPA's FPS purchasing strategy consistent with, and essential to, meeting BPA's other statutory mandates.

Faced with intense competition and the prospect of further loss of load, as amply evidenced in testimony cited above and elsewhere throughout this rate case record, BPA can enhance its ability to meet its statutory obligations by mitigating the erosion of its firm resources and competing for sales with marketable firm products. Hill, *et al*., E-BPA-51, at 6. The acquisition of power for the purpose of creating firm power for resale, where only less valuable nonfirm power existed before, is designed to enable BPA to execute that policy, and is well within the discretion vested in the Administrator by BPA's enabling statutes. This is not the same thing as "purchases by Bonneville to create unlimited surplus." IOU Ex. Brief, R-GE/PL/PS-02, at 11. As discussed above, it is not BPA's intent to purchase in order to create unlimited surpluses; BPA's intent is to, when necessary, purchase to create a more valuable firm surplus product, and to supplement existing surplus when that is required to meet contractual obligations. BPA's enabling statutes authorize the Administrator to execute this purchasing strategy.

The provisions delineating the Administrator's authority to purchase and sell power cited by the IOUs must be read *in pari materia* with the other provisions of the Northwest Power Act, and Bonneville's other three enabling statutes. *Utility Reform Project v. BPA*, 869 F.2d 437, 440 (9th Cir. 1989); *LADWAP v. BPA*, 759 F.2d 684, 695 (9th Cir. 1985). BPA is to act to assure the Pacific Northwest of an "adequate, efficient, economical and reliable power supply," to encourage the widest possible diversified use of electricity at the lowest possible cost consistent with sound business principles, and to recover its total system costs and meet its repayment obligations to the Treasury. Hill, *et al*., E-BPA-51, at 6; Bonneville Project Act, §§ 2(b), 6, 16 U.S.C. §§ 832a(b), 832e (1988); Flood Control Act of 1944, § 5, 16 U.S.C. § 825s (1988); Transmission System Act, § 9, 16 U.S.C. § 838g; Northwest Power Act, §§ 2(2), 7(a)(1), 16 U.S.C. §§ 839(2), 839e(a)(1) (1988). The Administrator must also use his authorities to fulfill BPA's fish and wildlife obligations. 16 U.S.C. § 839b(h)(10)(A).

The Administrator is also charged with implementing the Northwest Power Act in a sound and business-like manner, 16 U.S.C. § 839f(i)(3), and entering into those contracts he deems necessary, unless otherwise prohibited, 16 U.S.C. § 832a(f). Meeting these mandates requires BPA to conduct its affairs with a view toward market considerations. As outlined above, BPA is faced with a highly competitive market and a hydro-system increasingly constrained by non-power uses. Meeting the market requires flexibility in negotiating the term, prices and other provisions of power deals with the quality of firm products and services that the market is demanding. By strategically purchasing power to supplement existing resources BPA will be better able to market power during periods of high market demand, and will provide a better quality, that is, firmer product to compete for that demand. *Id*. at 7. BPA believes this strategy will enable it to effectively compete to maximize its net revenues and better assure its ability to recover its costs, including meeting its repayment obligation to the Treasury. *Id*. at 8; Hill, *et al*., E-BPA-51, at 6, 14; Moorman, Evans, E-BPA-09, at 30.

The IOUs in testimony argue that the only surplus power offered for sale under the FPS-96 schedule should be power which BPA has a pre-existing fixed obligation to acquire at a fixed price, and that BPA should not acquire resources for the purpose of creating a surplus under the FPS-96 schedule. Brattebo, *et al*., E-GE/PL/PS-03, at 16-17. In their brief the IOUs cite section 5(f) in combination with section 6(a)(2) of the Northwest Power Act for the proposition that BPA may not purchase power unless needed for its section 4(h) fish obligations or section 5(b)-(d) preference, exchange, and DSI contract obligations. IOU Brief, B-GE/PL/PS-02, at 18-19. This argument is incorrect. BPA is not prohibited from creating a surplus by purchasing power to firm-up existing nonfirm power, or purchasing firm power for resale, even where such purchases are in excess of that needed to serve its obligations under section 5 of the Northwest Power Act. Section 5(f) of the Northwest Power Act states that:

> The Administrator is authorized to sell, or otherwise dispose of, electric power, including power acquired pursuant to this and other Acts, that is surplus to his obligations incurred pursuant to [sections 5(b)-(d)] in accordance with this and other Acts applicable to the Administrator, including the Bonneville Project Act of 1937 (16 U.S.C. § 832, et seq.), the Federal Columbia River Transmission System Act (16 U.S.C. § 838, et seq.), and the Act of August 31, 1964 (Public Law 88-552) (16 U.S.C. §§ 837-837h).

16 U.S.C. § 839c(f).

Section 5(f) does not limit the sale of surplus power to a surplus created due to the circumstances cited by the IOUs. Brattebo, *et al*., E-GE/PL/PS-03, at 6. The provision states only that the Administrator is authorized to sell power that is surplus to his section 5 obligations. Nor is BPA prohibited from acquiring power that may be surplus to its section 5 obligations. Section 6(a)(2) of the Northwest Power Act authorizes BPA to acquire resources sufficient to meet its contractual obligations:

> In addition to acquiring electric power pursuant to section 5(c) [of the Northwest Power Act], or on a short-term basis pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act [16 U.S.C. 838i(b)(6)(i)], the Administrator shall acquire, in accordance with this section, sufficient resources-
>
> (A) to meet his contractual obligations that remain after taking into account planned savings from measures provided for in paragraph (1) of this subsection, and
>
> (B) to assist in meeting the requirements of section 839b(h) [fish and wildlife obligations] of this title.

16 U.S.C. § 839d(a)(2).

Contrary to the IOUs' position, nothing in either provision, or in any other provision of BPA's enabling statutes prohibits BPA from entering into a contract for sale in anticipation of purchasing power to meet the contract. The IOUs reason that BPA can purchase resources only to serve section 5 contracts, and therefore cannot enter into any contract for which is has no existing resources - the logic being that there is no authorization for the Administrator to purchase to serve the load. Acquisitions, however, under section 6(a)(2) are not limited to those required for BPA to meet its contractual obligations to its section 5 customers alone, as argued by the IOUs in their brief. Taken together, section 5(f) authorizes BPA to enter into contracts with both requirements and non-requirements customers for the sale of surplus power not needed to meet his obligations under section 5(b), (c) and (d), and section 6(a)(2) authorizes BPA to acquire power to serve those contracts.

In any case, as detailed throughout this case, BPA must have the flexibility to compete if it is to recover its cost. These costs include BPA's imposing fish and wildlife obligations. Absent such marketing tools as the FPS schedule, BPA might not be able to sustain those costs. Resource acquisitions to support FPS sales to generate funds available for fish and wildlife mitigation efforts are sanctioned by Northwest Power Act section 6(a)(2)(B), quoted above. Therefore, the IOUs' argument that BPA may not purchase power for resale to non-section 5(b), (c) and (d) customers is incorrect. To the contrary, firming existing BPA resources through a purchase and resale strategy is an effective way for BPA to enhance the value of its existing power products and compete in a very competitive market, and does not constitute "mission creep" as suggested by the IOUs. Tr. 2480. It is also consistent with the latitude given the Administrator by Congress to meet his statutory cost recovery mandates.

This strategy is consistent with the requirement that the Administrator establish the lowest possible rates to consumers consistent with sound business principles, while recovering its total system costs and meeting its Treasury repayment obligations. 16 U.S.C. § 838g; 16 U.S.C. 839e(a)(1). The Ninth Circuit has acknowledged that the history of BPA's enabling legislation demonstrates that Congress has repeatedly required BPA to operate in a manner that assures the agency is fiscally self-supporting. *Department of Water and Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 693 (9th Cir. 1985) (LADWP). While there may be other strategies the agency could implement to meet its statutory obligations, the court in *LADWP* noted that to the extent the policy at issue in that case was designed to mitigate projected revenue deficits, the policy was not only statutorily authorized but statutorily mandated. *Id; see also California Energy Resources v. BPA*, 754 F.2d 1470(9th Cir 1985)(citing prospect of severe shortfall in revenues and deferral of Treasury repayment in affirming agency action).

Decision

BPA's proposal to purchase power for the purpose of creating firm power for resale is consistent with the Administrator's statutory authorities, including in particular the Administrator's cost recovery responsibilities.

11.7.4 Product Descriptions

Issue

Whether BPA's FPS-96 rate schedule sufficiently describes the firm power products and services BPA intends to offer under the schedule.

Parties' Positions

The investor-owned utilities (IOUs) argue that BPA is planning to use the FPS-96 rate schedule to sell products that it has not yet identified. IOU Brief, WP-96-B-GE/PL/PS-02, at 9 fn 13. They argue that FERC will not review a BPA rate for an unidentified product, and that BPA should not seek approval of the FPS schedule for products other than those identified in the proposed Wholesale Power and Transmission Rate Schedules. *Id*.

BPA's Position

The FPS-96 rate schedule describes four categories of service consisting of: 1) Firm Power; 2) Supplemental Control Area Services; 3) Shaping Services; and 4) Reservation and Rights to Change Services. Wholesale Power and Transmission Rate Schedules, WP-96-E-BPA-64, at 59 (Rate Schedules). Each of these categories is defined more specifically in the General Rate Schedule Provisions for Power and Transmission Rates (GRSPs). *Id*. at 137, *et seq*. These unbundled products and services describe how power may be reserved in advance, requested and delivered. Dinsmore,*et al*., WP-96-E-BPA-21, at 9. The FPS-96 rate schedule is designed to be flexible enough so that if a customer wants a product that is not specifically named in the rate schedule or defined in the GRSPs, but the product fits under a category listed in the rate schedule, BPA may sell the product under the FPS-96 schedule. *Id.* at 10.

Evaluation of Positions

BPA has identified categories of power products, and in some cases specific products, both in the rate schedule, GRSPs and its testimony. Rate Schedules, E-BPA-64, at 59; Dinsmore, *et al*., E-BPA-21, at 9-13; Hill, *et al*., WP-96-E-BPA-91, at 2-4. The IOUs' statement that BPA intends to negotiate prices for products not yet identified under the FPS schedule mischaracterizes BPA's testimony. IOU Brief, B-GE/PL/PS-02, at 9 fn 13. The testimony cited by the IOUs for this proposition states in full that:

> [T]he FPS-96 rate schedule is intended to be flexible enough so that if a customer wants a product that is not specifically named in the rate schedule or defined in the GRSPs, *but the product fits under a category listed in the rate schedule*, BPA may sell the product under the FPS-96 rate. BPA may also combine separate products under one or more categories of the FPS-96 rate, and may combine FPS products with products from other rate schedules.

Dinsmore, *et al*., E-BPA-21, at 9-10 (emphasis added). Therefore, while not each and every possible product for sale under the schedule is defined, any product that is not specifically defined must fit under one or more of the four categories described in the FPS schedule and the GRSPs. In fact, the FPS-96 schedule contains more definition that the SP-93 schedule, which it supersedes and under which BPA may sell any product it proposes to sell under FPS-96. Furthermore, defining every conceivable product that could be sold under the schedule is not feasible. BPA must be able to compete with the products and services that its customers demand, and which competitors can provide. Denying BPA the ability to sell a power product under the schedule merely because it is not specifically defined would adversely impact BPA's ability to compete for such sales.

Nor does FERC require such specificity. As noted, FERC approved the SP-93 rate schedule, which lacks even the product specificity contained in the FPS schedule. The FERC order cited by the IOUs does not support their position. In that order, the Commission recognized the distinction between BPA's authority to determine the products it markets and the manner in which it markets them, and the Commission's role to review rates. *United States Department of Energy - Bonneville Power Administration*, 53 FERC ¶ 61,193, at 61,668 (1990). The Commission did not conclude that any particular level of product specificity was required, but only that its role was limited to the review of rates established by BPA.

Decision

BPA's FPS-96 schedule sufficiently represents the proposed firm power products and services BPA may offer under this rate schedule.

11.7.5 Market Power

Issue

Whether BPA possesses generation market power.

Parties' Positions

The investor-owned utilities (IOUs) argue that BPA has not provided evidence in the form of market analyses that demonstrate a lack of generation market power in the relevant markets. IOU Brief, WP-96-B-GE/PL/PS-02, at 6. They argue that absent a demonstration that BPA lacks market power, there is no assurance that Bonneville lacks market dominance sufficient to impede competition over the rate period, if FERC were to approve the market-based FPS-96 rate schedule. *Id*. at 7. The IOUs allege that because BPA historically has "marketed about one-half of the electric energy used in the Northwest" and because BPA has "forecast a continuing generating surplus over its contractual commitments throughout the five-year rate period," and because "Bonneville anticipates additional load loss over the rate period," that there is reason to believe BPA has generation market power. *Id*. at 5-6. They state that BPA possesses market power, and conclude that it is impossible to ensure that BPA has mitigated its generation market power based on the evidence on the record. *Id*. at 7.

In their brief on exceptions, the IOUs assert that the Draft ROD incorrectly defined the relevant geographic market, because BPA's market share analysis combines the capacity of all first-tier markets, rather than comparing BPA's share with each first-tier utility as a separate relevant market. IOU Ex. Brief, WP-96-R-GE/PL/PS/-02, at 6. They assert that by combining markets in this manner BPA greatly understated its generation dominance in the relevant markets. *Id*.

The IOUs note their agreement to BPA's proposed PTP and NT transmission tariffs discussed in the Transmission Settlement Agreement. *Id*. at 5; Transmission Settlement Agreement, WP-96-E-BPA-129. They agree that these tariffs should be found to satisfy FERC's threshold requirement that a power marketer have transmission open access tariffs that provide comparable services. IOU Brief, B-GE/PL/PS-02, at 5.

Clark argues in its initial brief that BPA has not demonstrated mitigation of its market power. Clark Brief, WP-96-B-CP-01, at 27. It states that BPA has yet to fully implement comparable and open access tariffs, and that BPA "has taken specific steps to retain its market power." *Id*. Clark asserts that the "lack of structure or limits" in the FPS schedule raises the likelihood of substantial and sustained revenue underrecoveries. *Id*. Clark repeats each of these assertions in its brief on exceptions, without elaboration. Clark Ex. Brief, WP-96-R-CP-01, at 14-15.

The Public Generating Pool (PGP) argues that BPA has not provided sufficient evidence to conclude that it lacks generation market power, and proposes that the Administrator withdraw that conclusion from the Final Record of Decision. PGP Ex. Brief, WP/TC-96-R-PG-01, at 10. PGP asserts that BPA maintains a barrier to entry of competition "by the way it interprets the 1981 power sale contract." *Id*. at 11. It maintains that "[a]s long as BPA can interfere with the ability of the customer to accept [an] offer or impose a penalty or other fee that makes the offer uneconomic, there is no actual competition."*Id*. at 12. PGP argues that a "proper analysis" of market power must consider whether BPA's proposed rates are higher than market prices, and whether "the price differential is likely to attract sufficient entry such that BPA will not be able to sustain the price for the upcoming rate period." *Id*. at 13. PGP also argues that BPA has not presented any evidence to support the conclusion that it lacks transmission market power. *Id*. at 14.

<u>BPA's Position</u>

BPA does not agree that it can sustain market-based rates only upon a showing that it lacks or has mitigated any market power it may have. Nevertheless, the record in this case contains substantial evidence demonstrating that BPA does not possess generation market power, measured either by market share or by any of the other standards articulated by FERC. The relevant market for BPA's capacity sales is not the Pacific Northwest (PNW), as argued by the IOUs, but the Western System Coordinating Council (WSCC), and BPA has a fairly small market share in that market. Tr. 899.

BPA disagrees with the IOUs position that the Draft ROD improperly defines the relevant market for purposes of calculating BPA's market share of capacity. In light of the fact that BPA is proposing comparable transmission terms and conditions that should be found to conform to FERC's Stage One pro forma tariff, the "smallest reasonable relevant geographic market" is the WSCC, and not each individual first-tier utility. *Louisville Gas & Electric Company*, 62 FERC ¶ 16,016, at 61,145 (1993)(smallest reasonable relevant market standard). BPA can demonstrate, using documentation contained on the record, its lack of market power when measured against FERC's test of market share and other standards articulated by FERC.

BPA maintains it has placed ample evidence on the record to demonstrate the competitiveness of the firm power market in the West Coast market. Surplus capacity in the WSCC is between 13,000 and 16,000 MW currently, and by 2004 it is projected to still exceed 4,000 to 8,000 MW. Norman, Oliver, WP-96-E-BPA-10, at 2-3. Marketers, IOUs and power brokers up and down the West Coast are competing vigorously for BPA's requirements load. *Id*. at 5-9; Moorman, Evans, WP-96-E-BPA-09, 12-14. As a result, BPA already has suffered significant load loss and is vulnerable to losing still more. *See* Supplemental Loads and Resources Study, WP-96-E-BPA-57, at 13; Supplemental Loads and Resources Study Documentation, WP-96-E-BPA-57A, at 229.

In addition, BPA continues to lose firm energy and capacity resources, due to increasing non-power constraints. Dinsmore, *et al*., WP-96-E-BPA-21, at 6. The struggle to save anadromous fish has reshaped the release of water in a manner contrary to BPA's power needs. Such competing demands on the hydro system infringe on BPA's ability to market power, by turning firm energy into nonfirm "spill" energy and reducing BPA's flexibility to shape its resources to meet load. *Id*. at 6-7. A system with little flexibility to shape its energy sales to meet or make market opportunities cannot exercise market power easily, no matter how great its market share, and this is the situation currently facing BPA.

BPA also has filed transmission tariffs that offer comparable transmission services. Metcalf, WP-96-E-BPA-84. Such tariffs effectively eliminate any ability BPA otherwise may have had to exercise either transmission or generation market power.

Evaluation of Positions

The IOUs assert in their initial brief that owners of generating facilities who wish to apply market-based rates "must demonstrate either that they have no market power in generation or that the market power is adequately mitigated." IOU Brief, B-GE/PL/PS-02, at 5. They assert that FERC, in determining whether a utility has "generation dominance," examines both the utility's "market share of installed generation and uncommitted capacity in each of the first- and second-tier markets available to the marketer." *Id*. at 5-6. They allege that "the record does not contain any evidence that Bonneville has completed market analyses necessary to demonstrate a lack of generation market power in the relevant markets." *Id*. at 6. Finally, without providing any evidence of their own to support their contention, the IOUs define the "relevant market" as being contained entirely within the PNW, where they state BPA has a market share greater than 50%. *Id*. at 7; Tr. 899.

The IOUs' assertion that BPA can demonstrate it lacks generation market dominance only through a market share analysis of installed generation and uncommitted capacity is incorrect. FERC has held that, because its principal concern is whether customers have a genuine alternative to buying the seller's product, it does not rely on any single or mechanical market share analysis method to determine if a firm has market power, but rather will "consider the evidence as a whole." *Southwestern Public Service Company*, 72 FERC ¶ 61,207, at 61,966 fn 5 (1995), citing, *Public Service Company of Indiana*, 51 FERC ¶ 61,367, at 62,205 (1990). FERC defined the essence of its concern with market-based pricing when it described market power in this way:

> The other potential abuse [in addition to self-dealing] of pricing flexibility is the exercise of market power. Market power for a seller exists when the seller can significantly influence price in the market by withholding service and excluding competitors for a significant period of time. Competitors can thwart the exercise of market power if they have access to the market and can supply more of their own service quickly enough to provide customers with an alternative.

Citizens Power & Light Corporation, 48 FERC ¶ 61,210, at 61,777 (1989).

In 1992 the United States Department of Justice (DOJ) and the Federal Trade Commission issued Merger Guidelines that define market power as "the ability profitably to maintain prices above competitive levels for a significant period of time." 57 Fed. Reg. 41,552 (1992). FERC has sought guidance in DOJ's Merger Guidelines in developing its market power standards. *See Entergy Services, Inc.*, 58 FERC ¶ 61,234, at 61,758 fn 79 (1992) (citing the "leading firm standard" used by the DOJ in its 1984 Merger Guidelines). FERC has clarified the heart of the issue by stating that its "primary concern in a market power analysis is whether customers have genuine alternatives to buying the seller's product." *Louisville Gas and Electric Company*, 62 FERC ¶ 61,016, at 61,145 (1993). The record contains overwhelming evidence concerning the fiercely competitive market in which BPA must sell its products. *See generally* Moorman, Evans, WP-96-E-BPA-09, and E-BPA-65; Norman, Oliver, WP-96-E-BPA-10; Buchanan, *et al.*, WP-96-E-BPA-11; Hill, *et al.*, WP-96-E-BPA-51. BPA contends that it does not have the power to simultaneously restrict output, force prices to increase, keep competitors out of the market, and sustain those price increases. Tr. 884. The record is littered with evidence to support that contention. In any case, as demonstrated below, BPA does not possess a market share in the relevant market in excess of the threshold percentages established by FERC.

The IOUs' brief ignores the effects of competition on BPA's potential ability to exercise generation market power. BPA is facing intense competition for its traditional requirements load. In the years preceding this case the cost of BPA's energy has been rising, while the price of alternative energy supplies has been falling, and those alternatives are being made available to BPA's customers. Moorman, Evans, E-BPA-09, at 9. Deregulation and open access to transmission have greatly expanded competition in the utility industry. *Id.* at 12. BPA's competitors include not only utilities in the Pacific Northwest, but utilities in California, as well as new market entrants such as independent power producers (IPPs), power marketers, and power brokers. Norman, Oliver, E-BPA-10, at 5. New market entrants, low gas prices, and surplus supplies of short term capacity and energy in California and the Inland Southwest have led to steadily falling electricity prices. Moorman, Evans, E-BPA-09, at 12. Current surpluses in the WSCC exceed 13,000 MW, summer and winter, and they are projected to remain at levels at least half that great as far into the future as 2004. *Id.* at 24; Norman, Oliver, E-BPA-10, at 2-3. Projected new generation from IPPs exceeds 3,000 MW of new capacity. *Id.* at 12.

As further evidence of the intense competition for BPA's load, many of BPA's traditional customers have issued Requests for Proposals (RFP) in the last two years and received tremendous responses. Clark PUD issued a request for 250 MW in 1993 and received 31 proposals totaling 4,000 MW. *See* Norman, Oliver, E-BPA-11. Snohomish PUD requested 250 MW in 1994 and received 47 proposals for about 8,000 MW, including 6,500 MW of new combustion turbines. *Id.* at 15. Springfield Utility Board issued an RFP for 24 MW in 1995, and received 17 proposals totaling 1,100 MW. *Id.* In 1994, Power Resource Managers, representing five BPA customers, issued an RFP for 250-1000 MW and received 53 proposals, including 5,400 MW of new combustion turbines, cogeneration and wind projects. *Id.* The Washington Public Agency Group, which includes twenty BPA customers, received 14 bids totaling over 3,700 MW in response to an RFP requesting a 200 MW block of firm power. *Id.* at 16-17. With all this competition, it is virtually impossible that BPA could have the capability to exclude competition by withholding its products.

As this evidence suggests, the market is rich with alternative suppliers who are competing to displace BPA's resources from the market. Clearly, BPA's eligible customers are sophisticated buyers of bulk power, able to recognize and take advantage of their alternatives in the market for generation. FERC considers this fact in its evaluation of potential market power by the seller. *See* <u>Public Service Company of Indiana</u>, 51 FERC ¶ 61,367, at 62,209 (1990). Many customers have demonstrated the competitiveness of alternative suppliers by choosing to reduce their purchases from BPA. *See generally* Norman, Oliver, E-BPA-10; Hill, *et al.*, E-BPA-51; Moorman, Evans, WP-96-E-BPA-65.

Competition has created tremendous pressure for BPA to lower its rates in order to retain loads. Moorman, Evans, E-BPA-09, 10. In fact, the competition already has siphoned off a large amount of BPA's traditional wholesale requirements load. As a result of offers to its existing customers from competing suppliers, BPA has lost 150 aMW of load from long-time customers like Snohomish PUD, 200 aMW from Clark PUD, 13 aMW from the City of Canby, 50 aMW from Chelan PUD, 24 aMW from Springfield Utility Board, and 100 aMW from the Eugene Water and Electric Board. Norman, Oliver, E-BPA-10, at 7; Moorman, Evans, E-BPA-65, at 3. Since BPA's initial proposal, BPA also has lost over 700 aMW of load from the DSI's. *Id.* at 6. In addition, industrial customers of BPA's wholesale customers are threatening to buy from competitors or build their own generation. Hill, *et al.*, E-BPA-51, 4. All of this has occurred in spite of BPA's effort to retain customers by lowering its requirements rates. Competitors are known to have used BPA's rates as a "stalking horse," asserting that they will beat BPA's price, whatever it turns out to be. Norman, Oliver, E-BPA-10, at 10.

It is absurd for the IOUs to argue that BPA load loss is evidence that BPA has market power, because its market share of uncommitted capacity will be increasing. IOU Brief, B-GE/PL/PS-02, at 6 fn 10. In fact, BPA's sizable amount of lost load, in spite of substantial BPA price reductions, is evidence to the contrary. This result is evidence of the impossibility of BPA having the capability to exclude competition at all, let alone by raising its prices. Loss of requirements load in today's surplus West Coast markets and low prices courts serious financial losses, Moorman and Evans, WP-96-E-BPA-09, at 10, not a behavior normally associated with market power.

While competition from other power suppliers intensifies, BPA continues to lose control of the operation of its hydroelectric resources. BPA's hydroelectric system serves multiple purposes besides electric power interests, including recreation, navigation, irrigation, and fisheries and wildlife. Most notably, the struggle to save anadromous fish has reshaped the release of water in a manner contrary to BPA's power needs. Dinsmore, *et al*., E-BPA-21, 6. By requiring BPA to store water in the winter when its loads are highest and release water in the spring and early summer when its loads are lowest, BPA in effect has lost a significant portion of its firm hydroelectric resources. *Id*.; *see also* Misley, Davis, WP-96-E-BPA-13. BPA not only has lost firm energy and capacity resources, it also has lost the flexibility to shape its resources to serve its power needs, which has forced the bulk of its nonfirm energy sales almost exclusively from the economy market to the spill energy market. Dinsmore, *et al*., E-BPA-21, at 6-7. The result has been increased purchased power costs and lower sales prices in short term markets, to the detriment of BPA's overall financial health. *Id*. at 6; Moorman, Evans, E-BPA-09, at 11.

With a declining resource base, declining ability to shape its resources to meet its power needs, and a high ratio of fixed to variable costs, BPA is in no position to profitably manipulate prices or maneuver its product availability in order to exclude its healthier competitors. On the contrary, BPA has presented substantial evidence to support the proposition that BPA cannot raise prices above proposed rates without incurring additional sales and revenue losses. Moorman, Evans, E-BPA-65, at 11. Clearly, BPA does not have the ability "profitably to maintain prices above competitive levels for a significant period of time." Merger Guidelines, 57 Fed. Reg. 41,552.

All this evidence notwithstanding, the IOUs argue BPA has nothing on the record to show it lacks generation market power. They assert that BPA must demonstrate it does not have a significant share in the relevant capacity market. IOU Brief, B-GE/PL/PS-02, at 6. The IOUs object that BPA has included no analysis of BPA's market power in the various first-tier and second-tier markets, as required by FERC. IOU Brief, B-GE/PL/PS-02, at 7. The concept of first and second-tier markets is explained most recently in FERC's final rule titled *Promoting Wholesale Competition Through Open Access Non-discriminatory*

Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities:

> The Commission's practice is to define the relevant markets as those utilities directly interconnected to the applicant (first-tier markets). For each first-tier market, we consider all utilities interconnected to the first-tier utility and all utilities interconnected to the applicant as competitors in that relevant market. Thus, the competitors include the second-tier utilities directly interconnected to the relevant market and those other first-tier utilities that can reach the market by virtue of the applicant's open access transmission tariff.

61 Fed. Reg. 21,540, at 21,555 fn 145 (1996), FERC Stats & Regs. ¶ 31,036 (1996) (hereinafter Order 888); *see also Kansas City Power & Light Company*, 67 FERC ¶ 61,183, at 61,556 (1994); *Heartland Energy Services, Inc*., 68 FERC ¶ 61,223, at 62,061 (1994); *Louisville Gas and Electric Company*, 62 FERC ¶ 61,016, at 61,145 (1993); *Entergy Services Inc*., 58 FERC ¶ 61,234, at 61,757 (1992). While the IOUs have presented no evidence to demonstrate that BPA has generation market power, they do allege, without providing support, that the relevant market is the Pacific Northwest (PNW) and that BPA has over a 50% market share of total capacity in that market. IOU Brief, B-GE/PL/PS-02, at 6. BPA believes the relevant market is more closely identified with the Western System Coordinating Council (WSCC). Tr. 899. BPA is interconnected directly with most of the utilities in the WSCC, and to the extent that BPA does not have transmission market power, that defines the relevant market. *Compare Heartland Energy Services, Inc*., 68 FERC ¶ 61,223, at 62,061 (1994) (evaluating generation market power in light of open access transmission tariff). Historically, BPA has competed for wholesale power business in the large West Coast market, including the Inland Southwest, California, the Pacific Northwest and Canada. Hill, *et al*., E-BPA-51, Attachment C, at 6; and Attachment D, at 6; Norman, Oliver, E-BPA-10, 1; Marginal Cost Study, WP-96-E-BPA-60, at 2-3. The AC and DC interties between California and the PNW are capable of transmitting about 7,700 MW between these two regions. The interconnection between the PNW and Canada has a capacity of about 2300 MW. Norman, Oliver, E-BPA-10, at 2. Power sales to the Southwest under long-term contracts currently approach 5,700 MW-months, as opposed to about 26,000 MW-months in the PNW. Wholesale Power Rate Development Study Documentation, Part 1 of 2, WP-96-E-BPA-61A, at 84, 86. Short term energy sales in FY97 are projected to be about 1500 aMW to the PSW and less than 600 aMW to the PNW. *Id*. at 117. Nonfederal firm power sales to the PSW are projected to exceed 1600 aMW. *Id*. at 118.

The IOUs take exception to BPA's definition of the relevant market. IOU Ex. Brief, R-GE/PL/PS-02, at 3-6. They assert that BPA must compute its market shares with each first-tier utility as a separate relevant market. *Id*. at 6. In support of this position the IOUs rely on FERC's decision in *Kentucky Utilities Company*, 69 FERC ¶ 61,260 (1994) ("KU"). In that case, KU calculated its share of generating capacity compared against the total capacity in all of the first-tier markets combined. FERC found KU's generation market analysis inadequate because it did not compute its capacity share with each first-tier utility as a separate market, and did not analyze the impact of the second-tier utilities interconnected to each of those first-tier utilities. *Id*. at 61,988. That case, however, presented a fundamentally different situation in that FERC found that KU had failed to propose a transmission service tariff that provided comparable service. *Id*. As a consequence, measuring KU's market share compared to the total capacity in all the first-tier markets combined was inadequate since it was not apparent that each first-tier utility could reach every other first-tier utility through KU. In the instant case each of the first-tier utilities directly interconnected to BPA will be able to reach every other first-tier utility pursuant to the applicable comparable transmission tariff. Therefore, computing BPA's market share with each of the first-tier utilities as a separate market does not accurately reflect BPA's true share of the capacity market vis-a-vis any given first-tier utility, and thus does not constitute the narrowest "relevant geographic market." Conducting the analysis as proposed by the IOUs would improperly ignore the effect of BPA's comparable transmission tariffs, and result in a distorted picture of BPA's true capacity market share. FERC recognized the impact of comparable transmission tariffs on market share analysis in *Louisville* when it stated that

> [t]he Commission finds that once Louisville's transmission tariff, as modified herein, is in place, all first-tier entities will be able to reach one another. Thus, the supply options available to each first-tier entity will be expanded to include every other first-tier entity.

Louisville, 62 FERC ¶ 61,016, at 61,145; *see also Heartland*, 68 FERC ¶ 61,223, 62,063 (FERC recognition of lack of market dominance when applicants open access tariffs are taken into account). The fact that BPA did not examine the impact of the second-tier utilities interconnected to the first-tier utilities works, if anything, to overstate BPA's capacity share, so that BPA's analysis should be viewed as stating its maximum share in any of the first-tier markets. Any first-tier utility that is interconnected with any utility in addition to BPA has a larger market than is shown in BPA's analysis, thereby reducing BPA's market share below the 16.0 % calculated by BPA.

In addition, FERC previously recognized the WSCC taken as a whole as the relevant geographic market when it reviewed the market power implications of the merger between Pacificorp and Utah Power & Light. *Utah Power & Light Company, Pacificorp and PC/UP&L Merging Corporation*, 45 FERC ¶ 61,095, at 61,284 (1988). The Commission stated that even though limitations to transmission access could inhibit the efficient functioning of that market by precluding some transactions, that nevertheless "the WSCC represents the overlying area within which them [sic] main bulk of electricity competition occurs." *Id*.

PGP presents several arguments in support of its assertion that BPA possesses generation and transmission market power. PGP Ex. Brief, R-PG-01, at 10-14. To the extent, however, that PGP is arguing that BPA possesses market power because PGP is obligated to purchase cost-based requirements service from BPA under the 1981 power sales contract, their arguments are irrelevant. FERC requires a market power analysis only where the seller seeks approval of market-based rates. *See e.g*., *Heartland*, 68 FERC ¶ 61,223, at 62,060 (1994). Nevertheless, PGP states that

> BPA has proposed reducing its prices from current levels but the proposed level still appears higher than competitive prices. A proper analysis of market power will consider whether the rates proposed by BPA are higher than the competitive levels and whether the price differential is likely to attract sufficient entry such that BPA will not be able to sustain the price for the upcoming rate period.

Id. at 13. This appears to be a reference to BPA's proposed PF-96 rate. Requirements service, however, is provided to the PGPutilities under a twenty-year contract having cost-based rates, not market-based rates. The fact that customers signed a long-term power sales contract they now wish to terminate is irrelevant to the issue of market power. Furthermore, any change to rates under that contract would be subject to a section 7(i) proceeding and FERC approval.

PGP argues that the Administrator's conclusion that BPA's share of the relevant market is 16% ignores the need for a "detailed analysis" of the competitive alternatives "actually available" to customers. PGP Ex. Brief, R-PG-01, at 10. PGP cites no support for this contention, nor does it detail how this analysis is to be conducted or what criteria it would have the Administrator evaluate in deciding what constitutes an "actual" alternative to BPA in any given case. As discussed above, this is not a standard that has been articulated by FERC in its opinions. In any case, as detailed elsewhere in this section BPA has provided substantial evidence to the effect that it faces intense competition from utilities throughout the WSCC for the products and services it would sell under the FPS schedule. Again, the PGP utilities' power sales contract obligations are irrelevant to the FPS schedule, since FPS sales will be made to them in cases where they otherwise have the ability to purchase from BPA's competitors.

PGP also asserts that BPA has not defined the relevant product market. *Id*. at 13. They state that BPA should conduct an analysis for non-firm power. *Id*. However, there is ample evidence on the record that BPA sells the bulk of its nonfirm energy as "spill" energy, due to its inability to control its inventory. The concept of market power in what is essentially a displacement market is illogical. In any case, PGP's objection is irrelevant since BPA is not proposing to sell non-firm power under the market-based FPS schedule. The single relevant product market for sales under the FPS schedule is firm bulk power and capacity, measured by installed generating capacity. BPA is proposing to make firm power sales under the FPS schedule from existing capacity, supplemented as needed by spot market power purchases; and BPA will face competition for sales under the FPS schedule from other suppliers with existing capacity. FERC views installed capacity as the relevant product market for sales of both firm and non-firm power. *Louisville*, 62 FERC ¶ 61,016, at 61,144.

PGP argues that using the WSCC as the relevant market "ignores the cost of accessing generation capacity outside the Northwest, including wheeling charges and losses." *Id*. at

12. These, however, are not relevant considerations is evaluating market power. BPA does not have market power by virtue of the fact that a customer may in some cases have to pay these extra costs to a third-party, and that in some cases this may make the alternative supplier's power more costly than BPA's power. What FERC considers is whether there is access to those other suppliers, not whether there is perfect price equality for every conceivable transaction. *Cf. Utah Power & Light Company*, 45 FERC ¶ 61,095, at 61,283 fn 117 (1988) (recognizing that imperfect transmission access does not negate WSCC as the relevant market). The relevant fact is that BPA has proposed comparable transmission tariffs that meet FERC's Stage One pro forma requirements, permitting every market participant to reach each of the first-tier utilities directly interconnected with BPA on an equitable basis. PGP has agreed that rates, terms and conditions adopted by the Administrator that conform to the transmission settlement agreement by and between BPA and many of the parties also conforms to FERC's Stage One open access tariffs. Transmission Settlement Agreement, WP-96-E-BPA-129.

In support of its contention that actual alternatives do not exist, PGP asserts that BPA has erected a barrier to entry "for marketers and brokers through its interpretation of the 1981 contracts." *Id.* at 11. To the extent that this argument is intended to challenge the appropriateness of the market-based FPS rate schedule, it is incorrect. The PGP utilities contractual obligations to purchase requirements power from BPA under the 1981 power sales contracts is not a barrier to entry that gives BPA market power in making surplus firm power sales at market-based rates under the FPS rate schedule. BPA has proposed cost-based rates for sales to the PGP utilities when they do not have the contractual option of purchasing from other suppliers, and they are not required to purchase power from BPA under the market-based FPS schedule. Under these circumstances, FERC has found contractual obligations to purchase do not constitute a barrier to entry. *See Duke*, 73 FERC ¶ 61,309, at 61,868 (1995); *Southwestern Public Service Company*, 72 FERC ¶ 61,208, at 61,968 (1995). Therefore, PGP's assertion that BPA possesses market power by virtue of the 1981 power sales contract is irrelevant to a market power analysis of firm power sales under the FPS schedule.

BPA's market share in the relevant geographic market is within the safe-harbor established by FERC in its cases. FERC has found that market shares as high as approximately 20 percent are low enough to indicate that the applicant did not possess market power. *Louisville*, 62 FERC ¶ 61,016, at 61,146. First-tier markets, or those markets directly interconnected to BPA, include all utilities in the PNW, British Columbia (B.C.) Hydro and all owners of generation in California. Nameplate capacity for January 1995 totals over 110,000 MW: 11,365 MW in B.C. Hydro, 23,152 MW in Northern California, 33,103 MW in Southern California, and 42,609 MW in the PNW. BPA's nameplate capacity is 22,686 MW. Marginal Cost Analysis Study Documentation, WP-96-E-BPA-04A, at 96-112. By this measure, BPA's share of first-tier markets is only 20.5%. However, because the FCRPS is predominately a hydro system, nameplate capacity is not the relevant measure of BPA's peaking capability. Hydro systems are energy constrained and the uncertainty of flows requires that BPA have the energy returned. Dinsmore, *et al.*, E-BPA-21, at 8. Since 1979, BPA has included in its determination of peak resource capability a sustained peaking adjustment, to account for the inability of the hydro system to generate at its peak capability without exhausting its firm energy supply. The sustainable peak is what defines BPA's capacity on BPA's system, and in January 1996, the sustained peak adjustment would reduce BPA's true peak capability by about 4941 MW. Loads and Resources Study, E-BPA-57, at 54. By this reckoning, BPA's capacity is 17,745, and its first-tier market share is only 16.0 percent. A table constructed from information contained in the Marginal Cost Analysis Documentation, WP-96-E-BPA-04A, can be found preceding the decision section for this issue.

By either measure, however, BPA does not have a dominant market share. FERC has held that where no generation dominance is found in the narrowly-defined first-tier markets (i.e., approximately 20% or less), there can be no generation dominance in markets which are defined more broadly. *Intercoast Power Marketing Company*, 68 FERC ¶ 61,248, at 61,128 (1994).

The IOUs argue that the data used by BPA to do these capacity share calculations is outdated, and that there is no evidence that the data "cobbled together" by BPA is relevant or appropriate for use in a market power analysis. IOU Ex. Brief, R-GE/PL/PS-02, at 3 fn 1. This is incorrect. The mere fact that some of the dates associated with page numbers in the documentation are prior to 1996 does not mean that the data is outdated. The data used is taken from the input data files for the Power Marketing Decision Analysis Model (PMDAM). PMDAM has been reviewed independently by the California Public Utilities Commission (CPUC) and the WSCC. Vatter, *et al*., WP-96-E-BPA-17, at 10. The CPUC compared PMDAM to several other models and ranked it highest in terms of accuracy. *Id*. In addition, the input data assumptions were reviewed by the parties to the rate case, and discussed at numerous workshops conducted by BPA. *Id*. at 9. If the dates precede 1996, it is only because the data has not changed. The IOUs assert that the data used is irrelevant because it is taken from the marginal cost documentation. This is also wrong. The market share analysis FERC has required focuses on capacity shares. The marginal cost documentation contains the data that displays the capacity in the relevant market. Therefore, the data in the marginal cost documentation is the relevant and appropriate data for conducting the analysis.

BPA has proposed transmission rates, terms and conditions that are consistent with FERC's recommended pro forma tariffs. Metcalf, *et al*., WP-96-E-BPA-84. As part of the Transmission Settlement Agreement, the IOUs' agree that BPA's proposed PTP and NT tariffs are comparable to FERC's Stage One pro forma tariff. IOU Brief, B-GE/PL/PS-02, at 5. Logically, the effect of these tariffs would be to maintain or reduce, but in no case increase, BPA's market capacity shares described above. Clark's argument that BPA has not proposed comparable and open access tariffs, and has taken specific steps to retain its market power, are incorrect. BPA's proposal regarding comparability and open access tariffs is discussed at section 2.4. Furthermore, Clark does not specify what its means when its states that BPA has "taken specific steps" to retain market power (Clark Brief, B-CP-01, at 27), nor is there any evidence on the record to support that proposition. PGP asserts that the submission of a tariff to FERC is not sufficient to mitigate transmission market power, but that actions taken under the tariff in response to requests for service is the "true test." PGP Ex. Brief, R-PG-01, at 14. Again, PGP cites no authority supporting its version of the "true test." In fact, FERC routinely has approved the application of market-based rates concomitantly with an applicants filing of open and comparable transmission tariffs. *Duke/Louis Dreyfus L.L.C*, 73 FERC ¶ 61,309 (1995*); Kansas City Power & Light Company*, 67 FERC ¶ 61,183 (1994); *Heartland*, 68 FERC ¶ 61,223 (1994); *Public Service Company of Colorado*, 58 FERC ¶ 61,322 (1994); *Louisville*, 62 FERC ¶ 61,016 (1993). The Commission has permitted market-based rates to take effect, subject to refund, pending completion of a hearing on the adequacy of the applicant's proposed open-access transmission tariffs. *Southwestern*, 72 FERC ¶ 61,208, at 61,967 (1995). In *Heartland*, FERC stated that "an *offer* of comparable transmission service will be required before the Commission will be able to find that transmission market power has been adequately mitigated."*Heartland*, at 62,060 (emphasis added).

In summary, BPA faces intense competition from utilities throughout the WSCC and from new market entrants. BPA already has lost large amounts of its historical requirements load, in spite of its concerted efforts to reduce its costs and lower its requirements rates. Increasing non-power constraints not only have reduced the amount of firm capacity and energy on BPA's system, but have severely restricted its ability to shape its resources to meet load. BPA will file open access transmission tariffs consistent with FERC directives to provide comparable transmission service. BPA's share of total capacity in the relevant market is less than 20 percent. BPA's request for the market-based FPS rate applies to only a small fraction of its total load, and is largely confined to sales in surplus markets.

Even if one were to conclude, despite the evidence on the record, that Bonneville possessed generation market power, that would not determine BPA's legal authority to charge market-based rates. While the Northwest Power Act specifies certain cost allocation standards and grants the Administrator considerable rate design discretion, section 7(a) continues pre-existing requirements of law that the Administrator establish rates (1) having regard to the recovery of the cost of generating and transmitting power, (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, and (4) in a manner that protects the interests of the United States in amortizing its investments within a reasonable period. 16 U.S.C. § 839e(a)(1). These directives do not require rates that are limited to "cost of service" standards. *Pacific Power & Light Co. v. Duncan*, 499 F. Supp. 672, 683 (D.C. Or. 1980). Depending on the facts, market-based rates not only may be appropriate but may be necessary under these standards.

Overall, BPA's rates are "cost-based" in the sense that BPA's rates "have regard to" cost recovery and ultimately do result in cost recovery. The resource pool directives of section 7 of the Northwest Power Act clearly depart from "cost of service" principles as they have developed in the context of investor owned utility ratemaking. Nevertheless, within the context of those directives, section 7(e) and its legislative history makes clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. 16 U.S.C. § 839e(e);

H.R. Rep. No. 96-976, Part II, 2d Sess. 53 (1980), H.R. Rep. 96-976, Part I, 2d Sess. 69 (1980). Market-based rates may be entirely appropriate to recover those revenues. Past features of BPA's rates, such as the irrigation discount, may be thought of as responding to the market and, hence, market-based. The same may be said for an entire rate, such as the DSI Variable Rate, which was designed to recover revenues greater than or equal to the revenues BPA would have recovered in the absence of the rate.

So, too, BPA's surplus firm power rate was designed to afford BPA considerable marketing flexibility, with a view to recovering its costs overall and over time. That rate was developed pursuant to Northwest Power Act section 7(f), which does not require that products priced thereunder be set to equal cost. 16 U.S.C. § 839e(f). *See discussion supra* under issue No. 1 in this section. Rather, its language is flexible enough to allow BPA to establish 7(f) rates that assist in overall cost recovery by BPA. Overall cost recovery is the paramount objective of BPA's rate directives.

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The following table with cites to the record is included to assist the reader.

Tier 1 January 1995 Capacity Resources in WSCC Power Market (MW)

1	So Cal Edison	20139	15	Pacific Gas	20948
2	CDWR	1536	16	Modesto	353
3	Anaheim	477	17	Turlock	200
4	Azusa	7	18	Redding	125
5	Banning	2	19	Santa Clara	240
6	Colton	2	20	SMUD	926
7	Riverside	172	21	NCPA	360
8	Vernon	46			
9	San Diego Gas	2767		**Subtotal, No Cal**	**23152**
10	LADWP	6537			
11	Imperial Irrigation	553	22	B.C.Hydro	11365
12	Pasadena	281	23	Pacificorp	3654
13	Burbank	308	24	Portland General	2521
14	Glendale	276	25	Other IOU	9154
			26	Generating Pubs	4664
	Subtotal, So Cal	**33103**	27	BPA	22686
				Subtotal, PNW	**42609**
	West Coast Total	**110299**			

1	WP-96-E-BPA-04A	p.106, l. 764-5,767,769-75, p.107, l.778-81,783-4
2	WP-96-E-BPA-04A	p.107, l.785-88
3	WP-96-E-BPA-04A	p.107, l.789-92
4	WP-96-E-BPA-04A	p.107, l.793-4
5	WP-96-E-BPA-04A	p.107, l.793-5
6	WP-96-E-BPA-04A	p.107, l.796
7	WP-96-E-BPA-04A	p.107, l. 797-9
8	WP-96-E-BPA-04A	p.108, l 800-02
9	WP-96-E-BPA-04A	p.108, l. 803-7,809-10,815-17,819
10	WP-96-E-BPA-04A	p.108, l. 8821-25,829-34,836-8
11	WP-96-E-BPA-04A	p.108, l.839-44
12	WP-96-E-BPA-04A	p.108, l.845-49
13	WP-96-E-BPA-04A	p.108, l.850-54
14	WP-96-E-BPA-04A	p.108, l.855-59
15	WP-96-E-BPA-04A	pp.109-10, l. 860-863,865-8,885-90,907-8
16	WP-96-E-BPA-04A	p.110, l. 909-13
17	WP-96-E-BPA-04A	p.110, l. 914-5
18	WP-96-E-BPA-04A	p.110, l. 916-19
19	WP-96-E-BPA-04A	p.110, l. 920-4,932-3
20	WP-96-E-BPA-04A	p.110, l. 934-39,947
21	WP-96-E-BPA-04A	p.110, l. 950-5

22 WP-96-E-BPA-04A p.101, l. 256-65
23 WP-96-E-BPA-04A p.96-101, l.14-18.70-2,125,133,148,158,172,174,201,210,215,221,244-5
24 WP-96-E-BPA-04A p.96-101, l.19-22,64-9,126,134,149,159,179,185,190,199-200,202,211,216,246-7
25 WP-96-E-BPA-04A p.96-101, l.1-12,23,26-30,32-4,39,51,59-60,73-86,127-8,132,135-6,141,150-1, 160,163,180-1,183,191-7,203,206,208-9,212-14,217-20,138,231-2, 238-43,248-49,252-53,255
26 WP-96-E-BPA-04A p.96-101, l.24,40,47-9,52-8,61-3,110-124,129,137-40,152-4,161-2,164-6, 171,173, 182,204-5,207,234-7,254
27 WP-96-E-BPA-04A p.96-101, l.31,35-8,41-46,50,87-109,130,155-7,167-70,175-8,198,230,250-1

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Decision

BPA does not have generation market power.

11.7.6 Addition Of The Industrial Margin To FPS Sales To The DSIs

Issue

Whether the FPS-96 rate schedule must include a provision under which the industrial margin is added to all sales made to the DSIs.

Parties' Positions

APAC argues that sales to the DSIs under the FPS rate schedule must include the typical margin. APAC asserts that, under section 7(c) of the Northwest Power Act, rates to the DSIs must be equitable in relation to the retail industrial rates charged by BPA's public body and cooperative customers (preference customers). APAC argues that, if BPA fails to include a margin in FPS sales to the DSIs, the DSI rates will not be comparable to preference customers' rates to their industrial customers. APAC Brief, WP/TR-96-B-PA-01, at 29-32. The DSIs argue that it is questionable whether Congress intended the section 7(c) rate directives to apply to the kind of market-expansion sales BPA would make to the DSIs under the FPS rate schedule. They add that the flexible rates under the FPS rate schedule are an "applicable wholesale rate." Therefore, any rate that equals or exceeds the typical margin meets the 7(c) rate directives. DSI Brief, WP-96-B-DS-01, at 8-10.

BPA's Position

BPA argues that it has signed up as much DSI load as possible at the Industrial Firm Power rate, and that it can retain additional DSI load only by offering power at competitive, market prices. If BPA must add a margin to FPS sales to the DSIs, it will not secure additional DSI load and will need to recover the lost revenues from the preference customers from which APAC members purchase power. Therefore, preference customers' retail rates will increase, reducing the comparability between their rates and DSI rates. Chang, Cocks, WP-96-E-BPA-110, at 4-5.

Evaluation of Positions

The FPS-96 rate schedule authorizes BPA to sell power at market rates. It is intended to provide BPA the rate flexibility it needs to respond to the competitive market. The FPS rate schedule seeks to combine the long-term rate stability desired by customers with reasonable assurance that BPA will recover its costs. Dinsmore, *et al.*, WP-96-E-BPA-21, at 4. BPA needs flexibility because of the profound changes in the electric utility industry. In the last few years competition in the utility industry has increased enormously. BPA faces strong competition for its existing load and must compete aggressively if it is to retain load and recover its costs. *Id.* at 5; *see also supra* §§ 2.2 and 8.2.2.

The FPS rate schedule contains no lower or upper rate limit. Instead, it contemplates the sale of power at a rate mutually agreed between BPA and the purchaser. APAC argues that the rate schedule must include a provision under which BPA adds the industrial margin for all sales to the DSIs. APAC Brief, B-PA-01, at 30; Wolverton, WP-96-E-PA-01, at 12. APAC adds that, unless the DSIs pay the industrial margin on all sales, their rates will not be equitable in relation to the rates BPA's preference customers charge their industrial customers. Wolverton, E-PA-01, at 12.

Section 7(a) of the Northwest Power Act is BPA's primary rate directive. It provides that

> [BPA's] rates shall be established . . . to recover, 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 . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law.

16 U.S.C. § 839e(a)(1).

Section 9 of the Federal Columbia River Transmission System Act provides that BPA's rates 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 . . . 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 . . . and (3) at levels to produce such additional 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 issued and outstanding pursuant to this Act.

Id. § 838g.

Section 7(c)(1)(B) of the Northwest Power Act provides that rates to the DSIs shall be set at a level "which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." *Id.* § 839e(c)(1)(B). Section 7(c)(2) provides that the determination under section 7(c)(1)(B) 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." *Id.* § 839e(c)(2).

BPA has never interpreted its rate directives to limit sales to the DSIs under all circumstances to the margin-based rate. In 1983 BPA adopted an Industrial Incentive Rate, under which the DSIs were offered a lower rate in exchange for high load commitments. The purpose of the rate was to "increas[e] BPA revenues and revenue stabilities while at the same time allowing for greater DSI operations through a lower rate for electricity." 1983 Administrator's Record of Decision, WP-83-A-02, at 258 [hereinafter 1983 Rate ROD]. Also in 1983, BPA sold power to the DSIs under the nonfirm rate schedule in order to increase revenues from the sale of power that otherwise would have been wasted. These sales were upheld by the Ninth Circuit Court of Appeals. *Portland General Electric Co. v. Johnson*, 754 F.2d 1475 (9th Cir. 1985).

Since 1987, BPA has had in place a Surplus Firm Power (SP) Rate schedule (currently designated the SP-93 rate schedule), under which sales of surplus power are made at negotiated rates. The SP-93 rate schedule provides that "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-95, VI-95, PF-95, or NR-95 rate schedules." The IP-95 and VI-95 rates are BPA's current rates for sales of Industrial Firm Power to the DSIs. The above language makes clear that BPA may make sales to the DSIs under the SP rate schedule. Since 1987, therefore, BPA has had in place a rate schedule that contemplates the sale of power to the DSIs at a market rate. The FPS-96 rate is intended to supersede the SP-93 rate; it "is very similar to the SP-93 rate schedule with regard to firm power sales." Dinsmore, *et al.*, E-BPA-21, at 2.

In 1986 BPA adopted the Variable Industrial (VI) Rate, under which the rate for power sold to the DSIs varies with the price of aluminum, in order to increase DSI loads and BPA's revenues at a time of low aluminum prices. At the time, the Industrial Firm Power (IP) rate, or margin-based rate, was 22.8 mills/kWh. Administrator's Record of Decision, 1986 Variable Industrial Power Rate Proposal, VI-86-A-02, at 11 [hereinafter 1986 VI Rate ROD]. In the VI rate proceeding, BPA's public agency customers argued that, as a matter of law, BPA was required to design a rate that guaranteed recovery of 22.8 mills/kWh on average, even if greater total loads and revenues could be obtained under a rate that might recover a lower average rate. *Id.*

The Administrator rejected this argument. He concluded that section 7(c) of the Northwest Power Act "provide[s] a DSI revenue target toward which BPA should strive if economic conditions permit. Section 7(a) is the paramount ratemaking directive, because it requires BPA to design rates that recover costs under all economic conditions." *Id.* at 15. He added that

> insistence on an average 22.8 mill rate level in the face of low aluminum price forecasts could cause BPA to violate the requirement of Northwest Power Act section 7(a) that BPA set rates to recover all its costs on the basis of "sound business principles." It is simply not a sound business principle to set rates that price BPA out of the market during times of power surplus and unrecovered fixed costs.

1986 VI Rate ROD, at 13.

The legislative history of the Northwest Power Act confirms the Administrator's conclusion. The House Report accompanying the final bill stated that the rate directives for particular customer classes are "[s]ubject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs." H.R. Rep. No. 976, Part II, 96th Cong., 2d. Sess. 36 (1980). To accomplish this objective, section 7(a) authorizes BPA to set rates within a wide discretionary range. 1986 VI Rate ROD, at 12.

When BPA adopted the 1983 Incentive Rate, low aluminum prices had placed its revenues from the DSIs at risk. BPA offered the Incentive Rate in exchange for DSI commitments to operate at high levels during the rate period. 1983 Rate ROD, at 258. Similarly, BPA adopted the VI rate when economic conditions had again placed DSI revenues at risk. In both instances BPA recognized its primary obligation to recover its costs and ensure repayment of the United States Treasury.

Today, it is the competitive marketplace that has placed DSI revenues at risk. By allowing BPA the means to compete in the marketplace, the FPS rate schedule is expected to play a significant role in BPA's fulfillment of its statutory obligations. In its initial proposal, issued in July 1995, BPA forecast 2,569 MW of sales to the DSIs at the IP rate. When BPA negotiated new DSI power sales contracts in September 1995, it signed up as many megawatts of DSI load as it could. *See* Chang, Cocks, E-BPA-110, at 4. Nevertheless, in its supplemental proposal BPA has forecast 1,842 megawatts of sales to the DSIs at the IP rate, a loss of approximately 700 MW (more than one-fourth of the DSI operating load) to the competition. Lee, *et al.*, WP-96-E-BPA-67, at 3.

In its brief on exceptions, APAC argues that BPA's reliance on the Variable Industrial rate and the Industrial Incentive rate is misplaced, because BPA adopted those rates when aluminum prices were low, and the DSIs were "unable" rather than "unwilling" to purchase power at the IP rate. APAC Ex. Brief, WP/TR-96-R-PA-01, at 7. This argument has been addressed elsewhere in this Record of Decision. *See supra* § 8.2.2. To reiterate, APAC raises a distinction without a difference. As noted above, in the Variable Industrial Rate ROD the Administrator concluded that section 7(a) of the Northwest Power Act requires BPA to recover its costs "under all economic conditions." In 1986 the obstacle to this goal happened to be low aluminum prices. Today, the obstacle is the competitive market. Nothing in the Variable Industrial Rate ROD suggests that its precepts apply to only one set of economic conditions; to the contrary, the ROD enunciated broad precepts, and applied them to the economic conditions at the time.

In addition, no reason appears (and APAC offers none) for drawing the distinction that APAC suggests. Although the prevailing economic conditions are different, the result of ignoring them would be the same. As in 1986, so today BPA must be concerned with its resource planning, financial strength, and rate stability. As in 1986, so today BPA faces the prospect of power surplus and unrecovered fixed costs if it loses substantial load. That the DSIs may be unwilling, rather than unable, to pay higher rates is immaterial; if they purchase power elsewhere because BPA's rate is above the market, the consequences the Variable Rate ROD was intended to forestall will come to pass.

Some of the DSI load is already committed to other suppliers. Vanalco, a large DSI customer (approximately 230 MW), has given BPA notice that it does not intend to purchase any firm power from BPA in the future. Hill, *et al.*, WP-96-E-BPA-51, at 18. BPA's only hope of retaining additional DSI load is to make sales under the FPS rate schedule. BPA will make no additional sales to the DSIs, however, if it must add the industrial margin to the sale price. The FPS rate schedule is intended to allow BPA to sell power at market rates. If anything, in a competitive market the DSIs can demand lower prices than can utilities. The DSIs have high load factors and their loads are fairly constant throughout the day and over the course of the year. Their loads are cheaper to serve than loads that vary more, and they are the object of more intense competition than BPA's other loads. Moorman, Evans, WP-96-E-BPA-65, at 5. By adding the margin to FPS sales, BPA will price itself well out of the market.

Therefore, BPA has two options: add the industrial margin and lose the load, or sell power without adding the margin, thus retaining the load and increasing revenues. BPA has consistently held that its primary ratemaking obligation under the Northwest Power Act is to recover its costs. Both BPA's cost recovery obligations and sound business principles require BPA to retain revenues when economic conditions place those revenues at risk. As in 1986, it would be unsound today for BPA to price itself out of the market during a time of intense competition, west coast surplus, and potentially unrecovered fixed costs. Section 7(a) requires BPA to meet the competition and ensure its ability to repay the United States Treasury. APAC's argument that BPA must add a margin to all sales to the DSIs under the FPS rate schedule ignores both the history of BPA's sales to the DSIs and BPA's statutory obligation to recover its costs.

In its brief on exceptions, APAC argues that BPA has presented no evidence that the addition of a margin would result in loss of DSI load. APAC Ex. Brief, R-PA-01, at 30.

To the contrary, the evidence exists in the market realities BPA has discussed throughout this Record of Decision. As noted above, the FPS rate schedule is intended for power sales at market rates. BPA must offer power to its preference customers at a competitive rate; if BPA prices its power above the market, it will lose the sale. As also noted above, the DSIs often can demand even better prices from the market than can BPA's preference customers. Therefore, if BPA offers power to the DSIs at the preference customer rate (that is, the market rate) plus a margin, the price will be well above the market. Elementary economics demonstrate that BPA will lose the sale. Indeed, APAC has acknowledged that "in a competitive market, where the customer has freedom of supplier choice, a supplier that raises prices and thereby over prices goods will lose revenue." Tr. 2134.

APAC argues, however, that unless BPA adds the margin to its FPS sales to the DSIs, the resulting FPS rate will not be comparable to the rate an industry would pay if its serving utility obtained the same FPS arrangement from BPA. Wolverton, E-PA-01, at 12. The serving utilities take a different view.

The Western Public Agencies Group, which represents 21 of BPA's preference customers, testified that the FPS rate schedule "will place Bonneville in the position of being able to compete with private utilities for customer load on a more equal basis." Beck, *et al.*, WP-96-E-WA-11, at 26. The Public Power Council, which represents the majority of BPA's preference customers, testified that BPA needs "greater flexibility to compete with jurisdictional competitors . . . . The FPS rate is one approach toward developing such flexibility." Carr, *et al.*, WP-96-E-PP-08, at 3. Similarly, the Full Meal Deal utilities, a group of 22 public body and cooperative customers, testified in support of the FPS rate schedule:

> As an exclusively wholesale supplier in today's regulated market, BPA's entire customer base is at risk. . . . [The investor-owned utilities] and other wholesale sellers are competing with BPA in an effort to displace BPA load. BPA must have the flexibility to offer its customers the kind of product choices which are necessary for BPA to remain competitive and to retain its load.

Wagner, *et al.*, WP-96-E-FM-02, at 9.

The Full Meal Deal utilities added that BPA must have "considerable flexibility in its surplus sales rate schedule in order to be competitive and to achieve revenues which are beneficial to its other wholesale power customers." Rosenberg, WP-96-E-FM-03, at 1. BPA's customers recognize that unless BPA is able to sell power at market prices, BPA will lose load and have to look elsewhere to recover its costs. In this event, BPA's public utility customers will have to bear the additional costs. Eldridge, *et al.*, WP-96-E-PP-01, at 3. Northwest Irrigation Utilities (NIU), which represents a group of full requirements customers, testified that "BPA's competitiveness at the wholesale level directly affects the competitiveness of its utility customers at the retail level." Saven, WP-96-E-NI-02, at 6. NIU added that

> it is BPA's full requirements public agency customers . . . who bear the greatest risk of a BPA underrecovery. . . . At the end of the day, it is the PF rate, which is paid by full requirements customers for most of their power, which would be a source that BPA may look to for making up the bulk of any underrecovery.

Id. at 13.

Consequently, NIU supports the FPS rate schedule as a necessary competitive tool. According to NIU, if BPA is unable to offer competitive products under the FPS rate schedule,

> the group that would lose the most . . . would be BPA's full requirements customers, the publicly and cooperatively owned utilities which look to BPA as their primary, if not exclusive provider of wholesale power, transmission and related services. If BPA cannot be a competitive supplier of bulk power and transmission services at the wholesale level, the utilities which rely on BPA for these services may have their competitive edge jeopardized at the retail level.

Id. at 2.

If BPA added the margin to FPS sales to the DSIs, two results would follow. First, BPA would lose revenue because the DSIs would purchase from non-Federal suppliers rather than pay the margin. Second, the public utilities from which APAC members and other industrial consumers purchase power would be responsible for additional costs and would need to increase retail rates. Congress intended the industrial margin to increase BPA's revenues and to ensure equitability between DSI rates and retail industrial rates. Therefore, the result of adding the margin to FPS sales would be doubly perverse: BPA would suffer a loss of revenues, while DSI rates and retail industrial rates would become less comparable. At the same time BPA would increase its risk of underrecovery and lessen its prospects of repaying the United States Treasury.

The DSIs suggest that Congress never intended the section 7(c) rate directives to apply to the kind of market-expansion sales BPA would make to the DSIs under the FPS rate schedule. DSI Brief, B-DS-01, at 8. Statutes should not be interpreted to lead to a perverse result. *Best Power Technology Sales Corp. v. Austin*, 984 F.2d 1172 (Fed. Cir. 1993) ("All statutes must be construed in light of their purpose. A reading of them which would lead to absurd results is to be avoided when they can be given a reasonable application consistent with their words and with legislative purpose." *Best Power*, 984 F.2d at 1175-76 (quoting *Haggar Co. v. Helvering*, 308 U.S. 389, 394 (1940)).

Moreover, "a statute is to be read as a whole . . . since the meaning of statutory language, plain or not, depends on context." *King v. St. Vincent's Hosp.*, 502 U.S. 215, 221 (1991).

Even if statutory language is plain, a court "must go beyond the literal language of a statute if reliance on that language would defeat the plain purpose of the statute." *Bob Jones Univ. v. United States*, 461 U.S. 574, 586 (1983). Statutes "must be construed to further the intent of the legislature as evidenced by the entire statutory scheme; a statutory subsection may not be considered in a vacuum, but must be considered in reference to the statute as a whole and in reference to statutes dealing with the same general subject matter." 2A Norman J. Singer, Sutherland Statutory Construction § 46.05, at 103 (rev. ed. 1992).

Section 7(c) must be interpreted in light of BPA's other rate directives as well as the entire statutory scheme. Section 5 of the Northwest Power Act establishes BPA's authority to sell power. Section 5(d) authorizes sales of power to the DSIs; section 5(d)(1)(B) provides that

> [a]fter the effective date of this Act, the Administrator shall offer in accordance with subsection (g) of this section to each existing direct service industrial customer an initial long term contract that provides such customer an amount of power equivalent to that to which such customer is entitled under its contract dated January or April 1975 providing for the sale of "industrial firm power."

16 U.S.C. § 839c(d)(1)(B).

BPA's rate directives track the authorizing language of section 5. Section 5(b)(1) authorizes sales of requirements power to BPA's preference customers. *Id.* § 839c(b)(1). Section 7(b) establishes the rate for requirements power. *Id.* § 839e(b). Section 5(d)(1) authorizes sales of Industrial Firm Power to the DSIs. *Id.* § 839c(d)(1). Section 7(c) establishes the rate for Industrial Firm Power. In the 1996 General Rate Schedule Provisions (GRSPs), as in prior GRSPs, BPA defines "Industrial Firm Power" as "electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser subject to the terms of the Purchaser's power sales contract with BPA." WP-96-E-BPA-64, at 171, § III(A)(14). This definition tracks the language of section 5(d)(1)(B) that "industrial firm power" is power sold under the DSIs' power sales contract. During the five-year rate period, BPA will be collecting the industrial margin on all 1,842 MW of DSI load it has forecast under the existing and new power sales contracts. BPA has signed up the maximum possible DSI load for sales at the IP rate under the power sales contracts; it cannot sell the DSIs additional Industrial Firm Power.

In its brief on exceptions, APAC asserts that BPA's "claim" that it has signed up as much load as possible at the IP rate is simply an assertion, unsupported by evidence. APAC Ex. Brief, R-PA-01, at 8 n.11. BPA's testimony supports BPA's conclusion. As noted above, BPA testified that, when it negotiated new power sales contracts with the DSIs, it signed up as much DSI load as possible for sales at the IP rate. No additional evidence is necessary; this conclusion is fully within BPA's knowledge. As demonstrated throughout its testimony, BPA is attempting to retain as much load as possible. Nevertheless, between the initial and supplemental proposals BPA lost approximately 700 MW of DSI load to alternative suppliers. Had BPA been able to sign up more load for sales at the IP rate, it would have done so. The fact that it did not proves its case.

Section 7(c) should not be extended to sales of additional power to the DSIs. Instead, it establishes the rate for sales of Industrial Firm Power sold under section 5(d). Because the market prevents BPA from selling any additional power to the DSIs under their power sales contract, additional sales do not meet the definition of "Industrial Firm Power."

BPA's authority to sell power under the FPS rate schedule stems from section 7(f) of the Northwest Power Act, which provides as follows:

> Rates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be based upon the cost of the portions of Federal base system resources, purchases of power under section 5(c) of this Act and additional resources which, in the determination of the Administrator, are applicable to such sales.

Id. § 839e(f).

Section 7(f)'s reference to "all other firm power" is to power not priced under sections 7(b) or 7(c). Section 7(f) establishes the rate for power sold to the DSIs under the FPS rate schedule. This interpretation accords with the statutory scheme. BPA must set rates in accordance with sound business principles to recover its costs and ensure repayment of the United States Treasury. In addition, BPA must set rates with a view toward encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.

Selling power to the DSIs under section 7(f) helps fulfill these overarching statutory goals. In addition, the statutory scheme Congress established in sections 5 and 7 of the Northwest Power Act suggests that section 7(c) is limited in its scope. Congress did not preclude the sale of power to the DSIs at other rates when necessary to fulfill BPA's mission and when the power cannot be sold as Industrial Firm Power.

APAC argues, however, that BPA will sell the same power product to the DSIs under the FPS rate as under the margin-based rate. APAC Brief, B-PA-01, at 30. This argument ignores the realities of today's marketplace. The market has defined the limits of BPA's ability to sell Industrial Firm Power to the DSIs. Sales to the DSIs at the IP rate and under the FPS rate schedule are neither in competition with each other nor substitutes for one another. BPA will not sell power to the DSIs under the FPS rate schedule if it is able to make the sale at the IP rate. Tr. 906. Any DSI load that BPA obtains under the FPS rate schedule is load it otherwise would have lost to the competition; BPA will make sales to the DSIs under the FPS rate schedule only when the alternative is loss of the load. Tr. 906; *see also* Chang, Cocks, WP-96-E-BPA-110, at 4. The FPS rate schedule is not an alternative to the IP-96 rate. Hill, *et al.*, E-BPA-51, at 17-18.

Nevertheless, in its brief on exceptions, APAC argues that Congress did not intend sales under section 7(f) to substitute for sales made under other rate directives. Instead, according to APAC, Congress intended that BPA make sales under section 7(f) only to meet load growth. APAC Ex. Brief, R-PA-01, at 31. As demonstrated above, FPS sales to the DSIs will not substitute for sales made pursuant to section 7(c). Moreover, neither the language of section 7(f) nor the legislative history that APAC cites supports its restrictive interpretation. As noted above, section 7(f) applies to rates "for <u>all other firm power</u> sold by the Administrator for use in the Pacific Northwest." 16 U.S.C. § 839e(f) (emphasis added). The report of the Senate Committee on Interior and Insular Affairs also adopted a broader view than suggested by APAC:

> Section 7(f) is the rate directives [sic] for the so-called "new resources rate" that BPA will charge customers <u>for sales other than those to which a different rate directive applies</u>. This rate directive applies only to firm power sales for use within the Pacific Northwest. It will be used, <u>for example</u>, for power sold to investor-owned utilities to meet their net requirements, and for power sold to preference customers for service to new large single loads.

S. Rep. No. 976, 96th Cong., 2d Sess., pt. 2, at 53 (1980) (emphasis added).

The broad language of both the statute and the Committee report indicates that Congress vested the Administrator with substantial discretion to make sales under section 7(f) when other rate directives were either inapplicable to or unavailable for such sales. Neither the statute nor the Committee report contains language of limitation; instead, both indicate an expansive grant of authority. Moreover, the Administrator has consistently interpreted section 7(f) to apply in cases other than sales to meet load growth. As noted above, the SP rate schedule, under which sales are made pursuant to section 7(f), has been in place since 1987. This schedule is broadly applicable to sales of surplus power.

Finally, APAC itself implicitly acknowledges the availability of section 7(f) for broader purposes. APAC has not challenged BPA's adoption of the FPS rate schedule, even though the rate schedule is intended to allow BPA to compete for load. Thus, APAC is attempting to have it both ways: on the one hand, it supports BPA's adoption of the FPS rate schedule for preference customers, from which APAC purchases power. On the other hand, when it comes to sales to the DSIs, APAC argues that section 7(f) is limited in its scope.

APAC also asserts that BPA contemplates "additional transactions" with the DSIs apart from FPS sales, in that certain DSI power sales contracts contain provisions for purchase and resale of power with a 0.1 mill/kWh adder. According to APAC, the draft ROD fails to discuss BPA's statutory authority for such transactions. APAC Ex. Brief, R-PA-01, at 32-33. These sales will be made pursuant to the FPS rate schedule. They raise no issues not already addressed in response to APAC's other arguments.

APAC acknowledges that, if BPA adds a margin (or "laundering service charge") to FPS sales to the DSIs, "[t]here is a risk that the DSIs would seek their power elsewhere and not use their Federal power contracts at all." Wolverton, E-PA-01, at 28. APAC asserts, however, that this risk may be small because there are advantages to purchasing Federal power. *Id.* Yet BPA has lost approximately 700 MW of DSI load in the ten months since publishing its Initial Proposal in July 1995. Moorman, Evans, E-BPA-65, at 6. Clearly the DSIs do not perceive the same problem with non-Federal power purchases. If BPA is unable to effectively compete for the remaining uncommitted DSI load, its loss of load and revenues will only increase.

APAC argues that nothing in the FPS rate schedule prevents the DSIs from canceling their contractual agreements to purchase power at the IP rate, and purchasing the same power under the FPS rate schedule. APAC Brief, B-PA-01, at 30. This prospect is fanciful. Under the DSIs' new power sales contracts, the DSIs are committed to a fixed amount of take-or-pay load for five years. Wolverton, WP-96-E-PA-03, Attachment 1, § 9. They have no unilateral right to terminate their new power sales contracts or to reduce their load commitments. *Id.*; *see also* Tr. 905-06. Certainly it is possible to conjure up scenarios in which BPA and its public utility customers, and hence their retail customers, will be harmed by BPA's sales to the DSIs under the FPS rate schedule. BPA's proposal, however, must be evaluated in light of the evidence. The evidence indicates that the FPS rate schedule will allow BPA to retain incremental DSI load that otherwise would be lost. Therefore, BPA will increase its revenues while benefiting its public body and cooperative customers.

In its brief on exceptions, APAC asserts that, in the draft ROD, BPA admitted that "a DSI, such as Vanalco, can cease its section 7(c)(2) [purchases] and obtain the same quantity and quality of power via the FPS-96 rate and thereby avoid the margin." APAC Ex. Brief, R-PA-01, at 32. APAC cites page 349 of the draft ROD for this "admission," without further identification. *Id.* Nothing on that page, all of which is repeated here, contains such an admission. As noted above, the DSIs have no right to terminate their block sale contracts to purchase the same power under the FPS rate schedule. For its part, Vanalco has given BPA a notice of termination of its 1981 power sales contract. As BPA testified, Vanalco indicated that it did not intend to purchase power from BPA under any rate schedule. Tr. 905. APAC has not challenged (or even acknowledged) this testimony.

APAC argues that BPA created its own competitiveness problem by executing long-term transmission contracts with the DSIs, thereby allowing them access to the wholesale power market. APAC Brief, B-PA-01, at 7. The emergence of a competitive market made BPA's execution of the contracts prudent. BPA negotiated the transmission contracts in part because it recognized that the DSIs "likely would have the ability to access the wholesale power market indirectly through their local utilities." 60 Fed. Reg. 47,938 (1995). The DSIs have the right to terminate their existing power sales contracts on one-year's notice. The transmission agreements were part of a BPA strategy to avoid the adverse effects of contract terminations. In exchange for the agreements, the DSIs agreed to continue providing BPA the stability reserves they have provided to the Federal system for years. BPA Brief, TC-96-B-BPA-01, at 31-32.

In its brief on exceptions, APAC asserts that BPA has speculated, without evidence, that the DSIs could access the wholesale market even if BPA did not grant them transmission rights. APAC Ex. Brief, R-PA-01, at 8, n.11. To the contrary, BPA's statement is not speculative at all. The DSIs have the legal right to purchase power from their local utility. No transmission access is necessary for them to do so.

Finally, APAC argues that BPA must also add a margin to non-Federal power the DSIs purchase from other suppliers for transmission over BPA's system, in order to ensure that the DSIs do not avoid any costs by purchasing power from non-Federal sources. Wolverton, E-PA-01, at 27, 31. APAC suggests that the margin should apply only when the DSIs "claimed and achieved Federal status that shielded them from state and local regulation." *Id.* at 27. Nothing in the Northwest Power Act requires the addition of a margin to transmission rates when the DSIs purchase non-Federal power. Section 7(c)(2) applies to power sales. 16 U.S.C. § 839e(c)(2). Moreover, the industrial margin is an adder to BPA's IP rate; it is not a catch-all charge to equalize rates in the region. Hill,*et al.*, E-BPA-51, at 18. APAC is suggesting that BPA monitor the DSIs' non-Federal purchases to ensure that, under all circumstances, the DSIs pay the same power rates as other industrial loads, even though the DSIs have the legal right to purchase from suppliers other than BPA. BPA is not a regional policeman charged with overseeing the DSIs' power sales contracts with other entities.

When the Northwest Power Act was passed, BPA was the undisputed low-cost provider of power in the Pacific Northwest. Moorman, Evans, WP-96-E-BPA-09, at 5. Neither the DSIs nor BPA's public utility customers had any incentive to purchase power elsewhere, nor did Congress envision that they would do so. In a world without competition, requiring a margin on sales to one group of customers—the DSIs—was realistic and feasible. Adding the margin increased BPA's revenues and benefited BPA's preference customers. Today, adding the margin to FPS sales would reduce BPA's revenues and put its public body customers at risk of having to pay costs BPA otherwise would be unable to recover. It should not be assumed that Congress intended section 7(c)(2) to apply under these circumstances. The more reasonable interpretation of the Northwest Power Act's rate directives is that BPA must add the margin to Industrial Firm Power sold under the DSIs' power sales contract. Power that BPA cannot sell as Industrial Firm Power is sold pursuant to section 7(f).

Decision

BPA will not add a provision to the FPS-96 rate schedule requiring the addition of a margin in the case of sales to the DSIs. BPA adds the margin to sales of Industrial Firm Power made under sections 5(d)(1)(B) and 7(c)(2) of the Northwest Power Act. Sales under the FPS-96 rate schedule will be made at market rates pursuant to section 7(f). If BPA added a margin in the case of sales to the DSIs, the price would be above market rates and BPA would lose the load to the competition. BPA's revenues would decline, and its public body and cooperative customers would be at risk of having to bear the costs BPA was unable to recover from the DSIs. The DSIs would purchase power elsewhere without paying the margin, while the public body and cooperative customers' rates could be expected to increase.

11.8 Other Power Rates

In addition to the wholesale power rate schedules addressed above, BPA proposed the following rate schedules:

New Resource Firm Power Rate, NR-96
Nonfirm Energy Rate, NF-96
Reserve Power Rate, RP-96
Power Shortage Rate, PS-96

See Wholesale Power and Transmission Rate Schedules, WP-96-A-02, Appendix. The proposed NR-96 rate schedule is similar to the proposed PF-96 rate schedule in its revisions of format and billing factors. The demand and energy rates in the NR-96 rate schedule are the same as those in the PF-96 Preference rate schedule. The RP-96 and PS-96 rate schedules are substantively the same as the 1995 versions, although both have been modified to incorporate BPA's proposal to charge for transmission separately from power.

The NF-96 Contract rate calculation has been changed from the NF-95 rate schedule. The NF-95 Contract rate was based on the weighted average revenue under an average of 50 water years from all forecasted nonfirm energy sales. Because the average revenues of nonfirm energy sales have varied significantly between rate periods, the Contract rates have varied significantly in past rate periods. In order to keep the Contract rate more predictable and stable, BPA has changed the basis of the NF-96 Contract rate to equal BPA's average cost of nonfirm energy as specified under sectionII of the NF-96 rate schedule. Dinsmore, *et al.*, WP-96-E-BPA-21, at 14. The methodology for calculating the average cost of nonfirm energy is unchanged, but two of the factors in the calculation have changed to reflect the rate design changes made in this rate case. Previously, the firm power factor in the calculation included Network transmission costs, and a separate factor reflected the costs of serving the first quartile of DSI load. Transmission costs are now unbundled and as a result are shown as a separate factor in the calculation. WPRDS Documentation, WP-96-FS-BPA-05A, section 3.5 The DSI load is no longer served in quartiles, so this factor has been removed from the calculation. *Id.*

The NF rate schedule formerly provided that BPA could reduce guaranteed nonfirm deliveries in order to serve firm loads only due to unexpected generation or transmission losses. BPA has included new language in the rate schedule to make clear that BPA does not undertake an obligation to purchase power from other sources to continue delivery of energy sold under the guaranteed nonfirm energy rate where it must interrupt delivery in order to serve firm loads, whether or not because of unexpected generation or transmission losses. Dinsmore, *et al.*, WP-96-E-BPA-21, at 15.

No party raised issues with regard to these rate schedules.

12.0 TRANSMISSION RATES

12.1 Introduction

As discussed in Section 2, BPA staff and most of the active parties to the rate case negotiated an agreement that proposed to settle all issues regarding the transmission rate proposal and terms and conditions proposal. The Administrator is proposing to adopt the Transmission Settlement Agreement. *See* Attachment 1. This section on transmission rates analyzes the record evidence and provides an explanation of the settled issues; addresses issues on transmission rates raised in the initial briefs by non-settling parties; and explains positions that may be different from the rate proposal in FERC's tariffs. The proposed transmission rates, along with the proposed terms and conditions, provide comparable service to all FCRTS users. The decisions proposed in the Settlement Agreement regarding the transmission rate proposal represent a regional consensus to be effective for the 5-year rate period. The positions adopted in the Transmission Settlement Agreement discussed in this section do not create any procedural or substantive precedents for establishing future transmission rates.

12.2 Segmentation

BPA operates and maintains the FCRTS to provide various transmission services throughout the PNW region. Because many services do not require the use of the entire system, the Segmentation Study categorizes the facilities of the FCRTS according to the types of services they provide. The Segmentation Study produces the segmented historical FCRTS investment base and the segmented averages of the last 3 years' actual operations and maintenance (O&M) expenses. This provides the basis for segmenting the transmission revenue requirements used to develop rates.

BPA's final proposed transmission rates reflect the segmentation of the FCRTS into six segments in accordance with the provisions of the Transmission Settlement: Generation-Integration; Network; Utility Delivery; DSI Delivery; Southern Intertie; and Eastern Intertie. The previously identified segments of the Northern Intertie and the IOU Delivery are now included in the Network. Also included in the Network is the portion of the former Fringe segment which consisted of BPA transmission facilities operating at voltages at 69 kV to 230 kV that were previously used to serve only Federal power customers. The cost of the General Transfer Agreements (GTA) was previously included in the Fringe; a small amount of GTA costs is now proposed to be included in the Utility Delivery segment, with the remaining cost allocated to the BPA power business. The Utility Delivery segment is now proposed to include facilities of voltages below 34.5kV, with the 34.5kV facilities moved to the Network. BPA is proposing to collect the cost of the Utility Delivery segment through a separate charge in the transmission rate schedules. DSI Delivery costs are recovered through Use-of-Facility charges.

12.2.1 Fringe

Issue

Whether BPA facilities formerly segmented to the Fringe should now be assigned to the Network.

BPA's and Parties' Position and Evaluation of Positions

In its initial proposal, BPA proposed to eliminate the Fringe segment and move the facilities to the Network segment. The Fringe consisted of facilities used to provide local area service and operating in the voltage range of 69kV to 230 kV. By combining the Fringe and Network facilities into one segment, BPA's power sales customers are able to buy from other providers and pay the same transmission charge as for buying Federal power. Gilman, *et al*., WP-96-E-BPA-28, at 2-3. BPA also proposed to roll-in facilities in the Delivery segment over 34.5 kV. *Id*. *See* section 12.2.2 for a discussion of the Utility Delivery segment.

The IOUs opposed the elimination of the Fringe, as well as the change in segmentation of Delivery facilities over 34.5 kV. The IOUs argued that the proposed change in segmentation would result in an unfair cost shift because historically BPA had assigned these costs to power sales. They also argued that the Fringe segment is needed to meet BPA's equitable allocation principle**.** Brattebo, *et al*., WP-96-E-GE/IP/MP/PL/PS/WP-03, at 3.

The Public Generating Pool (PGP) stated a number of conditions relating to wheeling contract terms they felt were appropriate in order for BPA to segment Fringe facilities to the Network. They concluded that for facilities to be rolled into the Network, Federal transmission facilities must be made available for both Federal and non-Federal wheeling. Black, *et al*., WP-96-E-PG-04, at 9.

The Requirements Customer Coalition (RCC) supported eliminating the Fringe as appropriate to have open and comparable access for power customers. A power customer who wanted to wheel over the Fringe to replace BPA purchases should be charged the same transmission cost as for a BPA power purchase. Saven, *et al*., WP-96-E-RC-06, at 3.

BPA and the parties to the Settlement Agreement agreed to include the facilities formerly segmented to the Fringe in the Network segment. Attachment 1, at 3.

Public Utility District No. 1 of Clark County, Washington (Clark) argues that Fringe facilities should not be assigned to the Network, as these facilities do not provide a Network function because they are used exclusively to deliver Federal power. Clark also argues that BPA has historically treated the Fringe as a separate segment and implementation of comparability does not change the nature or use of the Fringe facilities.

Clark asserts that because the Fringe facilities were constructed and used solely to serve BPA power customers, assigning the costs to the Network would be inequitable to other transmission customers and would shift $186 million in costs to the Network. Clark argues that as these facilities are used only by BPA's power customers, including the costs in the Network is preferential treatment. Clark also argues that such inclusion is inconsistent with the definition of Network in the FERC Tariffs. Finally, Clark claims that inclusion of these facilities in the Network is inequitable. Clark Brief, WP-96-B-CP-01, at 28-29; Clark Ex. Brief, WP-96-R-CP-01, at 15-18.

Clark individually offered no evidence on these issues during the rate case. However, as a member of WPAG, Clark offered evidence supporting including the former Fringe facilities in the Network. WPAG states, "While it is correct that the proposed treatment of certain transmission segments does result in a reallocation of costs, it does not follow that the purpose of the proposal is to benefit BPA's power business. In particular, the elimination of the Fringe segment and the redefinition of the Delivery segment are being implemented to achieve comparability." Beck, *et al.*,, WP-96-E-WA-15, at 28.

In its supplemental proposal, BPA established that the Fringe facilities are similar to Network facilities in voltage level and use, the only difference being their use to deliver only Federal power. BPA witnesses also testified that the fact that not every wheeling customer will use the facilities formerly segmented to the Fringe is not a reason they should not share in the Network cost pool. BPA pointed out that the major IOU wheeling customers utilize extensive portions of the BPA 115kV system that is similar in function to the Fringe. BPA has also built Network facilities primarily for the use of wheeling customers. Metcalf, *et al.*, WP-96-E-BPA-96, at 10.

Historically, BPA has treated the Fringe as a separate segment containing those facilities used to serve only wholesale power customers. Many of these customers, including Clark, have shown interest in diversifying their power supply and some have purchased non-Federal power. In order for the rates for such open transmission access to meet the FERC comparability standards, BPA must provide all customers, whether wholesale power or wheeling, comparable service at comparable rates. To do this, it was necessary to combine the cost of all facilities providing this service into a single segment, the Network, enabling BPA's power sales customers to buy from other providers, and still pay the same transmission charge as for buying Federal power. Gilman, *et al.*, E-BPA-28, at 2-3. Clark argues that maintaining a Fringe segment does not violate comparability. However, BPA demonstates clearly that maintaining a segment defined as facilities "used exclusively by Bonneville to deliver federal power to Bonneville customers," Clark Ex. Brief, R-CP-01, at 16, does violate comparability. When a customer that previously purchased all its requirements from BPA over Fringe facilities, considers purchasing from another source, the wheeling rate that customer would pay would not include Fringe costs in it, whereas the transmission costs associated with buying power from BPA would include those costs. This is a clear and obvious violation of comparability. Metcalf, *et al.*, WP-96-E-BPA-27, at 4-5.

The facilities that were formerly included in the Fringe are similar in voltage and operation to those facilities in the Network. The only difference is that the Fringe facilities were defined as used only by Federal power. With emerging competition and diversification of power supply, it is no longer appropriate to separately segment those facilities. The comparability construct developed by BPA resulted in all wholesale power customers becoming wheeling customers. The fact that not every wheeling customer would use the former Fringe facilities should not be a reason not to pay a rolled-in rate. Metcalf, *et al*., E-BPA-96, at 10-11. Clark argues that Fringe facilities are predominately radial in nature. Clark Ex. Brief, R-CP-01, at 16. However, no evidence is presented. In fact, BPA testified that the former Fringe facilities "are the same as Network facilities in purpose and operation." Gilman, *et al*., E-BPA-28, at 3. In addition, FERC has ruled that transmission level radial facilities should be rolled in with the backbone grid rather than treated like distribution radials. *Public Service Co. of Indiana v. FERC*, 575 F.2d 1204 (7th Cir. 1978).

Clark's statement that rolling in the Fringe is inconsistent with the definition of Network in the FERC Tariff is not supported and no explanation is given showing how it is inconsistent. In fact, FERC generally favors rolled-in pricing. *Central Maine Power Company*, 54 FERC ¶ 61,206 (1991). Clark's statement that the Fringe is used only by BPA or its power customers is no longer correct, as power deliveries now are also treated as wheeling transactions as noted above. Some of the power customers including Clark now buy non-Federal power delivered using former Fringe facilities. TRDS, WP-96-FS-BPA-06, at Table 17.

BPA demonstrated that wheeling customers utilize facilities that are the same nature as the former Fringe facilities. The Exchange Agreements with the major IOU wheeling customers were examined and many Points of Delivery (PODs) below 230kV were found where the power flow is always from BPA to the customer. Therefore, the wheeling customers are receiving the subtransmission system support that the former Fringe facilities provide the power customers. Metcalf, *et al*., E-BPA-96, at 15. In addition, BPA demonstrated that there are significant, costly facilities in the Network that were built solely or primarily for wheeling customers. *Id*. at 13-14.

BPA demonstrated that the former Fringe facilities are available to wheeling customers and have always been available for wheeling. It was also demonstrated that BPA does not build subtransmission facilities that are internal to a utility's system either for power or wheeling customers. *Id*. at 19-20.

Clark argues that BPA has included the Fringe in the Network in order to advantage its power marketing efforts. Clark Ex. Brief, R-CP-01, at 17. Yet on other issues, Clark argues that BPA has assigned too many transmission costs to its power sales customers, specifically GTA costs and delivery charge underrecoveries. *Id*. at 22-25. No explanation is given as how those proposals are consistent with Clark's theory that BPA is attempting to advantage its power marketing efforts.

Decision

In the context of the Settlement Agreement, the facilities that were formerly in the Fringe will now be included in the Network.

12.2.2 Utility Delivery

The proposed segmentation of Delivery facilities differs from that in previous rate filings. The previous segmentation divided Delivery facilities into segments based on the customer class served, which were Preference Customer, Direct Service Industrial (DSI), and Investor Owned Utility (IOU). The costs were then recovered through the power rates for each customer class. In this filing, Delivery costs are being recovered through transmission rates, so that power and wheeling customers can be charged the same rate. It was necessary to change the segment definitions to facilitate the recovery of costs. The new segmentation has two Delivery segments, the Utility Delivery and DSI Delivery. The DSI Delivery segment costs are recovered through UFT charges. The Utility Delivery segment treatment generated several contested issues that are discussed below.

Issue 1

Whether Utility Delivery facilities should be defined as facilities providing service at voltages below 34.5 kV.

BPA's and Parties' Position and Evaluation of Positions

BPA's initial proposal was to define Delivery segments as facilities providing service at voltages of 34.5 kV and below. Gilman, *et al.*, WP-96-E-BPA-28, at 9. Delivery segment facilities are available to serve both Federal power customers and wheeling customers at the same rate. BPA proposed a bright line test of the 34.5kV voltage level to provide a clear distinction between Network and Delivery facilities. Although BPA is not a distribution utility, the Delivery facilities provide a function analogous to a distribution function. Therefore, BPA examined its facilities, using the criteria in the NOPR for guidance, and concluded that the 34.5kV level provided a reasonable split between transmission and distribution. *Id*. at 10.

The RCC opposed BPA's proposal, stating that using a bright line voltage level as a criterion for determining Utility Delivery facilities is not appropriate and urging BPA to use a functional test to distinguish between transmission and distribution facilities. Saven, *et al.*, E-RC-06, at 26. RCC argued that some of the 34.5 kV facilities that BPA proposed to put into the Delivery segment were actually transmission and not delivery facilities. *Id*. at 30-31. The PGP also urged the adoption of a functional test. Black, *et al.*, E-PG-04, at 11-12. PGP expressed a concern that facilities at voltages *higher* than 34.5 kV should be included in the Delivery segment, and not in the Network. *Id.*

IOUs opposed any attempt to redefine the Delivery segment. They asserted that the costs should be charged only to those customers using those facilities. These arguments are similar to those made for not eliminating the Fringe. They also argue that a voltage level "bright-line test" is unfair and inequitably impacts wheeling customers; and that utilities classify facilities differently and there is no agreed-upon standard. IOUs argue that redefinition of the Delivery segment is not required by the FERC NOPR or any other rate making principle. Brattebo, *et al*., WP-96-E-GE/IP/MP/PL/PS/WP-03, at 13-16. BPA and the parties to the Settlement Agreement agreed to define as Delivery, facilities at 34.5 kV and below. Attachment 1, at 4.

Clark argues that subtransmission Delivery facilities should not be assigned to the Network. Clark Brief, B-CP-01, at 16. Clark notes that the Settlement Agreement proposes to assign facilities to the Network at 34.5kV and above that were previously in the Delivery segment. *Id.* Clark claims that these facilities are low voltage facilities which serve solely a delivery function and that no evidence has been offered to justify inclusion in the Network. *Id.* at 17. Comparability does not change the nature or use of these facilities. Inclusion of these facilities is inconsistent with the standard of treatment set out in the FERC NOPR. This is inequitable, as under BPA's Customer Service Policy, BPA would subsidize the construction of delivery facilities for small customers, but force large utilities to bear the costs of such facilities. *Id.* Clark concludes that the "proposed treatment of delivery facilities constitutes a preferential treatment of the users of these Delivery facilities, and is an inequitable allocation of costs to the Network." *Id.* at 18. Clark Ex. Brief, R-CP-01, at 18-20. Clark does not point to specific record evidence to support its assertions, nor did Clark file testimony on this issue.

There is evidence that many of the RCC utilities, as well as some IOUs, classify and use 34.5 kV facilities to perform a transmission function. Clark's argument that subtransmission Delivery facilities should not be in the Network ignores the purpose of the Delivery segment. BPA has defined the Delivery segment as those facilities that provide service analogous to distribution, while the Network segment would consist of facilities providing a transmission function, including what Clark called "subtransmission." While there is no clear industry standard regarding a dividing voltage level, the NOPR provided some guidance. Applying the criteria to BPA facilities, BPA concluded that facilities operated at 34.5 kV and below function as distribution and should be in the Delivery segment. Gilman, *et al*., E-BPA-28, at 10.

Many customers represented by the RCC contested the choice of 34.5kV as a dividing line and argued that 34.5 kV facilities provide a transmission function and should be in the Network. Their testimony provides both functional and historical rationale for including 34.5 kV facilities as transmission. They establish that where voltage has been stepped down to 34.5 kV, there is transmission to another substation over 34.5 kV lines prior to the power being transformed to lower voltage and distributed to end users. In addition, the 34.5 kV was the transmission voltage that the Bureau of Reclamation used. Many customers that take power at 34.5kV do so because of BPA's or their purchase of those

Bureau facilities. Excluding 34.5 kV facilities from the Network would penalizethem for conforming their system to Bureau standards. Saven, *et al*., E-RC-06, at 24-32.

Decision

In the context of the Settlement Agreement, Utility Delivery facilities will be defined as facilities providing service at voltages below 34.5 kV. Facilities at 34.5 kV and above will be assigned to the Network.

Issue 2

Whether the Utility Delivery charge should be set at $9.00/kW/yr.

BPA's and Parties' Position

The settlement parties, including BPA, agreed that the Utility Delivery Charge should be set at $9.00 per kW per year even though that charge will not fully recover the cost of the Utility Delivery segment. Attachment 1, at 4.

Clark argues that the Utility Delivery Charge should not be set at a level below cost. Clark Brief, B-CP-01, at 14-15.

Evaluation of Positions

In the initial proposal, as modified by the revised segmentation study, BPA proposed a Utility Delivery rate of $13.25/kW/year for a 5-year average rate. Woerner, Gilman, WP-96-E-BPA-39, Attachment A, A-29. It was calculated by dividing the total segment revenue requirement by the billing determinants, which recovered total segment costs. The billing determinant was the customer load at the specified point of delivery at the time of the BPA monthly transmission peak. TRDS, WP-96-E-BPA-06, at 19.

The RCC and FMD argued that the charge was too high. The RCC provided analysis showing alternative ways of calculating the charge using options for service available to BPA customers, including the cost of new construction and customer cost of O&M. These costs were all lower than BPA's proposed rate, giving customers an incentive to build around BPA. The RCC recommended a rate of $.50/kW/month, or $6.00/kW/year, for BPA to be competitive with lower-cost options available to the customers. Saven, *et al*., WP-96-E-RC-06, at 15-23; Wagner, *et al*., WP-96-E-FM-02.

In the supplemental proposal, using the same method used in the initial proposal, BPA calculated that the Delivery Charge would be $13.18/kW/year. TRDS, WP-96-E-BPA-62, at 22. In later testimony, however, BPA proposed a new method to recover Delivery costs: determine the charge for each point using the Use-of-Facilities (UFT) rate, capped by the average cost. BPA recognized that the combined use of UFT and a cap would result in some cost underrecovery, which was proposed to be allocated to the BPA power business. Non-Federal power using the Delivery facilities would be charged the UFT rate with no cap, so that the BPA power business would not be subsidizing a competitor. Metcalf, *et al*., E-BPA-96, at 8-10.

RCC responded that BPA should adopt a uniform flat delivery charge, pursue efforts to reduce costs, and institute a policy that would allow customers taking service over Delivery facilities to lease or purchase the facilities, or to do O&M on the facilities. Saven, *et al*, WP-96-E-RC-09, at 9-11. *See also* Beck, *et al*., E-WA-13, at 61; Black, *et al*., E-PG-04, at 21.

WPAG, which included Clark as a member, supported using UFT charges for Utility Delivery, similar to that used for DSI Delivery. Beck, *et al*., E-WA-13, at 61. WPAG also supported the cap proposed by BPA, which would have resulted in a larger underrecovery of Delivery segment costs than the $9/kW/year settlement proposal.

In contrast to the WPAG testimony, Clark now argues that the Utility Delivery Charge should not be set at a level below cost. Clark Brief, B-CP-01, at 14-15; Clark Ex. Brief, R-CP-01, at 20-21. Clark relies on evidence presented by BPA to claim that the costs of providing delivery services averages about $13.00/kW/year. *Id.* at 14. Clark argues that setting the rate at $9.00/kW/year does not cover BPA's cost of providing service from the parties who receive it and that the $9.00 charge is not supported by record evidence. *Id.*

The Utility Delivery Charge has not been used previously, as these costs were assigned to power and rolled in and recovered as part of BPA's power rate in past rate cases. This charge is a new, and for many customers, a significant expense. BPA was concerned that a high charge would not only be a significant hardship for some customers, but could encourage them to take measures which would lead to inefficient system operation and reduced reliability. In addition, if the customers reduced their use of the Delivery facilities, the result would be reduced revenue. In rebuttal testimony, BPA stated that it believes it is appropriate to limit the Utility Delivery Charge by use of a cap. The purpose of the charge is not to impose a hardship or encourage inefficient operation. Metcalf, *et al.*, E-BPA-96, at 9. Rather, the purpose of the charge is to recover costs from the users of the facilities.

The customers using these facilities, as represented by the RCC, have provided evidence that the charge will have a major financial impact on them. Saven, *et al.*, E-RC-06, at 9. The RCC also testifies that the supplemental proposal charge is too high. They describe several alternate methods to develop the cost of Delivery based on customer experience costs for O&M and replacement costs for facilities. Their methods result in a range for the charge of $.60 to $.80 per kW/month ($7.20 to $9.60/kW/year). They recommend that BPA use an even lower charge of $.50/kW/month due to the alternatives available to the customers. They state that if the charge is too high it will not be competitive. RCC argues that the customers will have the incentive to find other ways to provide this service, such as buying the Delivery facilities, switching load to lower cost points and abandoning high cost points, installing or upgrading their own facilities, or taking a number of other actions to reduce costs. *Id.* at 15-23.

The Settlement Agreement contains a Utility Delivery Charge that is lower than the cap proposed by BPA. WP-96-E-BPA-62, at 22. However, because it is a uniform charge rather than a UFT charge, the settlement Delivery Charge will collect more total revenues than BPA's earlier proposal. TRDS, WP-96-FS-BPA-06, Appendix E. This is a compromise to provide a transition period for the customers using these facilities, both to reduce hardships to these customers and to not encourage the construction of unneeded facilities or inefficient system operation. Clearly, a charge that does not promote the contruction of unneeded facilities or inefficient operation is consistent with BPA's requirement to adopt rates that are consistent with sound business principles. The implementation of a policy that gives customers the right to purchase or lease of the facilities, as provided in the Transmission Settlement Agreement, will also aid in the transition. Attachment 1, at 3-4.

The Utility Delivery Charge of $9.00/kW/year will not recover all of BPA's cost for this segment, but all costs will be recovered. The underrecovery will be assigned to the BPA power business. (*See* Issue 3, below). Since the underrecovery is being assigned to power, the delivery charge for wheeling could have been set at full cost recovery, as BPA proposed. However, setting the rates in that manner would have violated comparability, since wheeling customers would pay a different rate than power customers. The rate is not discriminatory as all users of the Utility Delivery service will pay the same rate.

<u>Decision</u>

In the context of the Settlement Agreement, the Utility Delivery Charge will be set at the $9.00/kW/year rate for both power and wheeling.

<u>Issue 3</u>

Whether a portion of a cost underecovery from the Utility Delivery Charge should be allocated to power customers.

<u>BPA's and Parties' Position</u>

BPA proposed to allocate the underrecovery from the Utility Delivery Charge to power customers. Metcalf, *et al*., E-BPA-96, at 8-10. The parties to the Settlement including BPA agreed to cover half the underrecovery with cost cuts. Attachment 2, at 3.

Clark and APAC argue that the underrecovery from the Delivery Charge cannot be allocated to power. Clark Brief, B-CP-01, at 15-16; Clark Ex. Brief, R-CP-01, at 22-24; APAC Brief, WP/TR-96-B-PA-01, at 33-35; APAC Ex. Brief, R-PA-01, at 34.

Evaluation of Positions

In BPA's initial proposal, the Utility Delivery Charge was set at a level, $13.25/kW/year, that would fully recover the costs of the segment on a forecasted basis. Woerner, Gilman, WP-96-E-BPA-39. Based on evidence presented by RCC that a delivery charge of that magnitude would cause significant hardship and would not be competitive with many of the delivery customers' transmission alternatives, BPA proposed in supplemental testimony to adopt a UFT design capped at the average cost level. Metcalf *et al.*, E-BPA-96, at 8-10. This design introduced an underrecovery which BPA proposed to be allocated to the power customers. BPA proposed to apply the cap only to Federal power sales; wheeling over the Delivery segment would pay the full UFT charge. *Id.* The RCC and others objected that this alternative was not comparable. Some customers would face higher delivery charges for power purchased from a BPA competitor than if they continued to purchase all their requirements from BPA. The RCC argued that the Utility Delivery Charge should be the same for power and wheeling and BPA should pursue efforts to reduce costs. Saven, *et al.*, WP-96-E-RC-09, at 9-11.

Clark argues that the underrecovery from the Delivery Charge cannot be allocated to power. These facilities are used to deliver both Federal and non-Federal power, so there is no rational basis for allocating the costs to power. They argue that this results in power customers providing a subsidy to the users of these facilities, and furthermore, that this violates BPA statutes requiring equitable allocation of costs to Federal and non-Federal customers. Clark Brief, B-CP-01, at 15-16. APAC also argues that Delivery facility costs (and GTA costs) should not be assigned to power, but should be assigned to distribution or customer accounts. They argue that pure power customers (customers with no wheeling) lose by the shift of costs from transmission to power. APAC Brief, B-PA-01, at 33-35.

Clark and APAC appear to be arguing that only delivery customers can pay Delivery segment costs. However, neither Clark nor APAC address or rebut the evidence presented by RCC that a delivery charge of that magnitude would be an undue burden on the RCC customers. When cost allocation methods change, it is common to phase in the change in a situation where certain customers or classes are severely harmed by the change. In previous rate cases, the Preference Customer Delivery segment costs were allocated to the power rates and spread over all power customers. The only situation where a customer paid directly for delivery costs was when they wheeled over the facilities. The cost-based Delivery Charge is greater than $13/kW/year, which exceeds the full PTP rate ($12/kW/year). Thus, the Clark and APAC proposal, if adopted, would result in transmission charges to the delivery customers increasing from the rolled-in postage stamp transmission costs contained in the current PF rate to paying essentially twice the average rolled-in rate.

Once the decision has been made to adopt a Delivery Charge that does not fully recover the segment costs, there are only two alternatives for recovering the underrecovery. It can be allocated to the power customers or it could be assigned to the Network and allocated over all network users, power and wheeling. The rationale for allocating this underrecovery to power is straightforward. These facilities were built to serve power customers and their costs have always been rolled into power rates. Since a new cost allocation methodology is being phased in, it is appropriate to use a combination of the new method (allocate to Delivery segment customers) and the old method (allocate to power and roll into the power rates). APAC characterizes the settlement approach as a shift of costs to high-voltage users by comparing it to BPA's initial proposal. APAC Brief, WP/TR-96-B-PA-01, at 34. However, APAC overlooks the fact that, compared to the current PF rate, the settlement proposal represents a cost shift of $9 out of the $13/kW cost of the Delivery segment *away* from high voltage users. Normally, the phrase "cost shift" refers to a change in methodology from previous rates, not from a proposed methodology that was never adopted.

Neither APAC nor Clark advocate allocating the underrecovery to Network. APAC even states that such an allocation would violate FERC policy. APAC Brief, B-PA-01, at 33-35. Clark opposes including former Fringe and Delivery segment costs in the Network, which are higher voltage than the Utility Delivery facilities, so it would be illogical for them to advocate that some below-34.5kV delivery costs be included in the Network.

Finally, the customers urge BPA to undertake efforts to reduce costs to offset the impact of the Delivery Charge. In response, BPA has adopted transmission cost reductions which more than offset the impact of the Delivery segment underrecovery on the power business. TRDS, WP-96-FS-06, Appendix J.

Decision

In the context of the Settlement Agreement, the underrcovery from the Delivery Charge should be allocated to power rates with at least half covered by cost cuts.

12.2.3 General Transfer Agreements

Issue

Whether the costs of the General Transfer Agreements (GTAs) should be allocated to power rates.

BPA's and Parties' Positions

BPA and the parties to the Settlement Agreement agreed to allocate the costs of the GTAs to power rates and delivery segments. Attachment1, at 4.

Clark argues that the GTA costs should be divided between Network and Delivery and allocated to Federal and non-Federal transmission customers. Clark Ex. Brief, R-CP-01, at 24-25.

Evaluation of Positions

Many of BPA's power customers are located in or near an IOU transmission system. BPA serves these customers by contracting with the local IOU to utilize its transmission facilities to serve BPA's wholesale power customer. These agreements, which also include reciprocal service to some IOU loads over BPA's transmission system, are called General Transfer Agreements (GTAs). BPA's initial and supplemental transmission rate proposals, supported by the Requirements Customer Coalition, segmented expenses associated with service received under the GTAs to the Network and Delivery segments on the basis that using non-Federal facilities to serve power customers is equivalent to an extension of the Federal transmission network. Gilman, *et al.*, WP-96-E-BPA-28, at 3-8; Metcalf, *et al.*, E-BPA-96, at20-27. Weidl, Kitchen, WP-96-E-RC-07, at 5-8.

The IOUs, on the other hand, argued that GTA costs should be allocated exclusively to power customers. They argue that the GTAs are bilateral agreements that confer no rights for transferring other than Federal power over their respective systems. Since the GTAs cannot be used for any purpose other than BPA power sales, it is inappropriate to allocate a portion of them to wheeling customers. Unlike the rest of BPA's network, the GTAs cannot be used by wheeling customers. In prior rate proceedings, BPA has identified these GTA costs as transmission costs assignable to the Fringe segment, which were allocated entirely to wholesale power rates. In addition, they argue the costs are incurred solely for the benefit of BPA's power customers. Brattebo,*et al.*, WP-96 E-GE/IP/MP/PL/PS/WP-04, at 2-7. MPC objected on the grounds that the resulting Network wheeling rates would in essence have BPA's wheeling customers pay BPA for transmission services they themselves are selling to BPA. Stauffer, WP-96-E-MP-01, at 5. The IOUs further objected to the proposal on the grounds that BPA was implying a contract interpretation pertaining to the scope of the GTAs that they, the other parties to the agreements, had not concurred with and in fact disagreed with. Tr.1945-1946.

In direct testimony, PGP offered limited support for BPA's proposal, but conditioned its support in part by stating that only GTA costs that had the "character of the Network" be allocated to network rates, but only if the transferring utility agrees in advance to non-Federal wheeling. Black, *et al.*, WP-96-E-PG-04, at 15. However, in rebuttal testimony, PGP advocated a transitional approach that would in effect keep the costs of the GTAs in BPA's power rates until such time as the applicability of the GTAs to non-Federal service could be resolved. Black, *et al.*, WP-96-E-PG-07, at 8-9.

BPA's proposal to include the GTAs in the network was partly based on the goal of achieving comparability for the GTA customers. Metcalf, *et al.*, WP-96-E-BPA-27, at 2. If the IOUs were to allow third party wheeling over the GTAs, inclusion of the GTA costs in the network would mean that the GTA customers could make non-Federal purchases and wheel over the BPA network and the GTA for the same transmission cost as if they continued to purchase from BPA. Gilman, *et al.*, E-BPA-28, at 8. However, the IOUs all testified that they believed the GTAs did not provide for third party wheeling and that they would oppose any attempt by BPA to provide third party wheeling over the GTAs.

Tr. 1945-1946. Thus, it appears that including GTA costs in the Network would not, by itself, provide for comparability for GTA customers.

Clark, in its initial brief, objects to including GTA costs in power rates. While arguing that the GTA costs should not be allocated to power customers, Clark does not explain how these costs should be allocated. It appeared that they favored allocating them directly to the transfer customers because they argued that allocating to power represents preferential treatment of GTA customers. Clark Brief, B-CP-01, at 18-19. No party, including Clark, presented evidence in favor of allocating GTA costs directly to GTA customers. BPA explained that if the GTAs had not been available, BPA would have built facilities to serve the GTA customers and those facilities would have been more expensive than the GTAs and would have been rolled in. Therefore, it would be very unfair to charge the individual GTA customers for the GTAs in addition to their share of the BPA network costs. In addition, this alternative would imply a substantial rate increase for some of these customers. Metcalf, *et al*., E-BPA-96, at 25-26.

In its Brief on Exceptions, Clark clarifies that it believes that the GTA costs should be divided between Network and Delivery and allocated to Federal and non-Federal transmission customers. Clark Ex. Brief, R-CP-01, at 25. Clark argues that the failure to allocate any of the GTA costs to wheeling customers is inequitable. It is interesting to note the inconsistency between Clark's positions on the Fringe and on the GTAs. Many of the facilities formerly in the Fringe segment are now or are about to be used for wheeling, and all the Fringe facilities are available for wheeling. Yet Clark argues that the Fringe should be allocated to power customers only. On the other hand, the GTAs are currently used only to serve power customers and it is not clear whether they can be used for wheeling. Yet Clark argues that some of these costs should be rolled in to the Network. It appears that rather than adopt consistent positions on these issues (or even positions that are consistently in its own economic interest), Clark is determined to oppose all aspects of the settlement.

Clark also argues that inclusion of the GTA costs in power results in a subsidy of the GTA customers. This argument is inconsistent with Clark's proposal to assign GTA costs to the Network and Delivery segments. The GTA customers buy the vast majority of their power from BPA. Assigning the GTA costs to power results in the GTA customers paying for a greater portion of the GTA costs than would assigning the costs to the Network and Delivery, as Clark proposes. Thus, if the settlement proposal subsidizes the GTA customers, Clark's proposal would constitute an even larger subsidy

APAC argues that allocating GTA costs and Delivery Charge underrecovery to power violates the requirement that transmission costs be unbundled from power rates. APAC Ex. Brief, WP/TR-96-R-PA-01, at 34. This argument overlooks the fact that there are transmission costs incurred by the power business as part of its overall cost of doing business. Examples of these kinds of costs include Generation Integration costs and transmission costs for power purchases, storage, exchanges, and other coordination transactions. Bliven, O'Meara, WP-96-E-PP/DS/PA/PG/PG/RC/WA-09, at 3-8; Brattebo *et al.*, WP/TC-96-E-GN-01, at 7-8; Opatrny, WP/TC-96-E-BC-07, at 30-31. The Settlement Agreement simply treats GTA costs and Delivery segment underrecoveries as similar power business costs. This treatment does not violate the requirement to unbundle transmission rates from power rates.

Decision

In the context of the Settlement Agreement, GTA costs are allocated solely to power customers. GTA customers taking delivery below 34.5 kV will pay the uniform Delivery charge for both power and wheeling, if any, over the GTAs. The remainder of the GTA costs will be rolled into the power rates.

12.2.4 Interties

Issue 1

Whether the Northern Intertie segment should be rolled into the Network.

Evaluation

Consistent with BPA's practice since 1983, BPA proposed a Northern Intertie rate based on the cost of transmission facilities that comprised BPA's interconnection with Canada. Powerex strongly opposed BPA's Northern Intertie rate, and proposed eliminating the Northern Intertie segment, and thus, the Northern Intertie rate. In response to Powerex's case to eliminate the Northern Intertie, only Puget Sound Power and Light and BPA submitted testimony.

Powerex also made a request on September 27, 1995 to BPA under Section 10.4.1 of the Northwest Regional Transmission Association (NRTA) for transmission service at rates that reflected a rolling-in of Northern Intertie costs with Network costs. BPA rejected Powerex's request, and Powerex initiated an arbitration proceeding under the "BPA Rate Issue Dispute" provisions of Section 12.5 of the NRTA Governing Agreement. At the prehearing conference, the arbitrator ruled that, among other things, Powerex's request for transmission service should be resolved in BPA's on-going rate case, and that the arbitration should be suspended until 30 days after FERC's first order dealing with BPA's rates. Tr. 1791-1792; Powerex Brief, WP-96-B-BC-01, at 5-6.

Powerex made a number of arguments to support the roll-in of Northern Intertie cost into the Network. Some of Powerex's arguments are: that the majority of Northern Intertie use is by BPA; that the primary function of the Northern Intertie is to support BPA's federal requirements as shown in the Transmission Rate Design Study; that the functions performed by the Northern Intertie facilities benefit the entire BPA system; that the reliability and flexibility of the interconnected transmission systems would be diminished if the Northern Intertie facilities were taken out of service; that the Northern Intertie facilities, the Bellingham Reinforcement Project facilities, and the Network are all integrated; that Northern Intertie facilities operate at the same voltage levels as the Main Grid portion (230 kV and above) of BPA's Network; that the Northern Intertie facilities interconnect BPA's Network facilities between Custer substation and the Intalco plant with BPA's Network facilties at Monroe, and thus connect the Network to the Network; that the Northern Intertie is relatively short compared to the Southern and Montana Interties; and that rolling-in the costs of the Northern Intertie facilities to Network revenue requirements has less than a 1 percent impact on the Network revenue requirement. Powerex Brief, B-BC-01, at 10-18; Opatrny, WP-96-E-BC-07, at 16-18. Settlement negotiations resulted in a consensus to treat the Northern Intertie facilities as part of BPA's Network segment for the 5-year rate period October 1, 1996 through September 30, 2001. Attachment 1, at 5.

<u>Decision</u>

In the context of the Settlement Agreement, the Northern Intertie segment is rolled into the Network.

<u>Issue 2</u>

Whether BPA may treat the Northern Intertie facilities as part of the Network without also treating the Southern Intertie and Eastern (or, Montana) Intertie similarly.

<u>BPA's and Parties' Positions and Evaluation</u>

Clark argues that all Interties must be treated the same--either all should be eliminated or all maintained as Interties. Clark argues that the Southern and Eastern Interties are indistinguishable from the Northern Intertie and any other portion of the Network because all three interties operate at transmission level voltages and provide support for local deliveries. Clark Brief, B-CP-01, at 20-22. In addition, Clark argues that BPA will "use its operational and ownership control of [the Southern] Intertie to regulate access to both the Northwest and Southwest market, and . . . advantage its power marketing activities in both regions." *Id*. at 21; Clark Ex. Brief, R-CP-01, at 28. Retaining the Southern Intertie will "hinder the development of a fully open, competitive wholesale power market." Clark Brief, B-CP-01, at 22; Clark Ex. Brief, R-CP-01, at 28.

Clark presents no evidence or information to support its claims. Powerex stated that it believed that the Interties should be treated on a "case-by-case basis rather than trying as [BPA] has done since the 1983 Rate Case to fit their differing characteristics and uses into a uniform Intertie rate policy." Opatrny, E-BC-07, at 18. BPA did not contest this statement, but did argue that differences between the Northern and Southern Interties were not dispositive of the issue of eliminating the Northern Intertie. Metcalf, *et al*., E-BPA-96, at 34-35. Clark argues that length is the only difference between the Northern Intertie and the Southern and Eastern Interties. Clark Ex. Brief, R-CP-01, at 27.

Powerex cited many differences between the Northern Intertie and the Southern and Eastern Interties including: length (the Southern and Eastern Interties are considerably longer than the Northern Intertie); structural (3100MW of Southern Intertie capability is attributable to a direct current line that has no counterpart on the Northern Intertie); ownership (multiple ownership on the Southern Intertie, unlike the Northern Intertie); and reliability benefits (the parallel path to BPA's trans-Cascades facilities that is provided by BC Hydro's east-west transmission reduces the necessity for BPA to reinforce its trans-Cascades facilities). The Eastern Intertie was built almost solely for the purpose of integrating the Colstrip generation, Opatrny, E-BC-07, at 16-18, and treatment of those facilities as direct assignment facilities is memorialized in the Colstrip contracts and the TGT rate. In addition, Powerex shows that BPA has always treated the Southern Intertie as a separate segment, but the treatment of the Northern Intertie as a separate segment was first introduced in the 1983 rate case.

Because the Northern Intertie is very inexpensive relative to the Network, rolling it in has minor impacts on other rates. On the other hand, the Southern Intertie costs are about 18% of the Network costs. TRDS, WP-96-FS-BPA-06, Table1. Since virtually all power that is allocated Southern Intertie costs is also allocated Network costs, rolling in the Southern Intertie would cause an additional increase of about 18% in Network wheeling rates. Thus, this last-minute proposal by Clark, if adopted, would result in major cost shifts. The issue of eliminating the Southern and Eastern Interties was not addressed in the rate case testimony, cross-examination, or settlement negotiations.

BPA proposed the new Montana Intertie rate (IM-96) for service over the Montana Intertie under the terms and conditions of the Point-to-Point tariff. Woerner, *et al.*, E-BPA-85, at 23-24. No testimony was received in opposition to this new rate. Throughout the case, BPA proposed the Southern Intertie segment and rate schedule (IS-96) for service over the Southern Intertie. *See* TRDS, WP-96-E-BPA-06 and WP-96-E-BPA-62. BPA is proposing that terms and conditions of service over the Southern Intertie are offered under the Point-to-Point tariff. PTP Tariff, TC-96-FS-BPA-02. Regardless of the status of the Northern Intertie, Clark could have raised its concerns regarding the Southern and Montana Interties at an earlier time during the rate case to allow an open discussion of their issues among all parties. Certainly, Clark's contention (raised for the first time in its Opening Brief) regarding BPA hindering the development of a competitive wholesale power market is unsupported and flies in the face of the substantial changes BPA is voluntarily undergoing in terms of functional unbundling; its membership in both NRTA and WRTA; the voluntary filing of open access tariffs, including access to the interties, and rates with FERC; and rolling in the Northern Intertie. In addition, the BPA power business is the major user of BPA's Southern Intertie and pays most of the costs. TRDS, FS-BPA-06, Table 20. Rolling in the Southern Intertie would have the impact of lowering BPA's power rates and increasing its wheeling rates. Therefore, keeping the Southern Intertie as a separate segment does not benefit BPA's power business, as Clark alleges.

The impact of rolling in the Southern Intertie on competition is unclear. It would lower the cost of transmission between the regions, but it would significantly raise the cost of transmission in the Pacific Northwest.

Decision

In the context of the settlement, the Southern and Montana Interties will be treated as separate segments of the FCRTS with rate schedules for service over these Interties under the terms and conditions of the PTP tariff.

12.3 Transmission Rate Development

12.3.1 Rate Construct For Network Service

BPA has a large amount (over 10,000 MW) of firm Network wheeling demand under contract. In addition to revising rates for these existing firm wheeling contracts (Integration of Resources (IR) rate and Formula Power Transmission (FPT) rate), BPA developed and proposed new rates (Network Integration (NT) rate and Point-to-Point (PTP) rate) for open access transmission service. IR service is similar to PTP service, while FPT service is a more limited service with a rate design based on the types of facilties used and the transmission distance. Following an initial proposal that included different rate levels for each Network service, BPA formulated and proposed a simpler and more efficient rate construct for pricing Network service in the supplemental proposal. Metcalf, *et al.*, E-BPA-84, at 5-8.

In the supplemental proposal, BPA proposed that the PTP rate, the IR rate, and the base charge for the NT rate be set equal to each other. (BPA's NT rate proposal includes a Base charge and a Transmission Load Shaping charge. *See* section 12.4.2 for a discussion of the NT rate schedule.) (The FPT rate is not included in this construct because it is based on the cost of types of facilities and distance.). BPA proposed this rate construct for IR, PTP, and NT service to avoid the problems associated with a proposal that includes multiple rates for similar service (in this case, for firm Network service). For example, two parties that want to do business may have different BPA transmission arrangements for similar service. They will tend to choose the cheaper transmission alternative, which could lead to systematic BPA revenue underrecovery. In addition, if the IR rate were lower than the PTP rate, even by a small margin, BPA would be placed at a competitive disadvantage since the IR rate is not available for BPA power sales. *Id.* at 6. Other reasons for setting the PTP and IR rates at the same level for firm annual service include the difficulty of pricing the differences in IR and PTP services, and the problems that the parties pointed out in the Initial Proposal methodology BPA used for distinguishing the cost of service. *Id.* at 6-7. Setting transmission rates at the same level for similar services helps to create a competitive market for all bulk power supplies and avoids market distortions.

12.3.2 Network Cost Allocation

In previous rate cases, BPA has focused on allocating transmission costs equitably between wheeling customers and power customers. In this rate case, the focus is on allocating costs among the different firm Network transmission services (FPT, IR, NT, and PTP), some of which are available to both power and wheeling customers. The resulting rates for services will then be applied uniformly to power and wheeling customers. In BPA's initial proposal, costs were allocated according to billing determinants, with a load shaping charge added to the NT rate to reflect the difference between the NT billing determinant of monthly coincidental demand, and the contract demand billing determinants for other classes. Metcalf, *et al.*, E-BPA-27, at 10-11. *See* section 12.4.2 for a discussion of the NT rate, including an explanation of the load shaping charge.

Parties objected to this allocation methodology, arguing that equity requires developing a uniform allocator for all firm Network rate classes. Generating Utilities of the Northwest (GUN) recommended using coincidental demands to allocate costs. Brattebo, *et al.*, E-GN-01, at 14-16. The DSIs argued that costs should be allocated using peak loads under cold weather conditions. Schoenbeck, Bliven, WP-96-E-DS-02, at 3-5. The IOUs also argued that abnormal cold weather peaks should be used. Schue, Semro, WP-96-E-GE/PS/WP/IP-01, at 5. WPAG supported the use of a 12-CP methodology. Beck, *et al.*, WP-96-E-WA-01, at 27-31.

In response, BPA proposed to allocate costs to firm Network rate classes using annual contract demands or their equivalent. For customers without contract demands (NT rate customers and 1981 Power Sales Contract customers under the NTP rate), the sum of their forecasted annual noncoincidental peaks is used as the contract demand equivalent. Woerner, *et al.*, WP-96-E-BPA-85, at 7-8. BPA identified three reasons to support the use of normal peaks, as opposed to cold weather peaks. First, BPA planning criteria are based primarily on meeting annual peak loading conditions with contingencies under normal weather conditions. Second, it is not clear that wheeling customers have adequate contract demand to cover cold weather peaks since they utilitize significant amounts of nonfirm transmission during cold snaps. Finally, NT customers deserve some recognition for their inability to use or assign unused capacity during off-peak hours. Metcalf, *et al.*, WP-96-E-BPA-115, at 8-11. This cost allocation method permits BPA to price all firm Network service on a similar basis.

12.3.3 Charging the BPA Power Business

BPA's initial proposal included an assignment of transmission costs to the BPA power business based on forecasted power sales, long-term exchanges and other incidental uses. TRDS, WP-96-E-BPA-06, at 8-15. A number of parties identified additional BPA uses which were not recognized in BPA's cost allocation and rate design process. Bliven, O'Meara, E-PP/DS/PA/PG/PG/RC/WA-09, at 3-8; Brattebo, *et al.*, E-GN-01, at 7-8; Opatrny, E-BC-07, at 30-31.

In its supplemental proposal BPA recognized these additional Federal uses, but explained that some did not require additional cost assignment. For some uses, additional cost allocation would constitute charging twice for an "L"-shaped schedule. For example, when BPA purchases power or receives power pursuant to an exchange or storage agreement, that power is used to serve a BPA load. Since Network costs are assigned to all BPA loads, there is no need to also allocate Network costs to BPA for transactions involving the receipt of power (i.e., purchased power, receipts of power pursuant to exchanges or storage agreements). On the other hand, Southern Intertie costs are not normally charged to BPA loads. Therefore, to the extent transactions involving the receipt of power use the Southern Intertie, then intertie costs should be assigned to BPA to recognize that usage. In addition, the PTP tariff allows customers to put nonfirm transmission uses under firm contract demands at no additional charge. Much of BPA's nonfirm uses of the Network and Southern Intertie will fit underneath BPA's firm PTP demands associated with its surplus firm power sales and long-term exchanges. Woerner, *et al.*, E-BPA-85, at 2-4.

No testimony was received from any party taking issue with BPA's supplemental proposal to allocate costs to the BPA power business' uses of the transmission system as described above. As no issues were raised, the BPA power business will be charged for all its uses in the manner described in BPA's supplemental proposal. *Id.* No additional charges will be made for NT or PTP wheeling, for BPA for L-shaped schedules, or nonfirm uses that fit underneath firm contract demands.

12.3.4 Calculation of the FPT Rate

In previous BPA rate cases and in BPA's initial proposal, the FPT rate class was combined with the IR rate class for the purpose of cost allocation. This treatment allowed for the development of a revenue deficiency due to the wheeling customers' ability to choose between the rate designs (IR or FPT), and to confine the recovery of that deficiency to those non-Federal customer classes. TRDS, WP-96-E-BPA-06, at 15-16. In this rate case, the focus is no longer limited to allocating transmission costs between Federal and non-Federal power, but includes developing open access tariffs to apply to both BPA power sales and wheeling. In this context, allocating to IR and FPT as a combined wheeling class is not required. Schoenbeck, Bliven, E-DS-02, at 10-11.

However, eliminating the combined FPT and IR firm network wheeling class raises the issue of how to set the level of the FPT rate. To what extent should the FPT rate should be based of the average cost of the facilities as determined using the power flow study, and to what extent it should be based on costs allocated according to contract demand. The FPT customers argued that the FPT rate should be calculated using the average cost of types of facilities, reduced by revenue credits, using the power flow study. Black,*et al.*, WP-96-E-PG/PL-02, at 1-10. This methodology would result in an average rate increase to FPT customers less than the average rate increase to IR customers. BPA proposed calculating an underrecovery from FPT based on the difference between revenues from the rates developed from the power flow method and costs allocated on a contract demand basis. This underrecovery is then allocated to all Network customers including FPT customers. This methodology would have resulted in an average rate increase to FPT customers greater the average increase to IR customers. Woerner, *et al.*, E-BPA-85, at 9-10; Black, *et al.*, WP-96-E-PG/PL-02; Metcalf, *et al*., E-BPA-115, at 6-18. In the DROD, BPA proposed to set the FPT rate so that the average percentage increase is the same as the IR increase, 13.5%. DROD, WP-96-A-01, at 368-369. This is a compromise between the method proposed by the FPT customers and the method proposed by BPA. It is consistent with the linkage between IR and FPT that BPA has maintained in previous rate cases and insures that the FPT customers are neither advantaged nor disadvantaged by the new cost allocations associated with comparability and the open access tariffs.

In its Brief on Exceptions, Pacificorp points out that BPA committed to limit the FPT rate increase to Pacificorp to 13.5% as well as the overall FPT increase to 13.5%. Pacificorp Ex. Brief, WP-96-R-PL-01, at 10. Pacificorp is correct that because it has a mix of FPT-95.1 and FPT-95.3 contracts and because the unit costs of each FPT component is changing by a different percentage, it would be possible for the increase to Pacificorp to exceed 13.5% while the increase to the FPT class as a whole was less than 13.5%. In its final rate proposal, BPA has set the FPT rate so that the total revenue increase from Pacificorp will not exceed 13.5%.

12.3.5 <u>Hourly Nonfirm Rate Calculations</u>

BPA is proposing to calculate its hourly nonfirm rates for the Network (ET rate), Southern Intertie (IS rate), and Montana Intertie (IM rate) using a method that results in lower nonfirm rates than the method articulated in the FERC NOPR. FERC's method in the NOPR starts with calculating the annual firm rate. Then, the monthly rate is 1/12 the annual rate, the weekly rate is 1/52 the annual rate, the daily rate is 1/5 the weekly rate, and the hourly rate is 1/16 the daily rate. The nonfirm rate caps are equal to the firm rates for the corresponding periods. However, in prior rate cases, BPA calculated its nonfirm rates in the ET and IS rate schedules prior to calculating its firm rates so that nonfirm revenues could be forecast and credited against the firm rates. Calculating nonfirm rates from the firm rates results in a circularity problem and would require BPA to set up a completely new way of modelling and calculating the rates. Woerner, *et al.*, E-BPA-85, at 11.

BPA therefore will continue to calculate the hourly nonfirm rates using the same method used in past rate proposals. That is, the nonfirm rates are calculated first in order to develop a forecast of revenues that is credited against the revenue requirement. Generally, that method sets the nonfirm rate equal to the average cost based on all usage of the segment, and results in an hourly nonfirm rate cap lower than the method in the FERC NOPR. Then, the annual firm rates are calculated using the adjusted revenue requirement. From the annual firm rates, the monthly, weekly, and daily rates are calculated using the method in the FERC NOPR. *Id.* at 12. No party opposed this proposal.

12.4 Transmission Rate Schedules

12.4.1 Rate Schedules Under PTP Tariff

BPA is proposing five rate schedules for service under the PTP tariff. Three rate schedules are proposed for service over BPA's Network: the PTP rate for firm service; the Reserved Nonfirm (RNF) rate for short-term nonfirm service; and the Energy Transmission (ET) rate for hourly nonfirm service. Metcalf, *et al.*, E-BPA-84, at 12. In addition, the proposed Southern Intertie (IS) and the Montana Intertie (IM) rate schedules provide PTP service over the Interties. The IS and IM rate schedules include rates for firm, short-term nonfirm, and hourly nonfirm PTP service. The IS rate schedule has been redesigned in this rate proceeding to provide all forms of PTP service over the Southern Intertie. The IM rate is new and makes available PTP transmission service over BPA's east-to-west capacity rights on the Montana Intertie. Woerner, *et al.*, E-BPA-85, at 22-23. BPA is not proposing a Northern Intertie rate schedule in accordance with the Settlement Agreement. Attachment 1, at 5. *See* section 12.2.4 on Northern Intertie segmentation.

With one exception discussed below regarding the PTP billing factor, all PTP rate schedules are modelled on and are consistent with the rate structure presented in FERC's NOPR pro forma tariffs. BPA has allowed for downward flexibility in the short-term and hourly nonfirm rates. In implementing the downward flexibility feature, BPA will offer discounted rates at a level that will maximize revenue. All parties, including the BPA power business, will pay the same price for the discounted service. Woerner, *et al.*, E-BPA-29, at 7. Discounted prices will be posted on BPA's OASIS and will be offered consistent with the Standards of Conduct.

PTP Rate Schedule

The PTP rate schedule is consistent with the rates in FERC's NOPR. Additional features in the PTP rate schedule include the Short-Distance Discount (SDD). The SDD provides a discount for transmission paths where the distance between the POI and POD are demonstrated to be less than 75 circuit miles. This SDD adjustment is also included in the IR rate schedule. Including the SDD in the PTP rate avoids a disincentive for customers interested in moving to PTP service from their IR service, and provides some disincentive for building around the FCRTS in short distance situations. The PTP rate schedule also includes the rates for DSIs that have executed 1996 Contracts that refer to point-to-point transmission charges but have not executed a PTP Service Agreement. Woerner, *et al.*, E-BPA-85, at 24-25.

Issue

Whether the Point of Interconnection demands for certain resources should be deemed to be zero for purposes of calculating the PTP billing factor.

BPA's and Parties' Positions

The settlement parties including BPA agreed that demands at resources within BPA's control area and subject to redispatch would be deemed to be zero for the purpose of calculating the PTP billing factor. Attachment 1, at 4-5.

Clark opposes the "zero POI" proposal. Clark Brief, B-CP-01, at 19-20.

Evaluation of Positions

BPA first proposed that for any PTP use involving BPA resources, a single "generic" Point of Interconnection (POI) would be specified. The single POI would be used for determining the PTP billing factor for BPA system sales. A POI Transmission Demand from a named Federal system resource would be difficult because all of BPA's sales are system sales. Woerner, *et al.*, E-BPA-29, at 6.

In later testimony, BPA pointed out the three ways that transmission service for BPA's power business was not precisely comparable to wheeling customers purchasing open access transmission PTP service. First, under the tariffs BPA's wholesale requirements customers themselves must purchase transmission under the NT or PTP tariffs—the BPA power business may not arrange for transmission and roll the transmission costs into the power price. Second, because BPA is not treated as one big wheeling customer for its requirements loads, it is impractical to require BPA to identify individual Federal System resources as POIs. Absent the ability to make system sales from a system POI, BPA could be required to identify specific resources for each wholesale power customer, whereas other PTP customers can purchase firm transmission to flexibly serve load at all their PODs with resources at all their POIs without specifying which POI is serving which POD. Finally, as part of the single POI proposal, the BPA power business cannot reduce transmission costs by taking advantage of short-distance situations to avoid paying full network costs. Although the BPA power business has many loads located near resources, it cannot use the Short-Distance Discount, or avoid paying for transmission for resources is in the middle of a load areas, or build its own by-pass transmission facilities, or demand a UFT rate with the threat of constructing by-pass facilities. BPA concluded that the negative aspects of the requirements sales treatment and inability to take advantage of various techniques to lower its network costs more than outweighed the benefits to it of the "single POI" proposal. Metcalf, *et al.*, E-BPA-84, at 14-15.

The PGP argued that the single POI proposal "creates a significant and unwarranted competitive advantage for BPA's power business" because no competitor of BPA is permitted to use the single POI concept. Black,*et al.*, WP/TC-96-E-PG-06, at 11. BPA argued that if it adopted the multiple POI construct, the BPA power business would actually be advantaged because some of its uses would not use the Network and other BPA uses could receive the Short Distance Discount. This reduced Network usage would result in a significant increase in transmission rates. Metcalf, Gilman, WP-96-E-BPA-114. In cross-examination, Pacificorp, who supported BPA's position on the single POI issue, expressed concern regarding BPA's redispatch proposal and the effect it would have on the single POI proposal. Tr. 68. Pacificorp pointed out that a single BPA POI was appropriate because BPA would have an obligation to redispatch its resources under the NT and PTP tariffs to avoid transmission constraints. Pacificorp reasoned that no particular transmission path was needed because BPA resources could be redispatched if necessary to ensure service to all loads. In contrast, a resource outside of BPA's control area required a firm transmission path because it could not be redispatched to avoid transmission constraints and should pay for each interconnection. However, because BPA was no longer requiring redispatching hydro resources for other hydro resources (the predominant type of BPA resource), the justification for the single POI proposal was eroded. Tr. 69-72. (In the Transmission Settlement, BPA withdrew the exemption from redispatch responsibility for hydro. Attachment 1, at 23.)

Specific firm transmission paths are not needed for resources that are in BPA's control area and that are redispatchable by BPA. Constraints on the transmission system could be avoided by redispatching resources which would allow the most efficient use of the transmission system. Therefore, the amount of firm transmission capacity required for a transaction for which the resources at the POIs are in BPA's control area and dispatchable by BPA is determined by the POD demand. This resulted in the "no POI" proposal: the PTP billing factor should be the greater of the sum of the POD demands or the sum of the POI demands. However, demands at POIs that are in BPA's control area and are redispatchable by BPA do not count in the sum of the POI calculation. Resources not dispatchable by BPA require a firm path that must be available for use at all times. Therefore, a POI demand for each such resource should be included in the billing factor calculation. This proposal provides comparable transmission service because any customer can put their resource in BPA's control area and allow BPA to redispatch their resource. Pacificorp's open access PTP tariff includes a "no POI" proposal and has been filed with FERC as part of an uncontested Settlement Agreement. FERC accepted the proposed filing subject to refund. *PacifiCorp,* 74 F.E.R.C. ¶ 61,163 (1996). Pacificorp urged the Administrator to adopt this proposal. Or.Tr. 2461-2463.

Clark disagrees with the "no POI" proposal for two reasons. First, Clark argues that transmission customers with resources in BPA's control area would be "economically coerced" into surrendering redispatch rights to BPA. Second, Clark argues that BPA is treated differently from other transmission users and claims this alleged disparity is inconsistent with the comparability standard in the NOPR. Clark Brief, B-CP-01, at 19-20. Clark's assertion of economic coercion is unsupported by any evidence in the record. Nothing in the "no POI" proposal would "coerce" a transmission customer into allowing BPA to redispatch its resources. As a transmission system owner, BPA has a greater responsibility than other transmission system users: it is required to redispatch its resources to alleviate constraints or provide system stability. If other transmission customers desire to secure the same treatment of their resources in the PTP billing factor, they may do so by locating their resource in BPA's control area and allowing BPA to redispatch their resources. Clark argues that the customer that agrees to allow its resources to be redispatched would face uncertainty concerning whether it would receive reasonable compensation. Clark Ex. Brief, R-CP-01, at 28. Currently, BPA faces just such uncertainty concerning redispatch of its resources because of the difficulty of quantifying the cost of hydro generation. BPA has agreed to follow FERC principles in calculating redispatch and opportunity costs. Woerner, *et al*., E-BPA-85, at 15; Appendix, at 179; Attachment 1, at 23. Further, if a customer disagrees with BPA's determination, it can pursue arbitration pursuant to the terms of the PTP tariff.

The no POI proposal does not give BPA a competitive advantage because it will make it easier for some customers to reduce the amount of power they buy from BPA. Consider a customer with 100 MW of loads that wanted to take 30% of its requirements off BPA and use two seasonal sources from different POIs to serve the 30MW, one during the winter and one during the summer. Absent the no POI proposal, the customer would have to purchase 130 MW of PTP demand since it would need 70 MW for its continuing BPA purchase and 30 MW each for its two purchases. With the no POI proposal, the BPA 70 MW purchase does not count as a POI, and the customer's POD demand of 100 MW exceeds its 60 MWs of POI demand, resulting in a contract demand of 100MW. Thus, the no POI proposal may actually make it more economical to reduce their purchases from BPA.

According to FERC's definition of comparable treatment:

> [A]n open access tariff that is not unduly discriminatory or anticompetitive should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system.

Order 888, at 21,548. The no POI proposal is available to all eligible transmission customers. Any party willing to have its resources redispatched in the same manner as BPA's resources will receive the same treatment for the PTP billing factor determination as will be applied to BPA. In addition, BPA will have to declare demands at PODs for out-of-region resources and purchases as well as any in-region resources which are not dispatchable. Thus, the no POI proposal is not a departure from open access comparability, as Clark claims.

Decision

In the context of the Settlement Agreement, the Point of Interconnection demands for specified resources in BPA's control area available for redispatch may be deemed to be zero for purposes of calculating the PTP billing factor.

12.4.2 NT Rate Schedule

FERC has proposed a load ratio pricing construct for NT service with a credit for customer-owned transmission facilities. In BPA's initial proposal, BPA adapted the load ratio share proposal that appeared in the NOPR to better fit BPA's overall rate-setting methodology. It appeared that the FERC rates were designed assuming only a small portion of transmission system use would be under these new rates. When formula rates are a small portion of total business, revenue from the formula rate can be used as a revenue credit and other rates designed to recover the total revenue requirement. However, BPA was forecasting that the NT and PTP rates would be used by a large portion of its power sales customers, and that many wheeling customers would choose to use the new services as well. Therefore, the NT and PTP use needed to be included in the cost allocation process to ensure that BPA would recover the total transmission revenue requirement. In addition, the FERC method seemed to spread the revenue requirement evenly across the 12 months, which would result in higher charges during low use months and lower charges during high use months. Customers with high use during months of overall low use would be penalized. Metcalf, *et al.*, WP-96-E-BPA-27, at 7-8. Finally, customers would not know the price they were paying until after the fact. BPA's initial proposal NT rate included a demand charge applied to the customer's total retail load (Network Load) on the hour of BPA's transmission system peak. The proposal also included a Customer Facilities Credit for customer-owned transmission facilities. Woerner, et al., E-BPA-29, at 3-6; WP-96-E-BPA-29(E1); Wholesale Power and Transmission Rate Schedules, WP-96-E-BPA-08, at 126-130.

Parties argued against the credit for customer-owned transmission facilities in rebuttal testimony. In the PNW, many of BPA's wheeling customers own substantial amounts of transmission facilities which could result, in some cases, of BPA paying the customer for BPA transmission service. Stamper, *et al.*, WP-96-E-GN-02, at 20-23. Parties also argued for billing on a net load concept—WPAG argued that it was a disincentive to use the NT rate when transmission was charged even for resources that never touch BPA's network, and that double charging is more likely to occur for purchased power resources. Beck, *et al.*, E-WA-01, at 31-33. GUN recommended using a customer's load net of any generation not transmitted by BPA. Stamper, *et al.*, E-GN-02, at 20-23.

BPA had similar concerns about the credit for customer-owned transmission facilities and, in its Supplemental Proposal agreed to eliminate it. If the customer could no longer receive a credit for their transmission facilities, BPA reasoned that it would no longer be fair to charge them for their total retail load. Therefore, BPA proposed to charge on net load. Metcalf, *et al.*, E-BPA-84, at 7-8. The net load approach is implemented through the concept of Customer-Served Load: internal generation, resources using a customer's own or another utility's transmission facilities, and power purchases for which the seller has a PTP contract with BPA may be excluded from the NT Base charge billing factor. Woerner, *et al.*, E-BPA-85, at 18. This position was adopted in the Transmission Settlement Agreement.

The NT rate schedule includes two charges: a Base Charge equal to the IR and PTP rates; and a Transmission Load Shaping Charge that recovers the difference between costs allocated to NT on a 1-noncoincidental demand basis and the revenues from the Base Charge applied to demand on the transmission system peak hour. The Transmission Load Shaping Charge also collects the cost of the transmission of losses. The Base Charge is applied to the customer's net load on BPA's transmission system. To ensure that the NT customer is not relying on BPA for free transmission backup, the customer must contractually declare a Customer-Served Load (CSL), which is the amount of load served through internal generation, over non-BPA transmission, or with power purchases where the seller of the power has PTP wheeling from BPA. The resources associated with the CSL must be running at a specified load factor over the Heavy Load Hours, or the NT Base Charge will be applied to the total load. In addition, the resources must be running at the level of the declared CSL at the hour of BPA's transmission system peak or the NT Unauthorized Increase Charge will be applied to the difference between the declared and actual CSL.

Issue

Whether the 60 percent load factor requirement in the Customer-Served Load provisions in the NT rate schedule should be adopted.

BPA's and Parties' Positions

If the NT customer elects to exempt certain resources and, thus, would not rely on BPA for backup transmission capacity or alternate paths, BPA proposed the requirement that the exempted resources operate over HLH at a load factor of 80 percent. If this requirement is not met, the customer would be billed for NT service on its total retail load instead of its net retail load (total retail load less CSL). In addition, the resource must be operating at the contractually specified level on the BPA transmission system peak hour to avoid an unauthorized increase charge. Woerner, *et al.*, E-BPA-85, at 17-19.

BPA proposed the 80 percent requirement to allow customers flexiblity in operating their systems. Removing a minimum operating requirement would allow customers to receive backup transmission service for their resources without charge. If the customer's Actual CSL is greater than its Declared CSL, BPA may be able to utilize the freed-up transmission capacity to sell nonfirm transmission. NT customers are credited with a share of nonfirm transmission revenues in the ratesetting process. If a customer declares a CSL, the customer is committing to BPA that it is able to reliably service that portion of its load without utilizing BPA's transmission system, and should be able to accommodate a certain amount of uncertainty about when the transmission system peak hour occurs. Metcalf, *et al.*, E-BPA-115, at 4-5. However, the customers argued that the requirements regarding CSL were onerous, Black, *et al.*, WP/TC-96-E-PG-06, at 2-4, and BPA and the parties agreed that the 80 percent requirement would be decreased to 60 percent to provide NT customers with more resource operation flexibility. The proposal continues to provide BPA with assurance that NT customers are not receiving free backup transmission service while providing the customers more flexibility in operating their resources.

Decision

In the context of the Settlement Agreement, BPA will adopt the lower 60 percent CSL requirement.

12.4.3 NTP Rate Schedule

The NTP rate schedule is available to utilities for transmission service under BPA's 1981 Power Sales Contracts (PSC). The current PF-95 rate includes transmission and generation costs in bundled rate charges. However, BPA has unbundled its PF rate and is proposing that transmission costs be recovered through the NTP rate and that generation costs be recovered through the PF rate. The NTP rate charges are based on the NT rate since transmission service under the 1981 PSCs is similar to NT service. However, the NTP billing factors are adapted to the specific service that Metered and Computed Requirements Customers receive under the 1981 PSC.

Issue

Whether the NTP Base Charge, Reserved Capacity Charge, and Utility Delivery Charge for Computed Requirements Customers (CRC) will use a billing factor based on the highest HLH Measured Demand for PF power.

BPA's and Parties' Positions

BPA proposed three NTP charges for transmission service under the 1981 power sales contracts (PSC) for CRCs. The NTP Base Charge which equals the IR rate, PTP rate, and NT Base Charge, would be applied to the purchases of power under the 1981 PSC on the hour of BPA's transmission system peak. Woerner, *et al.*, E-BPA-85, at 19. The Transmission Load Shaping charge would be applied to the customer's Computed Maximum Requirement (CMR). CMR represents the CRC's 1981 PSC rights to schedule power during Heavy Load Hours. Metcalf, *et al.*, E-BPA-115, at 6-7. The Reserved Capacity Charge that charges for the unused transmission capacity BPA is obligated to reserve for CRCs, would be applied to the difference between the customer's CMR and its Base charge billing factor. Woerner, *et al.*, E-BPA-85, at 21. BPA structured the transmission rate on the CRC's right to take power from BPA, and thus, their right to use the transmission system. Metcalf, *et al.*, E-BPA-115, at 2, 5.

CRC customers generally disagreed with the proposal to charge on the hour of BPA's transmission system peak, and argued for demand billing factors tied to the customer's peak. Leone-Woods, *et al.*, WP-96-E-PA/PG-03, 29-32. Among other reasons, the customers argued that demand billing factors for power and transmission should be the same to facilitiate the CRC's ability to control and manage their wholesale power costs. *Id.* at 30.

BPA and the parties agreed that the NTP Base Charge billing factor will be the highest monthly Measured Demand for power delivered under the 1981 PSC over heavy load hours, measured coincidentally across the customer's PODs, which is similar to the billing method that is currently used under the PF-95 rate schedule. This change in the NTP Base Charge billing factor is reflected in the Reserved Capacity Charge billing factor, which is, in part, based on the Base Charge billing factor. This change is also reflected in the Utility Delivery Charge billing factor: the hour of the month used for the Base Charge billing factor also sets the hour for determining use of Delivery facilities. WP-96-M-81, at 2.

Decision

In the context of the Settlement Agreement, BPA will use NTP billing factors for CRCs for the Base Charge, Reserved Capacity Charge, and Utility Delivery Charge shall be based on the highest HLH Measured Demand for PF power.

12.4.4 Advance Funding Rate

Introduction

BPA expects, as a result of open transmission access, to receive requests for new transmission service that may require the construction of transmission facilities. Where facilities are required to provide new transmission service for the benefit of the transmission customer requesting service, it may be appropriate for BPA to recover the costs of the facilities from such customer. Rehman and Dalton, WP-96-E-BPA-32, at 1. Such facilities may include those required to interconnect or integrate resources or loads with the FCRTS, such as Direct Assignment Facilities; upgrades or modifications to BPA's existing network or intertie facilities; or other arrangements where new use of the FCRTS is requested. Accordingly, BPA developed the proposed Advance Funding rate to recover the costs of such facilities from the transmission customer requesting the new transmission service. *Id.*

Description Of The Advance Funding Rate

The proposed Advance Funding rate will recover BPA's actual capital and related costs for specified FCRTS facilities. The capital and related costs may include the the costs for construction of facilities , reinforcements, modifications, upgrades or additions to existing facilities, or replacements associated with such facilities; allowance for funds used during construction (AFUDC) where applicable; costs associated with system impact studies or other applicable studies; costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide the new service. *Id.* , at 3-4; Appendix, Advance Funding Rate Schedule. The proposed Advance Funding rate will not recover any of BPA's annual costs associated with the required facilities, including the operation and maintenance, general plant and other direct and indirect costs. These annual costs will be recovered under other BPA rates such as the UFT rate. *Id.*

The proposed Advance Funding rate will allow BPA to recover the actual capital and related costs of the required transmission facilities from the requesting customer through advance funding or other financial arrangements, where such payment arrangement is provided for in an agreement with the customer. BPA may use the proposed Advance Funding rate to collect funds in advance of construction, as progress payments during construction or other payment arrangements. Lump sum advance or progress payments will be based on an estimate of the capital and related costs of the facilities being constructed. BPA will determine the actual project costs as soon as practicable after the date of commercial operation of the project, and after all costs associated with project construction have been recorded. BPA will either refund or bill the transmission customer for the difference between the estimated and actual capital and related costs. *Id.* at 2-4; Appendix, at 120-121.

Treatment Of Revenues From The Advance Funding Rate

BPA will own the facilities provided for under the proposed Advance Funding rate, and will capitalize and record the costs into a separate capital account. This accounting treatment will enable BPA to track the costs and separately identify them so they may be excluded from the capital investments of the appropriate transmission segment that are funded by BPA's Treasury borrowing authority for transmission system development. The payments received under the rate will be recorded as unearned revenues in the fiscal year that payment is made to BPA The annual accrual revenues will be associated with the appropriate transmission system segment as a revenue credit in rate design to account for recovery of depreciation expense. This accounting treatment assures that the facility costs that are recovered under the Advance Funding rate will not affect BPA's other transmission rates. *Id.* at 2. *See also*, DeWolfe, *et al.*, WP-96-E-BPA-14, at 26-27. BPA, however, has forecast no revenues under the Advance Funding rate for the rate period.

The Proposed Advance Funding Rate Would Be Applied Consistent With FERC's Transmission Pricing Policy

Application of this rate will be consistent with FERC's transmission pricing policy. TRDS, WP-96-E-BPA-06, at 26. The costs will be recovered from the transmission customer taking new transmission service over the facilities that are provided for under the Advance Funding rate, including BPA where applicable. The AF rate is intended to describe a method for recovering costs of specific facilities. BPA has had for many years a rate for recovering specific facility costs, the UFT rate. The difference between the UFT rate and the AF rate is that the UFT rate recovers specific facility costs over time whereas the AF rate would recover the capital costs from the customer up front.

Neither the UFT nor the AF rate are designed to specify precisely when it is appropriate to recover specific facility costs from a customer rather than rolling the costs of the facility into the network. In rebuttal testimony related to its Customer Service Policy, Metcalf, *et al.*, E-BPA-96, at 30, BPA describes how it intends to make this determination consistent with FERC policy:

> A power or wheeling customer may request new transmission service. If there is existing capacity, the service would be granted according to the terms of the tariff and rate schedules. New network PODs would be granted for existing IR contracts on the utility's system without additional charge. Existing provisions for UFT charges under IR agreements would not be renegotiated.
>
> If new facilities are needed, BPA would construct them if requested under the terms of the tariff. The facilities would be included in the Network or classified as direct assignment facilities according to the definitions in the tariffs and evolving FERC policy on this issue. If the customer disagrees with BPA's determination, it can pursue arbitration and/or appeal to FERC. Consistent with BPA's proposed segmentation, all facilities at 34.5 kV and below would be direct assignment.
>
> If the facilities are direct assignment facilities, the customer would pay for them, either through an up-front payment or UFT charges. If the facilities are network, the "OR" test will be applied to determine if the customer pays embedded cost or incremental cost.

12.4.5 Reactive Power Charge

Introduction

Several parties filed testimony on BPA's proposed Reactive Power Charge during the 1996 rate proceeding. *See, e.g.,* Brattebo, *et al.*,, WP-96-E-GN-04/06; Carr, *et al.*, WP-96-E- PP/PA-03; Weidl, Kitchen, RC, WP-96-E-RC-07; and Beck, *et al.*,, WP-96-E-WA-01. As part of the Transmission Settlement Agreement, however, the settling parties, including GUN, PPC, RC, and WPAG, agreed that the Administrator should adopt all other transmission rates in the Dockets, including the Reactive Power Charge, in the manner proposed by BPA in its supplemental proposal, as modified by subsequent rebuttal testimony. *See* Attachment 1, at 3. No legal, factual or policy issues pertaining to the proposed Reactive Power Charge were raised in any party's Initial Briefs for resolution by the Administrator. Accordingly the following discussion describes BPA's proposal.

A Separate Reactive Power Charge Is Appropriate For Users Of The FCRTS.

Reactive power flow considerations are one of the more critical factors in the design and operation of an integrated transmission system. Reactive power flows increase the real power (megawatts) losses and significantly contribute to voltage problems on an integrated system. Managing reactive power flows to maintain proper voltage levels is especially critical where real power is consumed by a large load or injected onto the system by a large generating resource. Reactive power, measured as kilovolt- or megavolt-amperes reactive (kVAr or MVAr), cannot be moved over long distances. Thus, mitigation measures necessary to manage the reactive power flows must be applied locally. Anasis, *et al.*, WP-96-E-BPA-31, at 1-2.

The reactive power support required on the Federal Columbia River Transmission System (FCRTS) is the result of the physical characteristics of customer loads that are served over the system, the characteristics and operation of generation units interconnected into the system, and also the characteristics and operation of the transmission system itself. Reactive power on the FCRTS is supplied by such devices as shunt reactors and capacitors, static VAr compensators, and by generators equipped with devices known as voltage regulators or automatic voltage control equipment. *Id.* BPA currently provides and will continue to provide the generation-related reactive power necessary to support transactions using the FCRTS that is not supplied by the customer. BPA's proposed Reactive Power Charge, however, is not a rate to sell generation-related reactive power. Rehman, *et al.*, TC-96-E-BPA-04, at 7.

The Proposed Reactive Power Charge Is Unbundled From The Transmission Revenue Requirement

The proposed Reactive Power Charge is based on costs associated with the types of transmission-related reactive power devices that are used to support the reactive power requirements of BPA's customers using the FCRTS at points of delivery (PODs) or points of interconnection (POIs). These devices include shunt reactors, which correct for leading reactive power; shunt capacitors, which correct for lagging reactive power; and associated support equipment (*i.e.*, circuit breakers, disconnect switches, controls) at such points. Shunt reactors, shunt capacitors, generation-related reactive power, transformer tap changers, static VAr compensators (SVC's), and series capacitors support the reactive requirements of both individual customers and the FCRTS. BPA, however, did not develop a separate rate for generation-related reactive power and the other types of transmission-related reactive power devices because it was too difficult and burdensome to determine which devices, or portions thereof, supported the customer's reactive needs and which supported the reactive needs of the FCRTS. Anasis, *et al.*, WP-96-E-BPA-86, at 4-5.

The proposed Reactive Power Charge unbundles the transmission-related reactive power costs associated with shunt reactors and shunt capacitors from the transmission revenue requirement. The Reactive Power Charge revenue forecast has been treated as a revenue credit against BPA's transmission revenue requirements. *Id.* at 7. *See also,* TRDS, WP-96-E-62, 3-4. This revenue credit approach provides that BPA will only recover the costs for these facilities once. No generation-related reactive power costs were refunctionalized to the transmission function. *See generally*, Revenue Requirement Study Doc. Vol. 1, WP-96-E-BPA-58A. Therefore, no generation-related reactive power costs were included in the transmission revenue requirement.

<u>BPA's Proposed Reactive Power Charge Will Apply To Both Power And Wheeling Customers.</u>

BPA's proposed Reactive Power Charge will supersede the current Power Factor Adjustment methodology in BPA's existing wholesale power rate schedules. Anasis *et al.*, E-BPA-31, 2-3. Upon review, BPA determined that its current Power Factor Adjustment methodology was inadequate in several ways. First, it does not apply to wheeling customers. Only BPA's wholesale power sales customers are subject to it. The loads and resources of BPA's wheeling customers also place reactive power requirements on the FCRTS. Hence, BPA determined that a common charge needed to be applied to all customer classes. Secondly, the current Power Factor Adjustment methodology is computed using the ratio of total MW-hours and total MVAr-hours over the entire billing month. This method yields a rough average power factor that does not accurately reflect the actual reactive power burden a customer is placing on the FCRTS because it masks short-term reactive peaks for which BPA must still make capital investments. *Id.* at 3.

The reactive power requirements of both BPA's power and wheeling customers increase the real power losses and significantly contribute to voltage problems on the FCRTS. This causes BPA to make additional equipment and plant investments to mitigate the increased reactive burden placed on the FCRTS by the power or wheeling customers' reactive power requirements. *Id.* Consequently, BPA proposed the Reactive Power Charge to address the increased or excessive reactive power flows on the FCRTS that are attributed to its wheeling and power customers reactive power needs. WPAG supports the principle of applying the proposed Reactive Power Charge to both wheeling and power customers. Beck, *et al.*, E-WA-01, at 54.

Making a customer responsible for its reactive power needs is consistent with the regional reliability standards. Section 8.1(a) of the Northwest Power Pool (NWPP) Minimum Operating Reliability Criteria provides that "[a]s far as practicable, each system or control area shall provide for the supply of its own internal transmission and load reactive requirements, including appropriate reserve, and its share of reactive requirements on interconnecting transmission circuits." Nearly identical language also appears in Policy 2--Transmission, Section B of the North American Electric Reliability Council (NERC) Operating Polices, and Section 8.1 of the Western Systems Coordinating Council (WSCC) Minimum Operating Reliability Criteria. Anasis *et al.*, E-BPA-86, at 2. The NWPP, NERC and WSCC standards are generally accepted reliability standards for interconnections and operations that are followed in the region. Tr.1441. In addition, BPA's contracts with most of its customers in the Pacific Northwest include provisions addressing the management responsibility of reactive power flows. These provisions generally provide that "parties shall jointly plan and operate their interconnected electrical facilities so that the flow of reactive power accompanying or resulting from deliveries of electric power and energy under this contract will not adversely affect the system of either party." Brattebo, *et al.*, E-GN-04, at 4 n.1. BPA, itself, is currently subject to power factor standards at network points of interconnection under three existing transmission agreements with PacifiCorp and Idaho Power Co. Anasis, *et al.*, WP-96-E-BPA-88, Attachments 3, 4, and 5. WPAG agrees that BPA's approach for dealing with reactive power flows on the interconnected system is consistent with the approaches employed by other Pacific Northwest utilities. Beck, *et al.*, WP-96-E-WA-15, at 34.

<u>Design Of The Proposed Reactive Power Charge</u>

The proposed Reactive Power Charge is designed to apply to those points of delivery and points of interconnection between BPA and its customers that behave like radial loads. The proposed Reactive Power Charge will be applied at all PODs between BPA and a customer, except, in most cases, customer PODs that are served by transfer over another utility's transmission system. It will also be applied to POIs between BPA and a customer where the flow of real power is unidirectional on all hours of a billing month. The proposed Reactive Power Charge will also apply to points that integrate generation resources directly to the FCRTS, unless the generation resource is equipped with automatic voltage control equipment that can support the voltage schedules at such point. Appendix, GRSPs, Section II.O., Reactive Power Charge. The voltage regulating equipment permits BPA to maintain transmission at acceptable voltage limits consistent with its reliability standards. Moreover, customer-owned generation resources that are equipped with voltage regulating equipment would permit the customer to provide its own generation-related reactive power in response to local voltage requirements.

The proposed Reactive Power Charge will include a Reactive Demand Charge and a Reactive Energy Charge at each qualifying point. The customer may be charged the greater of the reactive demand charge (*see* below) for reactive power flow that exceeds the deadband or a ratchet demand charge. The rate for reactive demand will consist of separate charges for lagging reactive demand and leading reactive demand applicable to heavy load hours and light load hours respectively. The proposed Reactive Power Charge also includes a reactive energy charge, which will only apply to the reactive energy at each point that is outside the deadband (*see* below). A reactive energy charge for lagging reactive energy will only apply during heavy load hours, and to leading reactive energy only during light load hours. Appendix, at 143-148.

<u>*Deadband*</u>

The Reactive Power Charge in BPA's Initial Proposal did not contain a deadband. Both the GUN and WPAG urged BPA to include a deadband in the Reactive Power Charge. Brattebo, *et al.*, E-GN-04, at 4; Beck, *et al.*, E-WA-01, at 53. BPA agreed with the parties that a deadband would be appropriate. Anasis, *et al.*, WP-96-E-BPA-88, at 11.

Accordingly, BPA modified the proposed Reactive Power Charge in its Supplemental Proposal to include a deadband equal to 25 percent of the maximum real power (equivalent to a 97 percent power factor standard) at each point as part of the rate design. Anasis, *et al.*, E-BPA-86, at 1.

The parties, however, urged BPA to further revise its supplemental proposal to a deadband equal to 33 percent of the maximum real power (which is equivalent to a 95 percent power factor standard). Brattebo, *et al.*, WP-96-E-GN-06; Kitchen, Weidl, E-RC-07, at 7; Carr, *et al.*, WP-96-E-PP/PA-03. Some parties supported the 95 percent power factor standard based on the contention that 95 percent power factor is an industry standard. Beck, *et al.*, E-WA-01, at 53; Kitchen, Weidl, E-RC-07, at 15. Contrary to the parties' assertions, however, a 95 percent power factor is not a universally accepted standard in the region. BPA is currently required under some existing agreements with two Pacific Northwest IOU's to adhere to a 98 percent power factor standard. Anasis, *et al.*, E-BPA-88, at 11. Moreover, reactive power requirements equal to 25 percent of the maximum real power is still a substantial amount of reactive power on the high voltage transmission system that BPA must provide. BPA would incur significant additional costs to supply the increment of reactive power associated with a 95 percent power factor standard. Anasis, *et al.*, E-BPA-86, at 2.

RCC expressed concern that meeting the 97 percent power factor standard would impose additional financial responsibilities on some customers. Weidl, *et al.*, WP-96-E-RC-07, at 6. BPA recognized that the deadband at a 97 percent power factor may be at a different level than some customers have operated at before. Therefore, BPA's Supplemental Proposal also proposed that the Reactive Power Charge would be equal to the 95 percent power factor standard for the first 3 years of the rate period, and would be phased in to the 97 percent power factor standard at that time. BPA believes the stepped in approach provides adequate notice for its customers to plan, design, and install reactive mitigation measures that are necessary to meet the 97 percent power factor standard. Anasis, *et al.*, E-BPA-86, at 2-3.

<u>*Ratchet Demand*</u>

The customer's reactive billing demand will be the higher of the largest measured reactive demand in excess of the deadband during the billing period or the ratchet demand. Appendix, GRSPs, Section II.O., Reactive Power Charge. The ratchet demand charge would recover a portion of BPA's investment for reactive power devices to support its customers reactive power needs. Anasis, WP-96-E-BPA-116, at 4. A power system operator must plan and operate the transmission system to deal with the maximum reactive needs of the system. That is, even if the reactive power condition only occurs for 1 hour per year, the transmission provider is obligated to make the necessary capital investments for the equipment necessary to manage the reactive power consistent with system reliability standards. Since reactive power cannot be transferred over long distances, it is more difficult for BPA to supply the reactive power to other markets. *Id.*. BPA has invested approximately $300 million in shunt capacitors and shunt reactors to help address the reactive needs of its customers and the FCRTS. *See* TRDS, WP-96-E-BPA-62, Appendix J.

In response to party concerns with BPA's proposed Reactive Power Charge in the Initial Proposal, BPA also reduced the ratchet period and allowed the customer to reset its demand ratchet to zero if it maintains a 97 percent power factor continuously for a 12 month period. Anasis, E-BPA-86, at 3. The customers supported this change. Brattebo, *et al.*, E-GN-06, at 3; Carr, *et al.*, E-PP/PA-03, at 24.

Reactive Energy Charge

BPA's Supplemental Proposal for the proposed reactive energy charge assumes that the reactive power on the BPA system amounts to about 25 percent of the real power. Anasis, *et al.*, E-BPA-86, at 5. This assumption yields an estimated total system reactive power of approximately 4575 MVAr. TRDS, WP-96-E-BPA-62, Appendix J, J-3. The assumption that the reactive power on the system amounts to 25 percent of the real power is based on BPA's knowledge of the integrated transmission system and experience with its operation, including monitoring actual system conditions and analyzing numerous power flow simulations. Anasis, *et al.*, E-BPA-116, at 5. This estimate of total system reactive power equal to 4575 MVAr is further supported by a BPA power flow analysis which indicates that BPA would supply approximately 4100 MVAr of reactive power to only 49 of its largest utility customers under the conditions modelled. Anasis, *et al.*, E-BPA-88, Attachment 1.

<u>BPA May Waive Application Of The Proposed Reactive Power Charge On A Case-By-Case Basis.</u>

BPA's proposed Reactive Power Charge would allow a customer to submit requests to BPA for consideration of unique circumstances, and would permit BPA to address the special circumstances, as appropriate. Appendix, GRSPs, Section II.O. Reactive Power Charge. For example, BPA recognizes that there may be some circumstances where two or more POIs or PODs are located electrically close enough together where their respective reactive power flows are related. Anasis, *et al.*, E-BPA-88, at 9. BPA will evaluate customer requests on a case-by-case basis. Such requests will be reviewed by BPA's transmission planning and operational staff. Tr. 1499. BPA's final determination will be recorded. This approach appears to conform with FERC's final rule on the Standards of Conduct pertaining to discretionary implementation of the open access transmission tariffs and associated rates. *See* Open Access Same-Time Information System and Standards of Conduct, 61 Fed. Reg. 21,737, 21,765 (1996) III FERC Stats. & Regs. ¶31,035 (Standards of Conduct).

12.4.6 <u>Reservation Fee for Transmission Capacity</u>

BPA is proposing a Reservation Fee in the firm transmission rate schedules, with the exception of the NT rate schedule, for application to customers who enter into a contract with BPA for new or increased firm transmission service on the FCRTS and want to postpone the commencement of such service while maintaining the availability of transmission capacity. The Reservation Fee is modelled closely on the reservation provisions in the FERC NOPR PTP pro forma tariff. Woerner, *et al*., E-BPA-29, at 8-10. The fee is 1/12 of the annual cost of the transmission service for a reservation of one year. BPA may grant annual extensions with the customer's payment of an annual fee for a total reservation period of up to 5years. Payment of the Reservation Fee preserves the customer's place in line for the first right to the transmission capacity until such time as the customer starts the transmission service or commences paying the monthly transmission charges. *See* Appendix, at 148-149.

12.4.7 Delivery Charge

Consistent with the Settlement Agreement, BPA set the Delivery Charge at $0.75/kW/month ($9.00/kW/year) and allocated the unrecovered cost to the BPA power business. An important principle for adopting the uniform Delivery Charge in the Settlement Agreement is that both Federal and non-Federal power should pay the same rate for the use of Delivery facilities. (*See* Section 12.2.2. for further discussion of the Delivery Charge.) BPA proposes to include the uniform Delivery Charge in the NT, NTP, and PTP rate schedules for application to all power, Federal and non-Federal power, using Delivery facilities. In addition, BPA proposes to apply the Delivery Charge to increases in IR service.

Some customers with existing IR agreements are charged a UFT rate for service over Delivery facilities they currently use. These charges are contractually specified. Customers may add resources to their IR contract and increase their Transmission Demands. Consistent with the decision to make the Delivery Charge neutral for new purchases or acquisitions of Federal or non-Federal power, a customer taking incremental IR service should pay the same rate for service over Delivery facilities as a customer taking transmission service under other rate schedules. Therefore, for new IR demand involving transmission over Delivery facilities, the uniform Delivery Charge will be applied where not precluded by contract. The Delivery Charge for the new IR service will be based on the total amount of power flowing over the Delivery facilities less the amount of transmission service used in calculating the UFT charge in order to avoid double-charging for the Delivery facilities.

The Delivery Charge is now a separate charge in the "Adjustments, Charges, and Other Rate Provisions" section of the transmission rate schedules. The Delivery Charge appears in the GRSPs and will apply to all power flowing over Delivery facilities with the exception of those Delivery facilities currently being charged a UFT rate under an IR agreement. *See* Appendix, at 130-131. For most customers, the Delivery Charge will be assessed to the demand on the Delivery facilities on the hour of the Monthly Transmission Peak Load. However, the the billing factor for CRCs for the Delivery Charge shall be the customer's peak purchase from BPA during HLHs. Therefore, the hour of the customer's peak purchase from BPA will be used to determine the Delivery Charge billing factor for

CRCs for both power purchases and wheeling. Where a CRC purchases no power under its 1981 Contract during HLH but uses a Delivery facility for wheeling, the billing factor will be all power using the Delivery facilities on the hour of the Monthly Transmission Peak Load.

13.0 ANCILLARY PRODUCTS AND SERVICES

13.1 <u>Introduction</u>

In the 1996 Wholesale Power and Transmission rate proceeding, BPA proposed to establish new rates for ancillary services. Ancillary services are those services necessary to support the transmission of electric power (capacity and energy) from resources to loads while maintaining reliable operation of the Federal Columbia River Transmission System (FCRTS). APS Rate Schedule, WP-96-A-02, Appendix. BPA proposed rates for ancillary services in response to both the competitive market for wholesale bulk power and FERC's Notice of Proposed Rulemaking *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities* (NOPR). Dinsmore, *et al.*, WP-96-E-BPA-22, at 2. BPA had already begun efforts to unbundle charges for particular services from its wholesale bulk power sales when FERC issued its Open Access NOPR on March 29, 1995. *See* Buchanan, *et al.*, WP-96-E-BPA-11. FERC's NOPR proposed to require transmission owners to unbundle transmission services and ancillary services from wholesale power services and establish separately stated rates for such services. Dinsmore, *et al.*, WP-96-E-BPA-22, at 2. While FERC's NOPR and subsequent final order on non-discriminatory open access transmission service (Order 888) do not directly apply to BPA, BPA has committed to provide open access transmission services in a manner comparable to that required of transmitting utilities regulated under the Federal Power Act. Order 888 requires public utilities to state separate rates for ancillary services. Order 888, at 21,552, 21,590.

BPA has defined the ancillary services it proposes to offer as part of its open access tariffs in the Terms and Conditions proceeding conducted contemporaneously with this rate proceeding. BPA will provide Scheduling and Dispatching service to all transmission customers using the FCRTS. The other ancillary services that BPA will offer to transmission customers using the FCRTS include Control Area Reserves for Resources; Control Area Reserves for Interruptible Purchases; Load Regulation; and Energy Imbalance services and Transmission Losses. Rehman, *et al.*, TC-96-E-BPA-04; Phillips, *et al.*, TC-96-E-BPA-12; Phillips, *et al.*, TC-96-E-BPA-10; and Metcalf, *et al.*, TC-96-E-BPA-14, 8-15. These proposed ancillary services are substantially similar to the ancillary services that were described in FERC's NOPR, but are grouped differently. Metcalf, *et al.*, WP-96-E-BPA-27, at 11-12. In Order 888, FERC adopted all of the ancillary services proposed in the NOPR as ancillary services, except for transmission loss compensation. Order 888, at 21,581. BPA's treatment of the proposed rates for Transmission Losses is discussed in more detail in Section 13.4. Generally, the transmission customer must purchase these ancillary services from BPA, unless it supplies them itself or acquires them from a third party. Rehman, *et al.*, TC-96-E-BPA-04; Phillips, *et al.*, TC-96-E-BPA-12; Network Integration Service, TC-96-E-BPA-15, at 27; Point-to-Point Service, TC-96-E-BPA-16, at 26. In addition to the ancillary services identified in the Terms and Conditions proceeding, BPA also will provide the generation-related reactive power necessary to maintain transmission voltage levels within acceptable limits on the FCRTS, that is not supplied by the transmission customer. BPA has not proposed to establish a separate rate for generation-related reactive power, however. *See* discussion in Section 12.4.5, Reactive Power Charge, for more detail. The terms and conditions for the ancillary services that BPA will offer have been settled as part of the Transmission Settlement Agreement. *See* Transmission Settlement Agreement, Attachment 1, at 3, "Transmission Terms and Conditions."

For the ancillary services BPA provides itself, BPA will allocate a charge to itself equal to the rates that it will charge to other transmission customers. Metcalf, *et al.*, WP-96-E-BPA-27, at 11-12. In its initial proposal BPA included a flexible rate provision for certain ancillary services under the APS-96 rate schedule. BPA stated that it would use the flexible rate provisions to price the specified ancillary services consistent with FERC's final policy. Dinsmore, *et al.*, WP-96-E-BPA-22, at 3-5. In Order 888, FERC permits public utilities to offer rate discounts on any ancillary services to reflect cost variations or to match rates available from any third party. The discounts, however, must be offered consistent with the Standards of Conduct and posted on the OASIS. Order 888, at 21,589. Accordingly, BPA will permit downwardly flexible rates for the following ancillary services: Energy Imbalance; Control Area Reserves (CAR) for Resources (full and partial service); CAR for Interruptible Purchases; Load Regulation, and Transmission Losses. *See* APS Rate Schedule WP-96-A-02, Appendix; and Dinsmore, *et al.*, WP-96-E-BPA-108, at 6.

13.2 <u>Scheduling and Dispatching</u>

BPA's proposed Scheduling and Dispatching service involves the movement of power through, out of, within, or into the BPA control area over the transmission system. This is the same service that FERC has named Scheduling, System Control and Dispatch Service. Order 888, at 21,581. This service consists of the prescheduling of available BPA transmission capacity; real-time scheduling of available BPA transmission capacity; dispatch of BPA's transmission system; confirmation and verification of individual transmission schedules, including preschedules; after-the-fact or real time changes; scheduling return energy associated with losses; and net interchange scheduling between control areas. *See* generally Bonneville's Proposed Open Access Tariffs, TC-96-E-BPA-15/16, Appendix D, Schedule 1 and Appendix E, Schedule 1.

BPA's proposed rate for Scheduling and Dispatching evolved over the course of the rate case. BPA's initial proposal proposed a separate unbundled rate for Scheduling and Dispatching, and separate unbundled rate for Preschedule Changes. Dinsmore, *et al.*, WP-96-E-BPA-22; Initial Wholesale Power Rate Development Study (WPRDS), WP-96-E-BPA-05, at 33-36. BPA withdrew its proposal for separate unbundled rates for these charges, however, due to concerns raised by the parties regarding the complexity of the proposal, errors in the data underlying the proposal, and consideration of the modifications proposed by the customers as well as the significant administrative and implementation issues raised by internal BPA staff. Moreover, BPA determined that it does not have the necessary accounting and billing systems in place to implement unbundled rates for Scheduling and Dispatching at this time. Dinsmore, *et al.*, WP-96-E-BPA-52, at 2-5.

During the rate proceeding, RN generally alleged that utilities move costs from generation where they face competition from other power suppliers to transmission where they face little competition. Marcus, WP-96-E-RN-01, at 2. This assertion is inapposite to BPA's supplemental proposal for charges related to Scheduling and Dispatching. Historically, BPA assigned all scheduling costs to the Power Scheduling activity and functionalized it to generation in its rate cases. These costs were recovered from power customers only. Dinsmore, *et al.*, WP-96-E-BPA-52, at 4. BPA's supplemental proposal, however, proposed to recover the costs related to scheduling and dispatching of BPA's transmission system from both wheeling and power customers. In its supplemental proposal, therefore, BPA reviewed the costs formerly functionalized entirely to generation as Power Scheduling, and identified a portion of those costs associated with scheduling BPA's available transmission capacity and dispatching BPA's transmission system. Thus, approximately 17 percent of the Power Scheduling costs were refunctionalized to transmission. Dinsmore, *et al.*, WP-96-E-BPA-77, at 3. *See* also, Revenue Requirement Study Documentation, Vol. 1, Chapter 4, WP-96-FS-BPA-02A. Moreover, consistent with past practice, BPA will continue to roll the costs associated with scheduling and dispatching Federal generation into its generation revenue requirement. *Id.*

Section 7(e) of the Northwest Power Act grants the Administrator broad rate design discretion. Specifically, the Northwest Power Act provides that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms." 16 U.S.C. § 839d(e). For the supplemental proposal, BPA assigned transmission scheduling costs based on the estimated staff necessary to provide the transmission scheduling service during the rate period because it currently has no separate budget for transmission scheduling and dispatching, and no discrete accounting data attributed to this activity. Dinsmore, *et al.*, WP-96-E-BPA-77, at 4. Accordingly, BPA did not propose to separately unbundle Scheduling and Dispatching costs from its transmission rates. Rather, BPA rolled in all of the costs associated with scheduling the transmission of power into the transmission revenue requirement and segmented the costs in the same manner as other operation expenses. BPA will collect these costs from each transmission user as part of the appropriate transmission rate. BPA currently does not schedule the transmission required to deliver Federal power to its customers. As a result of functional unbundling, however, BPA will schedule and account for the use of the transmission required to deliver Federal power. Accordingly, the transmission scheduling costs associated with delivering Federal power will be recovered as part of the transmission rate. *Id.* at 2-4. This treatment has been undisturbed consistent with the proposal reached in the Transmission Settlement Agreement. *See* Transmission Settlement Agreement, Attachment 1, at 3, "Transmission rates." Even though BPA is not proposing to separately unbundle Scheduling and Dispatching costs from the transmission rates at this time, BPA believes that some customers, especially in the future, will incur more scheduling and dispatching costs than others. Thus, as BPA continues to develop its transmission Scheduling and Dispatching service, including its ability to track or account for the costs associated with providing the service, it may subsequently develop separate unbundled rates for scheduling and dispatching in the future. Dinsmore, *et al.*, WP-96-E-BPA-77, at 5.

BPA's Rules of Procedure provide that if a party does not raise and fully develop its position on an issue in its initial brief, then it shall be deemed to take no position on the issue. No party in this proceeding raised any legal, policy or factual issues in the initial briefs for resolution by the Administrator relating to BPA's supplemental proposal regarding the proposed treatment of charges for Scheduling and Dispatching. Accordingly all arguments raised in the proceeding on BPA's proposed rate for Scheduling and Dispatching are deemed to be waived *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986).

13.3 Control Area Services

Introduction

The ancillary services that will be offered as control area services include Control Area Reserves (CAR) for Resources, CAR for Interruptible Purchases, Load Regulation, and Energy Imbalance. The rates for CAR for Resources, CAR for Interruptible Purchases, and Load Regulation are based on the costs associated with the reserves (control reserves, spinning reserves and non-spinning reserves) that are used to provide these control area reserve services. WPRDS, WP-96-FS-BPA-05, at 35-37. Control area services must meet the reliability standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP). The NWPP requires that each control area maintain an operating reserve obligation equal to at least 5 percent of all hydroelectric generation and 7 percent of all thermal and other on-line generation within the control area. *Id.* at 35. Spinning reserve is that portion of operating reserve that is synchronized to the power system and immediately responsive to system frequency. NWPP requires a minimum of 50 percent of each control area's operating reserve obligation to be spinning reserves. Non-spinning operating reserve is that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. NWPP requires a minimum of 50 percent of each control area's operating reserve obligation to be non-spinning reserves. *Id.* at 36. Control reserves are the generating capacity of a power system that is responsive to automatic generation control (AGC control) without human intervention. *Id.* Control reserves are required to provide AGC response to load and generation fluctuations. In order to maintain compliance with NERC's AGC Control Performance Criteria, BPA currently maintains 280 MW of control reserves (including 80 MW of regulating margin). Of this, 252 MW are deemed for use in load following and 28 MW are deemed for use generation following for ratemaking purposes. *Id.* at 36-39.

The Methodology for Calculating the Rates for Control Area Services

The rates for CAR for Resources, CAR for Interruptible Purchases, Load Regulation are developed in a similar manner. WPRDS, WP-96-FS-BPA-05, at 35. The rates for these services are based on the costs associated with the reserves (control reserves, spinning reserves and non-spinning operating reserves) used to provide the services. Because BPA does not have available data to directly derive the costs associated with reserves, BPA obtained the cost of reserves by costing the flexibility inherent in these reserves. *Id.* at 37. This is the first rate case in which BPA has proposed a methodology for developing rates for Load Regulation and the control area services. Prior to FERC's identification of these specific services in the NOPR, there was no consistent methodology for defining and charging for these services. Thus, there is no utility industry standard developed for determining the rates for these products and services. Dinsmore, *et al.*, WP-96-E-BPA-77, at 7. Consequently, BPA developed a pricing methodology to determine the rates for these services.

Issue

Whether BPA should adopt its proposed pricing methodology for control area services.

Parties' Positions

RN argued that BPA's pricing methodology for its control area services has several deficiencies: 1) that it is inappropriate to include firm energy capability component in the basic capacity cost; 2) that it is inappropriate to include energy return "adders"; 3) that using the difference in value between returning energy under normal and emergency conditions has no relevance to the energy required to cover small random outages for period of less than one hour; 4) that BPA does not provide substantial evidence of cost that support the inclusion of $1.50 per kW per month representing additional flexibility of operating and control reserves; and 5) that the methodology results in rates for control area reserves that are too high. RN also proposed that BPA use a capacity cost of $3.50 per kW per month. RN brief, WP-96-B-RN-01, at 4-5; Marcus, WP-96-E-RN-03, at 1-3; Marcus, WP-96-E-RN-01, at 9. WPAG, however, found BPA's pricing methodology to be a reasonable attempt to quantify BPA's costs and was consistent with generally accepted rate setting principles. Beck, *et al.*, WP-96-E-WA-01, 45-46.

BPA's Position

The rates for CAR for Resources, CAR for Interruptible Purchases, and Load Regulation are developed in a similar manner. WPRDS, WP-96-FS-BPA-05, at 35. The rates for these services are based on the costs associated with the reserves (control reserves, spinning reserves and non-spinning operating reserves) used to provide the services. Because BPA does not have available data to directly derive the costs associated with reserves, BPA obtained the cost of reserves by pricing the flexibility inherent in these reserves. *Id.* at 37. The basic cost component of reserves is capacity. A basic capacity cost of $2.09 per kW per month was derived from BPA's Marginal Cost Analysis, Table 10, MCA, WP-96-FS-BPA-04; WPRDS, WP-96-FS-BPA-05, at 37. This cost represents the marginal cost to BPA of standing ready to serve load. The components of basic capacity are: instantaneous peaking capability; sustained peaking capability; and firm energy capability. The cost of additional flexibilities were added to the basic capacity cost in the form of notice and return provisions. *Id.* at 37-39. Energy return provisions were added to the basic capacity: the cost associated with the ability to return energy in 168 hours (instead of 24 hours) and the ability to change the rate of energy return with 30 minutes' notice at $0.78 per kW per month and $0.33 per kW per month, respectively. *Id.* Notice provisions were also added to the basic capacity product. First, the ability to change scheduled demand amount with 30minutes' notice at $0.68 per kW per month was added to the basic capacity product. In addition, to represent the further flexibility of operating reserves being available on 10 minutes' notice, an additional cost of $0.50 per kW per month was added. For spinning and control reserves' additional flexibility of being available instantaneously, an additional $1.00 per kW per month was added. The cost of efficiency losses of $0.01 per kW per month were also included in the costs of spinning reserves and control reserves. WPRDS, WP-96-FS-BPA-05, at 38-39.

<u>Evaluation of Positions</u>

BPA has not previously priced control area reserves. The Corps of Engineers was contacted for actual cost data related to the additional costs of generation units used to provide load following, but no data was available from the Corps at that time. Marcus, WP-96-E-RN-01, Attachment 1, at 6. In the absence of actual cost data, BPA relied on the agency's experience gained from participation in power markets of the western US to develop the costs associated with the notice and return energy adders. Dinsmore, *et al.*, WP-96-E-BPA-52, at 9. Only one party, RN, raised issues with BPA's methodology for deriving the rates for Control Area Services. RN argued that it is inappropriate to include firm energy capability component in the basic capacity cost. RN Brief, WP-96-B-RN-01, at 4. RN argued that firm energy capability is a longer term planning issue that does not relate to the short-term fluctuations required for control area reserves. Marcus, WP-96-B-RN-03, at 1-2. In contrast, WPAG, representing a number of BPA's long-time power customers, supported BPA's pricing methodology. WPAG found the methodology to be a reasonable attempt to quantify BPA's costs to meet minute-to-minute fluctuations in load. WPAG also found BPA's approach was consistent with generally accepted rate setting principles. Beck, *et al.*, WP-96-E-WA-01, 45-46.

RN's assertion that firm energy capability does not relate to control area reserves is incorrect. BPA must have the capacity for control and operating reserves available on a firm basis, including the energy necessary to spin the capacity, at all times in order to provide the required level of control and operating reserves. BPA, therefore, must plan in advance to have adequate capacity and firm energy to meet the system's control area reserve requirements. Dinsmore, *et al.*, WP-96-E-BPA-108, at 2. Therefore, it is appropriate to include firm energy capability component in costing the control area reserves. *Id.*

RN argued that it is inappropriate to include most, if not all, energy return adders. RN Brief, WP-96-B-RN-01, at 5; Marcus, WP-96-E-RN-01, at 8. RN argued that there is no obligation to return energy associated with under CAR for Resources. *Id.* RN is correct that there is no energy return associated with control area reserves. Dinsmore, *et al.*, WP-96-E-BPA-108, at 2. However, RN misunderstands BPA purpose for including the energy return adder. *Id.* The nature of the capacity used to provide these services resembles 168-hour-per-week sustained capacity as compared to a typical capacity product for firm power, which is 50-hour sustained peaking capacity with 24-hour energy return. Dinsmore, *et al.*, WP-96-E-BPA-52, at 8. A cost commensurate with this type of capacity is most closely approximated by adding adjustments to the cost for known energy return options. *Id.* Therefore, it is appropriate to include energy return provisions for pricing operating reserves and control reserves. *Id.* Furthermore, RN's argument that it is inappropriate to include energy return adders is inconsistent. RN includes an energy return component in its own proposed alternative capacity cost of $3.50 per kW per month. RN states that the $3.50 includes "some adders for change without notice and for energy return." Marcus, WP-96-E-RN-01, at 9.

RN also disagrees with BPA's methodology of costing the energy return adder. Marcus, WP-96-E-RN-03, at 2. RN argued that BPA's basis of using the cost differential between returning energy under normal and emergency conditions has no relevance to the energy required to cover small random outages for period of less than one hour. *Id.* Control area reserves are provided by generation capacity on a firm basis and must stand ready to serve up to and through the hour. Firm energy must also be available every hour in a year to provide the protection service required by CAR. Dinsmore, *et al.*, WP-96-E-BPA-108, at 2. Control area reserves at this level of readiness are not analogous to normal conditions but is more like emergency conditions. Accordingly, pricing energy returns based on emergency conditions is appropriate.

The other flexibility features added to the basic capacity cost were in the form of notice provisions. WPRDS, WP-96-FS-BPA-05, at 37-39. First, the ability to change scheduled demand with 30 minutes' notice at $0.68 per kW per month was added to the basic capacity product. BPA also added $0.50 per kW per month to reflect additional flexibilities of non-operating and $1.00 per kW per month for spinning and control reserves. RN argued that BPA has not explained the basis for the inclusion of these additional costs. RN Brief, WP-96-B-RN-01, at 6. The additional cost of $0.50 per kW per month was added to represent the further flexibility of non-operating reserves being available on 10 minutes' notice. BPA also added $1.00 per kW per month to reflect the flexibility feature requiring the instantaneous availability required for spinning and control reserves. Dinsmore, *et al.*, WP-96-E-BPA-77, at 6. These costs are primarily derived from forgone revenues resulting because BPA cannot use the capacity for another purpose such as selling spot market energy. Dinsmore, *et al.*, WP-96-E-BPA-52, at 7-8. RN argued that it is wrong to charge the full value of the charges for the ability to demand capacity as needed since capacity will be needed infrequently and randomly by many purchasers. Marcus, WP-96-E-RN-01, at 8. The adjustments for notice period are particularly relevant in pricing operating and control reserves because reserves must be available up to and throughout the hour of delivery. Dinsmore, *et al.*, WP-96-E-BPA-52, at 8. Notice periods are designed to reflect that as a party retains the right to hold capacity closer and closer to and up through the hour of delivery, the seller has fewer option for making use of the capacity. Because BPA must maintain the capacity used to provide operating and control reserves up to and through the hour of delivery, BPA cannot use the capacity for another purpose such as selling spot market energy or other types of power sales. *Id. See also,* Marcus, WP-96-E-RN-03, RN/BPA:30.

RN's arguments, considered together, seem to conclude that the methodology results in rates for control area reserves that are too high. RN Brief, WP-96-B-RN-01, at 3. The cost of control area reserves is generally higher than an equivalent amount of capacity for firm sales. WPRDS, WP-96-FS-BPA-05, at 36. Generation units that provide these reserves must be operated at a level of readiness beyond the level necessary to provide capacity for firm power. This is because reserves must be available instantaneously at all hours. The additional costs are in the form of additional equipment, personnel and increased maintenance necessary to maintain the generation units, switching devices and control equipment at the required level of readiness. *Id.* at 36-37. After BPA priced its control area services, it compared its price to similar services offered in the region. Marcus, WP-96-E-RN-01, Attachment 1. BPA determined its pricing for these services was appropriate since its starting point was a hydro-based capacity service.

RN proposed that BPA use a capacity cost of $3.50 per kW per month which is based on a 60-hour per week capacity of $1.32 per kW per month and some adders for notice and energy return. Marcus, WP-96-E-RN-03, at 1. Marcus, WP-96-E-RN-01, at 9. However, RN's base of $1.32/kW per month is not representative of BPA's cost of basic capacity necessary for firm power because it does not account for instantaneous peaking capability, sustained peaking capability and firm energy capability. Dinsmore, *et al.*, WP-96-E-BPA-52, at 11. In addition, RN's proposal excludes any costs of efficiency losses. *Id.* Efficiency Losses are a real cost of operating BPA's hydroelectric based system because generating units cannot be operated at the maximum efficiency and also simultaneously provide reserves. *Id.* at 9.

BPA must price its services in a manner to recover its costs. Using the basic capacity cost from BPA's MCA was an appropriate starting point. Moreover, PPC urged BPA to base its capacity costs for ancillary services on the same capacity estimates used to determine power rates. Hicks, Wolverton, WP-96-E-PP-06, at 1. Because BPA's capacity necessary for control area reserves is substantially different than capacity used to provide firm power, it was entirely appropriate to add additional costs to reflect the flexible character of the services. BPA's price for control area reserves has changed slightly as new, lower gas forecast have been incorporated into the final studies. *See* Section 3.3.

Decision

BPA will adopt the methodology developed by BPA in this rate case for pricing control area services.

Market-Based Rates

Issue 1

Whether BPA's rates for Control Area Reserve Services are market-based.

Parties' Positions

RN claimed that BPA uses a "value-of-service" or "market-based" approach to determine the rates for CAR for Resources. WP-96-B-RN-01, at 3; Marcus, WP-96-E-RN-01, at 7.

BPA's Position

BPA's proposed pricing methodology for determining rates for control area services uses a marginal cost approach and is not a market-based approach. Dinsmore, *et al.*, WP-96-E-BPA-52, at 6; WP-96-E-BPA-77, at 5; WP-96-FS-BPA-05, at 8.

Evaluation of Positions

Bonneville's Proposed Pricing Methodology For Control Area Services Uses A Marginal Cost Approach And Is Not A Market-Based Approach.

In its direct testimony, RN alleged that BPA chose a market-based rate for its CAR for Resources. Marcus, WP-96-E-RN-01, at 7. RN claimed BPA uses a market based rate by applying additional costs to the basic capacity cost. It is unclear on what basis RN arrived at its conclusion. BPA made no references to "market-based" pricing in any of its testimony or studies relating to the rates for control area services. Furthermore, RN is inconsistent. RN's own proposal of a capacity cost of $3.50 per kW per month which RN urges BPA to adopt, is based on BPA's methodology with some modification, which RN argues is market-based.

RN claimed that BPA uses a "value-of-service" or "market-based" approach to determine the rates for CAR for Resources. RN Brief, WP-96-B-RN-01, at 3; Marcus, WP-96-E-RN-01, at 7. As support for RN's claim that BPA's rates for control area services are something other than cost-based, RN points to several references in BPA's testimony or studies to the word "value" (e.g., the "value" of capacity). RN has incorrectly inferred that BPA's use of the word "value" somehow means "non-cost-based." RN's conclusion that BPA's rates for control area services are "market-based" or "value-of-service" based is misplaced. BPA used the words "value" and "cost" interchangeably with no intent to imply a meaning different than the "cost to BPA." The CAR for Resources and other control area services are designed to recover BPA's costs of these services. Dinsmore, *et al.*, WP-96-E-BPA-52, at 6; WP-96-E-BPA-77, at 5.

RN has ignored the many references to cost in BPA's testimony and studies. BPA's rates for Load Regulation, CAR for Resources, and CAR for Interruptible Purchases are based on the costs associated with the reserves used to provide the services. WPRDS, WP-96-FS-BPA-05 at 37; WP-96-E-BPA-61, at 32. The cost of reserves is generally higher that an equivalent amount of capacity for firm sales because generating units must be operated at a level of readiness beyond the level necessary to provide capacity for firm power. *Id.* at 34. This is because reserves must be available instantaneously at all hours. *Id.* The additional costs are in the form of additional equipment, personnel and increased maintenance necessary to maintain the generation units, switching devices and control equipment at the required level of readiness. *Id.* Because BPA does not have available data to directly derive the costs associated with reserves, BPA obtained the cost of reserves by costing the flexibility inherent in these reserves. *Id.* The cost of additional flexibilities were added to the basic capacity cost in the form of notice and return provisions. *See* WPRDS, WP-96-E-BPA-61, at 32-35. The adjustments for notice period are particularly relevant in pricing operating and control reserves because reserves must be available throughout the hour of delivery. Dinsmore, *et al.*, WP-96-E-BPA-52, at 8. In the absence of actual cost data, BPA relied on the agency's experience gained from participation in power markets of the western US to develop the adders. Dinsmore, *et al.*, WP-96-E-BPA-52, at 9. The costs include foregone revenue due to the fact that BPA cannot use the capacity for another purpose such as selling spot market energy or other types of power sales. *Id.* Finally, the cost of efficiency losses were included in the costs of spinning reserves and control reserves. WPRDS, WP-96-E-BPA-61, at 35. Efficiency losses are a real cost of operating BPA's hydroelectric-based system because generating units cannot be operated at the maximum efficiency and also simultaneously provide reserves. Dinsmore, *et al.*, WP-96-E-BPA-52, at 9.

Without actual cost data, BPA's proposed pricing methodology is a necessary step to define the cost to BPA for providing control area services. BPA may modify this pricing methodology as it gains experience with the actual costs of providing these services.

Decision

BPA's rates for Control Area Services are cost-based not market-based.

Issue 2

Whether each of BPA's rates under the Northwest Power Act must be cost-based.

Parties' Positions

RN claimed that under the Northwest Power Act BPA's rates must be "cost-based." RN also argued that there is nothing in the Northwest Power Act that permits market-based or value-of-service based rates. RN Brief, WP-96-B-RN-01, at 3. The PGP asserts that BPA has interpreted section 7(e) of the Northwest Power Act to grant BPA "unbridled authority to use any rate methodology, including market-based rates to set its rates." PGP Ex Brief, WP-96-R-PG-01, at 14.

BPA's Position

The Northwest Power Act does not mandate that each of BPA's rates must be cost-based, and does not preclude BPA from developing rates using a "value-of-service" or "market-based" approach.

Evaluation of Positions

RN claimed that BPA's rates under the Northwest Power Act must be cost-based. *Id.* For support, RN relies on section 7(a)(1) of the Northwest Power Act. Section 7(a)(1) of the Northwest Power Act provides that

> The Administrator shall 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. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law. Such rates

> shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act, section 5 of the Flood Control Act of 1994, and the provisions of this chapter.

16 U.S.C. § 839e(a)(1). In addition, section 9 of the Transmission System Act provides that rates for the sale of electric power generated by Federal generating plants or otherwise acquired

> . . . shall be fixed and 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 . . . 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 and payments provided for in section 838i(b)(9) of this title, and (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 issued and outstanding pursuant to this chapter, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

16 U.S.C. § 838g (emphasis added). Similar language is also contained in section 5 of the Flood Control Act, which provides that electric power and energy generated at Federal reservoir projects shall be transmitted and disposed

> . . . in manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . . *Rate schedules shall be drawn having regard to the recovery . . . of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years. . .*

16 U.S.C. § 825s (emphasis added).

Finally, Section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a value-of-service approach or market-based approach, or rate designs which recover BPA's costs through formula rates or pricing methodologies. Section 7(e) provides that

> Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time of day, seasonal rates or other rate forms.

16 U.S.C. § 839e(e).

While the Northwest Power Act specifies certain cost allocation standards and grants the Administrator considerable rate design discretion, section 7(a) continues pre-existing requirements of law that the Administrator establish rates (1) having regard to the recovery of the cost of generating and transmitting power, (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, and (4) in a manner that protects the interests of the United States in amortizing its investments within a reasonable period. These directives do not require rates that are limited to "cost of service" standards. *Pacific Power & Light Co. v. Duncan*, 499 F. Supp. 672, 683 (D.C. Or. 1980). Depending on the facts, market-based rates may very well be appropriate under these standards. This does not mean that BPA has unlimited discretion; it means BPA may exercise such discretion as is appropriate to the circumstances.

Overall, BPA's rates are "cost-based" in the sense that BPA's rates "have regard to" cost recovery and, in the aggregate, do ultimately result in total cost recovery. The resource pool directives of section 7 of the Northwest Power Act clearly depart from "cost of service" principles, however, as they have developed in the context of investor owned utility ratemaking. Nevertheless, within the context of those directives, section 7(e) and its legislative history makes clear that the cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. Therefore, in the aggregate, BPA's rates must be, and are, restrained to recover no more than its total costs.

Market-based rates may be entirely appropriate to recover revenues from various customer classes. Features of past BPA rates, such as the irrigation discount in the PF rate, were designed to respond to the market and, in essence, are market-based rates. The same may be said for the DSI Variable Rate, which was designed to recover revenues greater than or equal to the revenues BPA would have recovered under the IP rate in the absence of the Variable rate. Likewise, BPA's surplus firm power (SP) rate was designed to afford BPA considerable marketing flexibility, with a view to recovering costs over time. The SP rate was developed pursuant to section 7(f) of the Northwest Power Act. Section 7(f) does not require that services priced thereunder be set equal to cost. Rather, the language in section 7(f) is flexible enough to permit BPA to establish rates that assist in recovering BPA's overall costs.

In the Administrator's Record of Decision for the 1987 Final Rate Proposal, the Administrator concluded that he does have authority to establish value-based rates under the Northwest Power Act, and under sections 9 and 10 of the Federal Columbia River Transmission System Act (Transmission System Act). In the 1987 ROD, BPA sought to establish a value-based rate called the Market Transmission rate, MT-87, for use with transactions undertaken pursuant to the Western Systems Power Pool (WSPP) Agreement. Administrator's Record of Decision: 1987 Final Rate Proposal, WP-87-A-02, at 242-251. Some parties claimed that BPA is prohibited by statute from establishing a rate that is not cost-based. Here, the parties relied on sections 9 and 10 of the Transmission System Act to support their argument. BPA explained that section 9 of the

Transmission System Act does not contain any express directive regarding the establishment of cost-based rates, nor does it preclude BPA from establishing a value-based rate. BPA determined that section 9 contains various references to cost recovery, but does not instruct the Administrator to design any particular rate in one fashion as opposed to another. BPA relied on Pacific Power & Light Co. v. Duncan, 499 F.Supp. 672 (D.C. OR. 1980) and City of Santa Clara v. Andrus, 572 F.2d. 660 (9th Cir. 1978) to support its claim that the courts have interpreted section 9 to vest the Administrator with extremely broad ratemaking authority, and in particular the authority to establish value-based rates. *See* 1987 ROD, WP-87-E-BPA, at 244.

In *United States Department of Energy-Bonneville Power Administration, Order Confirming and Approving Rates on a Final Basis*, 54 F.E.R.C. ¶61,235 (1991) over intervenor objections that the MT-87 rate was not cost-based, FERC affirmed and approved the MT-87 rate. FERC was persuaded by BPA's statement that MT-87 is market-based, and would enables BPA to participate in the WSPP experiment. FERC determined that the statutory requirement of equability transmission rates speaks only to Federal and non-Federal users as a class, but does not require that each individual customer be assigned responsibility for the equitable recovery of the cost of specific transmission facilities.

The PGP asserts that section 7(e) of the Northwest Power Act does not provide BPA unbridled authority to use any rate methodology, including market-based rates. The PGP claims that the examples relied on by BPA are exceptions to BPA's statutory obligations. PGP Ex Brief, WP-96-R-PG-01, at 14-15. As BPA previously explained, BPA's ratemaking directives do not require rates that are limited to cost of service standards. If the Administrator determines that it is appropriate to sell a product at market-based rates, then BPA has the discretion under section 7(e) to design its rates using market-based prices. The discretion provided by section 7(e) ensures that rates for each class of customer recovers appropriate costs, and that the sum of the rates for all customer classes recover no more than total costs. Notwithstanding this discretion, BPA has not set its rates for ancillary services in this rate case, as PGP implies, using market-based pricing.

BPA's rates for ancillary service may also be subject to FERC approval under section 212(i)(1)(B)(ii) of the Federal Power Act (FPA). Section 212(i) 212(i)(1)(B)(ii) provides that

> . . . the rates for the transmission of electric power on the [Federal Columbia River Transmission] system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 210, section 211, this section [212] and section 213, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(1)(B)(ii).

FERC has explained, however, that the neither the FPA nor its legislative history defines "just and reasonable." Moreover, the FPA does not limit the FERC to specific ratemaking methodologies, and the courts have deferred to FERC's reasoned choice of ratemaking methods. *Entergy Service Inc., Order on Rate Filing*, 58 F.E.R.C. ¶ 61, 234 (1992). In its Transmission Pricing Policy, FERC reiterated that there is no single appropriate ratemaking method under the FPA, and concluded that the end result is the appropriate yardstick against which to measure the legality of a rate, not the rate making method. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, Fed. Reg. 55,031, 55,034 (1994). In general, FERC encourages proposals that disaggregate costs to give better price signals to all users. In particular, FERC explains that transmission pricing should promote efficiency, and to the extent practicable, transmission rates, including rates for ancillary services, should be designed to reflect marginal costs, rather than embedded costs. *Id.* at 55,035.

PGP maintains that BPA has agreed to comply with Order 888, which does not allow market-based rates for ancillary services until it has made a demonstration that it does not have market power in these services. PGP Ex. Brief, WP-96-R-PG-01. PGP misunderstands the preceding explanation of BPA's authority under the rate directives of the Northwest Power Act, and misinterprets it to be a conclusion that the rates for ancillary service have been market-based. As explained under Issue 1 of this section, BPA has not proposed market-based rates for ancillary services. The rates for these services are cost-based and will be used to establish as price caps consistent the Order 888. Moreover, the final rates in the APS rate schedule have been clarified to include that the rates will not exceed the stated rates in the rate schedule. BPA, however, may offer discounted rates to reflect price variation for the service, as appropriate, or to match rates available from a third party consistent with Order 888. Order 888, at 21,590. *See also,* WP-96-FS-BPA-08, GRSPs, Section II.A.

Decision

The Northwest Power Act does not require that each of BPA's rates must be "cost-based."

13.3.1 Control Area Reserves for Resources Rates

Introduction

BPA provides Control Area Reserves (CAR) for Resources service to all resources in the BPA control area. Rehman, *et al.*, TC-96-E-BPA-04, at 4. The rate for CAR for Resources applies to all resources that are located within the BPA control area whose peaking capacity is greater than 3 MW, including consumer-owned generation that is internal to a customer's service territory. *Id.*; WP-96-A-02, Appendix; Tr. 2351-56. A generation owner may avoid the charge by either moving the generation resource out of BPA's control area or by making operating reserves available to BPA, when BPA determines the use of such reserves is appropriate. Rehman, *et al.*, TC-96-E-BPA-04, at 4.

BPA proposed the CAR for Resources service as an ancillary service in response to the FERC's proposed System Protection Service and the generation following portion of the Proposed Load Following Service in the NOPR. Rehman, *et al.*, TC-96-E-BPA-04, at 4-5. CAR for Resources includes the ancillary services identified in Order 888 as "Spinning Operating Reserve," "Supplemental Operating Reserve" and a component of "Regulating and Frequency Response Service." Order 888, at 21,588. CAR for Resources provides for the generation following needs and operating reserve obligations required to operate a resource located with BPA's control area. CAR for Resources provides resource support services, including regulating margin, spinning and non-spinning reserves and frequency control services for the remainder of the delivery hour when the resource incurs a force outage. It does not provide backup service for a forced outage period longer than 60 minutes. Final Transmission Terms and Conditions Tariffs, TC-96-E-BPA-15/16, Exhibit D, Schedule 3 and Exhibit E, Schedule 3.

BPA will offer CAR for Resources as a package (full service) or as separate services (partial service). WP-96-A-02, Appendix. The separate services include Non-spinning Operating Reserves, Spinning Operating Reserves, and Generation Following. Separate rates have been proposed for each service. BPA has also proposed rates for customers taking full service. *Id.*

<u>Issue 1</u>

Whether BPA should add additional capacity factors for wind, solar and geothermal resources to the billing demand under the CAR for Resources rate.

<u>Parties' Positions</u>

RN proposed that BPA add capacity factor of 0.35 for wind and solar resources and 0.80 for geothermal resources to the CAR for Resources rate. Marcus, WP-96-B-RN-01, at 9-10. RN also proposed that these would be maximum values. *Id.* at 10.

<u>BPA's Position</u>

The CAR for Resources rate includes two billing demand options. For service to a resource for which BPA receives appropriate metering information, the billing demand is the total Resource Capability which is defined in the appropriate contract. WP-96-E-BPA-64, at 72. For service to unmetered resources, the billing demand is determined by multiplying the Resource Capability by capacity factors defined in the rate schedule. For hydro-electric resources the capacity factor is 0.60 and for all other resources the capacity factor is 0.90. *Id.* Unmetered resources are those resources that do not have metering that provides hourly demand and energy readings with the accuracy and availability that is consistent with BPA and other Northwest billing standards. The billing demand options are designed to encourage resources to be metered. Tr1055. This billing factor is an appropriate technical match for intermittent renewable resources because of the unpredictable nature of these resources. Dinsmore,*et al.*, WP-96-E-BPA-52, at 12.

Evaluation of Positions

RN claims the CAR for Resources rate is burdensome for geothermal, solar, and wind resources. Accordingly, RN seeks to reduce the cost for renewable resources. Marcus, WP-96-B-RN-01, at 4, 9. RN argued that for resources too small to be economically metered, a 0.90 billing demand capacity factor makes the CAR for Resources Rate too high. RN Brief, WP-96-B-RN-01, at 8-9. RN argued that for unmetered wind, solar or geothermal resources a capacity factor of 0.90 is not appropriate. *Id.* at 9. RN proposed that BPA add a capacity factor of 0.35 wind and solar resources and 0.80 for geothermal resources. WP-96-B-RN-04, at 495, 578, 632-33. RN also proposed that these would be maximum values. *Id.* at 10.

If an intermittent resource cannot provide firm services on an hourly basis, the control area operator must use more control reserves to support the schedule. Tr. 1054-55. BPA explained that to manage the intermittent resource, it is important to know what the quantities are that are being produced. Consequently, BPA determined it is more appropriate that such resource be metered. Tr. 1049. Moreover, BPA provided an alternative billing factor to metering in the APS-96 rate schedule. WP-96-E-BPA-64. This billing factor is an appropriate technical match for intermittent renewable resources because of the unpredictable nature of the resources. Dinsmore,*et al.*, WP-96-E-BPA-52, at 12. BPA also explained that it limited the billing capacity factors alternatives for unmetered to 0.60 for hydro and 0.90 for non-hydro for rate design simplification and administrative ease. Tr. 1052.

RN also proposed that BPA allow a negotiable billing factor for extremely small renewable resources when metering would be too expensive. Marcus, WP-96-B-RN-01, 10. However, RN does not specify what “too small to be economically metered” means in terms of resource size. RN may believe such resources run in the 25 MW-50 MW size. Marcus, WP-96-B-RN-01, at 4. However, BPA agrees that it is reasonable to set the capacity factor that most closely approximates the resource’s operation. Upon request, BPA may consider the customer’s unique circumstances consistent with the Standards of Conduct, and, if appropriate, it may modify capacity factors for unmetered resources based on the historical and planned operation of the customer’s resources. Modifications will be posed on the OASIS.

Decision

BPA will retain the 0.90 capacity factor for non-hydro resources and the 0.60 capacity for hydro resources as the billing determinants for unmetered resources. These capacity factors represent the maximum level for unmetered resources. BPA may agree to *capacity factors other than 0.60 or 0.90 based on the historical and planned operation of the customer's resource(s). BPA will modify any capacity factors in a manner consistent with the Standards of Conduct and post its offer on the OASIS.*

Issue 2

Whether the Control Area Reserves for Resources rate should vary based on resource size.

Parties' Position

RN proposed that the rate for the Control Area Reserves (CAR) for Resources be adjusted depending on the size of the resource. RN Brief, WP-96-B-RN-01, at 6; Marcus, WP-96-E-RN-01, at 33. For resources under 50 aMW, the charge would be one-half the base charge. *Id.* For resource between 50 and 200 aMW the charge would be equal to the base charge. *Id.* For resources larger than 200 aMW, the charge would be increased to collect the reduction for smaller resources. *Id.*

BPA's Position

BPA did not propose rates for CAR for Resources that vary based on resource size. The per unit cost of the reserves required to operate a resource does not change with the size of the resource. Dinsmore, *et al.*, WP-96-E-BPA-52, at 11.

Evaluation of Positions

RN proposed that the rate for CAR for Resource be adjusted depending on the size of the resource. RN Brief, WP-96-B-RN-01, at 6; Marcus, WP-96-E-RN-01, at 33. RN argued that BPA's rate for CAR for Resource is burdensome for geothermal, solar and wind resources. Marcus, WP-96-E-RN-01, at 4. RN argued that ten 40 MW resources do not present the same risk from outage presented by one 400MW resource. RN Brief, WP-96-B-RN-01, at 6. RN's proposal is based on the assumption that the reserve costs are caused in larger part by large resources and to a lesser degree by smaller resources. *Id.* However, this assumption is not supported by the facts. Dinsmore, *et al.*, WP-96-E-BPA-52, at 11. BPA's total operating reserve requirement, established by NWPP, is based upon the total amount of generation on-line within BPA's control area, regardless of the actual size of the generating units. Dinsmore, *et al.*, WP-96-E-BPA-52, at 11. The per unit cost of the reserves required to operate a resource does not change with the size of the resource. *Id.* Furthermore, the fact that intermittent resources cannot operate to provide firm services on an hourly basis, the control area operator must use its control more often to provide the support services to firm up the schedules associated with these resources through the hour of delivery. *Id.* at 10. Finally, RN has not presented a sound technical basis upon which to charge a smaller resource for control area reserves on a lower per unit cost basis than a larger resource. *Id.*

Decision

BPA will not adopt rates for Control Area Reserves for Resources that vary based on resource size.

Issue 3

Whether the rates for Control Area Reserves for Resources is contrary to the Northwest Power Act with respect to renewable resources.

Parties' Positions

RN asserts that the rate design of CAR for Resources as it applies to renewable resources "runs afoul" of the Northwest Power Act. RN Brief, WP-96-B-RN-01, at 9.

BPA's Position

Bonneville's proposed rate design for CAR for Resources does not contradict the Northwest Power Act and is consistent with the Northwest Power Act.

Evaluation of Positions

RN argues that the proposed 0.90 capacity factor for "small" unmetered renewable resources would result in a CAR for Resources rate that would make "small" renewable resources uneconomical. RN concludes that BPA's rate for CAR for Resources, as it applies to renewable resources, is contrary to the Northwest Power Act. RN Brief, WP-96-B-RN-01, at 9. RN relies on section 2.1(b) and section 4(a)(1) Northwest Power Act to suggest that the Administrator must consider the importance of renewable resources in determining the rate design. *Id.* at 10-11.

Other than relying on selected statutory provisions, RN makes little or no attempt to define a "small" renewable resource, nor to explain that such unmetered renewable resources will not require the full range of resource support services that are provided under CAR for Resources. Furthermore, RN fails to provide any adequate rationale to justify shifting the costs associated with the transmission of a renewable resource to other customer classes.

Section 2 of the Northwest Power Act describes the six different purposes of the Act. Section 2 also provides that

> [t]he purposes of this chapter, together with the provisions of other laws applicable to the Federal Columbia River Power System, are all intended to be construed in a

> consistent manner. Such purposes are also intended to be construed in a manner consistent with applicable environmental laws . . .

16 U.S.C. § 839. A primary purpose of the Northwest Power Act (Act) is to assure the Pacific Northwest of an adequate, efficient, and economical, and reliable power supply. 16 U.S.C. § 839(2). Another purpose of the Act is to provide that BPA's customers and their consumers pay all costs necessary to produce, transmit, and conserve resources to meet the region's electric power requirements, including the amortization on a current basis of the Federal investment in the FCRPS. 16 U.S.C. § 839(4). The Act also provides for the development of a regional conservation and electric power plan, and a fish and wildlife program to facilitate the orderly planning of the region's power system, and providing environmental quality. 16 U.S.C. § 839(3). As RN notes, when BPA acquires resources, the Act provides that the Administrator shall acquire the resources that the Administrator determines are consistent with the Council's plan. 16 U.S.C. § 839d(a)(1) The Act also provides that the plan shall give priority to resources which the Council determines to be cost-effective, first to conservation, second to renewable resources, third to resources using waste hear or of high fuel conversion efficiency, and fourth to all other resources. 16 U.S.C. § 839b(e)(1).

Much of the Northwest Power Act provides a structure for BPA's resource acquisitions. As resources are acquired by BPA, then BPA must set its rates to recover all the costs necessary to produce and transmit such resources. In this rate proceeding, BPA is not making a determination whether to acquire resources, and such determination is not appropriate in BPA's rate proceedings. Tr. 1002. Rather, issues concerned with resource acquisitions must be addressed in a forum outside of BPA's rate case. In this rate proceeding, BPA is establishing its rates for power and transmission based on the costs associated with the sale and transmission of power for the 5-year rate period, including the costs associated with the transmission of resources owned by others. The purpose of the rate for CAR for Resources is to recover BPA's costs associated with providing the operating reserves and generation following that are necessary for the transmission of resources of any character in BPA's control area. In this rate case, BPA has tried to achieve rates that recover its costs, and that are competitive. Accordingly, designing the CAR for Resources rate as a vehicle to make renewable resource more economical, is not consistent with sound business principles.

Decision

The rate design for Control Area Reserves for Resources does not contradict the purposes of the Northwest Power Act and will recover costs for the services provided consistent with the Northwest Power Act.

13.3.2 Control Area Reserves (CAR) for Interruptible Purchases

BPA proposed the CAR for Interruptible Purchases service as an ancillary service in response to the System Protection Service identified in the FERC NOPR. Rehman, *et al.*, TC-96-E-BPA-04, at 4-5. While this service was not specifically identified in the FERC NOPR, BPA identified it separately because BPA is required to carry additional non-spinning operating reserve in the amount of 100% of all purchases that are interruptible during the hour of delivery. *Id.* at 5. CAR for Interruptible Resources provides the non-spinning operating reserves necessary to cover the non-spinning reserve obligation associated with customer purchases from outside the BPA control area whose energy or transmission components are defined as interruptible during the delivery hour. Final Transmission Terms and Conditions Tariffs TC-96-E-BPA-15/16, Exhibit D, Schedule 3 and Exhibit E, Schedule 3. The rate for CAR for Interruptible Purchases shall not exceed 2.87 mills per kWh and is based on the capacity cost of providing non-spinning operating reserves. The capacity cost used reflects a lower cost than was used in estimating the costs of other control area reserves, because BPA provides this product on an "as available" basis only. WPRDS, WP-96-FS-BPA-05, at 42. The rate applies to the schedules of all power purchases imported into BPA's control area that are designated as subject to interruption. APS Rate Schedule, WP-96-A-02, Appendix. A customer must purchase CAR for Interruptible Resources from BPA or it must make reserves equivalent to 100% of the amount of the interruptible purchase available to BPA from either its loads or resources. Such reserves must be in addition to reserves a customer is obligated to provide BPA under another arrangement. Tr. 1095-96.

No issues directly related to this rate were raised by any parties.

13.3.3 Load Regulation Rate

BPA proposed the Load Regulation service as an ancillary service in response to the Load Following Service identified in the FERC NOPR. Rehman, TC-96-E-BPA-04, at 2-4. Load Regulation is the instantaneous (second-to-second) regulation of the supply of firm power that is provided to follow variations in the customer's loads within the hour. The amount of Load Regulation provided is related to the customer's total retail load. Final Transmission Terms and Conditions Tariffs, TC-96-E-BPA-15/16, Exhibit D, Schedule 4 and Exhibit E, Schedule 4. In Order 888, FERC changed the name of its Load Following Service to "Regulation and Frequency Response Service," but did not redefine the service. Order 888, at 21,582.

The rate for Load Regulation is 0.28 mills/kWh and is based on BPA's cost of providing the portion of control reserves to follow loads located in BPA's control area. WPRDS, WP-96-FS-BPA-05, at 39-40. BPA also may offer discounted rates for Load Regulation, consistent with FERC Order 888. This products is provided for all loads in the BPA control area. Customers served by transfer also receive Load regulation services and will be changed the applicable rate. *Id*.

APAC expressed concern about Eccentric Load Following, a type of Load Regulation service, in its testimony. APAC argued that BPA's DSI customers would not be required to pay for eccentric load following, while other industrial customers might be required to pay such costs. Wolverton, WP-96-E-PA-03, at 10. APAC recommended that BPA drop the charges for Eccentric Load following for all other loads. BPA clarified that no area loads, DSI or otherwise, currently fall under its definition of Eccentric Load. Furthermore, BPA does not propose a separate unbundled rate for Eccentric Load Following in this rate case. Thus, Eccentric Loads that are served power over the FCRTS will be subject to the Load Regulation rate under the APS rate schedule.

For other issues related to Load Regulation, see Section 11.2.2.

13.3.4 Energy Imbalance Rate

BPA proposed an Energy Imbalance rate to be applied to imbalances between the total hourly schedules and hourly actuals for both loads and resources within the BPA control area, where another agreement was not handling the imbalances, rather than on a per transaction basis as suggested in the FERC NOPR. TC-96-E-BPA-04, at 5-7. Energy Imbalances occur both when energy is scheduled to a load in the control area and also when power is scheduled from a resource in the control area. Order 888 describes Energy Imbalance as a service to make up for "net mismatch over an hour between the scheduled delivery of energy and the actual load" rather than for individual transactions to loads and from resources. Order 888, at 21,582. BPA's approach of applying Energy Imbalance to the total power scheduled to loads is consistent with Order 888. The Energy Imbalance will also be applied to energy delivered from resources in the control area. BPA proposes no change to the Energy Imbalance proposal and will apply it to both loads and resource in the BPA control area. Final Transmission Terms and Conditions Tariffs, TC-96-E-BPA-15/16, Exhibit D, Schedule 6 and Exhibit E, Schedule 6.

BPA allows an hourly Energy Imbalance Band of +/- 1.5 percent of the schedule (with a minimum band of +/- 1 megawatt) to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transmission to loads or from resources located in BPA's control area.

The rates for Energy Imbalance are designed to discourage deviations that occur from the transmission of power scheduled to loads and/or from resources in BPA's control area. The energy rates for Positive Deviations (for payment by the Purchaser) within the Energy Imbalance Band are equal to 100 percent of BPA's adjusted marginal cost of firm energy. The demand rate for generation capacity for Positive Deviations within the Energy Imbalance Band is equal to BPA's adjusted marginal cost of generation capacity. The energy rate for Positive Deviations outside of the -1.5 percent Energy Imbalance Band is 100 mills, which is equal to BPA's Unauthorized Increase Charge. The demand charge for Positive Deviations outside of the -1.5 percent Energy Imbalance Band is equal to BPA's adjusted marginal cost of generation capacity. The energy credits for Negative Deviations (for payment or credit by BPA) *within* the +1.5 percent Energy Imbalance Band are equal to 100 percent of BPA's marginal cost of energy. The energy rates credits for Negative Deviation *outside* the +1.5 percent Energy Imbalance Band are equal to 50 percent of BPA's marginal cost of energy. *See* the MCA, WP-96- FS-BPA-04,

Table 10, for the marginal costs of firm energy and generation capacity. WPRDS, WP-96-FS-BPA-05, at 39-40.

Several issues that were raised by parties in testimony related to Energy Imbalance rate were not raised in parties' initial briefs. WPAG states that there was no cost basis for proposing a 100 mill charge for positive deviations outside the 1.5 %bandwidth for Energy Imbalance. Beck, *et al.*, WP-96-E-WA-13, at 52. WPAG also suggested that a penalty rate of 100 mills/kWh that was allowed by the NOPR was inappropriate because it was based on marginal costs for a thermal system and not relevant to BPA. *Id*. at 53. BPA responded that the charge for positive deviations was intended to be a penalty rate and was appropriate to influence behavior. Dinsmore, *et al.*, WP-96-E-BPA-108, at 6-7. BPA also responded that 100 mills/kWh was an established BPA penalty charge as early as 1974. *Id.* at 7-8. WPAG did not raise this issue in its initial brief, therefore, pursuant to § 1010.13(b) of the Procedures, these issues raised by WPAG testimony are waived.

PGP proposed that BPA eliminate the demand charge for generation capacity because it was inconsistent with the FERC NOPR. Black, *et al.*, WP-96-E-PG-06, at 13. BPA explained that when a positive deviation occurs on the hour of BPA's Monthly Federal System Peak Load that it is appropriate to apply a generation demand charge based on the marginal cost of demand since these additional capacity costs are associated with providing Energy Imbalance. Dinsmore, *et al.*, WP-96-E-BPA-108, at 6. PGP did not raise this issue in its initial brief, therefore, pursuant § 1010.13(b) of the Procedures, the issues raised by PGP testimony are waived.

The DSIs proposed that BPA offer an additional ancillary service referred to as the Industrial Hourly Load Variation Service. The DSIs proposed that this service have a bandwidth of 3 percent for overruns and 30 percent for underruns to support the delivery of non-Federal power purchases by a DSI. Schoenbeck and Bliven,WP-96-E-DS-01, at 45. BPA agreed that its initial proposal should be modified to include an Energy Imbalance service and included this service in its supplemental proposal for the transmission tariffs and the APS rate. Final Transmission Terms and Conditions tariffs, TC-96-E-BPA-15/16, Exhibit D, Schedule 6 and Exhibit E, Schedule 6; Dinsmore, *et al.*, WP-96-E-BPA-52, at 12-14. BPA found several problems with the DSI proposal, however. The size of the deviation band was a considerable departure from the FERC NOPR. The proposal also lacked the pricing incentives to discourage deviations. Finally, the DSI service which was limited to DSI loads or customers with similar characteristics, appeared inconsistent with FERC's construct for non-discriminatory transmission and ancillary services. Dinsmore, *et al.*, WP-96-E-BPA-77, at 8-11. The DSIs did not raise this issue in its initial brief, therefore, the issues raised by DSI testimony are waived.

Issue 1

Whether BPA should credit transmission customers for Negative Deviations under the Energy Imbalance Rate when BPA is in spill conditions or the Negative Deviation is intentional.

Parties' Positions

Clark argued that BPA should not include spill provision under the Energy Imbalance rate. Clark Brief, WP-96-B-CP-01, at 24-25; Clark Ex. Brief, WP-96-R-CP-01, at 31.

BPA's Position

Under the Energy Imbalance rate there is no credit when BPA is in spill conditions for all net negative imbalances during the month that the spill occurs. WP-96-A-02, Appendix; Dinsmore, *et al.*, WP-96-E-BPA-77, at 10; Dinsmore, *et al.*, WP-96-E-BPA-108, at 8.

Evaluation of Positions

For purposes of determining whether a credit is made under the Energy Imbalance rate, BPA is in spill condition when any one or more of the following conditions exist on the Federal System: high flows and full reservoirs; flood control implementation; spill priority implementation procedures; spill due to lack of Federal power load; spill past unloaded turbines; where acceptance of any storage would increase spill; where coordination storage is not accepted due to either lack of storage space or specified flow requirements for fish; or minimum generation requirements. BPA has little discretion over the conditions that constitute spill conditions. Dinsmore, *et al.*, WP-96-E-BPA-108, Attachment 1. If BPA is in spill conditions anytime during the billing the credit or payment for all net Negative Deviations for the month is zero. Dinsmore, *et al.*, WP-96-E-BPA-77, at 10.

Clark states that the rate absolves BPA of payment obligation to the transmission customer in any month that BPA was in spill condition or when BPA determined that the energy imbalance was intentional. Clark Brief, WP-96-B-CP-01, at 25; Clark Ex. Brief, WP-96-R-CP-01, at 30-31. Clark asserts that this provision is contrary to the approach used in the FERC Tariffs. *Id*. BPA disagrees. The NOPR states that the rates for negative deviations should be equal to the seller's decremental cost. Dinsmore, *et al.*, WP-96-E-BPA-77, at 10. When BPA is in spill conditions, the decremental cost of producing one less unit of energy is zero. Therefore, during spill conditions, it is appropriate that no credit be given for negative deviations. *Id.* Clark asserts that there is no linkage between the amount of energy spilled and the loss of payment, or whether the imbalance caused the spill. Clark Brief, WP-96-B-CP-01, at 26; Clark Ex. Brief, WP-96-R-CP-01, at 30-31. Clark further asserted that this proposal is merely a mechanism by which BPA can recoup money from firm transmission customers that is foregone due to spilling energy. *Id*. One of the conditions that constitutes spill conditions is when BPA is unable to accept storage into the system. Dinsmore, *et al.*, WP-96-E-BPA-108, Attachment 1. When a customer incurs a Negative Deviation, BPA, in effect, stores the customer's energy in the system. Dinsmore, *et al.*, WP-96-E-BPA-77, at 11; Tr. 1076. Therefore, when BPA is in spill conditions, BPA is unable to store additional energy due to a negative deviation. BPA receives no value from energy that BPA cannot store in its system. *Id.* Furthermore, it is possible that the customer would be unaffected by spill conditions that may occur even if a negative deviation occurs during the billing month. Dinsmore, *et al.*, WP-96-E-BPA-108, at 8-9. Before payment or credit is determined on either the heavy load hour (HLH) and light load hour (LLH) imbalances within the band, the negative and positive deviations for both HLH and LLH deviations for the month are netted, i.e.,the rate is applied to the Net Monthly Deviation, which is the difference between the Positive and Negative HLH and LLH deviations for the month. Only then is it determined whether a net positive or negative deviation occurs. Therefore, it is possible, depending on the variations during the month, that the customer would be unaffected by spill conditions that may trigger. It is also possible for the customer to avoid having a net negative imbalance when BPA is in spill conditions by making up the imbalances within the month. *Id.*

Clark also asserts that the proposed rate permits BPA to make a unilateral determination, with no right to dispute or appeal, that the energy imbalance was intentional. Clark Brief, WP-96-B-CP-01, at 26. BPA will determine if Negative Deviations are intentional by examining whether the Deviations occur in certain patterns: These patterns include: (1) chronic Negative Deviations received during either multiple hours in a row or at specific times of day; (2) chronic Positive Deviations received during either winter storm or heavy load hours with corresponding Negative Deviations in light load hours, particularly when the customer does not respond by adjusting schedules for future days to attempt to correct for these tendencies; and (3) chronic Negative Deviations during light load hours or otherwise lightly loaded system conditions; particularly when the customer does not respond by adjusting schedules for future days to attempt to correct for these tendencies. Dinsmore, *et al.*, WP-96-E-BPA-77, at 10-11. BPA will maintain log of Negative deviations that are intentional, consistent with the Standards of Conduct.

Decision

BPA will not credit transmission customers for Negative Deviations under the Energy Imbalance Rate when BPA is in spill conditions or the Negative Deviation is intentional.

Issue 2

Whether BPA should allow energy returns instead of charging for imbalances.

Parties' Positions

Clark argued that return of energy in lieu of cash payment should be allowed under BPA's energy imbalance rate. Clark Brief, WP-96-B-CP-01, at 25; Clark Ex. Brief, WP-96-R-CP-01, at 30-31. WPAG suggested that BPA include 168-hour return instead of a rate. Beck, *et al.*, WP-96-E-WA-13, at 54-55.

BPA's Position

BPA did not include the energy return option in lieu of payment beyond the billing month. Dinsmore, *et al.*, WP-96-E-BPA-108, at 8-9.

Evaluation of Positions

Clark argued that FERC Tariff permits the return of energy to compensate for energy imbalances. Clark asserts that return of energy in lieu of cash payment is not allowed under BPA's energy imbalance rate. Clark Brief, WP-96-B-CP-01, at 25; Clark Ex. Brief, WP-96-R-CP-01, at 30. This is not entirely correct. The deviation band allows the customer an opportunity to adjust its schedules on a real-time basis to eliminate imbalances during the month. Dinsmore, *et al.*, WP-96-E-BPA-108, at 8-9. Therefore, the customer *can* return energy. If a customer manages its schedule on a real-time basis, there should be little or no imbalances at the end of the month. *Id.* However, at the close of the billing month, the deviation accounts are settled and credited or charged at the appropriate rates. WP-96-A-02, Appendix. Clark offers no reason why it should be able to return the energy after the close of the billing cycle rather than make a payment. WPAG suggested that BPA include 168-hour return instead of a rate. Beck, *et al.*, WP-96-E-WA-13, at 54-55. BPA did not include the energy return option because of the additional administrative burden of scheduling additional transactions. Dinsmore, *et al.*, WP-96-E-BPA-108, at 8-9. If BPA created a schedule for every imbalance, the number of scheduling transactions would increase dramatically. This would only add to the administrative burden. *Id.* Moreover, the FERC NOPR proposed to permit utilities subject to the open access transmission provisions the choice in rate design, of either a return energy provision or a cash payment.

Decision

BPA will not offer the option of returning energy in lieu of payment after the close of the billing month.

13.4 Transmission Losses

Transmission losses are the real power losses associated with the transmission of power over the FCRTS. The rate for transmission losses is 22.80 mills per kWh and is derived from the generation costs included in Bonneville's Average System Cost (BASC) divided by total firm sales. This rate applies to customers who make an annual commitment to purchase losses from BPA pursuant to the applicable Agreement. WPRDS, WP-96-FS-BPA-05, at 40.

BPA proposed the Transmission Losses service as an ancillary service in response to the Loss Compensation Service in the NOPR. Rehman, *et al.*, TC-96-E-BPA-04, at 5-7. Transmission Losses are the real power losses associated with transmission service where the customer elects to purchase the loss amounts from BPA. Final Transmission Terms and Conditions Tariffs, TC-96-E-BPA-15/16, Exhibit D, Schedule 5 and Exhibit E, Schedule 5. FERC's Order 888 removes "Real Power Loss Service" from the mandatory ancillary services list and moves it to an "interconnected operations service" list. Order 888, at 21,583. Based on this change, Transmission Losses could be considered an unbundled power service and service and be sold under the FPS rate schedule or other appropriate rate schedules. Because the Transmission Settlement Agreement includes Transmission Losses as an ancillary services in the Network and Point-to-Point tariffs and APS rate, BPA will adopt the rate for Transmission Losses as an ancillary service. *Id*.; TC-96-E-BPA-15/16; WP-96-A-02, Appendix, at 75.

No issues were raised by parties related to the rate for Transmission Losses.

14.0 PROCEDURAL ISSUES

14.1 Introduction

This section will address procedural issues that were raised during the course of the hearing and in parties' briefs.

Several parties argued at oral argument that the section 7(i) rate process does not work and it is time for a change in the process. Or. Tr. 2374, 2388. While, as reflected in the decisions below, BPA believes it complied with the law in its conduct of the 1996 rate case, it nevertheless here reiterates its commitment to work with customers and interested rate case parties prior to the next rate case to determine whether more satisfying parameters can be devised for future rate cases.

14.2 Section 7(i) Process

14.2.1 Evidentiary Rulings

Issue 1

Whether the Hearing Officer erred in making certain evidentiary rulings affecting the participation of Renewable Northwest Project (RNP), as follows:

1. *granting BPA's motion to strike the testimony of Rachel Shimshak;*
2. *granting BPA's motion to strike sections IV and V of RNP's prehearing brief; and*
3. *declining to take official notice of the 1991 Regional Plan.*

Parties' Position

Renewable Northwest Project (RNP) asks that excluded evidence pertaining to renewable resources be received into the record. RN Brief, WP-96-B-RN-01. RNP asks that the testimony of Rachel Shimshak be included over the Hearing Officer's orders striking the testimony as beyond the scope of the rate case. *See* WP-96-O-22 and WP-96-O-26. RNP also asks that sections IV and V of its prehearing brief be received and considered by the Administrator even though those parts were stricken by the Hearing Officer. *See* RN Brief, B-RN-01, at 15-16. Finally, RNP asks that the 1991 Regional Plan be made a part of the record in spite of the Hearing Officer's refusal to take official notice of the document. *Id.* at 16-17; *see also* RNP's Memorandum in Opposition to BPA's Motion to Strike Prehearing Brief, at 3-4. RNP did not file a brief on exceptions.

BPA's Position

BPA believes the purpose of the testimony and exhibits offered by RNP relates only to urging BPA to place a higher priority on renewable resources and to complete four demonstration projects. The issues raised relate exclusively to resource acquisition decisions. These business determinations have broad implications inappropriate for consideration within the narrowly focused context of the rate hearing. Consequently, the Hearing Officer was correct in excluding Ms. Shimshak's testimony, striking sections IV and V of the brief, and declining to take judicial notice of the 1991 Regional Plan.

Evaluation of Positions

RNP submitted the prepared testimony of Rachel Shimshak. WP-96-E-RN-02. BPA objected by filing a motion to strike the testimony. WP-96-M-20. The Hearing Officer granted BPA's motion. WP-96-O-22. RNP then filed a motion for reconsideration. WP-M-96-44. It argued that Ms. Shimshak's testimony should not have been stricken because it was offered for the purposes of describing what RNP is; demonstrating the importance of renewable resources; supporting inclusion of renewable projects in BPA's revenue requirement; and opposing any cuts of those projects. *Id.* at 2-4. In response, the Hearing Officer affirmed his earlier decision to exclude Ms. Shimshak's testimony. WP-96-O-26. He concluded that the purposes for which the testimony had been offered fell outside the scope of the rate case. *Id.* at 2. He found that the first three purposes were merely preparatory to the ultimate purpose of opposing any cuts in renewable resource demonstration projects. *Id.* He therefore affirmed his earlier decision to exclude the testimony because decisions involving such broad implications could not be made in the confines of the rate proceeding. *Id.*

In its prehearing brief, RNP attempted to revive the issue by including sections discussing the importance of renewable resources and asserting that cutting renewable resources is not permitted by law. WP-96-P-RN-01, at 7-9. BPA moved to strike those portions of the brief (*i.e.*, sections IV and V) because they introduced issues beyond the scope of the hearing and violated the procedural requirement that "[a]ll evidentiary arguments in briefs must be based on cited material contained in the record." *See Procedures*, § 1010.13(a). In its memorandum in opposition to BPA's motion to strike, RNP addressed sections IV and V of its prehearing brief and requested that the Hearing Officer take official notice of the 1991 Regional Plan. WP-96-M-69/TC-96-M-40. The stricken portions are relevant, RNP argues, because they are related to ancillary products or preserve previously raised issues. *Id.* at 2-3; *see also* RN Brief, B-RN-01, at 15-16.

As for official notice of the 1991 Regional Plan, RNP argues that the Regional Plan underscores the importance of renewable resources and shows that the effects of BPA rate proposals on renewable resources is greater than BPA appreciates. RN Brief, B-RN-01, at 17. Oral arguments were held on both the motion to strike and the request that the Hearing Officer take official notice of the 1991 Regional Plan. Tr. 2277-2285. RNP and BPA reiterated earlier arguments. *Id.* BPA also argued that the 1991 Regional Plan was too voluminous and introduced too many extraneous issues to be received as evidence. *Id.* at 2280. BPA also pointed out that taking official notice of the plan would not conform to the procedural rules governing the rate case. *Id.* In an oral order without commentary, the Hearing Officer granted BPA's motion to strike the two sections of the prehearing brief and denied the request to take official notice of the 1991 Regional Plan. *Id.* at 2284.

The thread that ties all of these evidentiary rulings together is the question of whether issues raised by the submitted testimony and exhibits can legitimately be determined within the context of the rate hearing. RNP seeks to characterize its attempts to introduce testimony, arguments, and exhibits in various ways so as to come within the scope of the rate hearing. Viewed objectively, however, RNP's purpose has been

1. to encourage BPA to make renewable resources a higher priority and
2. to urge the completion of four demonstration projects currently underway.

These purposes, as well-intentioned and important as they may be, involve resource acquisition determinations, and these are not within the scope of issues to be determined in the context of the rate hearing.

The issues raised by the testimony of Rachel Shimshak are not rate issues. The testimony suggests that BPA give "high priority to completing the renewable resource demonstration projects that BPA has already started, and to renewable resources generally." Shimshak, E-RN-02, at 1. According to the testimony, the Northwest Power Act provides that "the [Regional Conservation and Electric Power] Plan shall give renewable resources the highest priority following conservation" and that "[t]he Administrator shall acquire resources that are consistent with the Regional Plan." *Id.* at 2. The testimony indicates that "renewable energy projects will have a positive effect on the environment and economy of the Northwest." *Id.* at 3. Finally, the testimony notes that four renewable resource projects are under review, and that completion of the projects "will help build non-hydro renewable resource capability and experience within BPA, and its public and private utility partners. They will provide leadership [and] generation diversity . . . . They are clean developments, and reduce the region's future environmental rise [and] . . . will create jobs in rural areas." *Id.* at 4.

The testimony did not address any studies emanating from BPA's initial proposal, question any expenditure in BPA's revenue requirement, or offer anything of substance to any specific aspect of the case. The ratemaking function does not encompass each and every aspect of BPA's responsibilities but rather focuses on the Administrator's obligation to set rates to recover, in accordance with sound business principles, the costs of producing and transmitting electric power, including the amortization of the Federal investment, over a reasonable period of years. Northwest Power Act, § 7(a)(1), 16 U.S.C. § 839e(a)(1). It would simply not be practical or feasible to consider renewable resource acquisition in the context of the rate hearing. To do so would require the Administrator to make a business decision having broad implications in a ratemaking forum that is designed for the narrower purpose of setting rates in accordance with the Northwest Power Act's rate directives. Because alternative forums are available for consideration of the issues raised by Ms. Shimshak's testimony, there is no danger of unfairness to the parties and duplicative consideration of issues is avoided. The testimony of Rachel Shimshak involves business judgments which should be undertaken outside the arena of the rate hearing, and it was, therefore, appropriate for the Hearing Officer to strike her testimony.

A similar analysis applies to the prehearing brief. Section IV suffers from the same deficiencies as the stricken testimony of Ms. Shimshak, dealing with resource acquisition concerns inappropriate for consideration in the rate case. In section V, RNP raises the argument that cutting support for renewable resources is a violation of the law. Again, RNP incorrectly assumes that the rate hearing is the appropriate forum for making resource acquisition decisions. The fact that an action may have an indirect effect on rates or revenues "does not mean that the action constitutes ratemaking."*California Energy Comm'n v. BPA*, 909 F.2d 1298, 1305 (9th Cir. 1990). The rate hearing is not a forum where the Administrator should be expected to consider every business decision that may have some conceivable impact on rates. Such an approach would introduce practically any business decision into the rate making process. Many decisions, including those pertaining to resource acquisition, are not appropriate for consideration here.

Similar deficiencies are also involved in the RNP request that the Hearing Officer take official notice of the 1991 Regional Plan. RNP asserts that the 1991 Regional Plan underscores the important role of renewable resources in the Pacific Northwest and it submits that it "intended to use this evidence to show the negative effects that some of BPA's proposals has on renewable resources is much greater than BPA may appreciate." RN Brief, B-RN-01, at 17. The request amounts to another attempt to avoid the initial adverse ruling of the Hearing Officer regarding the testimony of Rachel Shimshak. For all of the reasons cited previously, this last-ditch effort to introduce evidence regarding renewable resource acquisition should fail.

Beyond that, taking official notice of 1991 Regional Plan would improperly interject into the rate proceeding, not just the improper issues discussed above, but an entire host of extraneous issues not within the scope of the rate case. The Plan, in over one thousand pages, addresses a myriad of issues relevant to the Pacific Northwest's electric power needs, resources, and facilities. Renewable resources are just one small part of the document. Its major subject headings include entries on implementation of the power plan, confirmation of renewable resources, background and history of the Northwest power system, planning strategy, the existing power system, economic forecasts for the region, forecasts of power use, conservation resources, generating resources, environmental effects, resource portfolio, resource acquisition, model conservation standards, financial assumptions, resource cost-effectiveness, and risk assessment. Each of these major areas is further broken down into numerous sub-topics and the sub-topics are divided into literally hundreds of individual issues.

Allowing such a wide-ranging document into the record would risk bogging down the proceedings in an endless parade of arguments based on evidence that is not appropriate for this process. The 1991 Regional Plan is an important document for the Pacific Northwest. The issues it addresses and the policies it recommends deservedly get much attention. None of that, however, changes the fact that there must be a reasonable limit on the issues to be considered in the context of the rate hearing.

Furthermore, the document itself is not even appropriate for taking official notice as requested by RNP. *See Procedures*, § 1010.11. RNP requests official notice of the document so as to draw from it facts relevant to its renewable resource concerns. As noted above, it "intended to use this evidence to show the negative effects that some of BPA's proposals has on renewable resources is much greater than BPA may appreciate." RN Brief, B-RN-01, at 17. Under the rules governing this proceeding, official notice would be appropriate for such a purpose only if the facts contained in the Plan are either "(1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned." Federal Rules of Evidence, Rule 201. Given the document's voluminous and multi-faceted character, facts contained in the 1991 Regional Plan are not "generally known," and due to the emphasis on policy and planning, determination of accuracy would not always be "ready."

Nor can official notice be taken on the basis that BPA is an "expert" on the plan. This type of official notice contemplates only scientific, technical, or specialized information on which BPA has expertise given the nature of the agency. The 1991 Regional Plan is a general purpose document, enunciating policies of wide-ranging concern. Therefore, it does not lie within the special niche carved out by the rule.

To the extent that any of proffered testimony and exhibits address program spending levels, rather than renewable resource acquisition, they should still be excluded. The Federal Register notice published prior to commencement of this ratemaking process indicated that evidence pertaining to spending levels should be excluded by the Hearing Officer. 60 Fed. Reg. 36464, 36465 (1995). This limitation conforms with ratemaking directives found in Section 7 of the Northwest Power Act. Section 7(a)(1) requires rates to be set to recover costs associated with all of BPA's activities. The rates must recover the costs of those programs, but programs and program levels are not part of the rate case. *See* § 10.4.2, Access to Fish Cost Contingency Fund (BPA's decision not to take a credit of the full $325 million Fish Cost Contingency Fund in the rate case is an issue not properly litigated in the rate case forum because it involves program levels); *see also* Administrator's Record of Decision, 1993 Final Rate Proposal, WP-93-A-02, at 319-329 (litigation of program levels and budgets not appropriate for litigation in context of rate case).

Decision

The Hearing Officer did not err in any of the evidentiary rulings raised by RNP in its post-hearing brief. The rate hearing requirement of a full and complete record does not encompass all aspects of BPA's business. Rather, it is limited to legitimate ratemaking issues. The Administrator wishes to observe, however, that he is well aware of the priority the Northwest Power Act places on renewable resources, and is similarly familiar *with the Council's plan and the resource priorities discussed in that document. This familiarity comes from day-to-day experience with those important policy issues outside the rate case, where they are most appropriately dealt with. To place such issues in the confines of a rate case, with all its procedural rigidities, would be a disservice to the interests RNP represents. Accordingly, the Administrator finds that business determinations involving renewable resource acquisitions are not among those appropriate for consideration in the rate hearing. Therefore, the Hearing Officer was correct in excluding such evidence, regardless of whether the vehicle for its introduction was direct testimony, prehearing brief, or a request for official notice of a document containing such information.*

Issue 2

Whether the Hearing Officer erred in striking the prefiled direct testimony of Portland General Electric and Puget Sound Power and Light on stranded cost recovery.

Parties' Positions

The Major Residential Exchange Participants (MREP) argue in their initial brief that the Hearing Officer should have admitted into evidence the testimony of witnesses Alexanderson and Swafford (WP-96-E-GE/PL-01) regarding stranded cost recovery by BPA. MREP Brief, WP-96-B-GE/PL/PS-01, at 12-14. MREP argue that because BPA failed to address its alleged stranded cost problem, it was forced to eliminate residential exchange benefits to achieve a reduction in the DSIs' rates. *Id.* at 13. They argue that BPA engaged in "procedural ploys" when it moved to strike the stranded cost testimony partly on the grounds that the issue may be addressed at a later date, only to avoid the need to conduct a separate proceeding after transferring its otherwise stranded costs to the residential exchange customers. *Id*. MREP argues it was thereby denied the opportunity to raise "probably the most important issue to impact [its] rates." *Id.*

In its brief on exceptions, MREP argues that the Administrator has created a "Catch 22" by not overturning the Hearing Officer's order striking the stranded cost testimony, while noting that there is no evidence substantiating the MREP's positions. MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 1-2. MREP argues that the stricken testimony "is the evidence which the Draft ROD claims does not exist." *Id*. MREP asserts that failure to admit the stricken testimony in this proceeding is arbitrary, capricious and contrary to law. *Id*. at 3.

The Requirements Customers Coalition (RCC) takes no position on this issue in their initial brief, but they do outline several legal and policy arguments concerning BPA's ability to collect stranded costs from its customers. RCC Brief, WP/TC-96-B-RC-01, at 5-8.

BPA's Position

BPA argued to the Hearing Officer in its motion to strike that it would be prejudicial and unfair to all the parties to allow the testimony of Alexanderson and Swafford on an issue that was neither addressed by BPA's initial proposal nor by any other party, especially in light of the fact that the issue was specifically set aside to be dealt with in other forums. WP-96-M-13, at 2. The DSI's filed a separate motion also seeking that the Alexanderson and Swafford testimony be struck. WP-96-M-DS-24. The Hearing Officer granted these motions, holding that the testimony went "beyond the scope of the rate case." WP-96-O-15.

The Hearing Officer did not err in striking the testimony of Alexanderson and Swafford. BPA stated in its Federal Register Notice initiating these proceedings that it did not have a specific stranded cost proposal to make at that time, that it wished to enter into a stranded costs dialogue with its customers outside of the formal rate case process, and that a stranded costs recovery mechanism, if any, would be established in a separate section 7(i) proceeding. *See* WP-96-FR-05. MREP's allegation that BPA was compelled to reduce residential exchange benefits because it failed to address the stranded cost issue is a red-herring. Issues concerning the amount of the residential exchange have been fully litigated in this rate case, and BPA has established through evidence on the record that the reduction in the residential exchange is due to decisions and circumstances unrelated to stranded costs. *See* sections 7.3, 8.2, 8.3, 9.0. MREP's statement, therefore, that the issue of stranded costs is "probably the most important issue to impact their rates" is both overwrought and unsupported by the evidence regarding the residential exchange.

Because the stranded cost issue has not been litigated in this proceeding, BPA takes no position at this time in response to policy and legal arguments regarding stranded costs outlined by the RCC in its initial brief. The RCC brief does not take any positions on the stranded cost issues addressed by MREP in its initial brief, nor does the RCC brief raise any additional specific stranded costs issues that need be addressed by the Administrator in this Record of Decision.

Evaluation of Positions

MREP has pointed to no evidence to support the many allegations they make in their initial brief, in particular their argument that BPA's proposal to reduce its residential exchange payments is the consequence of its failure to address its alleged stranded cost problem. What the MREP essentially seeks is to have their business judgment with regard to BPA's approach to the stranded cost issue substituted for that of the Administrator.

BPA is well aware that it may incur stranded costs as a consequence of the transition to a deregulated and highly competitive wholesale power market. For BPA and its customers this issue has taken on particular importance as power sales contracts are amended or new contracts are executed. The Administrator, however, chose to address this issue outside of the context of the rate case. *See* WP-96-FR-05. That is not the same thing as ignoring the issue, or condemning BPA to incur stranded costs to the detriment of the residential exchange customers, as MREP suggests. Making stranded costs a rate case issue would have required that the parties litigate the myriad of technical and legal issues surrounding recovery by BPA of stranded costs, including whether BPA has even incurred any stranded costs, how those costs should be measured and collected, customers contractual obligations to pay such costs, which customers would be liable to pay such costs, BPA's statutory authority to collect such costs, the relevance of FERC's stranded cost rule makings, as well as many other highly contentious issues. Major customer groups have clearly indicated they are prepared to take a hard-line on these issues. RCC Pr. Br., WP-96-P-RC-01; RCC Brief, B-RC-01; Eldridge, *et al.*, WP-96-E-PP-01, at 9-10 (stranded cost portion of testimony struck, WP-96-O-19). Instead of engaging in a pitched battle with the very customers he was seeking to sign to amended or new contracts - or indeed to stay under existing contracts - the Administrator chose to first determine whether he could meet BPA's statutory cost recovery responsibilities through lawful, competitive rates and service arrangements, rather than resort to the extraordinary remedy of attempting to impose stranded cost charges.

To meet its many statutory obligations, in both the short-term and the long-term, BPA must retain its existing sales, and seek out additional sales and revenues, by offering competitive products and prices. *See supra* section 2 for a discussion of the issues surrounding BPA's competitiveness. This is especially important as 2001 approaches, at which time virtually all of BPA's power sales contracts will expire. The Administrator has set the agency on a course of implementing competitive prices and products to retain as many sales as possible during the 5-year rate period, thereby improving BPA's financial position and its ability to successfully compete for new power sales contracts in 2001 and beyond. Therefore, BPA's business strategy is to avoid, if possible, incurring any stranded costs by retaining load and cutting costs where lawfully possible. The MREP conclusion that BPA has already incurred stranded costs is not supported by any evidence admitted into the record, or, contrary to MREP's assertion in its brief on exceptions, by the stricken testimony itself which was tendered by counsel as an offer of proof (Tr. 2142); yet MREP rely on this faulty premise as a basis for their allegations regarding the impact of stranded costs on the residential exchange program. As explained elsewhere in this ROD, the reasons for the reduction in residential exchange benefits are totally unrelated to the issue of stranded costs. *See* sections 7.3, 8.2, 8.3, 9.0. To the extent that BPA's load retention and cost cutting strategy is not successful, then BPA will weigh its business and legal options for the recovery of any resulting stranded costs.

This, however, is a decision for the Administrator, not for the MREP utilities. As the DSIs noted in their motion to strike, as a matter of administrative law an agency is entitled to discretion in determining which issues it will address in which proceedings *Mobile Oil Exploration & Producing Southeast, Inc. v. United Distribution Cos.*, 498 U.S. 211, 230, 111 S. Ct. 615, 627 (1991) ("An agency enjoys broad discretion in determining how best to handle related, yet discrete issues in terms of procedures, *Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council*, Inc., 435 U.S. 519, 98 S. Ct. 1197, 55 L.Ed.2d 460(1978) and priorities, *Heckler v. Chaney*, 470 U.S. 821, 831-32, 105 S.

Ct. 1649, 1655-56, 84 L.Ed.2d 714 (1985).”). In *Mobile* FERC had declined to address the so-called “take-or-pay” issue in the gas industry rulemaking that was the subject of the litigation. The take-or-pay issue was the gas industry version of stranded costs during the period when it was being deregulated. FERC reasoned that the take-or-pay problem would be resolved through other processes, including contract renegotiations. The Court noted that it was “neither inclined nor prepared to second-guess the agency’s reasoned determination in this complex area.” *Mobile*, 111 S.Ct. 615, 628. This was the case even though some of the actions taken in the rulemaking at issue could have some impact on the take-or-pay issue. *Id*. at 627.

It is the Administrator’s obligation to set rates to recover, in accordance with sound business principles, the costs of producing and transmitting electric power, including the amortization of the Federal investment, over a reasonable period of years. Northwest Power Act, Section 7(a)(1), 16 U.S.C. § 839e(a)(1). The United States Court of Appeals for the Ninth Circuit has consistently recognized the broad scope of the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 112029 (9th Cir. 1984) ("[b]ecause BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA's statutory interpretation"); *PacifiCorp v. F.E.R.C.*, 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 Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA's rate determination upheld as a "reasonable decision in light of economic realities.”) BPA has presented substantial evidence on the record that its best chance to be competitive and meet its statutory obligations is to retain sales with market competitive prices and products. *See generally* Moorman, Evans, WP-96-E-BPA-09, and E-BPA-65; Norman, Oliver, WP-96-E-BPA-10; Buchanan, *et al*., WP-96-E-BPA-11. The decision by the Administrator to implement a business strategy that, if successful, may well eliminate the need for any stranded cost recovery is well within the discretion vested in him to conduct BPA’s affairs in a sound a businesslike manner.

Decision

The Hearing Officer did not err in striking the stranded cost testimony of Alexanderson and Swafford, and the decision by the Administrator not to reverse that decision is not arbitrary, capricious or contrary to law.

Issue 3

Whether the Hearing Officer erred in excluding from the record the DSIs’ oral direct testimony.

This issue is addressed in section 14.2.2.

14.2.2 <u>Compliance With BPA *Ex Parte* Rules</u>

<u>Issue</u>

Whether BPA employees and representatives of the DSIs engaged in ex parte communications that require rejection of BPA's proposed industrial margin study.

<u>Parties' Positions</u>

APAC argues that a BPA analyst and DSI representatives engaged in *ex parte* communications regarding the industrial margin study. APAC Brief, WP-96-B-PA-01, at 19-20. The investor-owned utilities (IOUs) argue that a BPA employee and the DSIs had *ex parte* conversations regarding the magnitude of the industrial margin and the issue of revenue taxes. MREP Brief, WP-96-B-GE/PL/PS-01, at 22. The IOUs also argue that BPA violated the *ex parte* rule when it received from the DSIs the data base used in calculation of the industrial margin. *Id.* at 17. The parties argue that the Administrator should reject BPA's margin study.

<u>BPA's Position</u>

BPA testified that its receipt of the data base and its conversations with the DSIs all took place when the *ex parte* rule was not in effect. Tr. 976, 1702. In addition, BPA testified that the conversations concerned the BPA analyst's questions about the data base rather than the merits of the industrial margin. *Id.* at 1702-03, 1706. Finally, BPA states that the parties were not prejudiced because the data base and notes of the conversations were entered into the record. *See* WP-96-E-GE-05; WP-96-E-GE-06; WP-96-E-PA-07.

<u>Evaluation of Positions</u>

The BPA Rules of Procedure prohibit *ex parte* communications regarding any matter pending before BPA in the hearing *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.7(a), 51 Fed. Reg. 7611 (1986). This prohibition does not apply to a communication "which relates solely to a request for supplemental information or data necessary for an understanding of factual materials contained in documents filed with BPA during a hearing and which is made in the presence of or after coordination with BPA counsel." *Id.* § 1010.7(b)(6). The prohibition takes effect "the day on which BPA publishes the FEDERAL REGISTER notice specified in section 1010.3, or the person responsible for such communication has knowledge that a notice will be published." *Id.* § 1010.7(c). Section 1010.3 requires BPA to publish a notice that, among other things, "specifi[es] the proposed rates and summariz[es] any studies, analyses, or other available information that BPA intends to use in the hearing to justify the proposed rates." *Id.* § 1010.3(a). This notice was published July 17, 1995. 60 Fed. Reg. 36,464 (1995).

BPA freely acknowledged receiving the data base from the DSIs and having conversations about the data base with the DSIs. In discovery, BPA turned over to the parties both the data base and notes of the conversations. *See* E-GE-05, E-GE-06, and E-PA-07. For three reasons, BPA's actions do not warrant rejection of its proposal:

1. BPA received the data base and had the conversations with the DSIs when the *ex parte* rule was not in effect.
2. The conversations did not concern the merits of any issues pending before BPA in the hearing. Instead, a BPA analyst asked the DSIs questions to clarify the data.
3. Because the parties have had full opportunity to rebut both the data base and the substance of the conversations, no party has been prejudiced.

<u>BPA's Receipt Of The Data Base And Conversations With The DSIs Took Place When The *Ex Parte* Rule Was Not In Effect</u>

In February 1995 BPA received from the DSIs a one-page summary of the data base labeled "Margin Analysis." Acting individually, two BPA employees immediately placed the summary in the BPA *ex parte* file. *See* WP-96-E-GE-21 and WP-96-E-GE-22. In a note accompanying one of the submissions, the BPA employee wrote that the document had been distributed within BPA on February 2nd, after the "January 20 exparte [sic] deadline." E-GE-21. Both APAC and the IOUs rely on this note for their argument that the *ex parte* rule was in effect as of January 20, 1995. *See* APAC Brief, B-PA-01, at 19; MREP Brief, B-GE/PL/PS-01, at 17-18. The other submission to the *ex parte* file was dated February 7, 1995, and indicated that BPA had received the attached "Margin Analysis" on February 1, 1995. E-GE-22.

BPA testified in cross-examination that the DSIs gave a BPA employee the data used in the margin study in April 1995. Tr. 952. Citing the earlier submissions to the *ex parte* file, the IOUs assert that BPA received the data "significantly earlier." MREP Brief, B-GE/PL/PS-01, at 17. In making their assertions, the parties have made two separate mistakes: first, they have confused the 1995 rate case with the 1996 rate case; and second, they have confused a summary sheet the DSIs provided in February with the data base they provided in April.

The first note to the *ex parte* file mentioned a January 20 *ex parte* deadline. On January 20, 1995, BPA was in the midst of the 1995 rate case. On December 28, 1994, BPA had published a Notice of Intent to Revise Wholesale Power Rates. 59 Fed. Reg. 66,947 (1994). On February 14, 1995 BPA published a Notice of Proposed Wholesale Power Rate Adjustment. 60 Fed. Reg. 8496 (1995). On that date BPA also published its preliminary rate proposal. The proposed rate adjustments were to become effective October 1, 1995, for fiscal years 1996 and 1997. *Id.*; *see also Administrator's Record of Decision, 1995 Final Rate Proposal* 1 [hereinafter *1995 Rates ROD*].

At this point BPA did not expect to be holding a 1996 rate case. Instead, as its Federal Register notices provided, BPA was holding a 1995 rate case in which it planned to set rates for two years beginning October 1, 1995. The parties argue that BPA received the "Margin Analysis" from the DSIs while the *ex parte* rule governing the 1996 rate case was in effect. To the contrary, even the notion of a 1996 rate case did not yet exist. Neither the *ex parte* rule nor any other aspect of the 1996 rates process was in effect. January 20 was the date the *ex parte* rule applied to the 1995 rate case. If the parties believed that BPA violated the *ex parte* rule in that case, they should have raised the issue in that case.

Their argument, however, would not have prevailed, because the level of the industrial margin was not an issue pending before BPA in the 1995 rate case. In that case, as in every rate case since 1985, the Industrial Firm Power rate was based on the IP-PF Link, under which no margin calculation is made. *See* Chang, Cocks, WP-96-E-BPA-25, at 2; *see also supra* § 8.2.1. Therefore, all data regarding the level of the industrial margin were irrelevant to that case, and BPA's receipt of the "Margin Analysis" would not have fallen within the *ex parte* prohibition. These facts do not change because two BPA employees, apparently out of an excess of prudence (*see* WP-96-E-GE-23), placed documents in the *ex parte* file.

Thus, BPA received the "Margin Analysis" when neither the 1995 nor the 1996 *ex parte* rule applied to it, and cannot be accused of wrongdoing; the document was irrelevant to the then-ongoing proceeding, while the present proceeding was not yet contemplated. The IOUs, however, cite a third memorandum by a BPA employee to the *ex parte* file dated April 14, 1995. MREP Brief, B-GE/PL/PS-01, at 18, n.16 (citing E-GE-23). This memorandum accompanied "updates of data that were used in the DSI margin study in 1985." E-GE-23. The author of the memorandum wrote that he did not believe the materials were subject to the *ex parte* rule, but that he was placing them in the *ex parte* file "so that all rate case parties and participants have immediate access to them." *Id.* On April 14, 1995, the 1995 rate case was still ongoing; most of the parties had only recently agreed to propose a settlement to the Administrator, and BPA filed its initial proposal on May 1, approximately two weeks after the materials were placed in the *ex parte* file. *1995 Rates ROD* 6. Thus, on April 14 BPA's employees remained subject to the *ex parte* rule in the 1995 rate case. The prior submissions demonstrate that employees were prudently placing materials in the *ex parte* file if they related to DSI rates, even though the issue was not relevant to the 1995 rate case.

On cross-examination the BPA analyst testified that the DSIs gave BPA the data for the margin study in April 1995. Tr. 952. The above memorandum confirms that testimony. Whereas the prior notes to the *ex parte* file accompanied a one-page "Margin Analysis," the April 14 memorandum accompanied "updates of data that were used in the DSI margin study in 1985"; that is, the actual data. Citing one of the notes accompanying the "Margin Analysis," however, the IOUs argue that BPA received the data "significantly earlier [than April]," thus attempting to contradict the witness's testimony. MREP Brief, B-GE/PL/PS-01, at 17. Here the IOUs have confused the three submissions to the *ex parte* file (two of which, as noted, were of the same document). What BPA received "significantly earlier"—in February—was the one-page "Margin Analysis" that included a summary of the data base. In her cross-examination question, however, counsel for the

IOUs asked the analyst when BPA received the data used in the study. Tr. 951. These data consisted of the data base attached to the April 14 memorandum. (All of the cross-examination questions concerned the data, not the one-page "Margin Analysis." Counsel for the IOUs began the cross-examination on this topic by referencing BPA's prefiled testimony "at BPA-25 at page 2, line 23." *Id.* Counsel continued: "And you asked in your testimony, 'How did you obtain the data for the margin study?'" *Id.* BPA's answer in the prefiled testimony was that the DSIs had updated "the data base" that was compiled in 1985. Chang, Cocks, E-BPA-25, at 2-3. Thus, it is clear that counsel's cross-examination concerned the data base, and that the witness's answer at cross-examination did as well.

Moreover, at oral argument counsel for the IOUs also made clear that her concern was with the data base itself; she alleged that "[t]he DSI attorneys and consultants handed over to your [the Administrator's] DSI marketing team as early as January and February of 1995, their own typical margin study." Tr. 2437. She added that "the study was given to a witness on your staff in about April of 1995." *Id.* The BPA cross-examination testimony on which this allegation relies, however, was that the study was given to Stan Kusaka by the DSIs in April 1995. ("Q. Do you know when Stan Kusaka got the data? A. To the best of our recollection, it was the first half of April. Q. April of— A. 1995." *Id.* at 952.) Stan Kusaka is the member of the DSI marketing team who received the study. Counsel mistakenly asserted that Mr. Kusaka received the margin study earlier, and gave it to the analyst in April.

Finally, in August 1995, more than six months before cross-examination took place, Portland General Electric Company, one of the IOUs, submitted a data request to BPA asking when BPA had received the study from the DSIs "referenced at page 2, line 24-25 through page 3, line 1-2 [of prefiled testimony BPA-25]." WP-96-E-GE-10. This page and line reference is to the answer BPA gave in the prefiled testimony to the question, "How did you obtain the data for the margin study?" As noted, in that answer BPA referred to "the data base." In its response to the data request BPA replied that "[t]o the best of recollection we received this information during the first half of April." E-GE-10. Thus, the witness's response at cross-examination was consistent with both BPA's response to the data request in August 1995 and the April 1995 memorandum to the *ex parte* file. Counsel's allegation against BPA is based on a confusion of the exhibits.)

The second *ex parte* issue the parties raise concerns BPA's conversations with representatives of the DSIs. The BPA employee who had the conversations with the DSIs testified that that none of the conversations took place after the *ex parte* window closed. Tr. 976, 1702. In the 1995 rate case the *ex parte* rule took effect on January 20, approximately three weeks before BPA published its Notice of Proposed Wholesale Power Rate Adjustment and its Preliminary Rate Proposal. WP-96-E-PA-06, at 3; E-GE-21, at 1. BPA's conversations with the DSIs took place from approximately May 19 to June 7, 1995. WP-96-E-GE-08. BPA published its initial proposal on July 10, 1996, more than one month later. (Because of procedural delays, the Notice of Proposed Wholesale Power Rate Adjustment was not published until July 17, 1996. 60 Fed. Reg.

36,464 (1995)). Therefore, the lapse of time between the time the conversations with the DSIs ended and the publication of BPA's initial proposal—June 7 to July 10, 1995—was greater than the lapse of time between the closing of the *ex parte* window in the 1995 rate case and the publication of BPA's preliminary rate proposal (January 20 to February 14, 1995).

BPA's procedural rules provide that the prohibition on *ex parte* communications applies when the Federal Register notice specifying the proposed rates is published, or when the person responsible for the communication has knowledge that a notice will be published. *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.7(c), 51 Fed. Reg. 7611 (1986). The IOUs assert that, when the conversations with the DSIs were taking place, "[t]here can hardly be a dispute that the person responsible for the contacts knew the Federal Register Notice would be published." MREP Brief, B-GE/PL/PS-01, at 22 n.21. There is no evidence in the record, however, as to whether the witness knew the notice would be published; the parties did not avail themselves of the opportunity on cross-examination to elicit this evidence. The rule's requirement that the involved individual rather than the agency know that a notice will be published contemplates actual rather than constructive knowledge.

If constructive knowledge were sufficient, the *ex parte* rule could be read to prohibit BPA from ever talking to its customers. Historically BPA has held rate cases every two years. The 1993 rate case set rates effective October 1, 1993; the 1995 rate case set rates effective October 1, 1995. As soon as BPA finishes one rate case, it must begin working on the next. Therefore, as of October 1, 1993, if not before, BPA knew it would publish a Federal Register notice initiating a 1995 rate case. BPA could hardly operate a power business if the *ex parte* prohibition applied two years before rates were to take effect (indeed, in such case it would always apply). Instead, BPA must apply a rule of reason that allows it to conduct its business while protecting the parties' rights to a full and fair hearing.

In their brief on exceptions, the IOUs assert that, according to the draft ROD, from May 19 to June 7, 1995, the BPA analysts "were not aware that a rate case proposal would be published." MREP Ex. Brief, WP-96-R-GE/PL/PS-01, at 5. In fact the draft ROD made two observations regarding this issue: first, it noted (as does the final ROD) that the parties rely on an assumption that the witnesses knew the Federal Register notice would be published, since they did not pursue the issue through discovery or cross-examination. Second, the draft ROD concluded (again, as does the final ROD) that BPA must apply a rule of reason in implementing the *ex parte* rule.

APAC's brief on exceptions demonstrates the need to interpret the *ex parte* rule reasonably. APAC asserts that, when BPA settled the 1995 rate case in March 1995, it was fully aware that it "would immediately be filing the 1996 rate case." APAC Ex. Brief, WP/TR-96-R-PA-01, at 18. (Presumably, APAC means that BPA would immediately be starting the 1996 rate case. Filing of documents would not occur for several months.) Therefore, according to APAC's logic, the *ex parte* rule immediately took effect, and BPA had not even a day between rate cases during which it could talk to its customers. Paradoxically, APAC then asserts, as it did in its initial brief, that the *ex parte* contacts took place "between January and June, 1995." *Id*. Yet APAC has not challenged BPA's evidence, discussed in the draft ROD, that as of January 1995 the *ex parte* rule for the 1996 case could not have been in effect. Indeed, APAC's prior reference to March 1995 appears to concede the point. Nevertheless, APAC insists that contacts with the DSIs in January 1995 violated the *ex parte* rule; indeed, APAC asserts that "BPA knew for ten years that the IP-PF Link would expire, and the Industrial Margin would have to be re-calculated, by 1995 or 1996. The contacts in early to mid-1995 clearly took place after BPA staff were aware that a notice would be published in the near future, and thus were made when the rule was in effect." *Id*.

Under APAC's logic, the *ex parte* rule could be held to apply from the time the IP-PF Link went into effect, since the Link contained an expiration date, and since BPA knew when it adopted the Link that it would be filing a Federal Register notice for a rate case in which it would recalculate the industrial margin. At the very least, according to APAC, the rule was in effect in January 1995, when BPA was in the midst of the 1995 rate case, when the settlement had not yet even been discussed, and when BPA did not expect to file a Federal Register notice initiating the 1997 rate case—during which it expected to recalculate the industrial margin—for at least a year and a half. If the rule applied under these circumstances, then it is difficult to conceive when it would not apply.

The IOUs note that the conversations with the DSIs ended approximately one month before BPA published the Federal Register notice initiating the 1996 rate case. MREP Ex. Brief, R-GE/PL/PS-01, at 5. Thus, they argue, the BPA analyst must have known that a Federal Register notice would be published. Similarly, APAC notes that in early 1995 BPA knew it would be publishing a notice "in the near future," and that in March 1995 BPA knew it would "immediately" be pursuing the 1996 rate case. Thus, despite APAC's additional reference to January 1995, both parties appear to concede BPA's point that a rule of reason must apply. BPA followed an appropriate rule of reason in this case. In early June, BPA notified the parties that the *ex parte* rule was not yet in effect for the 1996 rate case. On June 2, 1995, BPA sent the following notice to all rate case parties:

From: Prewitt, Janet L. - LQ
To: Arkills, Dick - Rate Case; Barnett, Darlene - Rate Case; Bechtel, W. Douglas -Rate Case; Beck, R.W. - Rate Case; Benedict, James - Rate Case; Blees, Jonathan - Rate Case; Bliven, Ray - Rate Case; Bosch, W. Bruce - Rate Case; Bottomly, Leslie - Rate Case; Brattebo, W. Scott - Rate Case; Bubenik, Mark L. - Rate Case; Buckley, Alan P. - Rate Case; Cameron, John A., Jr. RateCase; Carr, John D. - Rate Case; Cedarbaum, Robert - Rate Case; Chamberlain, William-Rate Case; Cohen, David B. - Rate Case; Cook, Stephen, F. - Rate Case; Coran, Ted - Rates Case; Dahlke, Gary A. - Rate Case; Dubay, Don - Rate Case; Eisdorfer, Jason - Rate Case; Fields, Willard - Rate Case; Fisher, Ann L. - Rate Case; Foianini, Ray A. - Rate Case; Gibson, Wallace - Rate Case; Goligoski, Charles - Rate Case; Gove, Rick - Rate Case; Green, Paula - Rate Case; Harper, W. Wayne - Rate Case; Heitman, Richard - Rate Case; Hyde, Jim - Rate Case; Jacklin,

Pamela L. - Rate Case; Johnson, R. Erick - Rate Case; Kari, Donald G. - Rate Case; Kaufman, Paul J. - Rate Case; Kitchen, Aleka U. - Rate Case; Larsen, Alan S. - Rate Case; Lauckhart, J. R. - Rate Case; Lewis, Steven - Rate Case; Lothrop, Rob - Rate Case; Marcus, William - Rate Case; Marold, Kelley J. - Rate Case; McNamee, Bill - Rate Case; Meek, Daniel - Rate Case; Melton, Ruby - Rate Case; Merkel, Joel - Rate Case; Mizer, Bruce E. - Rate Case; Moxness, Kay - Rate Case; Mundorf, Terence - Rate Case; Murphy, Harlan - Rates Case; Murphy, Kathleen - Rate Case; Murphy, Paul - Rate Case; Nadal, Joseph Jr. - Rate Case; Nelson, Ray - Rate Case; Nelson, Roger - Rate Case; Nelson, Wayne - Rate Case; Nichols, Patricia - Rate Case; Osborn, Dave - Rate Case; Patton, Sara - Rate Case; Peters, Lon - Rate Case; Piliaris, Jon - Rate Case; Pilon, Fergus - Rate Case; Rains, Jolynn - Rate Case; Reed, Lloyd - Rates Case; Richardson, Shelly - Rate Case; Rollins, Veronica - Rate Case; Saven, John - Rate Case; Schoenbeck, Donald - Rate Case; Schue, Steve - Rate Case; Seligman, Dan - Rate Case; Shapiro, Richard - Rate Case; Shelton, Noel - Rate Case; Sher, Phillip A. - Rate Case; Sheridan, William - Rates Case; Shields, Jeff - Rates Case; Smith, Leon J. - Rate Case; Soto, Andrew K. - Rate Case; Stauffer, Mark - Rate Case; Stephens, John - Rate Case; Strong, R. Blair - Rate Case; Szablya, Louis - Rate Case; Trippel, Stuart - Rate Case; Waddington, Steve - Rate Case; Wagers, Chuck - Rate Case; Waldron, Jay T. - Rate Case; Weirich, Michael - Rate Case; Weiss, Steve - Rate Case; Whitener, George - Rate Case; Williams, Linda - Rate Case; Williams, Walter - Rate Case; Wolverton, Lincoln - Rate Case; Wood, Marcus - Rate Case; Yanov, John - Rate Case; Harmon, Launa - Rate Case; Lessner, Rochelle - Rate Case; Crandall, Sean - Rate Case; Schue, Steve - Rate Case
Cc: Barclay, Paula - CKPS; Fletcher, Eva G. - LP; Larson, Stephen R. - LP; DeWolf, Mike - FPR; Lefler, Valerie - FPR; Metcalf, Dennis E. - MPPC; Moorman, Geoffrey - MPPC; Goodwin, Helen - MPPC; Hindman, Joyce - MPPC; Hansen, Mary - MPPC; LQ
Subject: Rate Case Workshop Schedule
Date: Friday, June 02, 1995 5:12PM

June 2, 1995

Dear Rate Case Participants and Other Interested Parties:

1996 Rate Case Workshops Rescheduled

Action: On May 8, 1995, the Bonneville Power Administration (BPA) announced a series of 1996 rate case workshops. On May 23, 1995, we announced that the workshops scheduled for May 25, 1995 and May 26, 1995 had been postponed. Also postponed are the workshop scheduled for June 7 on the revenue requirement, residential exchange cost projections, risk mitigation and segmentation and the workshop scheduled for June 8 on the marginal cost analysis. These two workshops now are rescheduled for June 27 and June 19 respectively. The workshops scheduled for June 14 and June 15 have been canceled.

The June 20 workshop on transmission policy, transmission terms and conditions and ancillary services also has been rescheduled for June 28. On June 20, we will hold a workshop on loads and resources, hydro studies, rate design and unbundled products. These workshops had been scheduled for May 25 and May 26. Please refer to the back of this letter for a complete workshop calendar showing all of the new dates for the rescheduled 1996 rate case workshops.

Background: The 1996 rate case workshops were designed to allow a continuing dialogue of rate case issues prior to the start of the formal rate proceeding. We are rescheduling or canceling the rate case workshops in order to allow staff to focus on and have more time to analyze and prepare the studies, documentation, and testimony required for the 1996 rate case. The formal rate case is scheduled to begin on July 10, 1995, when we will release our initial proposal.

For purposes of the 1996 rate case, BPA considers itself not to be under the ex parte [sic] until BPA's initial proposal is ready to be published in the Federal Register. Notes will be taken at all of the rate case workshops, however, and will be available at the BPA Public Information Center. Materials also will be provided at each workshop. The *ex parte* rule remains in effect for the 1995 rate case.

If you are unable to attend any of the workshops and would like to receive the handouts, please call the BPA document request line listed below. The handouts also are available at BPA's Public Information Center; BPA Headquarters Building, 1st Floor; 905 NE. 11th; Portland, Oregon.

For Additional Information: If you have questions about the 1996 rate case workshops, please contact your Account Executive or District Office. You also may contact Mary Hansen at (503) 230-4721 or the BPA Document Request Line at 1-800-622-4520.

Sincerely,

Helen A. Goodwin
7(i) Process Manager

No party objected to this notice. In *Iowa State Commerce Comm'n v. Office of the Fed. Inspector of the Alaska Natural Gas Transp. Sys.*, 730 F.2d 1566 (D.C. Cir. 1984), the court said that "'informal contacts between agencies and the public are the "bread and butter" of the process of administration.'" *Iowa State Commerce Comm'n*, 730 F.2d at 1576 (quoting *Home Box Office, Inc. v. F.C.C.*, 567 F.2d 9, 57 (D.C. Cir. 1977)). In *Iowa State Commerce Comm'n*, the Office of the Federal Inspector issued a Tentative Rate Base Determination under the Alaska Natural Gas Transportation Act (ANGTS) including certain costs in the rate base of Northern Border Pipeline Co. The Iowa Commission challenged the determination as having been based on *ex parte* contacts.

The court concluded that its jurisdiction under the ANGTS was limited to a determination of whether the Tentative Determination violated the Commission's constitutional rights. 730 F.2d at 1568. In addition, the court questioned whether the *ex parte* prohibition applied to the kind of informal rulemaking involved in the case. *Id.* at 1576. For purposes of analysis, however, the court accepted the proposition that the *ex parte* rule applied. *Id.* Noting that the court in *Home Box Office* had barred *ex parte* contacts only after the publication of the notice of proposed rulemaking, the court said that the Tentative Determination was "a rough equivalent of the notice of proposed rulemaking. Once that decision was issued no further *ex parte* contacts were allowed." *Id.* In part because "[t]he contacts about which [the Commission] complains occurred only before the Tentative Determination was published," the court held that the hearing procedures did not violate basic tenets of fairness. *Id.* at 1576-77. (The Administrative Procedure Act standard for when *ex parte* rules apply is identical to BPA's standard. 5 U.S.C. § 557(d)(1)(E)).

In the 1996 rate case, BPA published its initial proposal on July 10, 1995; the Final Record of Decision will issue June 17, 1996. Invocation of the *ex parte* rule in June 1995 means that it will have been in effect for over one year, which includes a period before the filing of any evidence in the case and the entire pendency of the case after the initial filing of evidence. This lengthy period protects the parties' rights and complies with the BPA procedures.

<u>The Discussions With The DSIs Did Not Concern The Merits Of Any Issue Pending Before BPA In The Hearing</u>

The BPA Procedural Rules exempt from the *ex parte* rule communications that relate "to a request for supplemental information or data necessary for an understanding of factual materials contained in documents filed with BPA during a hearing." *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.7(b)(6), 51 Fed. Reg. 7611 (1986). Under the Administrative Procedure Act, *ex parte* communications are those that are "relevant to the merits of the proceeding." 5 U.S.C. § 557(d)(1)(A).

The conversations with the DSIs concerned BPA's efforts to understand the data base. The BPA analyst involved in the conversations testified that they concerned questions she had about the data. Tr. 1702. She further testified that at no time did the DSI representatives tell her how they believed BPA should calculate the industrial margin. *Id.* at 1703.

The BPA analyst took notes both while reviewing the data base and during her conversations with the DSIs. *See* E-GE-06. During cross-examination, counsel for the IOUs questioned her extensively about the notes. The witness explained reasonably and credibly how each notation reflected either a question she asked herself while reviewing the data base or a question she posed to the DSIs so she could understand the data base. A few examples will illustrate her testimony.

The second page of notes contains a notation, "Criteria for throwing out utilities." WP-96-E-GE-06. Counsel for the IOUs asked the witness whether she and the DSIs were discussing "how to throw utilities out of the data base." Tr. 963. The witness responded as follows:

> No, we were not. What we discussed was the DSIs had prepared a smaller sample than the 19 utilities which were included in the data base and it was unclear from looking at that what the criteria was [sic]. And so in the "I would remember to ask" I wrote down, "What were the"—I wanted to know what the criteria were."

Id.

The same page contains a notation that reads "EWEB [Eugene Water and Electric Board]— "Why low load factor?" E-GE-06. Regarding this notation, counsel asked, "[W]ere you exploring ways to throw EWEB out of the sample based on load factor? Is that what that note is about?" Tr. 966. The witness responded that she "was worried about why it was low, especially—it was much lower, I think, than it had been in 1985. So I was curious if they had known anything about what had happened to the load that was being served there." *Id.* (Two items about this exchange are worth noting. First, load factor is not a criterion for inclusion in the sample used in the rate case, and therefore is not relevant to any issue in the case. *Id.* at 965. As the witness testified, she was concerned with the load itself. Second, in the 1985 sample, EWEB (listed as utility 18C, *see* Chang, Cocks, WP-96-E-BPA-120, Attachment E) had a load factor of 75.9 percent. WP-96-E-GE-16, Page 13 of 20. In the updated data the DSIs provided, EWEB's load factor is listed as 52.8 percent, considerably lower. WP-96-E-GE-22. These documents corroborate the witness's testimony.)

Next, counsel asked the witness about a notation on the top of the third page of the notes that reads, "To get to smaller sample—what did you do?" *Id.* at 968; *see* E-GE-06. The witness replied that this was another question she asked the DSIs. Tr. 968. Once again, therefore, she simply was trying to understand the data. In the witness's notes, the immediately following notation reads, "Larry said it was load size, but Clark, Seattle have larger loads than some of the remaining utilities." E-GE-06. Counsel asked the witness whether this was the answer she received to the previous question. Tr. 968. The witness's reply, and the next question and answer, were as follows:

> A. That he said it was load size, but in looking at what was there, Clark and Seattle, I think, were taken out of that small—were not in the smaller sample, but their loads were larger than some of the utilities that were in the smaller sample.

> Q. And you found that—
>
> A. Well, if it was load size, that didn't explain why Clark and Seattle were missing.

Id.

Further down page 3 of the notes is a notation that reads, "Grays—circular equation." E-GE-06. Again the witness's explanation demonstrated that she was attempting to understand the data base:

> We received a set of Lotus files and when translated into Excel the spread sheet to Grays Harbor came up with a circular equation, and I was curious if they'd had that problem themselves or it was something that happened because Excel is pickier about circular equations than Lotus.

Tr. 968-69.

In short, counsel engaged in a fishing expedition regarding the witness's notes and discovered that they were exactly what the witness had testified they were: attempts to understand data that BPA intended to introduce into evidence to be used in calculating the industrial margin. Both the witness's testimony and the notes themselves make this clear. The notes contain a mixture of darker and lighter writing. The darker writing runs straight across the page, while in several cases the lighter writing is at an angle. (The darker writing was originally in ink, while the lighter writing was in pencil. *Id.* at 1704.) This distinction reflects questions the witness posed to herself as she reviewed the data (the darker writing) and the answers she received (the lighter writing). *Id.*

Three examples will illustrate the nature of the notes. Page two of the notes contains a darker notation that reads, "Whatcom—Why didn't adjust for full year; only 8 months of data," followed by a lighter notation at an angle that reads, "our fault—we didn't make adj in spdsheet." E-GE-06. The explanation of these notations is as follows:

> A. The backup material included data for only eight months, and I was wondering why they hadn't adjusted to make that for a full year. The notes which are written at an angle was [sic] a note to myself that says I hadn't made the adjustment in the summary sheet I had done. It was not something—it was not the way I had gotten the material.
>
> Q. So that was your mistake?
>
> A. That was my mistake.

Tr. 1705.

The witness posed herself a question as she was reviewing the data, and answered it when she discovered her mistake.

The same page contains a notation that reads, "Grant—test period energy in file & on backup does not match summary sheet—can't locate demand figure." E-GE-06. This notation also reflects a question the witness had as she reviewed the data:

> It reflects the fact that I was unable to locate or that the test period energy that was in the summary sheet and what was in the backup material did not match, nor could I locate the demand figure, and was wondering why there was a difference between what had shown up, what was in the 1985 study, and what was in the current study."

Tr. 1704.

The lighter writing reflects the answer: "number comes from '85 study." E-GE-06. (According to the summary sheet of the updated study, the test period energy for Grant County PUD was 345,224 MWH. E-GE-21. Grant is utility 1A, *see* Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, Appendix A, at A-5. According to the backup data, Grant's test period energy was 670,463 MWH. WP-96-E-PA-07, Utility #1A Margin Analysis, Page 1 of 2. Therefore, as the witness testified, the summary sheet and the backup data do not match. The test period energy for Grant in the 1985 study was 345,224 MWH, the same figure as contained in the summary sheet. E-GE-16, at Page 13 of 20. Again, the documents confirm the witness's testimony.)

Finally, the third page of the notes contains a notation in darker writing that reads "Threw out 2 of mid-Columbias, why didn't you throw out the third." E-GE-06. This notation is followed by another in lighter writing that reads, "Douglas included by mistake." *Id.* The witness explained these notations as follows:

> The DSIs—RCS [DSI representatives] had presented a smaller sample which did not include all 20 of the utilities. And in that smaller sample, Douglas was included, but the other two mid-Columbias had been excluded. So my question was trying to get at what the criteria had been for excluding the two mid-Columbias, but not the third.

Tr. 1706.

None of this testimony was rebutted, and the notes make clear that, as she testified, the witness was simply trying to make sense of the data. The additional notes are in the same vein. For example, the second page of the notes contains a question in darker writing, "Oregon Trail—where does," followed by an answer in lighter writing, "p. 15 of 2/94 COSA." E-GE-06. Similarly, the same page contains a question in darker writing, "Why remove load for steel mill," followed by an answer in lighter writing, "don't know/can't tell." *Id.* The witness testified that none of the other notes concerned the merits of calculating the industrial margin. Instead, they concerned the witness's questions "regarding the data included in the material provided." *Id.* The notes confirm this testimony.

Nevertheless, APAC argues, without citation of evidence, that the discussions with the DSIs concerned "the methodology by which the Industrial Margin would be calculated." APAC Brief, B-PA-01, at 19. Then, citing page 971 of the hearing transcript, APAC argues that the witness's communications with the DSIs influenced BPA staff's decision to exclude revenue taxes from the margin. *Id.* at 19-20. APAC asserts that the communications must have influenced Staff to exclude revenue taxes from the margin because "by the staff's own admission they had no independent information upon which to base a contrary decision." *Id.* at 20.

On the page that APAC cited, the witness testified that she may have asked the DSIs what they thought about revenue taxes and got a response that "they don't pay revenue taxes." Tr. 971. There then occurred the following exchange between the IOUs' counsel and the witness:

> Q. Now, could you tell me please if the fact that the DSIs don't pay revenue taxes has anything to do with understanding the data base. Are the DSIs in the data base?
>
> A. Obviously not.
>
> Q. Are there any data in the data base about the DSI payment of revenue taxes?
>
> A. No.

Id.

This is the only possible reference for Staff's "admission" that it lacked "independent information on which to base a contrary decision" regarding revenue taxes. The exchange, however, is irrelevant to Staff's proposal regarding revenue taxes. The data base contains no information on whether the DSIs pay revenue taxes because such information is not relevant to Staff's margin study. The industrial margin is based on the margins included in retail industrial rates by BPA's public body and cooperative customers. BPA excluded revenue taxes from the margin because most of BPA's public body customers with industrial customers do not pay revenue taxes. Chang, Cocks, E-BPA-25, at 7; Chang, Cocks, WP-96-E-BPA-54, at 6-7. This was the "independent information" on which Staff based its proposal.

Nowhere in the evidence BPA filed in support of its margin study did BPA state whether or not the DSIs pay revenue taxes. In the exchange quoted above, BPA acknowledged that the data base contains no information about the DSIs' payment of revenue taxes. Thus, APAC is suggesting that, because the only information regarding the DSIs' payment of revenue taxes came from the DSIs themselves, Staff had no independent information on which to base a contrary decision regarding revenue taxes. Yet this information is irrelevant, and the witnesses did not rely on it in their study. Instead, they relied on information as to how many utilities with industrial customers pay revenue taxes. This information came from a BPA data base and BPA records. Chang, Cocks, E-BPA-54, at 6-7.

This is the single example APAC cites as relating to the merits of the case. The IOUs also argue that BPA's discussions with the DSIs concerned the merits of the case and specifically revenue taxes. MREP Brief, B-GE/PL/PS-01, at 21. They cite an exchange at cross-examination in which, according to the IOUs, the witnesses "admitted their conversations with the DSI representatives ventured into the merits and outcome of the rate case." *Id.* The IOUs then purported to quote this exchange. In doing so, however, they omitted two questions and answers, replacing them with the notation "[various statements by the witnesses about not recalling who said what about the margin not escalating]." *Id.* (emphasis added). In the interest of clarity, the exchange will be set out in full, with the portions the IOUs omitted underlined:

> Q. The next page [of the notes] . . . The top line says, margin should not escalate. Margin was 3.17 in '85 with same sample size 3.43.
>
> Was that a note of your statement or someone else's statement?
>
> A. I don't recall.
>
> Q. Do you recall one of the DSI representatives saying that to you?
>
> A. No, I do not.
>
> Q. Do you recall saying that to one of the DSI representatives?
>
> A. No, I don't remember exactly what was said at that meeting. I don't remember whether that was discussed there or not.
>
> Q. Is there some reason why the margin should not escalate?
>
> A. I don't recall what we were thinking about at the time. Certainly that's something I wrote down. I don't know if it was—I wrote it down going in to ask them about it or it's something they said to me.

Tr. 970.

Contrary to the IOUs' characterization, the witness did not testify that she could not recall "who said what" about the margin not escalating. Instead, she testified that she did not recall either party saying anything on this subject. Thus, the record contains no evidence that the subject was ever discussed. (It also should be noted that BPA concluded that the margin should not escalate, *see* Chang, Cocks, E-BPA-25, at 8, and the parties have not challenged this conclusion at any point in this case. Therefore, escalation of the margin has never been a contested issue in this case.)

As demonstrated above, many of the witness's notes simply reflect questions she asked herself as she reviewed the data. In the above exchange, the witness testified that the note at issue may have represented such a question. The parties have not challenged the credibility of this testimony or, indeed, any of the witness's testimony regarding her notes.

In their initial brief, the only other notation the IOUs cite as relating to the merits of the case is the notation regarding revenue taxes, discussed above. As has been demonstrated, this notation concerns the DSIs' non-payment of revenue taxes, a fact that is irrelevant to this case. The witness testified that the DSI representatives never told her their position as to whether revenue taxes should be included in the margin. Tr. 1703. Her notes support this testimony.

In their brief on exceptions, the IOUs do not return to these two examples; they do not rebut the draft ROD's discussion. Moreover, although they do not challenge the draft ROD's explanation of the question and answer regarding revenue taxes, they nevertheless assert that the decision to exclude revenue taxes from the margin was "worked out in private conversations with the DSIs in advance of the hearing." MREP Ex. Brief, R-GE/PL/PS-01, at 11. The IOUs offer no evidence for this assertion. As demonstrated above, the DSIs never told BPA their position on revenue taxes. The IOUs have not challenged BPA's testimony to this effect. They have not explained how a statement by the DSIs that they do not pay revenue taxes—the only evidence of any communication regarding revenue taxes—constitutes "working out" this issue in advance of the hearing. The record contains no support for their allegation.

As noted, in their brief on exceptions the IOUs abandon their two earlier examples of alleged *ex parte* conversations. However, in an attempt to demonstrate that at least some small portion of the analyst's notes concerned the merits of the proceeding, they have added two more examples not mentioned in their initial brief. First, they claim that the BPA analyst discussed with the DSIs the criteria the DSIs used to prepare a smaller sample than the 19 utilities included in the data base. *Id*. at 6. The IOUs assert without explanation that this "discussion" "relates to the quality of the data in the study and the data base and goes to the issue of reliability." *Id*. at 6-7.

First, the "discussion" the IOUs cite was simply a question and answer, wherein the DSI representative told the BPA analyst how he had derived a smaller sample. The notation on which the IOUs rely reads simply "criteria for throwing out utilities." E-GE-06, page 2 of notes. In an effort to understand the data, the analyst asked the DSIs what the criteria were for deriving their smaller sample. Tr. 963. Therefore, this note also does not concern the merits. Second, these criteria are irrelevant to this case. BPA's margin study included all 20 utilities. (The 1985 margin study included 19 utilities; the 1996 study included 20. Hence the discrepancy between the analyst's reference to 19 utilities and the 20 utilities in the study.) Neither BPA nor any other party presented any evidence, or made any argument, supporting any other sample or sample size. Therefore, the criteria for deriving the smaller sample are irrelevant; the only time they were mentioned in the case was in the IOUs' cross-examination on the *ex parte* issue. They were not mentioned by any party in regard to any substantive issue.

Moreover, the criteria are unrelated to either "the quality of the data" or its "reliability." The parties have made extensive arguments regarding the quality and reliability of the data. BPA has addressed these arguments at length. *See supra* § 8.2.1. The parties' arguments are based on the alleged bias of the DSIs and the fact that some of the original data were out of date. Neither the parties' arguments, nor BPA's response, mentions the criteria the DSIs used to derive a smaller sample. The DSIs indicated that the criterion for deriving a smaller sample was load size. Tr. 968. The IOUs' assertion is a non sequitur: a methodology for deriving a sample based on load size (or any other criterion) has nothing to do with the reliability of the underlying data.

Finally, the IOUs point out that the DSIs told the BPA analyst that they had sent the margin calculations to the Public Power Council. MREP Ex. Brief, R-GE/PL/PS-01, at 7. The IOUs argue that the analyst "discussed with the DSIs the actions the DSIs claimed to have taken to validate the DSI margin study." *Id*. Again, the witness's notes do not reflect any "discussion." They reflect the fact that the DSIs told the witness that they had "talk[ed] to Shelley Richardson—Info has been given to PPC & PGE." E-GE-06, page six of notes. Moreover, whether the DSIs sent the data to the PPC is not an issue in this case. The IOUs are correct that the reliability of the data the DSIs provided is an issue. That the DSIs sent the data to the PPC, however, is at best minimally related to this issue.

BPA's conclusion that the data are reliable was based first, on the fact that most of the data are photocopies of utility documents; and second, on the fact that independent evidence in the case supports the reliability of the data. After concluding that the data were reliable, the draft ROD rebutted (as does the final ROD) the parties' contentions that, despite the evidence of reliability, BPA should have verified the data with the utilities. *See supra* § 8.2.1. After an extended discussion of why this was unnecessary, the draft ROD rebutted the parties' contention that BPA should have verified the data with Northwest Utilities. Next the draft ROD rebutted a similar contention regarding the PPC. Finally, in the last sentence of the discussion, the draft ROD noted that the analysts reasonably relied on the DSIs' statement that they had sent the data to the PPC. The draft ROD's discussions are repeated in the final ROD. *Id*.

Whether the DSIs sent the data to the PPC has nothing to do with the data themselves. A conclusion that they did so is unnecessary to the Administrator's decision to use the data as a starting point for the margin study. The issue regarding verification was addressed only to rebut the parties' argument that verification was necessary. Even then, the draft ROD made clear that whether the DSIs sent the data to the PPC was a minor and tangential issue. It is the IOUs, not BPA, that argue that verification of the data with the PPC is important. BPA concluded that direct evidence of reliability supports the validity of the data, and that additional verification was not needed. *Id*.

Just as significantly, the IOUs have ignored the purpose of the *ex parte* rule. As discussed below, the *ex parte* rule exists to ensure that the Administrator's decision is based on a publicly developed record that all parties have had the opportunity to challenge. By searching through the BPA analyst's notes in an effort to find at least one example of a statement relating to the merits of the case, no matter how insignificant, the IOUs are in effect suggesting that even the slightest incursion into *ex parte*—for example, an innocuous statement by the DSIs, with no evidence of additional discussion, that the DSIs had sent data to the PPC—requires rejection of BPA's entire case. This argument celebrates technicalities over substance, and seeks draconian remedies for trivial acts.

Finally, in what may be an allegation of *ex parte* contacts, the parties assert that, in "private" discussions, BPA and the DSIs agreed that BPA would abandon its "share-the-savings" approach to reserves, under which the DSIs are credited with half of the reserves valuation, in favor of crediting the DSIs with the entire value of reserves. MREP Ex. Brief, R-GE/PL/PS-01, at 11; APAC Ex. Brief, R-PA-01, at 28. The parties base this allegation on one sentence in BPA's value of reserves testimony. In that testimony, BPA explained that, in a competitive market, it could not expect to obtain reserves from the DSIs at less than full value. BPA further testified that, in a competitive market, a business must expect to pay adequate compensation for any product it procures. Then, in the sentence on which the parties rely, BPA added that "[f]orced outage reserves are a significant issue in the contract negotiations over new DSI power sales contracts." Neal, *et al*., WP-96-E-BPA-24, at 20.[1]

Once more, therefore, the parties have no support for their allegation. The above sentence says only that reserves were an issue in the negotiations. Since the DSI contracts obligate the DSIs to provide reserves through BPA's right to cut off their power deliveries, reserves naturally would be an issue in negotiations. The new DSI power sales contracts contain significant provisions relating to BPA's use (rather than valuation) of the reserves. *See* Wolverton, WP-96-E-PA-03, Attachment 1, § 17. BPA's testimony does not indicate that BPA and the DSIs "worked out" or even discussed any issue regarding the valuation of reserves; the record contains no such evidence. Moreover, the DSIs themselves did not even testify that BPA should abandon the share-the-savings methodology. They suggested that BPA credit them with the reserves valuation necessary to achieve a competitive DSI rate; the DSI testimony suggests that, if the share-the-savings methodology would achieve this result, the DSIs would support it. Schoenbeck, Bliven, WP-96-E-DS-03, at 21. To suggest, as the IOUs do, that BPA and the DSIs "worked

[1] Although witness Neal was removed as a witness from BPA's case, for ease of reference BPA will continue to refer to this testimony by his name.

out" an abandonment of the share-the-savings methodology is to take an extraordinary leap of fact and logic.

All told, the parties introduced into evidence five pages of the witness's handwritten notes concerning her review of the data base and her conversations with the DSIs. (There are six pages of notes. The first page reflects the witness's discussions with another BPA employee. *Id.*) Testimony was elicited on a significant portion of these notes. The parties identified only two notations reflecting statements that went beyond BPA's attempt to understand the data base. In one, the witness asked the DSIs about revenue taxes, received an irrelevant response, and did not pursue the issue further. In the other, the DSIs told the witness they had sent the data to the PPC. The notes contain no evidence of any "discussion" of this issue, which is at best marginally related to the validity of the data. On this meager basis the parties would have the Administrator reject BPA's entire proposal.

The IOUs assert, however, that BPA's understanding of a "communication on the merits" is flawed. Although, yet again, the IOUs support their assertion with neither evidence nor argument, they do cite Professor Davis's Administrative Law text as support. MREP Ex. Brief, R-GE/PL/PS-01, at 8. In the section the IOUs cite, Professor Davis notes as a "for instance" that communications concerning procedure or timing do not violate *ex parte* restrictions. 1 Kenneth Culp Davis and Richard J. Pierce, Jr., Administrative Law Treatise § 8.4, at 390 (3d ed. 1994). Presumably the IOUs are suggesting that these are the only examples of discussions that are not related to the merits. Not only does Professor Davis state that these are only examples, but the IOUs ignore the draft ROD's citation to the BPA *ex parte* rule, which exempts communications necessary for an understanding of factual materials filed with BPA during a hearing. *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.7(b)(6), 51 Fed. Reg. 7611 (1986). Indeed, the IOUs' struggle to find at least one example of a conversation that involved something other than BPA's attempt to understand the data base reveals their realization that an effort to understand data does <u>not</u> concern the merits. According to Professor Davis, the APA's prohibition on *ex parte* communications applies only to "communications with respect to contested, material adjudicative facts." Davis and Pierce, *supra*, § 8.4, at 391. None of BPA's conversations with the DSIs concerned such matters.

The parties make one final argument. The DSI witnesses testified on March 8. After offering the DSIs' prefiled exhibits into evidence, the DSI attorney attempted to elicit additional direct testimony regarding the DSIs' development of the data base and the conversations with BPA. In their brief, the IOUs object to the DSIs' "supplementation of the record" with oral direct testimony after the time for direct testimony had closed. They allege that this "procedural error" prejudiced the parties and is "reversible error." MREP Brief, B-GE/PL/PS-01, at 20 n.19. No prejudice occurred, however, because the additional DSI testimony was not admitted into evidence.

Several parties objected to the additional DSI testimony on the grounds that the record for direct testimony had closed and the parties would not have a full opportunity to cross-examine the witnesses on the additional testimony. Tr. 2164-67. The hearing officer allowed the DSI attorney to elicit testimony as an "offer of proof and no more." *Id.* at 2171. He added that the testimony would be "an offer of proof, will be noted, and denied." *Id.* at 2173. After the witnesses testified, the Hearing Officer noted that he was

> denying the offer of proof. That means that as far as I am concerned, it has not become part of the record, but it gives [the DSI attorney] the right to present this as something, an argument, to an appellate body, if he can do so. . . . [I]t will not be part of the record as far as the trial court is concerned, this hearing officer.

Id. at 2178-79.

Therefore, the IOUs cite as reversible error a ruling that went in their favor. The testimony was not made part of the evidentiary record. The DSIs challenge the Hearing Officer's ruling. They argue that the Administrator should consider the oral testimony, since no party would be prejudiced by its admission. DSI Brief, B-DS-01, at 28 n.23. The Hearing Officer's ruling will be affirmed. As the parties pointed out during cross-examination, the time for direct testimony had closed. BPA's rate case is premised on the prefiling of written direct testimony, which is served on all parties in advance of cross-examination. In this instance, the parties had no opportunity to review the testimony in advance.

Moreover, the transcript demonstrates that few parties were present when the DSI witnesses testified. Cross-examination of the DSI panel had been waived. Tr. 2182. Had the parties known that the DSIs would attempt to present additional testimony, they would have been unlikely to waive cross-examination in advance, and may well have attended the hearing. Therefore, the parties would be prejudiced by the admission of the testimony. The DSIs note that no party availed itself of its right to cross-examine the witnesses. *Id.* Not only were the parties unprepared for cross-examination for the reasons already stated, but the Hearing Officer cautioned them that cross-examination might constitute a waiver of their objections to the offer of proof. *Id.* at 2186. Under the circumstances, it cannot be concluded that the parties had a meaningful opportunity to challenge the DSIs' additional evidence.

The DSIs' offer of proof will not be made part of the evidentiary record in this proceeding. It has not been relied on in any way for the findings or conclusions in this Record of Decision.

<u>No Party Was Prejudiced By BPA's Receipt Of The Data From The DSIs Or By BPA's Conversations With The DSIs</u>

The parties propose that, because of BPA's alleged *ex parte* communications with the DSIs, the Administrator should reject BPA's study. Even had BPA engaged in *ex parte* communications with the DSIs, and even had the communications concerned the merits of the case, the parties' proposed remedy would be inappropriate. Because the parties had full opportunity to rebut the substance of the communications, no party has been prejudiced.

Ex parte communications do not void an agency decision. *Southwest Sunsites, Inc. v. F.T.C.*, 785 F.2d 1431, 1436. (9th Cir. 1986). The agency's decision is voidable, and will be voided if "the agency's decisionmaking process was irrevocably tainted so as to make the ultimate judgment of the agency unfair, either to an innocent party or to the public interest that the agency is obliged to protect." *Southwest Sunsites*, 785 F.2d at 1436 (quoting *PATCO v. FLRA*, 685 F.2d 547, 564 (D.C. Cir. 1982)). Relevant considerations in determining whether to void an agency decision because of *ex parte* contacts include "the gravity of the *ex parte* communication, whether the communication may have influenced the decision, whether the party making the communication benefited from the decision, whether opposing parties knew of the communication and had an opportunity to rebut, and whether vacation and remand of the decision would serve a useful purpose." *Id.*

APAC argues that all of these factors are implicated in this case. APAC Brief, 96-B-PA-01, at 19. To the contrary, none of them are. The communications involved simply receipt of the data base and an attempt to understand it. The parties can cite no decision that the communications influenced. Finally, and most significantly, the parties have had full opportunity to challenge and rebut both the data base and the conversations with the DSIs, and have taken full advantage of that opportunity. The purpose of BPA's *ex parte* rule is to "ensure that the Administrator's decision is based upon a publicly developed record to which all parties and participants have had an opportunity to participate, rebut or challenge." 51 Fed. Reg. 7611, 7612 (1986). The Administrator's decision is based on a publicly developed record which all parties have had full opportunity to challenge. Consequently, no prejudice resulted.

The parties' first complaint concerns BPA's receipt of the data base from the DSIs. As demonstrated above, BPA placed both the summary sheet labeled "Margin Analysis" and the data base in the *ex parte* file almost immediately after receiving them, thereby ensuring that all parties had immediate access to them. Thus, in February 1995, before the 1996 rate case was even conceived, the parties had access to the one-page "Margin Analysis." In April 1995 the parties had access to the complete data base. The parties do not allege that BPA had any conversations with the DSIs when BPA received these documents; instead, their *ex parte* allegation concerns BPA's mere receipt of the documents <u>at the same time that the parties were given access to them</u>. Such conduct is not prejudicial.

Moreover, on August 7, 1995 BPA provided the documents directly to the parties through discovery procedures. *See* E-PA-07; WP-96-E-GE-05. In September the parties filed testimony challenging BPA's margin analysis based on the data base. *See* Wolverton, WP-96-E-PA-01, at 7-12; Piro, *et al.*, WP-96-E-GE/PL/PS-02, at 12-14. The parties had additional opportunities to file testimony challenging BPA's margin analysis, and the IOUs did so in January 1996. *See* Piro, Semro, WP-96-E-GE/PL/PS-08. In addition, the parties cross-examined BPA witnesses extensively regarding the data. *See* Tr. 1619-67.

The IOUs acknowledge that BPA placed the data in a public file in April, immediately after receiving them, so that "all rate case parties and participants have immediate access to them." MREP Brief, B-GE/PL/PS-01, at 18 n.16. The IOUs claim, however, that later in the case BPA had "a change of heart" regarding the parties' right to access, since BPA objected to the IOUs' motion to introduce the materials from the *ex parte* file into the record. *Id.* In fact the IOUs' motion had nothing to do with the parties' access to the documents. Instead, it was a request that the Hearing Officer take official notice of a number of documents, including those in the *ex parte* file. Tr. 918. In the same motion the IOUs requested official notice of, for example, BPA's 1985 Final Rate Proposal, Section 7(c)(2) Industrial Margin Study (20 pages plus voluminous appendix); BPA's Section 7(b)(2) Implementation Methodology, Administrator's Record of Decision (44 pages); BPA's legal interpretation of section 7(b)(2) of the Northwest Power Act (19 pages); and an excerpt from BPA's 1985 Final Rate Proposal, Administrator's Record of Decision (29 pages). *Id.*; s*ee also* E-GE-16, WP-96-E-GE-17, WP-96-E-GE-18, and WP-96-E-GE-19.

BPA objected to the motion on the narrow ground that official notice was appropriate only to establish the existence of the documents and the fact that the text of the documents was as set forth therein. Tr. 919. BPA's objection was to any attempt to use official notice as a vehicle for establishing the truth of the multitude of facts contained in the documents. *Id.* For example, BPA argued that the 1985 Industrial Margin Study was

> a voluminous study . . . [and] there are numerous technical and other matters dealt with in that study . . . . Bonneville would very much dispute the continuing relevance, the continuing correctness of a great many of the facts set forth in that document. The fact of the matter is this is a period document.

Id. at 924.

Similarly, BPA objected to official notice of Bonneville's legal interpretation of section 7(b)(2) of the Northwest Power Act because "[t]he procedure here [for official notice] is to deal with adjudicative facts that are beyond dispute." *Id.* at 925.

Thus, the IOUs have mischaracterized BPA's objection to their motion. The objection had nothing to do with access to the data or with the parties' right to rebut the data. Moreover, BPA made clear that it had no objection to receipt of the documents to prove that they existed and that the text was as set forth therein. *Id.* at 919. The IOUs in fact agreed that their only purpose for the motion was "to show that [the documents] exist [and] that they were in the *ex parte* file." *Id.* at 927. It appears that BPA and the IOUs were in agreement and simply had a misunderstanding; counsel for the IOUs even indicated that "we have a tempest in a teapot." *Id.* at 926. The hearing officer admitted the documents for the purpose requested. *Id.* at 927.

As to BPA's receipt of the documents, therefore, any *ex parte* allegation is unfounded. There was no "communication" to which the parties were not privy. BPA ensured immediate public access to the documents and provided copies to the parties through discovery. APAC and Portland General Electric Company both entered the data base into evidence. E-PA-07; E-GE-05. Even had BPA received the documents when the *ex parte* rule was in effect, their receipt would not have tainted the administrative process in any way.

The parties' other *ex parte* allegation concerns the conversations with the DSIs. As noted above, these discussions took place before the *ex parte* rule went into effect. Moreover, the conversations implicate none of the factors relevant in determining whether to void an agency decision. The first is the "gravity of the *ex parte* communication." *Southwest Sunsites, Inc. v. F.T.C.*, 785 F.2d 1431, 1436 (9th Cir. 1986). As demonstrated above, the conversations did not concern the merits of the issues in the case, but rather BPA's efforts to understand the data base. Moreover, such communications are specifically exempted from the *ex parte* prohibition. *Procedures Governing Bonneville Power Administration Rate Hearings* § 1010.7(b)(6), 51 Fed. Reg. 7611 (1986); 5 U.S.C. §§ 557(d)(1)(A) and (B).

The next issue is "whether the communications may have influenced the decision [and] whether the party making the communication benefited from the decision." *Southwest Sunsites*, 785 F.2d at 1436. The parties can cite no "decision" that the communications influenced. The conversations concerned BPA's need to understand the data used to calculate the margins for the twenty utilities in the data base. The parties have not even attempted to tie any of BPA's margin calculations to the conversations. Even if they did, helping the agency to understand data is not undue influence, as it does not relate to the merits.

Moreover, BPA changed twelve of the twenty calculations in response to testimony the parties filed. *See supra* § 8.2.1. To the extent that the conversations may have related to any "decision" as to how to calculate utility margins, that "decision" was subject to vigorous challenge. In addition, BPA rebutted several DSI arguments regarding how to calculate individual utility margins. *Id.* Indeed, the only "decision" the parties cite was BPA's decision to exclude revenue taxes from the margin. As demonstrated above, however, the conversations were irrelevant to BPA's proposal on taxes and to the Administrator's decision.

The next factor is "whether opposing parties knew of the communication and had an opportunity to rebut." *Southwest Sunsites, Inc.*, 785 F.2d at 1436. The parties have had full opportunity to rebut the communications. Both the data base and BPA's notes of the meetings were provided to the parties and offered into evidence. *See* E-GE-06 and E-PA-07. Although APAC argues that the parties had no opportunity to rebut the margin study, *see* APAC Brief, B-PA-01, at 20, APAC in fact filed extensive testimony challenging it. Wolverton, E-PA-01, at 6-12. BPA made a number of changes in the margin in response to APAC's testimony. *See supra* § 8.2.1. The parties received the data base in August 1995, filed testimony on it in September, had additional opportunities to file testimony in January and February, and extensively cross-examined BPA witnesses on the data base. *See* Tr. 951-97; 1619-67. As shown above, the parties received notes of the conversations in August 1995 and vigorously cross-examined BPA witnesses on the notes six months later. *Id.* at 959-74. (Indeed, this section of the Record of Decision is devoted largely to responding to the parties' rebuttal of the notes of the conversations. Section 8.2.1, *supra*, is devoted entirely to responding to the parties' rebuttal of the data base.)

An allegation that prohibited *ex parte* contacts took place must overcome a presumption that an agency's decision rests on proper grounds. *Southwest Sunsites, Inc.*, 785 F.2d at 1437. The parties have not overcome this presumption. No useful purpose would be served by vacation and remand or, in this case, by rejecting the study. In *Louisiana Ass'n of Indep. Producers and Royalty Owners v. F.E.R.C.*, 958 F.2d 1101 (D.C. Cir. 1992), the Federal Energy Regulatory Commission engaged in *ex parte* discussions with parties to a pending case. The Commission placed summaries of the meetings with the parties in the record. The court held that by doing so, the Commission "apprised the petitioners of any argument that may have been presented privately, thereby maintaining the integrity of the process and curing any possible prejudice that the contacts may have caused in this case." 958 F.2d at 1112. In *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981), the Environmental Protection Agency received comments on proposed emission control standards after the time for close of comments had passed. EPA placed the comments in the record. The Environmental Defense Fund objected to the receipt of comments after the comment period had closed. The court upheld EPA's action, stating that "[t]he decisive point . . . is that [the Environmental Defense Fund] itself has failed to show us any particular document or documents to which it lacked an opportunity to respond, and which also were vital to EPA's support for the rule." 657 F.2d at 398. (Although *Sierra Club v. Costle* did not explicitly concern *ex parte* contacts, it has been cited as authority for the principle that placing evidence on the record cures possible prejudice resulting from *ex parte* contacts. *See Louisiana Ass'n of Indep. Producers and Royalty Owners v. F.E.R.C.*, 958 F.2d 1101, 1112 (D.C. Cir. 1992)).

Finally, in *Iowa State Commerce Comm'n*, *supra*, the court denied the petitioner's *ex parte* claim because of the timing of the *ex parte* contacts and because "[t]he Final Determination made by the Federal Inspector was . . . based on the publicly available information which led to the Tentative Determination, and on subsequent public comments. . . . The contacts . . . were apparently open to public scrutiny . . . ." 730 F.2d at 1576.

In their brief on exceptions, the IOUs contest the draft ROD's conclusion that the parties can cite no decision that the communications influenced. They note that "even if this statement were true, which it is not, . . . the DSI margin study must be rejected." MREP Ex. Brief, R-GE/PL/PS-01, at 8. Again, the IOUs do not elaborate; they provide no support for their assertion that the draft ROD's statement is untrue. Thus, the parties still have cited no decision to which the communications were material. Moreover, although the IOUs now argue (as they did not argue in their initial brief) that they were prejudiced by the communications, they do not respond to the draft ROD's discussion of the case law, under which the admission of material into the record (and the extensive opportunity to rebut such as the parties were afforded) forecloses a claim of prejudice. Instead, the IOUs launch into an irrelevant discussion of a supposed conspiracy of prejudice, which includes BPA's actions regarding stranded cost relief, the rate test in the DSI contracts, the calculation of the "typical margin" in DSI rates, and the valuation of DSI reserves. *Id.* at 8-10. None of this discussion even touches on the question of prejudice arising from the communications with the DSIs.

The parties took full advantage of their opportunity to rebut the data base and the conversations with the DSIs. They suffered no prejudice and have offered no grounds for rejecting BPA's proposal.

Decision

BPA did not engage in ex parte communications with the DSIs. First, the communications with the DSIs took place when the ex parte rule was not in effect. Second, BPA's conversations with the DSIs concerned BPA's attempts to understand the data and did not concern the merits of any issue pending before BPA in the hearing. Moreover, even if the conversations were ex parte communications, they did not prejudice the parties, and rejection of BPA's proposal would be an inappropriate remedy. The mere receipt of the data base, which BPA immediately placed in a public file and later provided to the parties in discovery, is not prejudicial. Notes of the conversations were also provided to the parties. The parties had full opportunity to rebut both the data base and the conversations, and they took advantage of that opportunity.

14.2.3 Determination of DSI Rate Based On The Record

Issue

Whether the Administrator predetermined the level of the Industrial Firm Power rate.

Parties' Positions

BPA's new power sales contract with the DSIs contains a "rate test" under which the DSIs can terminate the contract if BPA adopts an Industrial Firm Power (IP) rate that exceeds a specified level. APAC argues that, by virtue of this provision, the Administrator has predetermined the level of the industrial firm power rate. APAC Brief, WP/TR-96-B-PA-01, at 6-7. The IOUs make the same argument. In addition, the IOUs argue that BPA acknowledged in its testimony that competitiveness was the primary factor driving the level of the IP rate, and that BPA set out to attain a low IP rate. MREP Brief, WP-96-B-GE/PL/PS-01, at 10-11. The DSIs argue that, even if BPA fails to meet the rate test in the contract, the DSIs can still purchase power from BPA. They assert that the Administrator retains the discretion to develop the IP rate consistent with the statutory rate directives and that the record does not support a finding that the Administrator has predetermined the level of the IP rate. DSI Brief, WP-96-B-DS-01. at 36-37.

BPA's Position

BPA agrees that it needs to achieve a competitive DSI rate if BPA is to survive in the new marketplace. Chang, Cocks, WP-96-E-BPA-25, at 7. BPA entered into evidence a margin study that it cites as the basis for the IP rate. *See generally* Chang, Cocks, E-BPA-25; Supplemental Wholesale Power Rate Development Study, WP-96-E-BPA-61, Appendix A.

Evaluation of Positions

In September 1995 BPA signed new power sales contracts with most of its DSI customers. Section 5(a) of the contract provides that the DSI customer may terminate the contract it if BPA adopts an Industrial Firm Power rate that fails to meet the contract's rate test. Wolverton, WP-96-E-PA-03, Attachment 1, § 5(a). The rate test for the IP rate is 22.1 mills per kilowatthour, excluding the use-of-facilities charge. *Id.*. § 11(a) (The attachment lists a rate test of 21.1 mills per kilowatthour. This is the rate test for Intalco Aluminum Corporation, which receives an additional reserves credit for providing stability reserves that the other DSIs do not provide. The rate test for all other DSIs is 22.1 mills per kilowatthour.)

APAC argues that the Administrator has prejudged the IP rate level because the new power sales contracts are effective only if the Administrator adopts an IP rate of 22.1 mills or less. APAC Brief, B-PA-01, at 6. This is incorrect. The contract is effective when executed by BPA. Wolverton, WP-96-E-PA-01, Attachment 1, § 1(a). Deliveries of firm power under the contract begin on the later of October 1, 1996, or the date that FERC provides interim approval of a rate schedule that satisfies the rate test. *Id.* § 3. Between the effective date of the contract and the commencement date for deliveries of power, the existing Power Sales Contract governs the sale of firm power by BPA to the DSIs. *Id.* § 2. Moreover, if FERC fails to approve a rate schedule that meets the rate test, the DSIs may waive their right to terminate the contract and begin purchasing power under the new power sales agreement. *Id.* § 3.

Therefore, the DSIs can continue to purchase power from BPA under either the existing contract or the new contract even if the rate test is not satisfied. (APAC acknowledges in a footnote that this is the case, although it denies that the DSIs are likely to purchase power from BPA if the rate test is not met. APAC Brief, B-PA-01, at 6 n.7.) Nevertheless, the parties argue that the mere existence of the rate test and the possibility that BPA will lose load proves that the Administrator has predetermined the level of the IP rate.

The remedy the parties request is rejection of BPA's proposal regarding the IP rate. MREP Brief, B-GE/PL/PS/-01, at 11; APAC Brief, B-PA-01, at 7. On this ground alone, their arguments must be rejected. As discussed below, the issue in prejudgment cases is whether the decision-maker has prejudged the case. Therefore, the remedy for prejudgment is disqualification of the decision-maker. In this case, while alleging prejudgment on the part of the decision-maker, the parties ask the decision-maker to reject his Staff's proposal. Because the Staff's actions are irrelevant to the question of prejudgment, there is no basis for this remedy.

Moreover, a decision-maker will be disqualified "only when there has been a clear and convincing showing that the agency member has an unalterably closed mind on matters critical to the disposition of the proceeding. The 'clear and convincing' test is necessary to rebut the presumption of administrative regularity." *Association of Nat'l Advertisers, Inc. v. F.T.C.*, 627 F.2d 1151, 1170 (D.C. Cir. 1979), *cert. denied*, 447 U.S. 921 (1980). The parties have presented no evidence that the Administrator's decision will be based on anything other than the facts and analyses developed in the hearing. Their argument reduces to a bare allegation that, because the Administrator might have an incentive to meet the rate test, he will do so regardless of the facts. This is not evidence of prejudgment.

In *Navistar Int'l Transp. Corp. v. United States E.P.A.*, 941 F.2d 1339 (6th Cir. 1991), *cert. denied*, 490 U.S. 1039 (1989), Navistar International Transportation Corp., a truck manufacturer, was not in compliance with the State of Ohio's implementation plan for meeting Federal air quality standards. In 1986 the Ohio EPA submitted to the United States EPA a proposed revision to the plan (also called a variance) to permit Navistar's operations. While the Federal EPA's decision on the variance was pending, it prosecuted a civil action against Navistar for violation of the existing plan.

Navistar argued that by pursuing both actions simultaneously, EPA created a potential for bias that undermined its ability to review the variance objectively. According to Navistar, EPA had "an extra incentive to disapprove the pending revision. The EPA could collect penalties for past noncompliance if it disapproved the revision, but not if the revision were accepted." *Navistar*, 941 F.2d at 1360. The court rejected this argument:

> The courts have long applied the presumption that policymakers with decisionmaking power exercise their power with honesty and integrity. (citations omitted). The burden of overcoming the presumption of impartiality "rests on the party making the assertion [of bias]" (citation omitted), and the presumption can be overcome only with convincing evidence that "a risk of actual bias or prejudgment" is present. (citation omitted). In other words, any alleged prejudice on the part of the decisionmaker must be evident from the record and cannot be based on speculation or inference. Navistar fails to meet this test.

Id.

The parties today also rely on speculation and inference, and have also failed to overcome the presumption of impartiality. Like Navistar, they rely solely on the Administrator's alleged economic interest in reaching a certain result. They have offered no evidence of prejudice.

In addition to the rate test, the IOUs cite BPA's testimony that one objective of the methodology for determining the industrial margin is to achieve a competitive DSI rate. MREP Brief, B-GE-PL/PS-01, at 10. The IOUs also cite the cross-examination testimony of BPA's margin analysts, in which the analysts recognized the importance of achieving a competitive DSI rate. *Id.* at 11. The IOUs argue that this testimony proves that BPA is not an "unbiased, analytical decision-maker." *Id.*

This argument has two flaws: first, it takes out of context one small piece of testimony that simply reflects BPA's overall approach to the 1996 rate case. Second, because it relies on Staff testimony, it is irrelevant to whether the <u>Administrator</u> (the "decision-maker") has predetermined the IP rate.

As has been amply demonstrated by evidence presented in this case by both BPA and its customers, BPA operates in a fiercely competitive electric marketplace. *See supra* §§ 2.2 and 8.2.2. BPA's primary ratemaking obligation is to recover its costs. 16 U.S.C. § 839e(a)(1); *See also supra* section 8.2.2. This entire rate case has focused on BPA's competitiveness and the need to achieve competitive rates for all BPA customers. *See generally* Moorman, Evans, WP-96-E-BPA-09; Norman, Oliver, WP-96-E-BPA-10; Moorman, Evans, WP-96-E-BPA-65. For example, BPA testified that "[n]otwithstanding substantial cost-cutting, the competitive market is unlikely to provide BPA with sufficient revenues to cover all its planned costs, including making payments in full and on time to the United States Treasury, unless we fundamentally change our approaches to marketing BPA's products, and unless we provide competitive rates." Moorman, Evans, E-BPA-09, at 10. BPA performed a sustainable revenues analysis "to estimate the possible effects of . . . competition on BPA sales and net revenues if higher PF and Industrial Power (IP) rates were to be implemented." *Id.* at 15. The analysis focused on "BPA's three major customer groups: (1) the generating public utilities; (2) the non-generating public utilities; and (3) the direct-service industrial customers (DSIs)." *Id.* at 16.

BPA has proposed the Firm Power Products and Services (FPS-96) rate, which permits flexible pricing for all customer groups, largely because of competition:

> There are two reasons why BPA intends to augment its firm power sales from Federal generation with power purchases. First, the intensity of competition has increased enormously in the past three years as the industry evolves toward a less regulated generation sector and comparable transmission access. . . . BPA faces strong competition for its existing load

> and must fight to sustain its fiscal integrity by competing aggressively in surplus markets.

Dinsmore, *et al.*, WP-96-E-BPA-21, at 5.

Thus, the testimony on which the IOUs rely is merely one small part of BPA's general policy approach to the entire rate case. BPA's need to be competitive is the background against which BPA has conducted its analyses. A previously announced position on an issue of law, policy, or legislative fact does not constitute prejudgment. 2 Kenneth Culp Davis and Richard J. Pierce, Jr., Administrative Law Treatise § 9.8, at 83 (3d ed. 1994). Thus, for example, in *City of Charlottesville v. F.E.R.C.*, 774 F.2d 1205 (D.C. Cir. 1985), a FERC administrative law judge disapproved a utility's methodology for calculating a tax allowance because the methodology permitted a consolidated tax return by affiliated companies. The Commission reversed the ALJ and reinstated the utility's methodology. The Court of Appeals remanded the case to FERC for reconsideration of the tax allowance question. FERC then remanded the case to the ALJ.

The City argued that, in its remand to the ALJ, FERC had prejudged the case. In the remand FERC indicated that, despite the remand by the Court of Appeals, its original views had not changed: "Our present view remains the same, based on our conviction about the proper way to set rates for a regulated company. Evidence of a particular company's circumstances is not needed to make this policy determination." *City of Charlottesville*, 774 F.2d at 1212. Although FERC made clear in its remand order that it again would adopt the utility's methodology, the court concluded that the remand was not evidence of prejudgment:

> In order to establish improper prejudgment of a case, it must appear to 'a disinterested observer . . . that [the agency] has in some measure adjudged the facts as well as the law of a particular case in advance of hearing it.' (citation omitted). The above-quoted passage from the Commission's order may establish that FERC 'prejudged' the law as to whether the stand-alone policy is consistent with its statutory mandate . . . . But preconceptions regarding the law no more invalidate agency action than they do the action of a court. (citation omitted). The "facts" that the Commission would have had to prejudge for Charlottesville to prevail on the present argument are whether the stand-alone policy, assuming its nature and validity, sustains the rate order—*i.e.*, whether the Columbia pipelines' ratepayers could satisfy the benefits/burdens test. There is no indication of any such prejudgment in this record.

City of Charlottesville, 774 F.2d at 1212.

Similarly, Staff's views regarding appropriate BPA ratemaking policy—even were they attributable to the Administrator—would not constitute prejudgment. Prejudgment is established only when the decisionmaker has prejudged the facts of a particular case.

Thus, for example, in *Gilligan, Will & Co. v. S.E.C.*, 267 F.2d 461 (2d Cir. 1959), three days after beginning a proceeding against the petitioners for violating the Securities Act of 1933, the Securities and Exchange Commission issued a press release stating that the petitioners were guilty. *Gilligan, Will*, 267 F.2d at 468. The court concluded that the press release indicated that the Commission had prejudged the facts as well as the law of the case in advance of hearing it. *Id.* at 469.

Gilligan, Will has two elements that are missing here: first, the evidence indicated that the ultimate decision maker, not the decision-maker's staff, had formed a prejudgment on the issue. Second, the prejudgment concerned the particular facts of the case rather than law, policy, or a general approach to the adjudication. In their allegations as to both BPA's testimony and the rate test, the IOUs parties have offered no evidence that the Administrator has prejudged any factual issues.

The IOUs also cite BPA testimony that, if BPA did not meet the rate test, the remaining DSI sales would be at risk because of the DSIs' right to terminate their contract. MREP Brief, B-GE/PL/PS-01, at 11; *see also* Piro, *et al*., WP-96-E-GE/PL/PS-07, at 3 (citing Moorman, Evans, E-BPA-65, at 9). As BPA pointed out in rebuttal testimony, the IOUs have also taken this statement out of context. Kitchen, Moorman, WP-96-E-BPA-98, at 11. The testimony the IOUs have selectively quoted describes the newly competitive wholesale power market in which BPA operates. The purpose of the testimony was to update BPA's sustainable revenues analysis. BPA analyzed the potential load and revenue losses at PF rates of 27 and 29 mills/kWh, and at DSI rates of 25 and 27 mills/kWh. Moorman, Evans, E-BPA-65, at 6-8. BPA concluded that

> (1) BPA could lose significant sales if rates are above the proposed levels; (2) even at the higher prices the sales loss would result in a reduction in net revenues . . . and (3) because of the <u>fundamental facts of the changing utility industry and BPA's place in that industry</u>, BPA cannot increase rates above proposed levels.

Id. at 10 (emphasis added).

In rebuttal testimony, BPA pointed out that "[n]othing in the contracts requires BPA to meet the rate test; market conditions and BPA's need to recover its costs compel BPA to meet the rate test if we can do so consistent with the rate directives of the Northwest Power Act." Kitchen, Moorman, E-BPA-98, at 11.

Finally, <u>all</u> of BPA's testimony is irrelevant to the question of prejudgment. Under the law, parties are entitled to "a neutral, or unbiased, adjudicatory <u>decisionmaker</u>." Davis and Pierce, *supra*, § 9.8, at 67 (emphasis added). According to Professor Davis, "[s]cholars and judges consistently characterize provision of a neutral <u>decisionmaker</u> as one of the three or four core requirements of a system of fair adjudicatory decisionmaking." *Id.* (emphasis added). Thus, for example, in *Navistar*, the court applied the presumption that "policymakers with decisionmaking power" exercise their power with integrity. *Navistar*, 941 F.2d at 1360. To overcome this presumption, a party must present convincing evidence of "prejudice on the part of the decisionmaker." *Id.*

The testimony the IOUs cite is testimony of BPA staff, not the Administrator. BPA staff is not the decision-maker in this proceeding. In all prejudgment cases the issue is whether the <u>decisionmaker</u> has prejudged the outcome of the case. Here, the IOUs cite as purported evidence of prejudgment testimony entered into the record for the decision-maker to consider in making his determination. It is the Staff's function to present its views to the Administrator. To suggest that Staff's testimony can constitute prejudgment is to misapprehend the nature of the administrative process. The IOUs have presented no evidence that the Administrator has prejudged any fact or issue in this case.

In its brief on exceptions, APAC argues that the draft ROD ignored evidence of prejudgment, including the results of BPA's failure to meet the rate test and the manner in which BPA's supplemental proposal "manipulated the section 7(c)(2) [sic] and overstated the value of DSI reserves in order to comply with the rate test." APAC Ex. Brief, WP/TR-96-R-PA-01, at 9. To the contrary, the draft ROD fully addressed APAC's arguments. This section (which was also contained in the draft ROD) addresses the parties' arguments regarding the rate test. Other sections of both the draft and final ROD fully address APAC's arguments regarding the value of reserves and the calculation of the industrial margin pursuant to section 7(c)(2). *See supra* §§ 8.2 and 8.3. The Administrator rejected APAC's allegations regarding these issues; therefore, it is unnecessary to address them further in this section.

Also in its brief on exceptions, APAC asserts that BPA misconstrued the remedy APAC seeks, and that its sole remedy is not disqualification of the Administrator. APAC Ex. Brief, R-PA-01, at 9. BPA did not misconstrue this remedy; as noted above, APAC seeks the <u>wrong</u> remedy. In its brief on exceptions, APAC asserts that the appropriate remedy is reform of BPA's proposal. *Id.* APAC has not addressed the draft ROD's point that prejudgment applies to the decision-maker, not to the decision-maker's staff, and that Staff testimony and proposals cannot form evidence of prejudgment. For the same reason, rejection or reform of a Staff proposal is not an appropriate remedy for an allegation that the Administrator has prejudged the issues in the case.

APAC has not challenged the draft ROD's conclusion that, under the case law, disqualification is the remedy for prejudgment. Instead, APAC has simply repeated its assertion that the appropriate remedy for prejudgment by a decision-maker is reform of a Staff proposal. APAC's allegations regarding the Staff's "manipulation" of the section 7(c)(2) rate directives, even were the allegations supported by evidence, would not constitute evidence of prejudgment.

Decision

The parties have presented no evidence that the Administrator has prejudged the level of the Industrial Firm Power rate. In addition, the remedy they request is inappropriate as a remedy for prejudgment. Their allegation of prejudgment is rejected.

14.2.4 Compliance of Settlement Agreement with Section 7(i) Requirements

Settlement Agreement Does Not Violate The Due Process Procedures Of Section 7(i)

Issue

Whether admission of the Settlement Agreements into the record without providing further opportunity for rebuttal or cross examination violated section 7(i) of the Northwest Power Act.

Parties' Positions

APAC claims that the Hearing Officers' admission of the Settlement Agreements into the record without providing opportunity for rebuttal or cross examination violated the Northwest Power Act, Federal Columbia River Transmission System Act, and the Federal Power Act. 16 U.S.C. § 839e; 16 U.S.C. §§ 838g, 838h; 16 U.S.C. § 824k(i)(1). APAC Brief, WP-96-B-PA-01, at 32-33; APAC Ex. Brief, WP-96-R-PA-01, at 33.

Clark Co. PUD (Clark) also claims that admission of the Settlement Agreements into the record violated the due process standards of section 7(i) of the Northwest Power Act. Clark Brief, WP-96-B-CP-01, at 7; Clark Ex. Brief, WP-96-R-CP-01, at 31.

BPA's Position

BPA does not agree that the admission of the Settlement Agreements into the record without opportunity for rebuttal or cross examination violated APAC's or Clark's due process rights as provided by section 7(i) of the Northwest Power Act.

Evaluation of Positions

APAC claims the Settlement Agreement proposal to assign a portion of the delivery facilities costs and all of the General Transfer Agreements costs to power is procedurally infirm and violates BPA's statutory rate making directives. In particular, APAC asserts that the proposal contained in the Settlement Agreement arose at the end of the rate case, and neither the settlement negotiations leading to the proposal to shift costs nor the actual amount of the cost shift is on record. APAC relies on *California Energy Resources Conservation and Development Commission v. Bonneville Power Administration*, 754 F.2d 1470 (9th Cir. 1985) (*CEC*), to argue that its due process rights have been denied by admission of the Settlement Agreements, unless BPA adheres to its statutorily-mandated ratemaking procedures. APAC Brief, B-PA-01, at 33. APAC reiterates its objections to the Settlement Agreements in its brief on exceptions. APAC Ex. Brief, R-PA-01, at 33-34.

Clark claims that admission of the Settlement Agreements into the record deprives non-settling parties of their rights under section 7(i) of the Northwest Power Act. Clark maintains that the Settlement Agreements contain a number of new proposals for resolving the issues in the rate proceeding, and their admission into the record should have provided the settling parties with an additional opportunity to introduce new evidence and proposals into the record. Clark argues that the non-settling parties were not afforded the opportunity to analyze, submit data requests, cross examine and offer testimony rebutting the proposals. Clark concludes that the denial of its right to examine, analyze and rebut the proposals violates the due process standards of section 7(i). As a cure, Clark seeks exclusion of the Settlement Agreements from the record. Clark Brief, B-CP-01, at 7-9. Clark repeats many of these arguments in its brief on exceptions. Clark Ex. Brief, R-CP-01, at 31-35.

<u>Parties Had Adequate Opportunity to Comment on the Settlement Negotiations</u>.

Section 7(i) of the Northwest Power Act provides that BPA shall use the following procedures in its rate proceedings:

> (1) Notice of the proposed rates shall be published in the Federal Register with a statement of the justification and reasons supporting such rates. Such notice shall include a date for a hearing in accordance with paragraph (2) of this subsection.
> (2) One or more hearings *shall be conducted as expeditiously as practicable* by a hearing officer to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data questions, and argument related to such proposals. In any such hearing--
> (A) any person shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person or the Administrator, and
> (B) the hearing officer, *in his discretion*, shall allow a reasonable opportunity for cross examination, *which, as determined by the hearing officer, is not dilatory*, in order to develop information and material relevant to any such proposed rate.
> (3) In addition to the opportunity to submit oral and written material at the hearings, any written views, data, questions, and arguments submitted by persons prior to, or before the close of, hearings shall be made part of the administrative record.

16 U.S.C. § 839(e)(i)(1),(2) and (3) (emphasis added). The Ninth Circuit Court of Appeals has ruled that BPA does not need to provide additional opportunities for comment each time the Administrator makes changes to BPA's rate proposals during the

course of the proceeding. In the first challenge to BPA's proposed rates under the Northwest Power Act,*Central Lincoln People's Utility Dist. v. Johnson*, 735 F.2d 1101 (9th Cir. 1984)(*Central Lincoln*), the parties appealed the Administrator's decision based on both substantive and procedural grounds. One of the alleged procedural defects was that BPA was required to provide new notice and opportunity for comment each time the Administrator revised the proposed rates and associated studies. The Ninth Circuit disagreed, stating that "Section 7(i) clearly requires the Administrator to hold hearings after the rates are originally proposed. Nothing in the statute, however, mandates the repetition of the hearing process each time a rate is revised." *Central Lincoln,* 735 F.2d at 1118. The Court also considered decisions of several other jurisdictions construing the Administrative Procedures Act to hold that even if a final rule contains substantial differences from the proposed rule, the agency does not automatically have to engage in a new round of notice and comment. Rather, "[t]he main concern is to ensure that the final rule is sufficiently related to the proposed rule that the challenging party had notice of the agency's contemplated action." *Id.*

Clark claims that *Central Lincoln* is not applicable here. Clark Ex. Brief, R-CP-01, at 33. Clark posits *Central Lincoln* as stating: "The fact that the final decision differed from the initial proposal did not warrant another round of hearings." *Id.* If this be the case, and if, as is demonstrated in this Record of Decision, the Administrator could have finally proposed rates like those provided for in the Settlement Agreements based on the rate case record (*sans* the Settlement Agreements) and argument of the parties, introduction of the Settlement Agreements into the record at the time they were introduced provides dissenting parties even greater opportunities than they would otherwise have, to argue why the Agreements are either unsupported by the record or contrary to law. Put another way, the parties could have gotten together amongst themselves without BPA and, based on their negotiations, filed a joint brief arguing for everything that we instead now see in the Settlement Agreements; in that case, the Administrator could have adopted the jointly-urged proposal. Here, due to the timing of the introduction of the Settlement Agreements into the record, both Clark and APAC were able to argue in their Initial Briefs why provisions of the Settlement Agreements were substantively infirm.

The Ninth Circuit has also held that the Administrative Procedures Act, " . . .does not require an agency to publish in advance every precise proposal which it may ultimately adopt as a rule," and that "[u]nder 5 U.S.C. § 553(b)(3) . . . a notice of rule making is sufficient if it provides a description of the subjects and issues involved." *California Citizens Band Assoc. v. U.S.*, 375 F.2d 43, 48-49 (9th Cir. 1967). In that case, the FCC had adopted two orders to which the petitioners objected based on procedural grounds. The petitioners contended that for these rule changes the agency had not provided adequate notice. The court held, however, that the rule changes were within the scope of the Federal Register notice, saying "[s]ince this is also the subject matter and issue dealt with in the language added to the introductory statement of 'Basis and Purpose' . . . the notice was sufficient with respect to the rule change." *Id.* at 49.

In its objection to the Settlement Agreements Clark refers to them as containing "new proposals." Clark Ex. Brief, R-CP-01, at 31, 32, 34. Clark, in distinguishing the proposals from the final decision which was the subject of *Central Lincoln*, rather disingenuously refers to the Settlement Agreements as "a proposal by a party to the rate proceeding." Clark Ex. Brief, R-CP-01, at 34. Clark persists in ignoring the significance of the Settlement Agreements. The Agreements are the result of negotiations and contain proposals to resolve issues that were fully litigated in the proceeding and supported by the evidentiary record. The fact that the Settlement Agreements represented alternative proposals that could be adopted only if they were supported by record evidence was explicitly recognized by the signing parties. See Settlement Agreements, Attachment 1, p. 1, "Proposal," and Attachment 2, p. 1, "Proposal." When Clark alleges that "new evidence" was entered in the record, it lists the contents of the proposals. Clark does not, however, identify any new facts, aside from the existence of the proposals themselves, that would be susceptible to elucidation by offering additional testimony or cross examination. Clark is, indeed, arguing to reopen the case and begin anew to litigate the proposals as if the year-long rate proceeding had never happened.

Clark also repeatedly describes the settlement negotiations as being held "off the record." Clark Ex. Brief, R-CP-01, at 34 It is the nature of settlement that discussions and negotiations are held "off the record": the confidentiality of the discussions is essential to a full and open discussion of the issues and mutual determination of the best solutions to diverse interests. The fact that the discussions were held "off the record" does not mean that they were not open to all parties to participate.

BPA afforded all parties to these proceedings adequate opportunity for meaningful participation in the settlement negotiations. Commencing with the Federal Register Notice published July 17, 1995, which defined the scope of the case, BPA indicated that meetings with its customers and interested third parties could occur on a frequent basis during the course of these proceedings, and alerted all interested parties to the likelihood that such meetings or workshops could be convened on short notice. 60 Fed. Reg. 36,464, 36,468 (1995). During the hearing convened on March 12, 1996, BPA provided notice of the proposed settlement negotiations on the record. Tr. 2273-2276. BPA also sent separate notices in advance of the settlement discussions on March, 12, 1996, and March 26, 1996, to all parties. Finally, at the hearing on March 29, 1996, BPA acknowledged that settlement negotiations were still pending, and would continue. Tr. 2289-2295. Neither Clark nor APAC objected to settlement discussions taking place.

Section 1.1.4 of this Record of Decision describes the procedural history of this rate proceeding, during which there were numerous opportunities for parties and BPA to offer evidence in support of, or in opposition to, the proposals or counterproposals of the parties. Proposals were revised based on new information, changing conditions, and testimony provided by the parties. The fundamental scope of the case, however, has remained the same throughout, and has been thoroughly litigated. The proposals contained in the Settlement Agreements represent a compromise of the opposing positions and divergent interests that were raised by the various customers and litigated during the preceding. While the compromise may arrive at different positions than any party espoused, the proposals contained in the Settlement Agreements are within scope of the specific proposals advanced and the evidence which supports them. They represent reasonable and logical outgrowths of the positions espoused by the various parties.

APAC complains that settlement negotiations were "hasty" with "little notice and with even less time for substantive analysis and evaluation." APAC Ex. Brief, R-PA-01, at 33. APAC first raised formal objections to the settlement (and by implication, the negotiations) on April 4, 1996, when the Agreements were offered into the record and when it became clear that the parties were willing to proceed to settlement without APAC. All parties, including APAC and Clark, had adequate opportunity for meaningful participation in the settlement negotiations. APAC was an active participant in the settlement as it was in the proceedings, and took many opportunities to raise its concerns. APAC's April 3, 1996, letter to Randy Roach and statements in the hearing record on April 4, 1996, demonstrate that APAC had adequate opportunity for meaningful participation in the settlement negotiations. Tr. 2335-2338; see also, APAC Motion, WP-96-M-72.

Similarly, Clark, although it intervened as a separate party, was also a member of the Western Public Agencies Group (WPAG). WPAG was an active party throughout all stages of the rate proceeding. WPAG participated in the settlement negotiations, and WPAG's members support the settlement, with the exception of Clark. Tr. 2334. Although counsel for WPAG noted that Clark did not support the final agreement, Tr. 2421, Clark could have but did not participate in the settlement negotiations in its own right. *See also* WPAG Brief, WP-96-B-WA-01, at 1. Clark only surfaced in its individual capacity when it determined to oppose the proposed Settlement Agreements. Clark admits it received notice of the settlement negotiations. Clark Ex. Brief, TC-96-R-CP-01, at 9. APAC and Clark were apprised of and had the same access to information exchanged during the settlement negotiations as all other participants to the discussions, and had the ability to ask questions of the proposals and seek additional information in support of the proposals at the time they were being discussed in settlement negotiations. The Hearing Officers in these proceedings ruled that notice has been adequate. Tr. 2315; Tr. 2335-2336. Clark and APAC have also expressed their continued disagreement with the Settlement Agreements in their Briefs, and, for APAC, at Oral Argument.

Parties Had Adequate Opportunity To Offer Refutation Or Rebuttal Material

APAC relies on *California Energy Resources Conservation and Development Commission v. Bonneville Power Administration*, 754 F.2d 1470 (9th Cir. 1985) (*CEC*) to argue that "without a right to challenge an alleged failure to follow required procedures, the right to participate in such procedures could be rendered meaningless." APAC Brief, B-PA-01, at 33. APAC's reliance on *CEC* is misplaced. There, the Ninth Circuit Court found that because the CEC had a right to participate in the rate making procedure it had standing to argue that BPA had failed to follow its statutory ratemaking procedures. *CEC*, 754 F.2d at 1473. The CEC had challenged a BPA power sale on the grounds that the sale was made at a rate that was less than the established rate for such power sales. Concurrent to the challenged power sale, BPA initiated a rate proceeding to establish a rate that would permit such sales at a lower price. Accordingly, the CEC claimed the transaction constituted a power sale at a price that modified BPA's rates without adherence to the ratemaking procedures mandated by the Northwest Power Act. While the Ninth Circuit Court of Appeals found that the transaction was a sale of energy that ordinarily would require modifications to the rate schedule through BPA's statutory ratemaking procedures, it concluded that, due to the unusual circumstances, BPA was not required to follow its statutory ratemaking procedures in this case. *CEC*, 754 F.2d at 1474.

Here, however, BPA has complied with its statutory ratemaking procedures and conducted formal proceedings for the Wholesale Power and Transmission Rate (WP-96 and TR-96) proposals, including providing ample opportunity to participate and develop the issues. Section 7(i)(2) of the Northwest Power Act provides that BPA's rate "hearings will be conducted as expeditiously as practicable . . . to develop a full and complete record" and "the hearing officer shall (A) provide adequate opportunity to refute or rebut material submitted by BPA or others, and (B) exercise discretion to allow reasonable opportunity for cross examination that is not dilatory to develop information or matter relevant to such proposal." 16 U.S.C. § 839e(i)(2). Section 7(i)(2)(A) should not, however, be read to require BPA to allow parties an opportunity to refute or rebut its proposal each time BPA adjusts its position in the course of the hearing. Such a reading of the statute would lead to rate proceedings that would never end. Indeed, as stated by Congress:

> It is the clear intent of the Committee that no one may use these procedures to frustrate the Act or to delay rate revisions. The BPA must act fairly to ensure full public and customer input, but dilatory tactics must be avoided. Few relish rate changes that result in higher rates, but often they cannot be avoided. The burden is on BPA to justify increases. These procedures should ferret out unjustified or inadequately supported changes.

H.R. Rep. No. 976, 96th Cong., 2d Sess., pt.1, at 69-70.

This issue has also been decided with regard to BPA rate cases by the Ninth Circuit in *Central Lincoln*, where the Court held that:

> [s]ection 7(i)(2)(A) ensures that BPA creates a complete administrative record, allowing all interested parties to participate in a meaningful way. *This does not mean, however, that each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin.*

Central Lincoln, 735 F.2d at 1118 (emphasis added). Thus, the right of a party to obtain additional discovery or offer refutation or rebuttal to a proposal must be tempered by a rule of reasonableness. In this rate proceeding, ample opportunity has been given for all parties to thoroughly explore the issues. The Settlement Agreements represent a compromise proposal for the Wholesale Power and Transmission Rates proceeding that is directly based on, or is a logical and reasonable outgrowth of, evidence already on the record. That evidence was thoroughly tested through almost nine months of direct and rebuttal testimony, clarification and discovery, and cross-examination. The Administrator's final decision, however, must still be supported by and made based on the record in the proceeding. APAC and Clark, through its representative WPAG, were active parties in BPA's rate proceeding and participated in the hearings and settlement discussions in a meaningful way. The majority of the active parties found the proposals in the Settlement Agreements to be in their best interest and they executed the settlement agreements. *See* Transmission Settlement Agreement, Attachment 1, pp. 6-23; Power Settlement Agreement, Attachment 2, pp. 3-17. APAC and Clark, however, were the only two parties to object to the Settlement Agreements.

Decision

The proposals contained in the Settlement Agreements represent a compromise of the opposing positions raised during the rate proceeding, and are within the scope of the issues litigated in this proceeding. APAC and Clark had ample opportunity to participate in settlement negotiations and, during negotiations, to request and examine information on the proposals being considered and raise their concern. The proposals are directly based on, or are a logical and reasonable outgrowth of, existing record evidence that has been thoroughly developed and tested throughout this proceeding. The non-settling parties are not entitled to reopen the hearing for additional discovery, rebuttal testimony and cross examination. Neither APAC nor Clark's due process rights under section 7(i) were violated. The Settlement Agreements were appropriately admitted into the record.

Administrator Statements Do Not Constitute Prejudgment In Violation of Section 7(i)

Issue

Whether the Administrator's public statements regarding the Settlement Agreements constitute a premature decision prior to the close of the hearing record.

Parties' Positions

Clark alleges that the Administrator's public statements at a meeting with Pacific Northwest utility executives constitute a premature decision of the proposals contained in the Settlement Agreements in violation of section 7(i) of the Northwest Power Act. Clark Brief, WP-96-B-CP-01, at 10-11; Clark Ex. Brief, WP-96-R-CP-01, at 35-36.

<u>BPA's Position</u>

BPA disagrees that the Administrator made a premature decision to approve the settlement agreement, and that his mind was unalterably closed to consider alternatives prior to the close of the hearing record.

<u>Evaluation of Positions</u>

Clark claims that the Administrator made statements at a meeting between BPA and public power executives on April 2, 1996, about the Settlement Agreements, and these statements indicate that BPA staff communicated staff's positions on the Settlement Agreement to the Administrator. Clark argues that staff's communications with the Administrator constitute improper *ex parte* contacts. Clark also claims that the Administrator's statements that "he approved the terms and conditions of the settlement, that such settlement would benefit a number of public utilities, and would cost Bonneville in excess of $50 million" indicate that he made decisions on matters at issue in the rate case "prior to the record in this matter being fully developed" and has a closed mind to consider arguments in oral argument and in briefs opposing the Settlement Agreements. Clark concludes that the Administrator made a premature decision, in violation of the procedural requirements of Section 7(i). Clark argues that the Settlement Agreements must be excluded from the record. Clark Brief, B-CP-01, at 10-11.

<u>Communications Between BPA Staff And The Administrator Do Not Constitute Ex Parte Communications.</u>

The general rule on *ex parte* communications in BPA's Procedures provides that

> . . . no party or participant in any hearing shall submit *ex parte* communications to the Administrator or any BPA employee regarding any matter pending before BPA in the hearing. Neither shall the Administrator nor any BPA employee request or entertain such ex parte communications.

Procedures, Section 1010.7(a). The Procedures further provide that a "party" is a person who intervenes in the rate hearing, may engage in discovery and file testimony in the hearing, and may participate in cross examination. Procedures, §§ 1010.2(h), 1010.4, 1010.8, 1010.11, and 1010.12. On the other hand, a "participant" is a person who submits oral or written comments in legislative-style hearings. Procedures, §§ 1010.2(g) and 1010.5. The rule on *ex parte* communications in BPA's rate proceedings is clear on its face that the communications that are barred are the exchanges *between* parties or participants and BPA, not the exchanges between BPA staff and the Administrator. Moreover, a section 7(i) rate proceeding is a rulemaking proceeding on the record. *Central Lincoln*, 735 F.2d at 1119. While section 554(d) of the Administrative Procedures Act prohibits *ex parte* contacts between prosecutors and administrators in adjudications, the same separation-of-function provision does not apply in either an informal or formal rulemaking. *Hercules, Inc. v. Energy Policy Act*, 598 F.2d 91 (D.C.

Cir. 1978); *see also Burke v. Bd. of Gov. of Fed. Reserve,* 940 F.2d 1360 (10th Cir. 1991), *cert. denied*, 112 S. Ct. 1957 (1992). Accordingly, BPA staff are not barred from briefing the Administrator on matters of substance relative to the merits of issues in a pending 7(i) rate proceeding. Moreover, in the instant case, staff were obligated to inform the Administrator of the proposals being considered as part of the settlement negotiations, as some aspects of the settlement proposals would require decisions on issues outside the rate case, such as the amount of additional cost cutting BPA could sustain, had policy implications or had the potential to affect BPA's business decisions made or considered in other forums, such as power sales contract negotiations.

<u>Administrator Statements Did Not Constitute A Final Decision On Matters At Issue In The Rate Case.</u>

Clark's allegations that the Administrator's public statements were indicative that he had made a final decision, and had a closed mind to consider alternative arguments in oral argument and in briefs, are not supported by any evidence in the record. Clark asserts that the Administrator made the described statements and concludes that these statements prove that he made a premature decision, in violation of the procedural requirements of section 7(i). Prejudgment, however, does not result just because the Administrator takes a position, in public, on an issue related to issues in the rate case. Clark must show that the Administrator has formed a final judgment on the rate case issues; that the judgment concerned the facts pending in the rate case rather than matters of policy or law; and that the Administrator is not capable of judging the issue on the basis of its own circumstances. *See C&W Fish Co. Inc. v. Fox*, 931 F.2d 1556 (D.C. Cir. 1991) [hereinafter *C&W Fish Co*.], which held that an individual should be disqualified from rulemaking "only when there has been clear and convincing showing that [he] has an unalterably closed mind on matters critical to the disposition of the proceeding";*quoting Association of National Advertisers v. Federal Trade Commission*, 627 F.2d 1151, 1170 (D.C. Cir. 1979), *cert. denied*, 447 U.S. 921 (1980). Such a showing cannot be made based on a single statement that the Administrator knew of the settlements, knew what the costs of the settlement would be to BPA, and also believed that there was substantial regional benefit in the settlement. The only approval or decision implicated in the reported statement is approval of the cost to BPA of the settlement; that is, the nature and extent of the cost cuts that would be necessary if the proposal were to be adopted. Furthermore, the reported statement that there is regional benefit in a settlement is so general that it cannot be viewed as having decisional weight.

As a Federal power marketing agency, BPA must continue to engage in regular business dealings with its customers, including conducting contract negotiations independent of the ratemaking process. *Central Lincoln*, 735 F.2d at 1119. As part of its regular business dealings, and concurrent with this rate proceeding, BPA has been in negotiations associated with its power sales contracts that would either continue or modify its business relationships with its current requirements customers. The April 2, 1996, meeting relied on by Clark was a meeting with Pacific Northwest utility executives to discuss BPA's strategy for these contract negotiations. Some of the same customers that also participated in this rate proceeding, and who support the Settlement Agreements, were in attendance. The focus of the meeting was to discuss strategies for determining the level of load commitment that BPA would require from its customers, in exchange for a level of power supply diversification, 5-year rate certainty and 5-year stranded investment protection. In response to questions from customers seeking greater power supply diversity, the Administrator commented that he approved the parties' efforts to negotiate a settlement and that the settlement seemed to accommodate the concerns of many of the customers in the meeting. The Administrator noted, however, that the settlement would cost BPA about $50 million to implement. The Administrator's statements were made to underscore that BPA would be unable to grant its customers greater power supply diversity and, at the same time, achieve the rate certainty they sought through the Settlement Agreements. The Administrator did not state or intend to state that he had adopted the Settlement Agreement. Indeed, in a hallway conversation prior to the meeting with the general manager of Umatilla Electric Cooperative, the Administrator was careful to comment that he retained the ability to accept or reject the Settlement Agreements following a review of the record. Moreover, these statements are consistent with BPA's April 5, 1996, press release, which characterizes the Settlement Agreements as proposals and states, "this is a tentative agreement, subject to the final approval by the BPA Administrator, and ultimately by FERC."

Clark also claims that the Administrator's statements result in a decision, in violation of the procedural requirements of section 7(i). Specifically, Clark relies on section 7(i)(5) of the Northwest Power Act which provides that:

> (5) The Administrator shall make a final decision establishing a rate or rates based on the record *which shall include the hearing transcript*, together with exhibits, and such other materials and information as may have been submitted to, or developed by, the Administrator. The decision shall include a full and compete justification of the final rates pursuant to this section.

16 U.S.C. § 839e(i)(5) (emphasis added). In making this assertion, Clark ignores the provisions in the Settlement Agreements that, consistent with section 7(i)(5), provide that "[t]he Administrator's final decision in the Dockets must be supported by and made based on the records in the Dockets." Attachment 1, p. 1, "Proposal"; Attachment 2, p. 1, "Proposal."

Finally, in its Initial Brief, Clark asserts that the Administrator has a closed mind to consider arguments that may be presented in oral argument or in briefs. At the close of Oral Argument on April 30, 1996, the Administrator made the following statements:

> I want to assure you that I'm approaching all of these issues with an open mind and that what's been said today, together with the entire record, will be taken under very careful consideration by me before making final decisions on any of the issues in these proceedings, including ultimately whether to adopt the transmission and power settlements and the terms and conditions settlements, which are in a

> sense, recommendations that the Hearing Officer will render . . . its judgment on and ultimately will make final decision on. So I'm taking all of those things into account. And I'm approaching this with an open mind, and I want to assure you that both as a result of the proceedings today, the readings that I've done of a fair amount of some of the testimony that you have provided and the process that we go through with BPA staff in responding to the various arguments that have been raised, that I will weigh those carefully before reaching any final decisions.

Tr. 2498-2499. During Oral Argument, the Administrator heard from a majority of the parties that they supported the Settlement Agreements, and presented reasons why he should adopt the proposals contained in them. The Administrator also heard from APAC, which, like Clark, opposed the Settlement Agreements. Clark, however, did not appear at Oral Arguments, and presented no arguments to the Administrator why he should not adopt the proposals in Settlement Agreements.

Clark urges that "[t]he only way the procedural violation can be purged from this record is to exclude from the record the settlement agreements." Clark Ex. Brief, R-CP-01, at 36. Clark's assertion is contrary to law. The remedy in the event of prejudgment is recusal or disqualification, not the withdrawal of evidence in the record. See*C&W Fish Co, 931 F.2d at 1565*. However, Clark has not shown sufficient evidence that the Administrator cannot be an impartial decisionmaker.

Decision

The Administrator's April 2, 1996, statements, considered in context, do not evidence a closed mind or prejudgment by the Administrator.

14.2.5 Waiver of Issues by Failure to Raise in Briefs

Issue 1

Whether a party that fails to raise and fully develop its position on an issue in its initial brief or that, once having raised the issue in its initial brief, fails to raise the issue in its brief on exceptions, waives the issue.

Parties' Positions

The Public Generating Pool (PGP) stated in its initial brief: "To preserve its right to review by the Federal Energy Regulatory Commission (FERC) or in other judicial review, the PGP states here that it maintains the position it has taken on the record on all issues in these proceedings." PGP Brief, WP/TC-96-B-PG-01, at 5. PGP asserts that section 1010.13(b) of the Procedures Governing Bonneville Power Administration Rate Hearings, 51 Fed. Reg. 7611 (1986) (hereinafter "Procedures") does not prohibit any reservation of rights such as this. PGP Ex. Brief, WP/TC-96-R-PG-01, at 5. PGP further asserts that because the Administrator responded in the draft record of decision to issues raised by the

PGP in the evidentiary stage of the rate case, Procedures section 1010.13(b) cannot be used to prevent PGP from excepting to BPA's treatment of those issues in the draft record of decision. PGP Ex. Brief, R-PG-01, at 6.

<u>BPA's Position</u>

Section 1010.13(b) of the Procedures requires parties' briefs to "raise and fully develop their positions on any issue" or "be deemed to take no position on such issue. Arguments not raised are deemed to be waived." Whenever a party fails to raise and fully develop its position on an issue in either its initial brief or brief on exceptions, BPA may rely on Procedures section 1010.13(b) to assume that the party has waived the issue. *E.g.*, DROD, WP-96-A-01, at 259. BPA and the parties to the Settlement Agreements have, however, agreed that in the event the Administrator does not adopt the Settlement Agreement, the parties shall be deemed to have raised in brief all issues covered by the Power or Transmission Settlement Agreement, as the case may be. DROD, WP-96-A-01, at 10.

<u>Evaluation of Positions</u>

Procedures section 1010.13 states the rule regarding briefs. Section 1010.13(a) states that "[b]riefs shall be filed at times specified by the hearing officer. . . ." and shall conform to page limitations imposed by the hearing officer. The section assumes that more than one brief shall be filed, and in fact section 1010.13(c) discusses initial briefs and section 1010.13(d) discusses briefs on exception.

Section 1010.13(c) states the rule regarding initial briefs:

> At the conclusion of the evidentiary portion of a hearing, the hearing officer shall allow each party to submit an initial brief. The purpose of an initial brief is to <u>identify separately</u> <u>each</u> <u>legal</u>, <u>factual</u>, <u>and</u> <u>policy</u> issue to be resolved by the Administrator <u>and present all arguments</u> in support of a party's position on each of thses issues. The initial brief should also rebut contentions made by adverse witnesses in their prepared testimony.

(Emphasis added). During the course of a rate case, particularly one as long and complicated as this one, the parties and BPA will have raised a multitude--possibly hundreds--of issues, whether it be through motions, testimony or cross-examination. The purpose of initial briefs is to identify and develop a party's position on legal, policy and factual issues that it believes must still be decided by the Administrator. This narrowing and clarification of the issues allows the Administrator to fully consider the issues so raised and to modify the rate proposal as and if warranted. In view of the number and complexity of the potential issues in any rate case, it is imperative that parties timely raise and develop issues they believe must be considered by the Administrator. Doing so allows BPA and the parties the maximum time possible to consider evidence and arguments on all sides of the issue so that both the parties' and the Administrator's positions will be better informed. Accordingly, in this case, as well as in prior cases, more time is generally provided between the date of parties' initial briefs and the Administrator's draft record of decision than is provided between the date of parties' briefs on exception and the Administrator's final record of decision.

"Simple fairness to those who are engaged in the tasks of administration, and to litigants, requires as a general rule that courts should not topple over administrative decisions unless the administrative body not only has erred but has erred against objection made *at the time appropriate under its practice*." *U.S. v. L.A. Tucker Truck Lines*, 344 U.S. 33, 36-37 (1952)(emphasis added); *cf. Alabama Electric Cooperative, Inc. v. F.E.R.C.*, 684 F.2d 20 (D.C. Cir. 1982). In line with this notion of procedural regularity and fairness, section 1010.13(b) of the Procedures states "[p]arties whose briefs do not raise and fully develop their positions on any issue shall be deemed to take no position on such issue. *Arguments not raised are deemed to be waived.*" (Emphasis added). If a party waives an issue by not raising it in the party's initial brief, the party is not entitled to subsequently raise the issue. Procedures, sections 1010.13(b) and 1010.13(d).

BPA interpreted section 1010.13 in the foregoing way in the 1993 rate case record of decision. After discussing testimony filed by NCAC and rebutted in separately filed testimony by BPA and PNGC, the Administrator's Record of Decision, WP-93-A-02, at 139, states:

> NCAC, however, failed to raise its LDD proposal as an issue in an initial brief. At the onset of the 1993 rate proceeding, the Hearing Officer expressly stated that the Procedures Governing Bonneville Power Admin. Rate Hearings (Procedures), 51 Fed. Reg. 7,611 (1986) would govern this proceeding. Prehearing Tr. 7-8. Section 1010.13(b) of the Procedures requires a party to raise and fully develop its position on any issue in its initial brief, or else be deemed to take no position on that issue. Arguments not raised in an initial brief are deemed waived. As NCAC failed to file an initial brief to raise and fully develop its position on the LDD issue in this proceeding, NCAC is deemed to take no position on this issue.

See also Administrator's Record of Decision, WP-93-A-02, at 161. This is also fully consistent with the Summary of section 1010.13(b) from the Procedures that PGP quotes, PGP Ex. Brief, R-PG-01, at 6:

> Paragraph (b) requires the parties to fully raise and develop their position on any issue or else be deemed to take no position on that issue. Arguments not raised are deemed waived. This paragraph is intended to encourage the fullest development of the record possible at the appropriate

> time and to prevent after-the-fact raising of questions to which the Administrator could have responded had the issues been timely raised.

Procedures, at II.M. The summary recognizes that the record does not stop at the end of the evidentiary stage of the hearing. Rather, it continues through briefing, where parties are afforded the opportunity to, for the first time, present the legal and evidentiary merits of its case on disputed issues in a comprehensive and, hopefully, cohesive package.

PGP argues that section 1010.13(b) "is designed to assure that the Administrator has not been put in a position of addressing after-the-fact questions which could have been raised earlier and to which the Administrator is then not able to respond. . . ." PGP Ex. Brief, R-PG-01, at 5. PGP goes on to argue that because the DROD is replete with BPA references to PGP testimony and positions on issues, the Administrator understood and responded to the issues raised by the PGP. Therefore, PGP argues that under the circumstances the purpose of the rule has been satisfied, and BPA should not be allowed to use the rule to invoke a PGP waiver. BPA disagrees. Clearly, the PGP and BPA litigated a number issues during the evidentiary stage of the hearing. But unless PGP raises and argues an issue in its brief, BPA does not have appropriate notice that the issue remains a live one that must be evaluated and determined in the Administrator's Record of Decision, and other parties do not have notice that they should begin marshalling the law and evidence on their position on the issue, should it become necessary to present that position in a brief on exceptions.

The fact that the Administrator has undertaken in some instances to address issues not raised on brief does not mean that he must therefore raise, consider and decide in the ROD every possible issue that could have been raised, but was not. The Administrator's action may be prompted by, among other things, business concerns that an explanation of the particular issue be given, a caution that perhaps an issue was indirectly raised, or a sense that this is necessary to provide a full and complete justification for the final proposed rate or rates. That does not, however, excuse a party's failure to raise and fully develop the issue at the appropriate time.

It would defeat the purpose of the requirement for intial briefs if a party could wait until its brief on exceptions to raise an issue for the first time that it could have raised in its intial brief. While the PGP accuses BPA of attempting to "hide behind" this interpertation of the Procedures, that reasoning erroneously invites Administrative free-for-alls, where there are no rules but the ones each party thinks are fair. PGP Ex. Brief, R-PG-01, at 6. PGP is wrong. If a party could wait until briefs on exceptions to develop its position, BPA would not know whether to change its draft decision because of a party's position, and would be unable to respond to legal arguments until the final record of decision. Such an interpretation of the Procedures is unreasonable and unfair to BPA, as well as to other parties who are afforded the opportunity in briefs on exceptions to respond for the first time, if need be, to the issues raised in other parties' initial briefs and that have therefore been considered in the Administrator's draft record of decision. *See U.S. v. L.A. Tucker Truck Lines*, 344 U.S. 33, 36-37 (1952).

<u>Decision</u>

A party that fails to raise and fully develop its position on an issue in its initial brief or that, once having raised the issue in its initial brief, fails to appropriately raise and develop the issue in its brief on exceptions, waives the issue. This affords all parties, including BPA, a fair opportunity to evaluate and respond to issues raised.

14.3 <u>Environmental Analysis</u>

14.3.1 <u>Introduction</u>

In the 1996 rate proceeding, BPA proposed significant changes in the design of its rates for power and transmission products and services. To address the increasingly competitive market for power and energy services, BPA is proposing to offer a menu of unbundled or separately priced products. Most of the products offered will be available both under current power sales contracts and under new power sales and transmission contracts. BPA is proposing to "unbundle" the products and services it offers so customers can choose among them based on what they need to meet their loads and support their own resources, if any, or to transmit power from one point to another. BPA's power rate proposal also includes changes to rate levels and seasonality, billing factors, rate adjustments, and other rate components. In the case of certain products, BPA expects that the market also will require flexible pricing, so BPA has proposed rate schedules that allow for negotiated terms. BPA's transmission rate proposal includes changes in rate design and rate adjustments to better reflect the costs of open access transmission for firm services, and services that may be offered at downwardly flexible prices.

BPA's final 1996 rate proposal is consistent with BPA's Business Plan, the Business Plan Final Environmental Impact Statement (BP FEIS) (DOE/EIS-0183, June 1995), and the Business Plan Record of Decision (ROD) (August 15, 1995). The BP FEIS and ROD were intended to guide BPA in a series of related decisions on various issues and actions. Before taking specific action on any of these issues, BPA stated that the Administrator would review the BP FEIS to ensure that a particular action was adequately covered within the scope of that FEIS and, if appropriate, issue a tiered record of decision. Tiering subsequent RODs to the Business Plan ROD is helping BPA delineate decisions clearly, and provides a logical framework for connecting broad programmatic decisions to more specific actions.

Consistent with the Business Plan ROD, the Administrator reviewed the BP FEIS to determine whether the actions embodied in proposing the 1996 rates were adequately covered within the scope of the BPFEIS. BPA's 1996 rate proposal, the subject of this tiered ROD, includes some of the issues and actions contemplated within the BPFEIS.

Comments on the Business Plan EIS were received outside the formal rate hearing process, but are included in the rate case record and considered by the Administrator in making a final decision establishing BPA's 1996 rates. The following section summarizes and incorporates information from the Business Plan and the BP FEIS.

14.3.2 NEPA Analysis

The Business Plan FEIS evaluates several business structure alternatives. BPA explored six alternative plans of action in the BP EIS: Status Quo (no action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. In the Business Plan ROD, the BPA Administrator selected the Market-Driven alternative. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also helps BPA to ensure the financial strength necessary to maintain a high level of support for public service benefits such as energy conservation and fish and wildlife mitigation activities.

The alternatives examined in the BP EIS were evaluated against the need for and purposes of the action. BPA's fundamental need is to be able to compete in the changing utility market, which competitiveness will allow the agency to meet its public service and business missions. The 19 key policy issues analyzed for market responses include several rate-related decisions, including unbundling or rebundling BPA's power products and services, and a range of rate level and design alternatives. Alternatives for rates analyzed in the BP FEIS include tiered rates, streamflow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts. General market responses to the 19 key policy issues are shown in Table 4.2-1 of the BP FEIS. Environmental consequences of power pricing and rate attributes are discussed for each of the alternative plans of action in section 4.2.2.1 of the BP FEIS. Environmental consequences of transmission and wheeling pricing are discussed for each of the alternative plans of action in section 4.2.2.2 of the BP FEIS. Environmental consequences for the range of power rate design alternatives are discussed in section 4.5.2 of the BP FEIS. Appendix B to the BP FEIS includes an exhaustive evaluation, including market response and environmental impacts, of a range of power and transmission rate types, attributes, and adjustments.

Besides the issues related to pricing, another of the 19 key policy issues addressed in the BP FEIS is bundling or unbundling of BPA power and transmission products and services. A range of bundling/unbundling options was analyzed. General market responses to the issues are shown on Table 4.2-1 of the BP FEIS. Environmental consequences of bundling or unbundling of BPA power products and services are discussed in section 4.2.1.1 of the BP FEIS.

Additional information on the environmental consequences of the six alternative plans of action is presented in sections 4.3 and 4.4 of the BP FEIS.

The BP FEIS found that environmental impacts would be caused for the most part by the responses to BPA's marketing actions, rather than by the actions themselves. See BP FEIS, page 4.1. The BP EIS identified four types of market responses: resource development; resource operation; transmission development and operation; and consumer behavior. These market responses, summarized for the 19 key policy issues on Table 4.2-1 in the BP EIS, determined the environmental impacts. Tables B-3 and B-4 in Appendix B summarize load and resource responses for the range of rate alternatives examined. The environmental impacts addressed in the BP FEIS include those related to the physical environment, including air quality, water quality, land use, and human health and safety. They also include those related to the socioeconomic environment, such as the effects of changes in products, services, and rates on end-users (consumers) of electricity, including BPA's DSI customers.

The potential environmental impacts of all alternatives fell within a fairly narrow band, and several of the key impacts are virtually identical across alternatives. In addition, the costs of environmental externalities differ only slightly between alternatives. Business Plan ROD, page 6.

In deciding to propose the 1996 rates as a feature of implementing the Market-Driven approach, BPA understands that the conditions that permit the agency to function successfully may change over time. Therefore, the Market-Driven alternative contains preparatory mitigation measures (response strategies) to respond to change and allow the agency to balance costs and revenues. Such mitigation will enhance BPA's ability to adapt to changing market conditions. These response strategies--which include means to decrease spending, increase revenues, and transfer costs--could be implemented if BPA's costs and revenues do not balance. BPA has already decided (in the Business Plan ROD) to apply as many mitigation response strategies as necessary whenever BPA's costs and revenues do not balance. These mitigation strategies, or equivalents, will be implemented to enable BPA to best meet its financial, public service and environmental obligations, while remaining competitive in the wholesale electric power market.

14.4 Participant Comments

This section addresses the comments of participants in BPA's 1996 rate proceeding. Participants are persons and organizations who comment on BPA's rate proposal but do not take part in the formal proceeding.

14.4.1 Introduction

Participants' comments are made part of the Official Record of the proceeding. The participants' portion of the Official Record consists of transcripts of 8 field hearings held September 14 - 28, 1995, throughout the region. A total of 137 persons presented comments at the field hearings. The field hearings were transcribed, and the transcripts were made part of the Official Record. BPA also received 609 pieces of correspondence and documented telephone calls related to the rate filing during the public comment period, which officially ended October 2, 1995. These comments also are part of the

Official Record. An additional 197 pieces of correspondence were received after the conclusion of the official public comment period. The names of the participants who commented on BPA's proposals from July 10 through October 2, 1995, are listed in section 14.4.4.

BPA reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this chapter of the ROD. Comments on technical areas addressed by the parties are evaluated in the ROD chapters that address those topics, *supra*. Following is a summary of the testimony provided at the field hearings and the letters and telephone calls that BPA received during the comment period, along with BPA's responses to those concerns. The letters received after the public comment period had roughly the same distribution of comments across issues as the letters received by the deadline. The major difference was that more letters were supportive of the rate proposal, including reducing the residential exchange benefits.

Copies of the comments of participants and letters received after the comment period are available for inspection in BPA's Public Reference Room.

14.4.2 Evaluation of Participant Comments

The summary indicates the total responses for each issue; many letters contained more than one comment. A total of 1279 comments from letters and 366 comments from the field hearings were analyzed.

Five-Year Rates	Field Hearings Comments	Letters Comments
a. Opposed to rates commitment for five years.	0	2
b. Supports five-year fixed rates.	0	1

Discussion: In response to customers' requests for greater rate certainty, BPA is proposing to eliminate any automatic interim rate adjustments from its power rates schedules, and to seek FERC approval of the rates for five years. In exchange for getting a known, stable rate from BPA for five years, BPA expects that customers would make a purchase commitment for the same period of time. For those customers who are not willing to contractually commit to a specified purchase in exchange for rate stability, BPA retains the discretion to adjust the rates during the five-year period. Customer response to these measures has been favorable. However, some participants have objected to customers having to make a five-year load commitment in exchange for five-year price commitment.

Locking in a rate for five years exposes BPA to uncertainties that its costs may be greater than expected or that loads may be lower than expected. BPA believes that both BPA and the customers should share the risks of locking in a rate for five years. Without some corresponding purchase commitment, BPA faces cost uncertainties and load uncertainties over the next five years. BPA's customers, however, would not face any of these risks. While BPA is willing to take the necessary steps to manage its costs to mitigate the cost uncertainties, BPA needs some load certainty to go forward with a five-year rate.

Some participants do not oppose the commitment in concept, but rather oppose the level of the commitment BPA is seeking in the concurrent contract negotiation process. The rates do not prescribe the nature or amount of the load commitment. These complex contractual issues involving the business and purchase relationship are outside the rate case, and should be addressed in contract negotiations. BPA's five-year rates are addressed in section 2.7 of the ROD.

Rate Levels	Field Hearings Comments	Letters Comments
a. Supports rates as proposed.	41	38
b. Don't erode the decrease by eliminating the LDD or adding delivery charges or any other charges – we don't need a rate decrease as much as we need a reduction in our wholesale power bill.	1	0
c. Opposes rate increase. BPA's rate increase will encourage utilities that have the ability to move from BPA to do that. SCL's rate for BPA power will actually increase when the cost of transmission is taken into account.	7	121
d. Hard to pay rates on a fixed/low income, includes senior citizens, disabled, and retired citizens.	0	80
e. Would affect my investment as a shareholder.	0	2

Discussion: Overall, BPA's proposed power rates, which would go into effect October 1, 1996, are lower than those currently in effect. BPA's 1996 rate proposal includes reduced rates to most customers to respond to market conditions and the increased competition BPA faces. See ROD section 2.0 for a discussion of BPA's business construct. The way the proposed rates are applied to specific utility customers and individual consumers varies. One group of BPA customer utilities is facing a rate increase in October of 1996. Utilities that participate in the residential exchange program described in the Northwest Power Act will face an increase in the rate for power they purchase under the residential exchange. In response, these utilities may pass all or part of the BPA rate increase on to consumers. BPA has no control over the rates utilities charge their customers. The reason BPA must raise its rates to the residential exchange utilities is based on a requirement of the Northwest Power Act, section 7(b)(2), which states that rates to preference customers must be protected from certain costs BPA incurs when it implements provisions of the Northwest Power Act. See ROD chapter 5.0, Residential Exchange Costs, and chapter 9.0, 7(b)(2) Rate Test, for further information. Other changes in rate levels will result from changes in rate design, including changes made to the Low Density

Discount and changes due to implementing Order 888 from the Federal Energy Regulatory Commission. The Low Density Discount is addressed in ROD section 11.2.4. Transmission issues are discussed in chapter 12. Also see the discussion of the Low Density Discount below.

Unbundled Products	Field Hearings Comments	Letters Comments
a. Appreciates the changes, would like to see even more flexibility.	2	0
b. To charge the all-requirements customers the shaping and regulation charges for every kWh does not seem fair. The new charges for load shaping and scheduling fall disproportionately on preference customers.	2	0
c. The reactive power charges proposed are not workable; please consider staying with the power factor penalty. There should be a bandwidth around unity power factor for which there are no additional charges, and the reactive charge should be phased in.	2	0
d. The schedule change charge should not be applied if it is due to BPA's own activities.	1	0

Discussion: BPA traditionally has sold products and services that would meet all of a customer's needs. Because a customer now has greater choices in a competitive market environment, BPA is providing unbundled products and services in order to be a competitive supplier and increase benefits to customers. BPA's proposal allows a customer to choose from a menu of products to meet its specific needs. Some commenters like these proposed changes. A few commenters did not think charging load shaping and load regulation for all kilowatthours is fair. BPA designed these rates in this manner because the amount of load shaping or load regulation service that BPA provides to the customer is related to their entire load, not just Federal load. For more discussion on load shaping and load regulation, see ROD sections 11.2.1 and 11.2.2.

There was one comment on BPA's application of the proposed schedule change charge. Due to the complexity of scheduling, BPA will not have a separate charge for transmission schedule changes at this time. For further discussion of schedule change charge, see ROD chapter 13. Finally, a few commenters did not like the changes to the reactive power charge. BPA believes that BPA's proposed Reactive Power Charge is workable. In response to comments, the proposal includes a deadband. Customers who keep their reactive power demands within the deadband will not be assessed a reactive power charge. The proposed Reactive Power Charge will replace the existing Power Factor Adjustment. The existing Power Factor Adjustment applies only to BPA's power sales customers, even though both power sales and wheeling customers place reactive power requirements on

BPA. The Reactive Power Charge will apply to both power and wheeling customers. For further discussion of reactive power, see ROD section 12.4.5.

Rates for Irrigators/Irrigation Discount	Field Hearings Comments	Letters Comments
a. The irrigation discount should be retained.	2	5
b. Take a look at seasonal rates and make sure they reflect the lower cost of service during those periods of time; irrigators support BPA's proposal of greater seasonal differentiation for energy; rate increases to irrigators do not reflect the economic value to BPA of serving loads that are summer seasonal; the August and September energy rates adversely affect the irrigation segment; the demand charge is too high in the summer; a summer seasonal product should be offered to reflect available surplus energy in the summer; the price of a summer seasonal product should be 12-15 mills per kWh.	16	0
c. The irrigation discount should be eliminated.	1	1
d. Farming is a business that needs to be helped.	0	6
e. Public power utilities will accept the elimination of discount if other subsidies are reduced.	0	2
f. Surplus energy in May, June, and July should be priced to remedy the adverse rate increase on the irrigators.	1	0
g. The 1996 rate proposal is incomplete without a summer surplus product for the irrigators.	3	0

Discussion: As discussed in BPA's Business Plan, BPA is undergoing dramatic changes to become more competitive. BPA's 1996 rate proposal includes unbundled products and services to offer our customers more choice. Unbundling allows BPA to be more competitive, and gives customers the opportunity to purchase and pay for only those products and services that they need. The proposed rates are based on a marginal cost analysis that differentiates seasonal and diurnal energy costs. The August marginal costs in heavy load hours are lower in the final proposal. See ROD section 6.1.2.3. With the greater seasonal differentiation of BPA's power rates and the lower summer rates, including August, the proposed rates may be more economic than an Irrigation Discount for utilities with irrigation loads, and such rates also will provide accurate price signals consistent with BPA's proposed rate designs. In addition, a new Summer Seasonal Product (SSP) is under development. The SSP will be a cost-based rate and would take advantage of excess energy on the Federal system in the spring and summer months. The target audience for the SSP is public utilities having separately metered load that is substantially higher during the spring and summer period than during the rest of the year. Irrigation loads represent the majority of the expected load that will purchase this product.

Considering the measures discussed above, BPA believes that the Irrigation Discount should be eliminated. See the discussion in ROD section 11.2.3.

Low Density Discount	Field Hearings Comments	Letters Comments
a. The LDD should be applied to the BPA power bill bottom line.	1	0
b. Including losses in the calculation of K/I causes the lowest-density systems to receive smaller discounts.	1	0
c. BPA should not eliminate the LDD to a customer in order to block a large industrial load trying to get nonfirm energy.	1	0
d. If BPA proposes not to include the LDD on transmission billing determinants, other compensation measures are required; the RCC has proposed to increase the LDD on non-transmission billing determinants.	1	0
e Low density utilities cannot compete with those in urban areas. Any utility with three or fewer customers per mile should get the maximum discount.	2	0
f. BPA can no longer afford to offer the low-density discount. The LDD should be reduced significantly and limited to non-industrial customers.	2	0
g. Supports the LDD.	0	3
h. Public power utilities will accept the elimination of discount if other subsidies are reduced.	0	2

Discussion: The Low Density Discount (LDD) currently is applied to the total bill for power purchased under the PF rate schedule each month, including a transmission component. To implement FERC's Order 888, which includes comparability, BPA has committed to provide transmission services at similar terms, conditions, and rates to power customers and wheeling customers. See ROD section 2.4. Applying the LDD to the transmission portion of power purchases would violate the comparability principle. It appears that most LDD customers will receive overall rate reductions even though the LDD will not apply to transmission rates. In this rate proposal, BPA's proposed LDD methodology reduces and controls our LDD costs over the 5-year term, and helps keep rates low so all customers benefit The proposal achieves the intent of the LDD to provide assistance to customers with low system densities with high distribution costs in sparsely populated service areas. As a direct result of comments received during field hearings, BPA realized that BPA's proposed changes to the LDD methodology would have reduced the LDD benefits to at least one utility with a sparsely populated service area. BPA therefore is proposing an additional one-half of 1percent adjustment to utilities with very low system densities. For further detail, see ROD section11.2.4.

Demand Charge	Field Hearings Comments	Letters Comments
a. Concern about using the hour of the monthly transmission peak load to bill demand.	1	0
b. The generation demand charge should be seasonally differentiated.	3	0

Discussion: A few participants expressed concern about BPA's power demand charge being applied at the time of the transmission peak. Initially BPA proposed to measure a customer's power demand in the same hours as the hour for measuring the customer's transmission use to simplify the administration of BPA's rates and maintain consistency between power and transmission rates. During the hearing, BPA changed its power demand proposal, so that the power demand would be measured at the time of the generation system peak load for most customers, instead of the transmission peak. Measuring and billing for power demand based on a customer's contribution to the generation system peak load provides customers with a better price signal. And for most customers who do not own or control their resources, their bill for power demand likely will be lower. For Computed Requirements customers who own or control their resources and continue to purchase under the 1981 Contracts, BPA will continue to bill for power demand at the hour of the customer's peak load on BPA during BPA's heavy load hours. For these customers, billing at the time of their peak load on BPA allows them to manage and operate their resources consistent with the 1981 Contracts. This issue is further discussed in section 11.3.1 of the ROD.

The comments received related to seasonal demand charges were from irrigators who would like to receive a lower rate in the summer, when their loads are highest, than in the winter. Seasonal and diurnal differentiation of BPA's rates, if they are performed, are based on results of the Marginal Cost Analysis (MCA). See ROD chapter 6.0. Although the marginal cost of demand varies by month, BPA did not seasonally differentiate the demand charge to reflect the results of the MCA, because the marginal cost of demand is higher in the summer. As such, seasonal demand charges would result in higher summer power rates and lower winter power rates compared to power rates without seasonal demand charges. Consequently, seasonalized demand charges produce seasonal rates contrary to the irrigators' expectations. The reason the seasonal variation in the marginal cost of demand is not incorporated in the design of BPA's power rates is that BPA is trying to avoid disproportional impact of the seasonal rates on the summer peaking customers of BPA, such as utilities with a high proportion of irrigation loads. Not incorporating a seasonal demand charge offsets some of the cumulative effect of eliminating the irrigation discount, and other rate design changes, on smaller, summer-peaking customers. In addition, the level of the demand charge is small in relation to the energy charge and as such does not send a strong price signal. The revenues to be recovered from the power demand charge are significantly less than the revenues to be recovered from the energy charges. To seasonally differentiate the power demand charge would provide a much less powerful price signal than the energy charges. The administrative complexity of time differentiating generation capacity costs outweighs the benefits to BPA from providing such a price signal.

Delivery Charge	Field Hearings Comments	Letters Comments
a. We cannot take higher-level voltage, so we are being charged for something we have no control over, making this rate uncompetitive. The low-voltage delivery charge is expensive and strangles the utility's choice for transmission service. If BPA does not reconsider the charge and the level of the charge, BPA should sell or lease facilities and work with customers to reduce and eliminate this charge.	3	0
b. The cutoff point for the delivery segment charge is arbitrary.	1	0

Discussion: In implementing comparability, BPA agreed with the customers that the transmission charge should be the same for transmitting non-Federal power (wheeling) as it is for Federal power. However, under current rates, the cost of Delivery facilities is allocated totally to BPA power customers. This cost allocation method violates the comparability principles because it would result in a transmission component of BPA's power rate that is different than the wheeling rate the customer would pay if it stopped buying power from BPA and purchased power from another supplier. To remedy this situation, BPA proposed to charge only customers that use Delivery facilities regardless of whether they are power or wheeling customers. Therefore, the transmission cost would be the same regardless of whether the Federal or non-Federal power is delivered. Although this results in a comparable solution, some customers who are served over the low-voltage Delivery facilities would pay more than they currently do for use of Delivery facilities.

In the Transmission Rates and Terms and Conditions Settlement Agreement, BPA and the parties to the settlement agreed that the Utility Delivery charge would be set at $9.00/kW/year, applied to the customer's demand on Delivery facilities. This rate recovers less than the full cost of the Delivery facilities and, therefore, results in a revenue underrecovery that will be allocated to the BPA power business and recovered through power rate charges. BPA also agreed to exclude the costs of 34.5-kV facilities from the Delivery segment, and therefore, the Delivery charge. Finally, BPA agreed to adopt, by October 1, 1996, a policy to sell or lease Delivery substations, with the price, terms, and conditions subject to binding arbitration.

Residential Exchange/7(b)(2)	Field Hearings Comments	Letters Comments
a. BPA should comply with the law and reduce exchange payments.	31	31
b. IOUs do not pass on the benefits of the exchange payments.	1	1
c. It does not make sense that an IOU can offer wholesale power at rates lower than BPA's and continue to receive the exchange subsidy. BPA can no longer afford the costs of the residential exchange. The residential exchange is unnecessary in today's market-power environment. Residential exchange costs can and should be reduced. Residential exchange credits should be eliminated.	12	1
d. BPA should be required to provide the same pricing treatment to residential and small farm customers of IOUs as it does for publics. Retain the current exchange rate. A rate increase would hurt consumers. The exchange is not a subsidy to the IOUs but is passed through to consumers.	15	15
e. The test under 7(b)(2) is not accurate and is a bad test. There are questions about what data were used and how.	2	3
f. Share the benefits of low cost federal power equally with all, including Oregonians.	1	180
g. Changing the residential exchange violates the spirit of the Northwest Power Act.	0	3
h. PGE using dirty tactics; shareholders should pay for PGE lobbying.	0	2

Discussion: A number of the public comments urged that BPAshould comply with the law and reduce exchange payments. Other comments argue that the section 7(b)(2) rate test has not been properly implemented, and exchange benefits should be increased. All of these comments refer to the implementation of section 7(b)(2) of the Northwest Power Act and the payment of benefits to regional utilities under the residential exchange program. Section 5(c) of the Northwest Power Act established the residential exchange program. This program provides Pacific Northwest utilities a monetary form of access to low-cost Federal power. Benefits to participating utilities are calculated based upon the difference between a utility's average system cost and BPA's generally lower PF Exchange rate. The difference between these rates, multiplied by a utility's regional residential load, determines the amount of subsidy BPA pays to the utility to be passed through to the utility's residential consumers. The proposed increase in BPA's 1996 PF Exchange rate, the applicable rate for utilities participating in the residential exchange program, is the result of implementation of section 7(b)(2) of the Northwest Power Act.

When Congress established the residential exchange program, it was concerned that the subsidies provided by BPA to exchanging utilities could result in adverse economic consequences to BPA's public agency utility customers. H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980); H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess 34 (1980); S. Rep. 272, 96th Cong., 1st Sess 15 (1979). In order to protect public agency customers from such adverse economic consequences, Congress established a rate ceiling for such customers in section 7(b)(2) of the Act. *Id.* Section 7(b)(2) requires that BPA conduct a rate test in every BPA rate case to compare firm power rates for BPA's public agency customers with and without five specific assumptions stated in the Northwest Power Act. The rate test ensures that BPA's public agency customers' firm power rates are no higher than rates calculated using the five specific assumptions that remove certain effects of the Act, including the residential exchange program. Section 7(b)(3) of the Act requires that any amounts not charged to public agencies because of the 7(b)(2) rate ceiling must be recovered from sales to BPA's non-public agency customers. Therefore, because investor-owned utilities are not public agencies, some of the costs from the rate ceiling must be allocated to the PF Exchange rate. These costs increase the PF Exchange rate and therefore reduce the difference between that rate and the utilities' average system cost rates, consequently reducing the exchanging utilities' residential exchange subsidies.

In 1984, BPA conducted a section 7(i) rate hearing with all interested parties in order to establish a methodology to govern the implementation of section 7(b)(2) in subsequent rate cases. In August 1984, BPA issued a Record of Decision establishing a Section 7(b)(2) Implementation Methodology. The methodology has been used by BPA in each rate case since the methodology was established. The methodology provides detailed guidance in the manner in which the section 7(b)(2) rate test is conducted. When BPA conducted the section 7(b)(2) rate test in the 1996 rate case, the rate test triggered significantly. There are many issues which are included in the implementation of the section 7(b)(2) rate test. These issues are discussed in greater detail in ROD chapter 9.0. In response to comments that BPAshould comply with the law and reduce or increase exchange payments, BPA has complied with the law in conducting the section 7(b)(2) rate test, and the effect of the implementation is reflected in the resulting rates.

One public comment suggests that the IOUs do not pass on the benefits of the exchange payments. Section 5(c)(3) of the Northwest Power Act, however, requires that utilities pass residential exchange benefits through directly to the utility's residential loads. This issue is not resolved through BPA's rate case but rather through a separate administrative process. BPA has established compliance reviews of the exchanging utilities to help ensure that benefits are passed through to residential consumers. Concerns regarding the proper passthrough of benefits should be addressed to BPA's residential exchange staff.

Some public comments argued that it does not make sense that an IOU can offer wholesale power at rates lower than BPA's and continue to receive the exchange subsidy. Other comments argued that the residential exchange is unnecessary in today's market-power environment. BPA understands the concerns expressed on this issue. When the residential exchange program was first established, regional utilities did not have access to cheap power in the same manner that such power is available in the current market. If the current market had existed at the time the Northwest Power Act was established, the residential exchange program might not exist. However, despite the questionable logic of the program in the current market environment, BPA must implement the residential exchange program in accordance with law, and IOUs may market power at rates lower than BPA's while still receiving subsidies. It should be noted that a recent Conference Report on the Energy and Water Development Appropriations Act, P.L. 104-46 urged that "Bonneville and its customers should work together to gradually phase out the residential exchange program by October 1, 2001." H.R. Conf. Rep. No. 293, 104th Cong., 1st Sess. 95 (1995).

Some public comments argue that BPA should be required to provide the same pricing treatment to residential and small farm customers of IOUs as it does for publics and that BPA should retain the current PF Exchange rate. As noted above, however, the PF Exchange rate cannot simply be set in any manner BPA desires. A primary factor in determining the PF Exchange rate is the section 7(b)(2) rate test. As explained previously, when the rate test triggers, as it has done in the current rate case, costs must be allocated to other rates, including the PF Exchange rate. Under section 7(b)(2) of the Northwest Power Act, Congress recognized that the rate for preference customers might properly differ from the PF Exchange rate due the to results of the section 7(b)(2) rate test.

Some public comments argued that residential exchange benefits are not a subsidy to the IOUs but are passed through to consumers. The dictionary defines "subsidy" as "1. a direct pecuniary aid furnished by a government to a private commercial enterprise, a charity organization, or the like. 2. a grant or contribution of money . . . ." Under the residential exchange program, BPA provides direct pecuniary aid in the form of money to exchanging utilities. This monetary aid is passed through to the utility's residential customers in the form of lower retail rates. The exchange program thus satisfies the dictionary definition of a subsidy. BPA has always recognized, however, that the exchange program provides a monetary form of access to low-cost Federal power for residential customers of regional utilities and that exchange benefits must be passed through to residential consumers.

Direct Service Industries	Field Hearings Comments	Letters Comments
a. BPA is giving away the store to the aluminum companies in this rate case and in secret sweetheart deals;	1	0
b. BPA should not offer subsidies to DSIs beyond those cost-justified.	2	1
c. Against subsidies to DSIs.	0	10
d. Rates to publics should be as favorable as those to DSIs.	0	3
e. Concerned about losing DSI load.	0	1

Discussion: Under the Northwest Power Act, BPA is required to set its rate to its direct-service industrial customers (DSIs) (the Industrial Firm Power (IP) rate) at a level that is equitable in relation to the retail rates charged by BPA's public body and cooperative customers to their industrial consumers. Thus, the IP rate is based on the rate that BPA charges its public body and cooperative customers (the Priority Firm Power (PF) rate) and the typical margins included by such customers in their retail industrial rates. BPA also must take into account the value of reserves made available to BPA through its right to restrict the DSI load. BPA has followed this methodology in all rate cases since 1985. This is not a subsidy to the DSIs.

Even after accounting for the value of the DSI reserves, the DSIs are paying energy charges higher than those paid by BPA's public customers. The perception exists that the DSIs are receiving a much cheaper rate than public customers because the effective average IP rate is lower than the effective average PF rate. However, the difference in effective average rates is due to the characteristics of the DSI load (high load factor, flat seasonal shape). In addition, BPA's public customers do not provide reserves. If the DSI customer were not required to provide reserves, and if the DSI customer and public customer had identical load characteristics, then the public utility customer's rate would be significantly lower than the DSI customer's rate. Comparing loads with like characteristics demonstrates that the DSIs are not being given preferential treatment or receiving subsidies. For discussion on specific DSI rate issues, see ROD chapter 8.0, and sections 11.4, 11.5, and 11.6.

Cross-Subsidies	Field Hearings Comments	Letters Comments
a. Emerald PUD is willing to give up part of the LDD and all of the irrigation discount so BPA can remain competitive.	1	0
b. If BPA is going to cut the LDD it needs to cut the residential exchange. Rural co-ops and BPA cannot compete with utilities who are subsidized in the exchange program. The residential exchange is a subsidy. BPA must oppose concessions that would adversely impact non-exchanging preference customers. Full requirements customers will see all the costs for the residential exchange, fish and wildlife, WPPSS debts, and conservation shifted to them. IOUs' rates are lower than cooperatives' now, and it's not fair for customers of public utilities to support customers of IOUs.	10	0

c. Rates should be equitable. BPA is taking a piecemeal approach and is arbitrarily shifting costs from one customer to another – benefits should be shared equally. Supports reduction of subsidies in LDD, irrigation discount, and residential exchange. BPA must eliminate all programs that are not mandated by law and offer a product that is free from social engineering. Opposes shifting costs onto RCC utilities, and favors equally viable and unbiased options for full and partial requirements customers. Lowest cost power for everyone, not just a few.	7	7
d. Cross-subsidization of products and services must not be allowed. Against all cross-subsidies.	1	257
e. BPA has incurred huge costs to serve the DSIs, why should those costs be shifted to families in Puget Power's service territory? BPA is shifting the benefits of the residential exchange to DSIs. The DSIs will not be paying their fair share. BPA should not serve DSIs at the expense of others.	9	2
f. There is no linkage between offering contracts to the DSIs and the reduction in residential exchange payments.	3	0
g. Supports BPA's offering competitive rates to DSIs because in the past DSIs have paid higher rates to subsidize other customers.	1	0
h. BPA's proposal devalues power in the peak periods compared to LLH.	1	0

Discussion: The issue of cross-subsidies, or the perception that some customers' rates are higher because other customers' rates are lower, received a large volume of comment. Many commenters connected the contractual rate test for the DSIs with the PF Exchange rate being increased, claiming that this constituted a cross-subsidy. The rate test in the DSI "block sale" contracts states that a DSI purchaser may terminate its contract if BPA's proposed rate for the DSIs is higher than a level specified in the contract. The DSI "block sale" contracts were signed prior to the end of the rate case and will go into effect October 1, 1996. The timing of the signing of the contracts does not, however, mean that the DSI rate was predetermined, as many commenters apparently fear. Rather, the DSI rate has been determined in the rate process, based on BPA's costs and the relevant provisions of the Northwest Power Act. ROD chapter 8.0 and sections 11.4, 11.5, and 11.6 discuss issues related to DSI rates. The PF Exchange rate, as explained above, also was determined based on BPA's costs and the relevant sections of the Northwest Power Act, in particular section 7(b)(2). ROD chapter 5.0 discusses residential exchange costs, and chapter 9.0 discusses the section 7(b)(2) rate test. The Irrigation Discount and the Low Density Discount are addressed above, and in ROD sections 11.2.3 and 11.2.4.

Transmission	Field Hearings Comments	Letters Comments
a. Encourages BPA to adopt open access and comparable charges for the transmission system including use of facilities and delivery, with a reasonable and fair transition plan.	1	0
b. Encourages BPA to consider selling to the local utility the local delivery (low voltage) facilities.	1	1
c. Public utilities rely on BPA to maintain the transmission grid.	1	1
d. It costs more to serve a utility customer at a distribution voltage than at a transmission voltage, so adding costs of transformation makes sense.	1	0
e. BPA should assess its proposed transmission rate that negatively impacts renewables.	1	0
f. The transmission network charge should be seasonally differentiated.	1	0
g. BPA is shifting some of its costs onto transmission rates, inconsistent with FERC policy; transmission pricing subject to FERC as all other utilities.	2	1
h. We have our choice of two very unappealing and incomplete transmission alternatives.	1	0
i. Against shifting generation-driven fish costs into transmission.	0	2
j. Support uniform low rates in which transmission services to customers are included in the price of power; against shifting power costs to transmission.	0	2

Discussion: BPA has committed to FERC's comparability principle, and will offer third parties access on the same or comparable terms and conditions, and at the same or comparable rates, that BPA uses for itself. In addition to proposing new transmission rates, BPA also is proposing terms and conditions of service for general applicability under the Point-to-Point and Network Integration tariffs. These two tariffs are modeled closely on FERC's open access tariffs. In these rates, terms, and conditions proceedings and associated workshops, BPA and the parties have engaged in a great deal of discussion regarding the rates and tariffs, and were finally able to forge the Transmission Rates and Terms and Conditions Settlement Agreement. All parties to the settlement agreed to certain rate methodologies, maximum rate increases, and that BPA's proposed rates, terms, and conditions conformed to the open access tariffs in the NOPR. These rates, terms and conditions will aid the Region in making a smooth transition to new competitive open-access power markets.

BPA's transmission revenue requirement reflects significant budget cuts, which serve to lower the cost of the transmission services for all users, Federal and non-Federal. In developing rates, transmission costs are allocated to power rates to the extent that the BPA power business is forecasted to use the transmission system. The major issues in the transmission rate case have involved the allocation of certain transmission costs--whether such costs are allocated to the power business only, or whether they should be shared by all transmission system users. The Settlement Agreement reflects a compromise on these allocation issues for all parties to the settlement, including BPA. No costs associated with fish are included in the transmission revenue requirement. BPA's transmission rate design does not include seasonally differentiated rate charges; the work involved for BPA and the parties dealing with the major cost allocation issues and development of the new open access rates, terms and conditions precluded BPA and others from proposing more rate design changes at this time. Please see the Delivery section above regarding BPA's low-voltage Delivery facilities.

Conservation/Renewables	Field Hearings Comments	Letters Comments
a. BPA is canceling conservation contracts and least-cost resources.	4	0
b. BPA must continue to support conservation and renewables. The aluminum plants could be made more efficient. A rate increase and elimination of conservation programs will hurt low-income households.	8	4
c. BPA can no longer afford to bankroll conservation for the region. Conservation is more effectively done at the local level.	3	1
d. Against rate differential for excessive use.	0	1
e. Ratepayers should be rewarded for conserving.	0	2
f. Californians should conserve.	0	1
g. Make conservation programs available to all.	0	1
h. Consumer will convert to natural gas/other alternatives. Higher rates will cause more wood burning and be hard on the environment.	0	6

Discussion: Some participants expressed concerns related to BPA's conservation programs and the funding of these programs. Decisions on BPA's programs, including conservation programs, are not made as part of BPA's rate case process. Decisions on BPA's conservation efforts were made in BPA's Strategic Business Plan. See section 4.1.2 of the ROD for a discussion of the Strategic Business Plan and process to develop that Plan. As stated in the Strategic Business Plan and in other forums, BPA remains committed to regional conservation, and has redesigned its conservation efforts to meet specific customer needs. This redesign of conservation replaces incentive-based programs with other approaches that are more market-driven. As a result, BPA will support utilities in their transition to locally funded conservation programs and in the development of local conservation plans. Alternative financing mechanisms and other joint efforts are available to help utilities with this transition. In addition, market transformation ventures with business partners will facilitate changes in the marketplace leading to the adoption of more energy-efficient technologies and practices. BPA will further encourage conservation through the development of energy efficient products and services aimed at meeting the changing needs of customers.

A number of participants suggested that BPA's rates should be higher to encourage or support conservation efforts. However the rates consumers face depend on retail rate levels, which are set by their utility, not BPA. Moreover, the record of this case contains strong warnings that BPA must reduce its rates to survive. Failure to establish rates at competitive levels may have negative revenue implications, making it difficult for BPA to make financial contributions to support conservation efforts and to maintain and restore endangered fish. See chapter 2 of the ROD for further discussion of BPA's need for competitive rates in order to meet its statutory obligations.

Business Plan/Regional Review	Field Hearings Comments	Letters Comments
a. Supports the Business Plan.	2	0
b. BPA must fulfill its original mission and role as a federal agency.	0	35
c. Concerned about refinancing debt.	0	1
d. BPA should be privatized and operated as a corporation.	1	9
e. Concerned about BPA becoming a corporation.	0	2
f. Congress/others should intervene/investigate BPA.	0	8

Discussion: Over the past several years, BPA has been reinventing itself to succeed in a fast-changing, competitive, and deregulated electric power market. The capstone of that effort was the BPA Business Plan. The Business Plan includes many initiatives BPA has taken under the Competitiveness project. It shows how all the pieces fit together to achieve one goal: to make BPA competitive, so it can continue to fulfill its public mission in the rapidly changing electric utility environment. BPA's business success will support the substantial public benefits BPA provides to the region, improving the environment and the economy. As a self-financed agency, BPA is committed to succeed financially so it can continue to deliver the value and unique public benefits of fish enhancement, conservation, low-cost power, and stewardship of the Columbia River system it has historically provided, and maintain its role of excellence and service to the Pacific Northwest.

Several commenters stated that BPA should be privatized and operated as a corporation. Some were concerned about BPA becoming a corporation and that Congress and others should intervene and investigate BPA. While this is outside of the scope of the 1996 rate proceeding, BPA appreciates hearing feedback from the public on these issues. In response to concerns such as these, on January 4, 1996, the four Northwest governors initiated a review of how the region's electricity system should be structured, including the future of BPA. The year-long review is expected to produce legislative proposals for Congress and will lay the framework for the region's power system in the 21st century.. This is an important process with major economic and environmental consequences for BPA and the region as a whole. The region has a year to develop consensus on what it wants from its power system in the next century. One of the issues that may be considered during the year-long review is BPA's corporate status.

Competitiveness	Field Hearings Comments	Letters Comments
a. For utilities and businesses to be competitive, BPA must be a reliable and competitive supplier. We need competitive, reasonable, equitable, predictable rates. If we're going to keep a strong economy, we need to keep our power cheaper than the east.	35	8
b. Our public utility needs more access to the marketplace.	2	0
c. BPA should continue efforts to reduce costs to remain competitive. Neither revenue-financing long-lived assets nor unnecessary use of borrowing authority is defensible.	15	1
d. BPA's costs are still too high, and BPA is uncompetitive. Requiring a load commitment in return for a price commitment puts BPA at a competitive disadvantage.	2	0
e. BPA needs to be competitive to continue its regional role protecting salmon and other environmental efforts. The rate case undermines BPA's legal and ethical obligations to restore fish and wildlife, to develop sources of clean renewable energy, and to vigorously pursue energy conservation.	7	0
f. Applauds the competitiveness of BPA's rate proposal.	18	6
g. BPA is enhancing its competitive position at the expense of Pacificorp's customers and other energy providers.	2	1
h. Learn to be more efficient, keep costs down, be a reliable business partner.	0	80
i. Fight for lower rates to be competitive.	0	2
j. Cost-driven pricing is obsolete; accept market-based pricing.	0	3
k. BPA/power companies have monopoly.	0	3
l. BPA should maintain its contractual commitments to its business partners. BPA is essentially abrogating our existing contracts via this ratemaking process. BPA should develop trust as a business partner. BPA is lacking in accountability to the people who provide it the funds that it operates on.	5	1

Discussion: The electricity industry is changing rapidly. BPA now competes with many different suppliers. The only way BPA can sustain its revenues and maintain positive business relationships with its customers is to establish competitive rate levels, along with rate designs that allow BPA to meet market prices while covering its costs and that offer its customers non-price features of the products they desire (e.g. flexibility) In addition, BPA believes that the only way to fulfill its legal and statutory responsibilities to fish and wildlife, renewable energy, and other environmental mandates is by offering competitive products and prices that recognize the competitive marketplace and meet customer needs.

The current competitive marketplace requires BPA to do whatever it can to attract the business of its current customers in order to sustain revenues sufficient to cover costs, including the costs of BPA's social and environmental obligations. BPA does not have a monopoly. The electricity industry has been deregulated increasingly over the past few years. BPA now faces significant competition from other electricity suppliers for the business of its traditional customer base. Such competition is coming from regional IOUs and other power suppliers such as Enron and Louis Dreyfus. Open access requires that BPA provide transmission to its customers who choose to purchase electricity from other suppliers. The rate case includes no anticipated increase in business at the expense of PacifiCorp and other regional IOUs. BPA is not enhancing its competitive position at the expense of utilities participating in the residential exchange program. The impacts of BPA's proposed rates on exchanging utilities are the result of implementation of section 7(b)(2) of the Northwest Power Act, as described in greater detail in the section discussing participants' comments on the residential exchange program and the section 7(b)(2) rate test. In contrast, however, PacifiCorp and other regional IOUs already have taken a significant amount of business away from BPA by signing multi-year contracts with such customers as Clark Public Utilities, Snohomish Co. PUD, Canby Utility Board, and some of the DSIs.

BPA also continues to search for ways to cut costs in order to provide competitive rates. BPA's commitment to continuing to reduce costs is necessary for BPA to offer the most competitive rates. BPA is required by statute to set rates that recover its costs. In response to the market, however, BPA is proposing to cut costs such that cost-based rates reflect market rates. In addition, the proposed FPS rate schedule will allow market-based rates for sales that are consistent with BPA's mission but could not be made at the cost-based "requirements" rate schedules (i.e., PF, IP and NR).

The 1996 rate proposal does not require BPA's customers to make a load commitment in return for a price (rate level) commitment, although to receive five-year rate certainty a customer will have to make a load commitment in a separate contract negotiation process. The negotiations surrounding the conditions for purchasing from BPA are beyond the scope of this rate case.

Fish and Wildlife Program	Field Hearings Comments	Letters Comments
a. IOUs should assume some of the fish costs. The aluminum industry should assume some of the fish costs. DSIs have benefited at expense of salmon.	2	2
b. I do not want low cost power if it means we have to jeopardize salmon. BPA must not disregard its obligation to restore fish runs. BPA is a federal agency sworn to uphold the law, but now is demanding protection from it [via the fish cap]. Keep funding fish and wildlife.	5	4
c. F&W costs must be brought down. Ensure that F&W costs are economically feasible and predictable. BPA must insist that the money spent on fish runs is worthwhile. BPA cannot continue to be a blank check for fish recovery. Costs are too high for a fish species that has been wiped out. There are many endangered species, and it is unreasonable to spend so much on salmon.	13	4
d. BPA should take advantage of the research that has been done in enhancing fish runs. The dams can and should be modified to improve the Idaho fishery. The Snake River salmon could be saved by using good science and economic feasibility.	3	1
e. Against shifting generation-driven fish costs into transmission.	0	1

Discussion: BPA continues to fulfill its responsibilities and obligations under the Northwest Power Act, the Endangered Species Act and other environmental statutory directives. Activities to protect, mitigate and enhance fish and wildlife affected by the construction and operation of the Columbia River Basin hydroelectric system are based on fish and wildlife measures adopted by the Northwest Power Planning Council (Council) in its Fish and Wildlife Program. The Federal Columbia River Power System is operated to comply with the Endangered Species Act by implementing the reasonable and prudent alternatives called for under Biological Opinions issued by the National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS).

In September 1995, the Clinton Administration and the Northwest Congressional delegation announced an agreement to develop a plan for stable funding of BPA's fish and wildlife obligations. BPA, NMFS, USFWS, the Army Corps of Engineers, and the Bureau of Reclamation, in consultation with the Council and the Columbia Basin Tribes, are currently negotiating a fish and wildlife memorandum of agreement (MOA). The MOA will establish the budgeting and accounting practices necessary to implement the Administration/Congressional agreement on a stable multi-year BPA fish and wildlife budget. The MOA will provide greater certainty to BPA and its customers relating to its fish and wildlife obligations. BPA will pay an average of $252 million per year for the next six years, for all fish and wildlife activities except hydropower operations. Hydropower operations will be performed in conformance with the NMFS and USFWS Biological Opinions and consistent with the Council's fish and wildlife program. The cost of these operations will be borne by BPA and is currently estimated to average between $90 million and $280 million annually for the next six years. These costs will be recovered through BPA's power rates.

Treasury Payment	Field Hearings Comments	Letters Comments
a. It is essential that BPA charge rates high enough to cover debt service. BPA must make Treasury payments so Congress will not sell BPA.	4	2

<u>Discussion</u>: In developing its rates, BPA evaluates the probability that its rates will produce sufficient revenues to meet all of its scheduled Treasury payments in full and on time. According to the long-term policy BPA adopted in its 1993 final rate proposal, BPA plans to set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each two-year rate period. The 95 percent standard for a two-year rate period is equivalent to an 88percent probability of making all five Treasury payments in a five-year rate period. 1996 Final Rate Proposal, Revenue Requirement Study Documentation Volume 1, WP-96-FS-BPA-02A, Chapter 13. BPA also must consider the competitive market it faces, however, and thus includes an average of $13 million per year of planned net revenues for risk in its revenue requirements, bringing the total cash flows available for risk to an average of $86 million per year. This compares to the $101 million annually that would be indicated by BPA's policy. Based on an average of $86 million per year cash flows available for risk and on other factors, the 1996 final proposal results in an 80 percent probability of BPA making all of its Treasury payments during the five-year period. See ROD chapter 4.0 for further discussion on this issue.

Stranded Investment	Field Hearings Comments	Letters Comments
a. BPA should protect itself against stranded investments. Any BPA customer that was part of the WPPSS project should not be allowed to escape its fair share of the costs. If customers change to gas from electricity, they should pay their fair share of BPA's debt. Stranded investment is a big issue, and BPA must remain competitive.	5	2

b. BPA is shielding the aluminum smelters from their share of the dead nuclear debt. Concern that aluminum plants could leave requirements utilities with insurmountable stranded investment costs.	2	1
c. Exit fees are not legal or justified. Opposes exit fees.	3	3

Discussion: Several comments stated that BPA should protect itself from stranded investments, and that any customer that was a participant in the Washington Public Power Supply System (WPPSS) nuclear projects should pay its fair share of the costs of those projects. This issue is outside the scope of the rate case. In the Federal Register Notice initiating the rate proceeding, BPA stated that it would have no specific stranded investment proposal to make as part of this rate case, and that the issue would be addressed outside of the rate case forum. 60 Fed. Reg. 36,466 (1995). The Hearing Officer issued several orders striking testimony filed by several parties addressing the issue of stranded investments. WP-96-O-13, -15, -19, -20. To clarify, however, BPA agrees that it must protect itself from stranded cost exposure. Separately through the rate case and its contract negotiation process, BPA is attempting to retain as much of its existing load as possible, thereby mitigating or eliminating the threat of a stranded cost problem. In the event that these measures are not sufficient to preclude a stranded cost problem, including those stranded costs that may be attributable to the nuclear projects, BPA will move to implement a stranded cost recovery mechanism that is consistent with its statutory authorities and obligations, and its contract rights. In addition, BPA recently signed new power sales contracts with its DSI customers that protect them from stranded cost recovery mechanisms that specifically target the DSI customer. BPA agreed to this in return for a commitment from the DSIs that they would place 80 percent of their existing load on BPA at a certain rate. BPA determined that stranded cost protection in exchange for a significant load commitment from the DSIs was in the best interest of BPA's other customers.

It is not clear what the comments mean by the term "exit fees." If by that term they take the position that as a general proposition BPA has neither the statutory or contractual authority to implement a stranded cost recovery charge of any kind, then BPA disagrees with this position. Whether a stranded cost charge will be necessary has not yet been determined. If BPA determines that such a charge is required, it will conduct the appropriate administrative process to implement such a charge, which will then be submitted to the Federal Energy Regulatory Commission for review and approval.

Nuclear Plants/WPPSS	Field Hearings Comments	Letters Comments
a. Notes the significant cost reductions of WPPSS.	1	1
b. Supports WNP-2.	0	1
c. Terminate WNP-2; BPA should shed load and thereby shed expensive generation, such as WNP-2.	2	1

d. Don't want to pay for Trojan.	0	2
e. Urges BPA to completely phase out its nuclear programs and shift revenue toward renewable energy programs and energy efficient programs.	1	1

Discussion: Resource acquisition and termination decisions are not appropriately resolved in BPA's rate case. These business decisions are not rate issues and have broad implications inappropriate for consideration within the narrowly focused context of the rate case. The fact that resource decisions are not being made in the rate case hearing does not mean that BPA is not considering the issues raised by the participants. BPA has alternative forums, outside the rate case forum, in which these issues can be considered in the context of the broader business implications. See discussion in section 14.2.1 of the ROD.

BPA has a contractual obligation to pay the remaining debt service on Trojan, and must set its rates to recover its obligations. Similarly, BPA has a contractual obligation to pay for the WNP plants. BPA continues to monitor the economics and the costs of the nuclear plants. In fact, BPA recently released a draft analysis of WNP-2 as part of its efforts to keep power costs competitive. The study recommends that BPA continue to monitor the plant operation, and that the Supply System look for more ways to cut the plant's cost.

Process	Field Hearings Comments	Letters Comments
a. BPA tends to act in the interest of those who bring the most political pressure on the agency, but recent efforts by the IOUs and DSIs must not be allowed to cause BPA to withdraw the current rate proposal. Proposal is partisan.	2	2
b. BPA should not have offered DSI contracts before the rate process was completed. The rate case proposal was arrived at through a series of secret back room deals, depriving BPA's customers fair access to information and to this process. Suspend new contract negotiations; negotiations should cease during public process.	3	5
c. Urges BPA to hold additional hearings. There should be more direct public involvement in the rate process regarding fish, conservation, and renewable energy programs. The timing of this hearing could not have been worse to encourage participation. Should be more hearings in small towns, especially in Puget Power territory. Complains about lack of information. A comprehensive examination of the region's energy picture is needed.	10	12
d. Urges BPA to withdraw this case and start over.	1	0

e. The rates the DSIs will pay will indeed be determined in the rate process and are not predetermined.	1	0
f. Commends BPA for continuing to listen to its customers.	1	5
g. Rates are not "good news"/deceptive advertising.	0	43
h. Wants fair treatment/rates for all. Questions fairness of the process.	0	195
i. Please respond to PGE ad. Emphasize 7(b)(2) issue.	0	7
j Reconsider the rate case.	0	4
k. BPA should not be allowed to arbitrarily/unilaterally change benefits.	0	2
l. Calculation errors in process.	0	2
m. Supports the position of the RCC.	1	0

Discussion: Concern was expressed by some of the commenters that BPA is not committed to an open, fair, and unbiased ratesetting process. BPA's ratesetting process is governed by section 7(i) of the Northwest Power Act and by the Procedures Governing BPA Rate Hearings. Both section 7(i) and the Procedures require that BPA's wholesale power and transmission rates be established according to certain procedures. These procedures include, among other things, issuance of a Federal Register Notice announcing the proposed rates; one or more hearings; the opportunity to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. BPA is committed to setting its rates consistent with the requirements of the Northwest Power Act.

BPA's procedures also allow for submission of comments, views, opinions, and information from rate case parties and non-rate case participants. Participants' written comments are part of the official record of the case and are carefully considered by the Administrator when making his final rate decision. During this rate proceeding, BPA held eight public field hearings around the region and received over 800 letters from the public. In addition, BPA conducted numerous workshops on subjects relevant to its ratemaking. Opportunity was provided at the workshops to address the impacts of BPA's proposed 5-year rate, transmission rates, terms and conditions, and rate design issues. The workshops provided for an opportunity for informal, public comment on issues outside of the formal hearing process.

The Administrator develops final rates based on this open and unbiased process, including the written and oral comments received from participants. Consideration of these comments , along with other material contained in the official record, aids the Administrator in developing the final rate proposal, based on the entire record.

Miscellaneous	Field Hearings Comments	Letters Comments
a. Other.	0	5

Discussion: We appreciate all of the participants' comments. They are part of the record, as discussed directly above, and may be viewed at BPA's Public Reference Room.

14.4.3 Public Field Hearing Transcripts

Copies of the Public Field Hearing transcripts are available through BPA's Public Information Center.

14.4.4 Commentor Letters, July 10, 1995, through October 2, 1995

Copies of letters and recorded telephone conversations of participants are available through BPA's Public Information Center.

15.0 CONCLUSION

As required by law, the rates established and adopted in this ROD have been set to recover 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 (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and all other costs and expenses incurred by the Administrator 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, to encourage the widest possible use of BPA's power, to equitably allocate the recovery of transmission costs between Federal and non-Federal users, and to satisfy BPA's other ratemaking obligations, including those contained in the Energy Policy Act of 1992. The hearing officer has assured that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate the proposed rates in a section 7(i) proceeding pursuant to the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rate increases and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's 1996 final rate proposal. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this Record of Decision.

Based upon the record compiled in this proceeding, including my decisions to further cut costs, the decisions expressed herein, and all requirements of law, I hereby adopt the attached Wholesale Power and Transmission Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R. section 300.10(g), the Administrator hereby certifies that the Wholesale Power and Transmission Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this _14__ day of June, 1996.

/s/ Randy Hardy______________
Administrator

ATTACHMENT 1

TRANSMISSION RATES AND TERMS AND CONDITIONS

SETTLEMENT AGREEMENT

TRANSMISSION RATES AND TERMS AND CONDITIONS SETTLEMENT AGREEMENT

WHEREAS, Bonneville is obligated to have rates in place that recover costs, assure repayment over a reasonable number of years in each of the transmission and generation functions, equitably allocate transmission costs between Federal and non-Federal uses of the transmission system, and otherwise comport with requirements of law; and

WHEREAS, starting in July of 1995, the parties have been engaged in formal hearings to establish transmission terms and conditions, and wholesale power and transmission rates; and

WHEREAS, the parties are of the opinion that, among other things, it would be conducive to a good business relationship and therefore consonant with sound business principles to settle the matters covered by this settlement agreement;

NOW, THEREFORE, the undersigned and parties who otherwise indicate assent to this agreement on the record of Bonneville's 1996 Wholesale Power and Transmission Rate (WP/TR-96) and Terms and Conditions (TC-96) Proceedings (hereinafter collectively referred to as parties) hereby mutually agree as follows:

Proposal: This Transmission Rates and Terms and Conditions Settlement Agreement (Transmission Settlement Agreement) represents an agreed-upon proposal for Bonneville's 1996 Transmission Rate and Terms and Conditions Proceedings in Dockets TR-96 and TC-96, herineafter collectively referred to as the Dockets. The Administrator’s final decision in the Dockets must be supported by and made based on the records of the Dockets. Neither the fact of this Transmission Settlement Agreement or the Power and Transmission Partial Settlement Agreement (Power Settlement Agreement) (the Transmission Settlement Agreement and the Power Settlement Agreement hereinafter collectively referred to as the Settlement Agreements) being concurrently entered into the record of the Dockets, nor any provision of the Settlement Agreements, nor the fact of the Administrator's eventual adoption of the proposals contained in the Settlement Agreements in any way evidences a closed mind by the Administrator or constitutes a prejudgment or predetermination by the Administrator as to any matter at issue in the Dockets, and no party agreeing to this Transmission Settlement Agreement may argue otherwise; provided, however, that this in no way precludes that party from arguing on the basis of any other evidence that the Administrator has a closed mind or has prejudged or predetermined any matter at issue in the Dockets.

No precedent: No action taken or not taken by Bonneville, any party, or the Hearing Officers in accordance with matters covered by this Transmission Settlement Agreement shall serve to create any procedural or substantive precedent in any subsequent administrative, arbitral, or judicial forum reviewing such rates or terms and conditions, establishing future rates, charges or transmission terms and conditions, or addressing contractual issues between or among any of the litigants herein; nor shall any party to this Transmission Settlement Agreement argue otherwise. The parties to this Transmission Settlement Agreement acknowledge that certain parties have opposing positions on certain issues, including without limitation, whether non-Federal power may be transferred under Bonneville's General Transfer Agreements (GTAs) and the separation of Bonneville's generation and transmission functions. Nothing provided in this Transmission Settlement Agreement shall affect in any way the determination of contract rights under the GTAs, or any other contracts, or affect or limit the position any litigant may take on the GTAs, or any other contracts, or any issue in any proceeding outside the Dockets (except that no party to this Transmission Settlement Agreement shall argue that rates, terms and conditions that conform to this Transmission Settlement Agreement fail to conform to FERC's Stage One Open Access Tariffs).

Cost recovery and subsequent revision of rates: The parties intend that the Administrator's transmission rates, if established in accordance with the Transmission Settlement Agreement and approved by FERC, remain in effect through September 30, 2001, for the level of firm wheeling that a party contractually commits or has committed to Bonneville through September 30, 2001. However, for the level of firm wheeling so committed contractually, and notwithstanding this or any other provision in this Transmission Settlement Agreement, then to the extent the Administrator suffers or expects to suffer costs or revenue losses that arise from loss of sales of firm power to Pacific Northwest customers, nothing in this Transmission Settlement Agreement is intended to in any way alter the Administrator's authority and responsibility, if any, to periodically review and revise, whether during or following the five-year rate period (October 1, 1996 through September 30, 2001), the Administrator's power and transmission rates so that they meet statutory requirements, including but not limited to any requirement that the Administrator's rates recover costs. For firm wheeling levels not so contractually committed, and notwithstanding any other provision in this Transmission Settlement Agreement, nothing in this Transmission Settlement Agreement is intended to alter in any way any authority and responsibility of the Administrator to periodically review and revise, whether during or following the five-year rate period (October 1, 1996 through September 30, 2001), the Administrator's power and transmission rates so that they meet statutory requirements, including but not limited to any requirement that the Administrator's rates recover costs.

Right to Contest: In the Dockets and in subsequent FERC and judicial review of the transmission rates or terms and conditions as adopted in the Dockets, and in any related proceeding challenging such rates, terms or conditions as not conforming with FERC Stage I open access tariffs, parties will not contest that the transmission rates or terms and conditions comply with all regulatory and statutory requirements applicable to such rates and Stage One Open Access Tariffs. In the event the Administrator establishes rates and terms and conditions consistent with this Transmission Settlement Agreement, but FERC or judicial review or any related proceeding necessitates change to the rates or terms and conditions covered by this Transmission Settlement Agreement, such change may be contested by any party and such change or contest shall not be considered a violation of this Transmission Settlement Agreement. If the Administrator does not adopt rates, terms and conditions consistent with this Transmission Settlement Agreement, then this Transmission Settlement Agreement will not be binding on the parties; provided, however, that the parties shall be deemed to have raised in brief all issues covered by this Transmission Settlement Agreement.

Transmission terms and conditions: In the Dockets, the Administrator should establish the transmission terms and conditions proposed by Bonneville in its Supplemental Proposal (as modified by the attached list of changes (Attachment A), and the modifications described in this Transmission Settlement Agreement) as Bonneville's FERC Stage One open access tariffs.

Transmission rates: In the Dockets, the Administrator should establish transmission rates (IR, FPT, PTP, NT, NTP) and related transmission rate schedules for the network segment generally as proposed by Bonneville in its Supplemental Proposal, including errata and subsequent record revisions thereto, subsequent testimony, and the modifications specified in this Transmission Settlement Agreement, with the increases in the rates determined as follows:

Increases in 1996 FPT rates will be constrained such that the overall increase in total revenues for all FPT service will not exceed by more than 13.5% the revenues for the same services under current 1995 rates, such comparison to be based on the forecasted five-year rate period billing determinants.

The 1996 IR rate (IR-96) will not exceed $1.001 per kW per month.

The firm transmission rates for the PTP Network service, the NT Network Base service, and the NTP Network Base service will be equal to the IR-96 rate.

Except as otherwise specified in this Transmission Settlement Agreement, the Administrator should establish all other transmission rates in the Dockets in the manner proposed by Bonneville in its Supplemental Proposal, including errata, subsequent record revisions, and its subsequent testimony.

Delivery facilities:

(A) Purchase and Sale Policy: Bonneville will adopt, by October 1, 1996, a policy which gives customer(s) the right, upon such customer(s)' request(s), to purchase or lease, and obliges Bonneville to sell or lease to such requesting customer(s), substations (or such portion thereof that can be reasonably segregated), exclusive of any high-side protection equipment necessary to protect the Bonneville network, which are assigned to the delivery segment and are used exclusively to deliver power to the purchasing or leasing customer(s). Bonneville and such customer or customers shall negotiate in good faith to agree upon a price, terms and conditions which reflect the reasonable cost or value of such substations. Should Bonneville and such customer or customers be unable to agree on the price, terms or conditions for such purchase or lease, such customer(s) may take any such unresolved issues to binding dispute resolution, and the arbitrator shall establish the purchase or lease price, terms and conditions, and may consider including, without limitation, fair market value, depreciated book value, remaining investment costs, environmental clean-up costs, reliability considerations as they pertain to segregation of facilities, net present value of the revenue stream had such substation not been sold or leased, or such other methodology as a party believes should form the basis for such sale or lease. In the event of arbitration, Bonneville shall sell or lease and the customer shall purchase or lease the facilities in accordance with the arbitrator's award; provided, however, that the arbitrator's decision shall be subject to judicial review for fraud, misconduct, and/or misrepresentation; provided further, however, in the event of such arbitration and assuming that Bonneville will be responsible for performing the environmental clean-up of any such substation, (i) Bonneville shall have no obligation to sell or lease such substation to the requesting customer(s) if the price established by the arbitrator is less than the depreciated book or remaining investment cost of such substation plus the costs of performing such environmental clean-up, as determined by the Arbitrator, and (ii) the requesting customer(s) shall have no obligation to purchase or lease such substation from Bonneville if the price established by the arbitrator exceeds the replacement cost of the substation adjusted for its remaining economic life, as determined by the Arbitrator. Nothing in this Transmission Settlement Agreement requires Bonneville to continue the aforementioned policy beyond September 30, 2001.

(B) Delivery Charge: In the Dockets, the Administrator should establish for service over Utility Delivery facilities, a fixed demand charge of $.75 per kilowatt per month ($9.00 per kW-yr) applied to the customer's demand on such facilities at the time of Bonneville's Monthly Transmission Peak Load. In the Dockets, for Computed Requirements Customers purchasing under the 1981 Power Sales Contract, the Billing Factor for Utility Delivery facilities should be power delivered over such facilities on the hour of the customer's monthly system peak.

(C) Facility cost allocation: In the Dockets, the Administrator should allocate to the Network segment the costs of 34.5 kV utility delivery facilities that otherwise would have been allocated to the utility delivery segment. In the Dockets, customers served by Bonneville with 34.5 kV facilities should not be subject to a utility delivery segment charge based on such facilities.

General Transfer Agreements (GTA) cost: In the Dockets, the Administrator should allocate the costs of GTAs entirely to power rates and delivery segments.

Eligible Customer under Section 1.8 of the NT tariff: In the Dockets, the Administrator shouldchange "Bonneville" to "Bonneville for delivery of power under Service and Exchange agreements existing as of March 25, 1996 and for Bonneville's power sales, either of which is to 1) a direct-service industrial customer or 2) a Bonneville power customer whose total retail load is equal to or less than 50 aMW during calendar year 1995."

"No points of integration" proposal: In the Dockets, the Administrator should substitute the following language for Section III.A.1.a.(1) of the PTP-96 rate schedule:

"(1) Billing Demand
The Billing Demand for each charge specified in section II.A.1. shall be the greater of:
(a) the sum of the relevant Transmission Demands at the Point(s) of Interconnection for (i) generating units that are not located within Bonneville's Control Area and (ii) generating units that are located within Bonneville's Control Area but are not subject to redispatch by Bonneville, or
(b) the sum of the relevant Transmission Demands at the Point(s) of Delivery."

Redispatch: The redispatch provisions of Bonneville's Point to Point Transmission Service Tariff and Network Integration Transmission Service Tariff should be conformed by the Administrator in the Dockets to the redispatch provisions of FERC's Stage I Point to Point Transmission Service Tariff and Network Integration Service Tariff, respectively.

Northern Intertie: In establishing rates in the Dockets, the Administrator should (a) treat Bonneville's Northern Intertie facilities as part of Bonneville's Network segment; (b) terminate Bonneville's IN rate schedule; (c) allocate Bonneville's costs of the Northern Intertie facilities to Network revenue requirements; and (d) allocate Bonneville's costs of the Bellingham Reinforcement Project to Network revenue requirements. Thereafter, for the five-year rate period (October 1, 1996 through September 30, 2001), the Administrator shall (a) render transmission service over the Northern Intertie facilities pursuant to all applicable Network rate schedules (including, but not limited to, where applicable, the Short Distance Discount for firm service and downwardly flexible nonfirm service), and (b) with respect to Bonneville's NT and PTP tariffs: (i) make such tariffs fully available on the Northern Intertie facilities and (ii) make the points of interconnection between the Federal Columbia River Transmission System and the British Columbia Hydro and Power Authority system on the United States-Canada border near Blaine, Washington and Nelway, British Columbia eligible as points of integration and points of delivery for the Network, subject to all terms and conditions of such tariffs.

System Operations Agreement: The parties agree that nothing in this Transmission Settlement Agreement prohibits any party from taking any position with respect to a Bonneville proposal, if any, of a System Operations Agreement.

PTP Rate Schedule: Substitute for Section III.A.1.b.(1) of the PTP-96 rate schedule:

"b. For a DSI That Has Not Executed a PTP Service Agreement

(1) For a DSI that executes a 1996 Contract that refers to point-to-point transmission charges and that has not executed a PTP Service Agreement to wheel the Federal power purchased under the 1996 Contract, the Billing Demand for the Network charge in section II.A.1.a. shall be the greater of:

(a) the highest monthly Demand specified pursuant to section 10(a) of the 1996 Contract for the contract year; or

(b) the highest transmission Billing Demand for any prior contract year beginning on or after October 1, 1996 (or after the effective date of any reduced Billing Demand pursuant to section III.A.1.b.(3), if applicable)."

NTP Rate Schedule: For Computed Requirements Customers purchasing power under the 1981 Power Sales Contract, the Administrator should adopt the following in the Dockets:

(a) The monthly Billing Demand for the Base Charge specified in Section III.A.1.a. shall be the Measured Demand for Power Delivered under the 1981 Contract on the hour of the Customer's monthly system peak.

(b) The monthly Billing Demand for the Reserved Capacity Charge for Computed Requirements Customers shall be the customer's Computed Maximum Requirement less the Measured Demand for power delivered under the 1981 Contract on the hour of the customer's monthly system peak.

NT Rate Schedule: In the Dockets, the Administrator should replace 80% with 60% in Section III.A.1.b.(1) and (2) of Bonneville's NT-96 rate Schedule.

No Amendment to Contracts: Nothing in this Transmission Settlement Agreement amends any contract or limits the remedies available thereunder.

Attachment A

The following changes will be made to Bonneville's Supplemental Transmission Terms and Conditions Proposal described in documents TC-96-E-BPA-06, -07 and -08 (including errata thereto).

1. Reservation and Scheduling:

The reservation and scheduling information contained in the two documents (TC-96-E-PL-06 and -07) discussed at pages 40-44 of the February 20, 1996, hearing transcript and entered into the record at page 141 of such transcript shall be incorporated.

2. Term of Firm PTP Service:

Add to section 2.1 of the PTP Tariff after "service Agreement" (page 9, line 22) the following: "consistent with FERC principles generally applicable to point-to-point transmission service tariffs."

3. Third Party Facilities:

Add to section 4.1 of the PTP Tariff after "Transmission System" (page 19, line 18) the following: "(excepting capacity which is contracted for or leased and over which the owner is unwilling and is not required to allow such transmission services)."

4. Conversion to PTP:

A customer who converts from IR to FPT service to PTP service must, unless otherwise agreed, maintain the level of its Contract Demands existing on the date of conversion to the earlier of (i) when it would have had a right to reduce such demands under its IR or FPT contract or (ii) October 1, 2001.

5. Curtailment of Short-term Nonfirm PTP Service:

Curtailments of Nonfirm PTP Service shall begin with Hourly Nonfirm Service and, if necessary, proceed thereafter to Daily, then Weekly and finally Monthly Nonfirm Service.

6. Redispatch Costs:

Redispatch costs shall be determined in accordance with FERC guidelines.

7. Eligible Customer

As indicated in TC-96-E-BPA-14, page 6, remove from the Network Integration and Point-to-Point Tariff definitions of Eligible Customer the words "on the effective date of this Tariff."

ATTACHMENT 2

POWER AND TRANSMISSION

PARTIAL SETTLEMENT AGREEMENT

POWER AND TRANSMISSION
PARTIAL SETTLEMENT AGREEMENT

WHEREAS, Bonneville is obligated to have rates in place that recover costs, assure repayment over a reasonable number of years in each of the transmission and generation functions, equitably allocate transmission costs between Federal and non-Federal uses of the transmission system, and otherwise comport with requirements of law; and

WHEREAS, starting in July of 1995, the parties have been engaged in formal hearings to establish transmission terms and conditions, and wholesale power and transmission rates; and

WHEREAS, the parties are of the opinion that, among other things, it would be conducive to a good business relationship and therefore consonant with sound business principles to settle the matters covered by this settlement agreement;

NOW, THEREFORE, the undersigned and parties who otherwise indicate assent to this agreement on the record of Bonneville's 1996 Wholesale Power and Transmission Rate (WP/TR-96) and Terms and Conditions (TC-96) Proceedings (hereinafter collectively referred to as parties) hereby mutually agree as follows:

Proposal: This Power and Transmission Partial Settlement Agreement (Power Settlement Agreement) represents an agreed-upon proposal for Bonneville's 1996 Transmission Rate and Terms and Conditions Proceedings in Dockets TR-96 and TC-96, and an agreed-upon partial proposal for Bonneville's 1996 Wholesale Power Rates Proceedings in Docket WP-96, hereinafter collectively referred to as the Dockets. The Administrator's final decision in the Dockets must be supported by and made based on the records of the Dockets. Neither the fact of this Power Settlement Agreement, nor the Transmission Rate and Terms and Conditions Settlement Agreement (Transmission Settlement Agreement) (the Power Settlement Agreement and Transmission Settlement Agreement hereinafter collectively referred to as the Settlement Agreements) being concurrently entered into the record of the Dockets, nor any provision of them, nor the fact of the Administrator's eventual adoption of the proposals contained in the Settlement Agreements in any way evidences a closed mind by the Administrator or constitutes a prejudgement or predetermination by the Administrator as to any matter at issue in the Dockets, and no party agreeing to this Power Settlement Agreement may argue otherwise; provided, however, that this in no way precludes that party from arguing on the basis of any other evidence that the Administrator has a closed mind or has prejudged or predetermined any matter at issue in the Dockets.

No precedent: No action taken or not taken by Bonneville, any party, or the Hearing Officers in accordance with matters covered by this Power Settlement Agreement shall serve to create any procedural or substantive precedent in any subsequent administrative, arbitral, or judicial forum reviewing such rates or terms and conditions, establishing future rates, charges or transmission terms and conditions, or addressing contractual issues between or among any of the litigants herein; nor shall any party to this Power Settlement Agreement argue otherwise. The parties to this Power Settlement Agreement acknowledge that certain parties have opposing positions on certain issues, including without limitation, whether non-Federal power may be transferred under Bonneville's General Transfer Agreements (GTAs) and the separation of Bonneville's generation and transmission functions. Nothing provided in this Power Settlement Agreement shall affect in any way the determination of contract rights under the General Transfer Agreements, or any other contracts, or affect or limit the position any litigant may take on the GTAs, or any other contracts, or in any proceeding outside the Dockets (except that no party to this Power Settlement Agreement shall argue that rates, terms and conditions that conform to the Transmission Settlement Agreement fail to conform to FERC's Stage One Open Access Tariffs).

Subsequent revision of rates: Notwithstanding any other provision in this Power Settlement Agreement, nothing in this Power Settlement Agreement is intended to alter in any way any authority and responsibility of the Administrator to periodically review and revise, whether during or following the five-year rate period (October 1,1996 through September 30, 2001), the Administrator's power and transmission rates so that they meet statutory requirements, including but not limited to any requirement that the Administrator's rates recover costs.

Right to Contest: In the Dockets and subsequent FERC and judicial review, parties will not contest that the rates and terms and conditions adopted in the Dockets comply with all contractual, regulatory and statutory requirements applicable thereto,*with the exceptions* that the parties hereto preserve anyrights they may have to raise in the appropriate forum any issue--contractual, statutory, regulatory, factual, or otherwise--concerning (a) compliance with and implementation of sections 4(h)(8), 4(h)(10), 7(b), 7(c), and 7(d) of the Northwest Power Act, (b) power rate design not specifically covered by this Power Settlement Agreement, or (c) BPA’s Average System Cost (BASC) (hereafter all collectively referred to as the Contested Issues). In the event the Administrator establishes rates and terms and conditions consistent with this Power Settlement Agreement, but FERC or judicial review of the rates or the Contested Issues or any related proceeding necessitates change in the rates covered by the Power Settlement Agreement, such change or contest may be contested by any party and such change or contest shall not be considered a violation of this Power Settlement Agreement. If the Administrator does not adopt rates, terms and conditions consistent with this Power Settlement Agreement, then this Power Settlement Agreement will not be binding on the parties; provided, however, that the parties shall be deemed to have raised in brief all issues covered by this Power Settlement Agreement.

Priority Firm Power rate: The Administrator should establish and submit to FERC a PF-96 Priority Firm Power rate for power delivered to preference customers equal to or less than 24.4 mills per kWh as shown on line 21 of Table RDS 50 of the 1996 Final Documentation to the Wholesale Power Rate Development Study.

Delivery Charge Underrecovery: In establishing the PF-96 Priority Firm Rate set forth above, the Administrator should assume that one-half of any projected underrecovery of the Utility Delivery facilities' costs due to the limit on the Delivery Charge will be absorbed by Bonneville through cost reductions.

Transmission Settlement Agreement: Parties to this Power Settlement Agreement adopt and agree to the Transmission Settlement Agreement.

Availability Charge: Bonneville shall reformat the Priority Firm Power and New Resources rate schedules to show an "Availability Charge" as a fixed component of the energy charge. The Administrator should establish an Availability Charge in these rate schedules, which applies to computed requirements customers under the 1981 Power Sales Contracts, of 7 mills per kWh for the months September through December, and 8 mills per kWh for the months January through March. The level of the Availability Charge in all other months will be established following one of the two methods (use of '95 water or an average of 50 water years) described in Bonneville's Supplemental Proposal, including any errata and subsequent record revisions thereto.

Computed Maximum Requirement Waiver: The Administrator should include the following language in the definition of Computed Maximum Requirement included in the General Rate Schedule Provisions,

> Purchaser may waive its right to schedule a portion of its Computed Maximum Requirement, as specified in an agreement between BPA and the Purchaser.

The Administrator should eliminate any reference to dates for such waivers in the rate schedules or General Rate Schedule Provisions.

Partial Load Shaping for Computed Requirements Customers: The Administrator should adopt rate schedules which make Partial Load Shaping available to Computed Requirements Customers who choose to purchase power under a 1981 Power Sales Contract as a Planned Computed Requirements Customer.

No Amendment to Contracts: Nothing in this Power Settlement Agreement amends any contract or limits the remedies available thereunder.

1996

WHOLESALE

POWER AND TRANSMISSION

RATES

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

June 1996

WP-96-A-02
Appendix

1996 WHOLESALE POWER AND TRANSMISSION RATES

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COMMONLY USED ACRONYMS

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

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

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

BPA'S 1996

POWER RATE SCHEDULES

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SCHEDULE PF-96
PRIORITY FIRM POWER

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; and for construction, test and startup, and station service. 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 (RPSA). Rates in this schedule are available for purchases under requirements sales contracts under which power deliveries began before October 1, 1996 (hereinafter termed the 1981 Contract, although some are actually dated 1984 or later), and under contracts under which power deliveries may begin on or after October 1, 1996 (1996 Contract), for up to a 5-year period.

This rate schedule supersedes the PF-95 rate schedule, which went into effect October 1, 1995. Sales under the PF-96 rate schedule are subject to BPA's General Rate Schedule Provisions (GRSPs). Products available under this rate schedule are defined in the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS FOR EACH PF PRODUCT

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified below. Applicable adjustments and special rate provisions are listed for each customer designation. PF customers shall be charged for transmission service under separate transmission rate schedules (NTP, NT, or PTP). 1981 Contract customers shall be charged for transmission service under the NTP rate schedule. A PF customer who amends its 1981 Contract and executes a Network Integration (NT) or Point-to-Point (PTP) Service Agreement shall be charged for transmission service for PF power under the NT rate schedule or PTP rate schedule, respectively. 1996 Contract customers shall be charged for transmission service under the NT or PTP rate schedule depending on which transmission service they have. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges and shall not be based on rates under the Flexible PF rate option.

This rate schedule contains six subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A. Metered Requirements customers who purchase under 1981 Contracts.

Section II.B. Full Requirements customers who purchase under 1996 Contracts.

Section II.C. Customers who elect to purchase on a composite rate basis.

Section II.D. Computed Requirements customers who purchase under 1981 Contracts.

Section II.E. Partial Requirements customers who purchase under 1996 Contracts.

Section II.F. Customers who purchase under Residential Purchase and Sale Agreements (RPSA).

A. METERED REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1981 CONTRACTS

Metered Requirements customers purchasing power under a 1981 Contract receive Full Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Metered Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. PRIORITY FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year,
multiplied by
the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh times the Utility Factor, *multiplied by*
the Purchaser's total HLH and LLH Measured Energy, which includes Measured Energy under the PF rate schedule and Measured Energy, if any, for New Large Single Loads under the NR rate schedule.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, times the Adjusted Utility Factor, *multiplied by*
the *difference* between (1a) and (1b):
- (1a) the Purchaser's total HLH and LLH Measured Energy, which includes Measured Energy under the PF rate schedule and Measured Energy, if any, for New Large Single Loads under the NR rate schedule;
- (1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by*
the *sum* of (2a) and (2b):
- (2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and
- (2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate times the Utility Factor, *multiplied by*
the Purchaser's total HLH and LLH Measured Energy, which includes Measured Energy under the PF rate schedule and Measured Energy, if any, for New Large Single Loads under the NR rate schedule.

4. FLEXIBLE PF RATE OPTION

The Flexible PF rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

4.1. Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1, 2, and 3 above been applied to the same sales.

4.2. Cash flow test: Forecasted revenues from all Purchasers under the Flexible PF rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1, 2, and 3 above for the same products.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1, 2, and 3, above, unless such power would be charged as an unauthorized increase.

5. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

6. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

6.1. Rate Adjustments

Rate Adjustment	*Section*
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Low Density Discount	II.K.
Phase-In Mitigation	II.N.
Transitional Service	II.Q.

6.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.
Utility Factor	II.S.

B. FULL REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Full Requirements customers purchasing power under a 1996 Contract receive Full Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Full Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. PRIORITY FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year,
multiplied by
the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh, *multiplied by* the Purchaser's Total Retail Load.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, *multiplied by* the *difference* between (1a) and (1b):
- (1a) the Purchaser's Total Retail Load;
- (1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by* the *sum* of (2a) and (2b):
- (2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and
- (2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Retail Load.

4. FLEXIBLE PF RATE OPTION

The Flexible PF rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

4.1. <u>Equivalent Net Present Value Revenues</u>: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1, 2, and 3 above been applied to the same sales.

4.2. Cash flow test: Forecasted revenues from all Purchasers under the Flexible PF rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1, 2, and 3 above for the same products.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1, 2, and 3 above, unless such power would be charged as an unauthorized increase.

5. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the applicable rate schedule (NT or PTP).

6. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

6.1. Rate Adjustments

Rate Adjustment	*Section*
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Deviation Adjustment	II.G.
Low Density Discount	II.K.
Phase-In Mitigation	II.N.

6.2. Special Rate Provisions

Special Rate Provisions	*Section*
Cost Contributions	II.D.

C. CUSTOMERS WHO ELECT TO PURCHASE POWER ON A COMPOSITE RATE BASIS

Only customers whose average annual retail loads during each year of the 1996-2001 rate period, as forecasted by BPA, are 25 average annual MW or less are eligible to purchase at this rate. Such customers also must agree to buy all their power from BPA during the entire rate period. The composite rate charge includes the PF-96 charges for Demand, Energy, Load Shaping, and Load Regulation. These customers are charged for transmission service under the applicable transmission rate schedule.

1. COMPOSITE CHARGE

The composite charge shall be 23.42 mills/kWh in all months of the year, *multiplied by* the Purchaser's monthly Measured Energy.

2. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

3. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

3.1. Rate Adjustments

Rate Adjustment	***Section***
Conservation Surcharge	II.C.
Low Density Discount	II.K.
Phase-In Mitigation	II.N.
Transitional Service	II.Q.

3.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

D. COMPUTED REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1981 CONTRACTS

Actual Computed Requirements customers purchasing power under a 1981 Contract receive Full Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Planned Computed Requirements customers do not receive Full Load Shaping but have the option of purchasing Partial Load Shaping. Contracted Computed Requirements customers do not receive Load Shaping. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Computed Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. PRIORITY FIRM POWER

1.1. Demand Charge

1.1.1. For purchasers who have not waived part of their Computed Maximum Requirement

The total monthly charge for demand shall be the sum of (1) and (2):

(1) The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the Purchaser's PODs.

(2) The charge for reserving power demand shall be $0.67/kW/mo. in all months of the year, *multiplied by*
the Purchaser's Computed Maximum Requirement minus the Purchaser's highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the Purchaser's PODs.

1.1.2. For purchasers who have waived part of their Computed Maximum Requirement

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's Computed Maximum Requirement minus the declared megawatt amount waived.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1), (2), and (3):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy;

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy; and

(3) the applicable Availability Charge rate for that month, *multiplied by* the Purchaser's Computed Energy Maximum minus the Purchaser's Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***	***Availability Charge***
September - December	22.43 mills/kWh	20.99 mills/kWh	7.00 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh	8.00 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh	8.00 mills/kWh
May - June	11.01mills/kWh	9.59 mills/kWh	4.99 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh	4.60 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh	7.00 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh times the Utility Factor, *multiplied by*
the Purchaser's Computed Energy Maximum.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, times the Adjusted Utility Factor, *multiplied by*
the *difference* between (1a) and (1b):
- (1a) the Purchaser's Computed Energy Maximum;
- (1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by*
the *sum* of (2a) and (2b):

(2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and

(2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. PARTIAL LOAD SHAPING

The Partial Load Shaping charge shall be $2.27/MWh-hr. *multiplied by*
the Purchaser's Partial Load Shaping Purchase Amount for the month.

4. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate times the Utility Factor,
multiplied by
the Purchaser's total HLH and LLH Measured Energy, which includes Measured Energy under the PF rate schedule and Measured Energy, if any, for New Large Single Loads under the NR rate schedule.

5. FLEXIBLE PF RATE OPTION

The Flexible PF rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

5.1. <u>Equivalent Net Present Value Revenues</u>: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1-4 above been applied to the same sales.

5.2. <u>Cash flow test</u>: Forecasted revenues from all Purchasers under the Flexible PF rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1-4 above for the same products.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit shall be billed at the

Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1-4 above, unless such power would be charged as an unauthorized increase.

6. FIRM CAPACITY WITHOUT ENERGY

The monthly charge for Firm Capacity Without Energy shall be the applicable rate for that month, *multiplied by*
the Purchaser's Computed Peak Requirement associated with the purchase of Firm Capacity Without Energy.

Applicable Months	***Rate***
September - December	$1.18/kW-mo.
January - March	$1.18/kW-mo.
April	$1.07/kW-mo.
May - June	$1.18/kW-mo.
July	$1.25/kW-mo.
August	$1.42/kW-mo.

7. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

8. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

8.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Energy Return Surcharge	II.H.
Low Density Discount	II.K.
Transitional Service	II.Q.
Unauthorized Increase Charge	II.R.

8.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.
Utility Factor	II.S.

E. PARTIAL REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Partial Requirements customers purchasing power under a 1996 Contract who are either required to purchase Full Load Shaping or have the option to purchase Full or Partial Load Shaping (as determined by the Purchaser's contract) will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible PF rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Partial Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. PRIORITY FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the *greater* of (1) the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load *or* (2) the Purchaser's Monthly Contract Obligation.

1.2. Energy Charge

1.2.1. For customers without a contractual right to displace their PF purchases

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by*
the *greater* of Purchaser's HLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum HLH Contract Obligation, and

(2) the applicable LLH rate for that month, *multiplied by*
the *greater* of Purchaser's LLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum LLH Contract Obligation.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

1.2.2. For customers with a contractual right to displace their PF purchases

The total monthly charge for energy shall be the sum of (1), (2), and (3):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Adjusted Measured Energy;

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Adjusted Measured Energy; and

(3) unless otherwise agreed to by BPA and the Purchaser, the applicable Availability Charge rate for that month, *multiplied by* the sum of the Purchaser's Monthly Minimum HLH and LLH Contract Obligations minus the Purchaser's Adjusted Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***	***Availability Charge***
September - December	22.43 mills/kWh	20.99 mills/kWh	7.00 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh	8.00 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh	8.00 mills/kWh
May - June	11.01mills/kWh	9.59 mills/kWh	4.99 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh	4.60 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh	7.00 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh, *multiplied by* the Purchaser's Total Retail Load.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, *multiplied by* the *difference* between (1a) and (1b):

(1a) the Purchaser's Total Retail Load;

(1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by* the *sum* of (2a) and (2b):

(2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and

(2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. PARTIAL LOAD SHAPING

The Partial Load Shaping charge shall be $2.27/MWh-hr. *multiplied by* the Purchaser's Partial Load Shaping Purchase Amount for the month.

4. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Retail Load.

5. FLEXIBLE PF RATE OPTION

The Flexible PF rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

5.1. <u>Equivalent Net Present Value Revenues</u>: Forecasted revenues from a Purchaser under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1-4 above been applied to the same sales.

5.2. <u>Cash flow test</u>: Forecasted revenues from all Purchasers under the Flexible PF rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1-4 above for the same products.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1-4 above, unless such power would be charged as an unauthorized increase.

6. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the applicable rate schedule (NT or PTP).

7. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

7.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Deviation Adjustment	II.G.
Low Density Discount	II.K.

7.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

F. CUSTOMERS WHO PURCHASE UNDER RESIDENTIAL PURCHASE AND SALE AGREEMENTS (RPSA)

The PF Exchange rate includes Load Shaping and Load Regulation. These customers are charged for transmission service under the NTP rate schedule.

1. PRIORITY FIRM POWER

1.1 Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's Billing Demand, which is calculated by applying the load factor, determined as specified in the RPSA, to the Billing Energy for each billing period.

1.2. Energy Charge

The monthly charge for energy shall be the applicable rate for that month, *multiplied by* the Purchaser's Billing Energy, which is 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 RPSA.

Applicable Months	***Rate***
September - December	32.33 mills/kWh
January - March	32.83 mills/kWh
April	29.37 mills/kWh
May - June	15.39 mills/kWh
July	18.91 mills/kWh
August	26.92 mills/kWh

2. TRANSMISSION

Transmission services for delivery of PF power shall be billed under the NTP rate schedule.

3. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

Rate Adjustment	***Section***
Conservation Surcharge	II.C.
Low Density Discount	II.K.

SCHEDULE NR-96
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; for direct consumption; and for construction, test and startup, 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 (NLSL), as defined by the Northwest Power Act.

Rates in this schedule are available for purchases under requirements sales contracts under which power deliveries began before October 1, 1996 (hereinafter termed the 1981 Contract, although some are actually dated 1984 or later), and under contracts under which power deliveries begin on or after October 1, 1996 (1996 Contract), for up to a 5-year period. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

This rate schedule supersedes the NR-95 rate schedule, which went into effect October 1, 1995. Sales under this schedule are subject to BPA's General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS FOR EACH NR PRODUCT

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified below. Applicable adjustments and special rate provisions are listed for each customer designation. NR customers shall be charged for transmission service under separate transmission rate schedules (NTP, NT, or PTP). 1981 Contract customers shall be charged for transmission service under the NTP rate schedule. An NR customer who amends its 1981 Contract and executes a Network Integration (NT) or Point-to-Point (PTP) Service Agreement shall be charged for transmission service for NR power under the NT rate schedule or PTP rate schedule, respectively. 1996 Contract customers shall be charged for transmission service under the NT or PTP rate schedule depending on which transmission service they have. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges and shall not be based on rates under the Flexible NR rate option.

This rate schedule contains four subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A. Customers who serve New Large Single Loads.

Section II.B. Full Requirements customers who purchase under 1996 Contracts.

Section II.C. Computed Requirements customers who purchase under 1981 Contracts.

Section II.D. Partial Requirements customers who purchase under 1996 Contracts.

A. CUSTOMERS WHO SERVE NEW LARGE SINGLE LOADS

Customers purchasing power to serve a New Large Single Load (NLSL) buy New Resource Firm Power as needed for that NLSL. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. These customers are charged for transmission service under the applicable transmission rate schedule.

1. NEW RESOURCE FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year,
multiplied by
the Purchaser's Measured Demand, unless mutually agreed by BPA and the Purchaser, that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy, unless BPA and the Purchaser agree to bill based on a contracted amount of energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy, unless BPA and the Purchaser agree to bill based on a contracted amount of energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

2. LOAD REGULATION

2.1 For purchasers whose requirements service is provided exclusively under the NR rate

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate times the Utility Factor, *multiplied by*
the Purchaser's HLH and LLH Measured Energy, unless BPA and the Purchaser agree to bill based on a contracted amount of energy.

2.2 For purchasers whose requirements service is provided under both the PF rate and the NR rate

There is no separate charge for Load Regulation under the NR rate schedule.

3. FLEXIBLE NR RATE OPTION

The Flexible NR rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

3.1. <u>Equivalent Net Present Value Revenues</u>: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1 and 2 above been applied to the same sales.

3.2. <u>Cash flow test</u>: Forecasted revenues from all Purchasers under the Flexible NR rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1 and 2 above for the same products.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Regulation if appropriate) charges specified in sections 1 and 2 above, unless such power would be charged as an unauthorized increase.

4. TRANSMISSION

Transmission services for delivery of NR power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

5. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

5.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Low Density Discount	II.K.
Phase-In Mitigation	II.N.
Transitional Service	II.Q.

5.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

B. NR RATES FOR FULL REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Full Requirements customers purchasing power under a 1996 Contract receive Full Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Full Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. NEW RESOURCE FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh, *multiplied by* the Purchaser's Total Retail Load.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, *multiplied by* the *difference* between (1a) and (1b):
- (1a) Purchaser's Total Retail Load;
- (1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by* the *sum* of (2a) and (2b):
- (2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and
- (2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. LOAD REGULATION

3.1 For purchasers whose requirements service is provided exclusively under the NR rate

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Retail Load.

3.2 For purchasers whose requirements service is provided under both the PF rate and the NR rate

There is no separate charge for Load Regulation under the NR rate schedule.

4. FLEXIBLE NR RATE OPTION

The Flexible NR rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

4.1. Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1, 2, and 3 above been applied to the same sales.

4.2. Cash flow test: Forecasted revenues from all Purchasers under the Flexible NR rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1, 2, and 3 above for the same products.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1, 2, and 3 above, unless such power would be charged as an unauthorized increase.

5. TRANSMISSION

Transmission services for delivery of NR power shall be billed under the applicable rate schedule (NT or PTP).

6. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

6.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Deviation Adjustment	II.G.
Low Density Discount	II.K.
Phase-In Mitigation	II.N.

6.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

C. COMPUTED REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1981 CONTRACTS

Actual Computed Requirements customers purchasing power under a 1981 Contract receive Full Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Planned Computed Requirements customers do not receive Full Load Shaping but have the option of purchasing Partial Load Shaping. Contracted Computed Requirements customers do not receive Load Shaping. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Computed Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. NEW RESOURCE FIRM POWER

1.1. Demand Charge

1.1.1. For purchasers who have not waived part of their Computed Maximum Requirement

The total monthly charge for demand shall be the sum of (1) and (2):

(1) The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the Purchaser's PODs.

(2) The charge for reserving power demand shall be $0.67/kW/mo. in all months of the year, *multiplied by*
the Purchaser's Computed Maximum Requirement minus the Purchaser's highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the Purchaser's PODs.

1.1.2. For purchasers who have waived part of their Computed Maximum Requirement

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's Computed Maximum Requirement minus the declared megawatt amount waived.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1), (2), and (3):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy;

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy; and

(3) the applicable Availability Charge rate for that month, *multiplied by* the Purchaser's Computed Energy Maximum minus the Purchaser's Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***	***Availability Charge***
September - December	22.43 mills/kWh	20.99 mills/kWh	7.00 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh	8.00 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh	8.00 mills/kWh
May - June	11.01mills/kWh	9.59 mills/kWh	4.99 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh	4.60 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh	7.00 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh times the Utility Factor, *multiplied by*
the Purchaser's Computed Energy Maximum.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, times the Adjusted Utility Factor, *multiplied by*
the *difference* between (1a) and (1b):

(1a) the Purchaser's Computed Energy Maximum;

(1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by* the *sum* of (2a) and (2b):

(2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and

(2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. PARTIAL LOAD SHAPING

The Partial Load Shaping charge shall be $2.27/MWh-hr. *multiplied by*
the Purchaser's Partial Load Shaping Purchase Amount for the month.

4. LOAD REGULATION

4.1 For purchasers whose requirements service is provided exclusively under the NR rate

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate times the Utility Factor, *multiplied by*
the Purchaser's HLH and LLH Measured Energy.

4.2 For purchasers whose requirements service is provided under both the PF rate and the NR rate

There is no separate charge for Load Regulation under the NR rate schedule.

5. FLEXIBLE NR RATE OPTION

The Flexible NR rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

5.1. Equivalent Net Present Value Revenues: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1-4 above been applied to the same sales.

5.2. Cash flow test: Forecasted revenues from all Purchasers under the Flexible NR rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1-4 above for the same products.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1-4 above, unless such power would be charged as an unauthorized increase.

6. FIRM CAPACITY WITHOUT ENERGY

The monthly charge for Firm Capacity Without Energy shall be the applicable rate for that month, *multiplied by*
the Purchaser's Computed Peak Requirement associated with the purchase of Firm Capacity Without Energy.

Applicable Months	*Rate*
September - December	$1.56/kW-mo.
January - March	$1.55/kW-mo.
April	$1.31/kW-mo.
May - June	$1.55/kW-mo.
July	$1.70/kW-mo.
August	$2.09/kW-mo.

7. TRANSMISSION

Transmission services for delivery of NR power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

8. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

8.1. Rate Adjustments

Rate Adjustment	*Section*
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Energy Return Surcharge	II.H.
Low Density Discount	II.K.
Transitional Service	II.Q.
Unauthorized Increase Charge	II.R.

8.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.
Utility Factor	II.S.

D. PARTIAL REQUIREMENTS CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Partial Requirements customers purchasing power under a 1996 Contract who are either required to purchase Full Load Shaping or have the option to purchase Full or Partial Load Shaping (as determined by the Purchaser's contract) will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this section of the rate schedule. Customers purchasing under the Flexible NR rate option purchase the same set of power products and services that they would otherwise purchase under this section of the rate schedule. Partial Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. NEW RESOURCE FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the *greater* of (1) the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load *or* (2) the Purchaser's Monthly Contract Obligation.

1.2. Energy Charge

1.2.1 For customers without a contractual right to displace their NR purchases

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by*
the *greater* of Purchaser's HLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum HLH Contract Obligation, and

(2) the applicable LLH rate for that month, *multiplied by*
the *greater* of Purchaser's LLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum LLH Contract Obligation.

Applicable Months	*HLH Rate*	*LLH Rate*
September - December	22.43 mills/kWh	20.99 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh
May - June	11.01 mills/kWh	9.59 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh

1.2.1 For customers with a contractual right to displace their NR purchases

The total monthly charge for energy shall be the sum of (1), (2), and (3):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Adjusted Measured Energy;

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Adjusted Measured Energy; and

(3) unless otherwise agreed to by BPA and the Purchaser, the applicable Availability Charge rate for that month, *multiplied by* the sum of the Purchaser's Monthly Minimum HLH and LLH Contract Obligations minus the Purchaser's Adjusted Measured Energy.

Applicable Months	*HLH Rate*	*LLH Rate*	*Availability Charge*
September - December	22.43 mills/kWh	20.99 mills/kWh	7.00 mills/kWh
January - March	22.78 mills/kWh	21.36 mills/kWh	8.00 mills/kWh
April	20.22 mills/kWh	19.32 mills/kWh	8.00 mills/kWh
May - June	11.01mills/kWh	9.59 mills/kWh	4.99 mills/kWh
July	13.53 mills/kWh	11.79 mills/kWh	4.60 mills/kWh
August	19.29 mills/kWh	16.75 mills/kWh	7.00 mills/kWh

2. FULL LOAD SHAPING

2.1. For Purchasers without Industrial Exemption loads

The charge for Full Load Shaping shall be 0.32 mills/kWh, *multiplied by* the Purchaser's Total Retail Load.

2.2. For Purchasers with Industrial Exemption loads

The charge for Full Load Shaping shall be the sum of (1) and (2):

(1) The Full Load Shaping rate, 0.32 mills/kWh, *multiplied by* the *difference* between (1a) and (1b):

(1a) Purchaser's Total Retail Load;
(1b) the Purchaser's total HLH and LLH Industrial Exemption Measured Energy.

(2) The Industrial Exemption rate, 1.16 mills/kWh, *multiplied by* the *sum* of (2a) and (2b):
(2a) the absolute value of the difference between the Purchaser's HLH Industrial Exemption Measured Energy and HLH Industrial Exemption energy forecast; and
(2b) the absolute value of the difference between the Purchaser's LLH Industrial Exemption Measured Energy and LLH Industrial Exemption energy forecast.

3. PARTIAL LOAD SHAPING

The Partial Load Shaping charge shall be $2.27/MWh-hr. *multiplied by* the Purchaser's Partial Load Shaping Purchase Amount for the month.

4. LOAD REGULATION

4.1 For purchasers whose requirements service is provided exclusively under the NR rate

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Retail Load.

4.2 For purchasers whose requirements service is provided under both the PF rate and the NR rate

There is no separate charge for Load Regulation under the NR rate schedule.

5. FLEXIBLE NR RATE OPTION

The Flexible NR rate option shall be offered at BPA's discretion to purchasers who make a contractual commitment to purchase under this option. The charges and billing factors under this option shall be specified by BPA at the time the Administrator offers to make power available to a Purchaser under this option. The actual charges and billing factors will be mutually agreed to by BPA and the Purchaser subject to satisfying both of the following conditions:

5.1. <u>Equivalent Net Present Value Revenues</u>: Forecasted revenues from a Purchaser under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenues BPA would have received had the appropriate charges specified in sections 1-4 above been applied to the same sales.

5.2. Cash flow test: Forecasted revenues from all Purchasers under the Flexible NR rate option shall not create an annual cash flow problem for BPA compared to forecasted revenues at the charges specified in sections 1-4 above for the same products.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit shall be billed at the Demand and Energy (and Load Shaping and Load Regulation, if appropriate) charges specified in sections 1-4 above, unless such power would be charged as an unauthorized increase.

6. TRANSMISSION

Transmission services for delivery of NR power shall be billed under the applicable rate schedule (NT or PTP).

7. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

7.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Conservation Surcharge	II.C.
Deviation Adjustment	II.G.
Low Density Discount	II.K.

7.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

SCHEDULE IP-96
INDUSTRIAL FIRM POWER RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their industrial operations. DSIs that purchase power under power sales contracts under which power deliveries began on or before September 30, 1996 (hereinafter termed the 1981 Contracts), and DSIs that purchase power under contracts under which power deliveries begin on or after October 1, 1996 (1996 Contracts), are eligible to purchase under this rate schedule for up to a 5-year period. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

This rate schedule supersedes the IP-95 rate schedule, which went into effect October 1, 1995. Sales under the IP-96 rate schedule are subject to BPA's GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS FOR EACH IP PRODUCT

For each customer designation, the rate(s) for each product along with the associated billing factor(s) are identified in separate sections of the rate schedule. Under the power sales contracts, the DSIs provide operating reserves and stability reserves, the latter provided by the Import Contingency Load Tripping Scheme (ICLTS). The credit for these reserves is reflected in the level of the applicable energy charges specified in this rate schedule. Applicable adjustments and special rate provisions are listed for each customer designation. IP customers shall be charged for transmission service under separate transmission rate schedules (NTP, NT, or PTP).

This rate schedule contains three subsections, corresponding to the customer categories to which this rate schedule applies:

Section II.A. DSI customers who purchase under 1981 Contracts.

Section II.B. Full Requirements DSI customers who purchase under 1996 Contracts.

Section II.C. Partial Requirements DSI customers who purchase under 1996 Contracts.

A. DSI CUSTOMERS WHO PURCHASE UNDER 1981 CONTRACTS

Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this rate schedule. These customers are charged for transmission service under the applicable transmission rate schedule.

1. INDUSTRIAL FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year,
multiplied by
the Purchaser's BPA Operating Level that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Measured Energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.80 mills/kWh	21.34 mills/kWh
January - March	23.15 mills/kWh	21.71 mills/kWh
April	20.56 mills/kWh	19.63 mills/kWh
May - June	11.19 mills/kWh	9.74 mills/kWh
July	13.76 mills/kWh	11.99 mills/kWh
August	19.61 mills/kWh	17.03 mills/kWh

2. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by*
the Purchaser's Total Plant Load.

3. TRANSMISSION

Transmission services for deliveries of IP power shall be billed under the applicable rate schedule (NTP, NT, or PTP).

4. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

4.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Curtailment Charge	II.E.
Local Stability Reserves Adjustment	II.J.
Operating Reserves Adjustment	II.M.
Transitional Service	II.Q.
Unauthorized Increase Charge	II.R.

4.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

B. FULL REQUIREMENTS DSI CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Full Requirements customers purchasing power under a 1996 Contract receive DSI Load Shaping service and will be charged for that product at the rate specified in this section of the rate schedule. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this rate schedule. Customers who choose to purchase the Fixed Curtailment Fee product will be charged at the rate specified in this rate schedule. Full Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. INDUSTRIAL FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of:

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Adjusted Measured Energy, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Adjusted Measured Energy.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.80 mills/kWh	21.34 mills/kWh
January - March	23.15 mills/kWh	21.71 mills/kWh
April	20.56 mills/kWh	19.63 mills/kWh
May - June	11.19 mills/kWh	9.74 mills/kWh
July	13.76 mills/kWh	11.99 mills/kWh
August	19.61 mills/kWh	17.03 mills/kWh

2. DSI LOAD SHAPING

The charge for DSI Load Shaping shall be $201/aMW, *multiplied by*
the Purchaser's Calculated Energy Capacity.

3. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Plant Load.

4. FIXED CURTAILMENT FEE

The charge for the Fixed Curtailment Fee shall be 4.95 mills/kWh, *multiplied by* the Purchaser's Curtailed Energy.

5. TRANSMISSION

Transmission services for delivery of IP power shall be billed under the applicable rate schedule (NT or PTP).

6. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

6.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Deviation Adjustment	II.G.
Local Stability Reserves Adjustment	II.J.
Operating Reserves Adjustment	II.M.

6.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

C. PARTIAL REQUIREMENTS DSI CUSTOMERS WHO PURCHASE UNDER 1996 CONTRACTS

Partial Requirements customers purchasing take-or-pay power under a 1996 Contract who choose to purchase DSI Load Shaping and/or the Fixed Curtailment Fee product will be charged at the rates specified in this rate schedule. Customers purchasing non-take-or-pay power under a 1996 Contract may not purchase the Fixed Curtailment Fee product. Customers in BPA's load control area and those served by transfer receive Load Regulation service and will be charged at the rate specified in this rate schedule. Partial Requirements customers are charged for transmission service under the applicable transmission rate schedule.

1. INDUSTRIAL FIRM POWER

1.1. Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the *greater* of (1) the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load *or* (2) the Purchaser's Monthly Contract Obligation.

1.2. Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by*
the *greater* of Purchaser's HLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum HLH Contract Obligation, and

(2) the applicable LLH rate for that month, *multiplied by*
the *greater* of Purchaser's LLH Adjusted Measured Energy *or* Purchaser's Monthly Minimum LLH Contract Obligation.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	22.80 mills/kWh	21.34 mills/kWh
January - March	23.15 mills/kWh	21.71 mills/kWh
April	20.56 mills/kWh	19.63 mills/kWh
May - June	11.19 mills/kWh	9.74 mills/kWh
July	13.76 mills/kWh	11.99 mills/kWh
August	19.61 mills/kWh	17.03 mills/kWh

2. DSI LOAD SHAPING

The charge for DSI Load Shaping shall be $201/aMW, *multiplied by* the Purchaser's Calculated Energy Capacity.

3. LOAD REGULATION

The rate for Load Regulation shall not exceed 0.28 mills/kWh. Any discounts shall be determined pursuant to section II.A. of the GRSPs.
The charge for Load Regulation shall be the effective rate *multiplied by* the Purchaser's Total Plant Load.

4. FIXED CURTAILMENT FEE

The charge for the Fixed Curtailment Fee shall be 4.95 mills/kWh, *multiplied by* the Purchaser's Curtailed Energy.

5. DSI NON-TAKE-OR-PAY OPTION

The charge for the DSI Non-Take-or-Pay Option shall be 0.46 mills/kWh, *multiplied by* the Purchaser's Billing Energy.

6. TRANSMISSION

Transmission services for deliveries of IP power shall be billed under the applicable rate schedule (NT or PTP).

7. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

7.1. Rate Adjustments

Rate Adjustment	***Section***
Ancillary Services Rate Discount	II.A.
Deviation Adjustment	II.G.
Local Stability Reserves Adjustment	II.J.
Operating Reserves Adjustment	II.M.

7.2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

SCHEDULE IPG-96
INDUSTRIAL POWER SPOT GAS RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their industrial operations. If a DSI customer is purchasing power under a 1996 Contract, this rate schedule is available only for power purchases above the amount specified in such contract. Purchases of power under this rate must be for the full five-year term, beginning on October 1, 1996, and ending on September 30, 2001. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

Sales under the IPG-96 rate schedule are subject to BPA's GRSPs. For sales under this rate schedule, bills shall be rendered and payments shall be due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

If the customer is receiving Load Regulation service from BPA under the IP rate schedule or the VI rate schedule, it will not be charged for Load Regulation under this rate schedule. If the customer is purchasing power from BPA only under this rate schedule and is in BPA's load control area or is served by transfer, it will receive Load Regulation service and will be charged at the rate specified in this rate schedule. Purchasers under this rate schedule are charged for transmission service under the applicable transmission rate schedule.

A. INDUSTRIAL FIRM POWER

1. RATES

The spot gas rate is the sum of two components: a fixed charge and a variable charge derived by multiplying the Average Spot Market Gas Price by an energy multiplier. Both of these charges are expressed in mills per kilowatthour. The Average Spot Market Gas Price will be calculated monthly on a rolling twelve-month average basis and will be a simple average of the monthly spot gas price in each of the previous twelve months. The monthly spot gas price will be the price reported in <u>Natural Gas Week</u> as "Spot Prices on Interstate Pipeline System, Delivered to Pipeline: California border: Topock Station." If this gas index is discontinued, another index, chosen by mutual agreement between BPA and the customer, will be used as the basis of the monthly spot gas price.

1.1 Fixed Charge

4.75 mills/kWh.

1.2 Variable Charge

Average Spot Market Gas Price multiplied by 10.25 (resulting in a mills/kWh charge).

2. BILLING FACTORS

The *greater* of the Purchaser's Adjusted Measured Energy *or* the Purchaser's Monthly Minimum HLH and LLH Contract Obligation.

B. LOAD REGULATION

1. RATE AND BILLING FACTOR

0.28 mills/kWh multiplied by Purchaser's Total Plant Load.

C. TRANSMISSION

Transmission services for deliveries of IPG power shall be billed under the applicable rate schedule (NT or PTP).

D. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

All adjustments are described in the GRSPs. The applicable sections are identified for each adjustment.

1. RATE ADJUSTMENTS

Rate Adjustment	***Section***
Deviation Adjustment	II.G.
Local Stability Reserves Adjustment	II.J.
Operating Reserves Adjustment	II.M.

2. SPECIAL RATE PROVISIONS

Special Rate Provisions	***Section***
Cost Contributions	II.D.

SCHEDULE VI-96
VARIABLE INDUSTRIAL POWER RATE

SECTION I. AVAILABILITY

This schedule is available to BPA's direct-service industrial (DSI) customers for firm power to be used in their aluminum and nickel smelting operations. This schedule is made available only for that portion of a DSI's load used in primary metal reduction including associated administrative facilities, if any. Only DSIs that purchase power under the 1996 Contract and that have signed a new Variable Industrial Rate Contract are eligible to purchase under this rate schedule. BPA is not obligated to sell power under this rate schedule. Products available under this rate schedule are defined in BPA's General Rate Schedule Provisions (GRSPs).

Sales under the VI-96 rate schedule are subject to BPA's GRSPs. For sales under this rate schedule, bills shall be rendered and payments shall be due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

A. VARIABLE INDUSTRIAL FIRM POWER

1. Rates

The variable rate formula will be based on the IP rate. The Demand Charge for the variable rate will be the same as the Demand Charge in the IP rate schedule. The Base Energy Charge will be the average annual charge that results from applying the Energy Charges and the Load Regulation charge from the IP rate schedule to the customer's Contract Obligation.

The monthly Energy Charge varies with the price of aluminum, in the case of customers engaged in primary aluminum reduction, and with the price of nickel, in the case of customers engaged in primary nickel reduction. Individual rate formulas will be established for each customer. Each rate formula shall be such that, at the time BPA and the individual customer enter into a Variable Industrial Rate Contract incorporating such formula, BPA has the ability to hedge the aluminum or nickel price risk inherent in such rate formula, at zero cost to BPA, by entering into transactions with one or more substantial financial institutions.

"Zero cost to BPA" means that either a) BPA will incur no cost to hedge the price risk of the variable rate, or b) BPA will recover the sum it pays to hedge the price risk of the variable rate from the applicable customer, either as a lump sum paid at the time BPA and the customer enter into the Variable Rate Contract, or over a time period no longer than the term of the variable rate formula incorporated in such contract. In the event that such sum is recovered over time, it shall bear interest at the rate payable on the Bonneville Fund in the United States Treasury at the time BPA and the customer enter into the Variable Rate Contract.

Individual rate formulas may be established for any period from one to five years. At the expiration of any rate formula, a new rate formula for that customer may be established pursuant to the guidelines stated in this section, or the customer may purchase power under the IP rate schedule. However, the total term of all variable rate formulas for any single DSI purchaser shall not be longer than five years.

The monthly Energy Charge shall be based on the monthly billing aluminum or nickel price. The monthly billing aluminum or nickel price shall be the average price of aluminum or nickel, in dollars per metric ton, on the London Metal Exchange (LME) during the calendar month immediately preceding the billing month. The average price during the month shall equal the average of all official LME daily cash settlement prices during such month rounded to the nearest dollar. BPA and each customer may agree to base the monthly energy charge on the average price of aluminum or nickel during a month other than the immediately preceding month.

In the case of variable industrial rate formulas that contain pivot prices, the monthly Energy Charge shall be the Base Energy Charge when the monthly billing aluminum or nickel price is between the Lower Pivot Aluminum or Nickel Price and the Upper Pivot Aluminum or Nickel Price inclusive. In the case of variable industrial rate formulas that do not contain pivot prices, the monthly Energy Charge shall be the Base Energy Charge when the monthly billing aluminum or nickel price equals the price established in the customer's Variable Industrial Rate Contract at which the Base Energy Charge applies.

The Lower Pivot Aluminum or Nickel Price is the aluminum or nickel price established in an individual customer's Variable Industrial Rate Contract such that the monthly energy charge decreases when the monthly billing aluminum or nickel price is below such price.

The Upper Pivot Aluminum or Nickel Price is the aluminum or nickel price established in an individual customer's Variable Industrial Rate Contract such that the monthly energy charge increases when the monthly billing aluminum or nickel price is above such price.

2. Billing Factors

2.1. Billing Demand

The *greater* of the Purchaser's Measured Demand that occurs during the hour of the Monthly Federal System Peak Load *or*
the Purchaser's Monthly Contract Obligation.

2.2. Billing Energy

The *greater* of the Purchaser's Adjusted Measured Energy *or*
the Purchaser's Monthly Minimum HLH and LLH Contract Obligation.

B. TRANSMISSION

Transmission services for deliveries of IP power shall be billed under the applicable rate schedule (NT or PTP).

C. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

All adjustments are described in the GRSPs. The applicable sections are identified for each adjustment.

1. Rate Adjustments

Rate Adjustment	***Section***
Deviation Adjustment	II.G.
Local Stability Reserves Adjustment	II.J.
Operating Reserves Adjustment	II.M.

2. Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

SCHEDULE NF-96
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. BPA is not obligated to offer nonfirm energy to any purchaser that results in displacement of firm power purchases under BPA's 1981 or 1996 Power Sales Contracts. The offer of nonfirm energy under this schedule shall be determined by BPA.

This rate schedule supersedes schedule NF-95, which went into effect on October 1, 1995. Sales under the NF-96 rate schedule are subject to BPA’s General Rate Schedule Provisions. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA’s GRSPs and Billing Procedures.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

The average cost of nonfirm energy is 22.25 mills per kilowatthour. The NF-96 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 calculated in accordance with the methodology specified in the Adjustments, Charges, and Special Rate Provisions section of this document. For purchases under the NF-96 rate schedule, transmission service shall be charged under the applicable transmission rate schedule.

A. RATES FOR NONFIRM ENERGY

1. STANDARD RATE

The Standard rate is any offered rate not to exceed 26.70 mills per kilowatthour.

2. 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.

3. INCREMENTAL RATE

The Incremental Rate is the Incremental Cost of energy plus 2.00 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.

4. CONTRACT RATE

The Contract Rate is 22.25 mills per kilowatthour.

B. BILLING FACTOR FOR NONFIRM ENERGY

The billing factor for nonfirm energy purchased under this rate schedule shall be the Measured Energy unless otherwise specified by contract.

C. ADJUSTMENTS FOR NONFIRM ENERGY

All adjustments are described in the GRSPs. The applicable sections are identified for each adjustment.

1. RATE ADJUSTMENTS

Rate Adjustment	***Section***
Guaranteed Delivery Charge	II.I.
Reactive Power Charge	II.O.

2. SPECIAL RATE PROVISIONS

Special Rate Provision	***Section***
Cost Contributions	II.D.
NF Rate Cap	II.L.

SECTION III. DETERMINATION OF THE APPLICABLE NF RATE

Any time that BPA has nonfirm energy for sale, the Standard rate, the Market Expansion rate, the Incremental rate, the Contract rate, or any 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 1981 utility 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 satisfying the Market Expansion Rate Qualifying Criteria specified in section III.B.2, above, 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 2.00 mills per kilowatthour.

Purchasers qualifying under section III.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 4.00 mills per kilowatthour.

b. When more than one Market Expansion rate is offered:

Purchasers qualifying under section III.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 2.00 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 2.00 mills per kilowatthour.

Purchasers qualifying under section III.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 4.00 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 4.00 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 2.00 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 (WSPP)

BPA may make available nonfirm energy for transactions under the 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 not exceed the maximum rate specified in the WSPP Agreement. The rate for WSPP sales 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 IV. 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.

SCHEDULE RP-96
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; or
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 both inside and outside the United States. This rate schedule supersedes the RP-95 rate schedule, which went into effect on October 1, 1995. Purchases under this rate schedule shall be charged for transmission service under the applicable transmission rate schedule. Sales under this schedule are subject to BPA’s General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA’s GRSPs and Billing Procedures.

SECTION II. RATES AND BILLING FACTORS

A. DEMAND CHARGE

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by* the 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 that occurs during the hour of the Monthly Federal System Peak Load.

B. ENERGY CHARGE

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser’s HLH Billing Energy, and
(2) the applicable LLH rate for that month, *multiplied by* the Purchaser’s LLH Billing Energy.

If use of the Contract Demand for determining Billing Energy is specified in the power sales contract, the Billing Energy shall be the Contract Demand multiplied by the number of hours in the relevant diurnal period in the billing month. Otherwise, the Billing Energy for such purchasers shall be the HLH and LLH Measured Energy.

Applicable Months	*HLH Rate*	*LLH Rate*
September - December	20.4 mills/kWh	19.2 mills/kWh
January - March	20.7 mills/kWh	19.5 mills/kWh
April	18.5 mills/kWh	17.7 mills/kWh
May - June	10.3 mills/kWh	9.1 mills/kWh
July	12.6 mills/kWh	11.0 mills/kWh
August	17.7 mills/kWh	15.4 mills/kWh

C. TRANSMISSION

Transmission service for delivery of RP power shall be billed under the applicable transmission rate schedule.

SECTION III. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

A. RATE ADJUSTMENTS

Rate Adjustment	*Section*
Reactive Power Charge	II.O.

B. SPECIAL RATE PROVISIONS

Special Rate Provisions	*Section*
Cost Contributions	II.D.

SCHEDULE PS-96
POWER SHORTAGE RATE SCHEDULE

SECTION I. AVAILABILITY

This schedule is available inside the Pacific Northwest for the purchase of Shortage Power by signatories to the Share-the-Shortage Agreement, or a similar substitute agreement. Any transactions entered into by BPA pursuant to a Share-the-Shortage Agreement shall be subject to the terms and conditions specified in that agreement. The PS-96 rate does not incorporate the Agreement, but the Agreement controls if there is any conflict between the PS-96 rate and the Agreement. The PS-96 rate shall not be available for transactions with a party who triggers the Share-the-Shortage Agreement if BPA elects to meet its required service obligations under the agreement by entering into an alternative agreement.

This rate schedule is also available inside the Pacific Northwest when BPA arranges for the purchase of energy at the request of, and for the account of, a customer pursuant to a Share-the-Shortage Agreement.

BPA is not obligated either to make Shortage Power available or to broker power under this rate schedule unless specified by contract.

This schedule supersedes the PS-95 rate schedule, which went into effect on October 1, 1995. Sales under the PS-96 rate schedule are subject to BPA's General Rate Schedule Provisions (GRSPs) and BPA's Billing Procedures.

SECTION II. RATES AND BILLING FACTORS

A. POWER PURCHASES

The charge for Power Purchases shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

1. Rate

The power rate is any offered rate not to exceed the lesser of:

1. 100.00 mills per kilowatthour; or
2. the maximum rate specified in the Share-the Shortage Agreement.

The offered rate may be specified as an energy charge only or as demand and energy charges.

2. Billing Factors

The billing factors shall be the Contract Demand and Contract Energy, unless otherwise specified in the agreement initiating the Share-the-Shortage sales transaction.

B. BROKERING SERVICES

The charge for Brokering Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

1. Rate

The brokering rate may be up to 1.00 mill per kilowatthour for services provided when BPA arranges for energy purchases for a customer from a seller other than BPA.

2. Billing Factors

When BPA arranges for energy purchases at the request of a customer, the purchaser shall be billed for such services based on the total number of kilowatthours purchased.

The charge for power brokering applies only to the service provided by BPA of finding purchased power for a customer from a seller other than BPA. BPA may agree to provide other services in addition to finding purchased power, but these services shall be billed separately at charges specified in the appropriate rate schedule(s) or agreement(s). Such services may include, but are not limited to, wheeling and load shaping.

SECTION III. TRANSMISSION

The transmission charge for deliveries under this rate shall be the charge for Network Integration service under the Network Integration (NT) rate or the charge for Point-to-Point service under the Point-to-Point (PTP) rate.

SECTION IV. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

Special Rate Provisions	***Section***
Cost Contributions	II.D.

SCHEDULE FPS-96
FIRM POWER PRODUCTS AND SERVICES

SECTION I. AVAILABILITY

This rate schedule is available for the purchase of Firm Power, Supplemental Control Area Services, Shaping Services, and Reservation and Rights to Change Services for use inside and outside the Pacific Northwest during the period beginning October 1, 1996, and ending September 30, 2005.

Products and services available under this rate schedule are described in section III.A. of BPA's General Rate Schedule Provisions (GRSPs). BPA is not obligated to enter into agreements to sell products and services under this rate schedule or make power or energy available under this rate schedule if such power or energy would displace sales under the PF-96, NR-96, IP-96, or VI-96 rate schedules or their successors. Sales under the FPS-96 rate schedule are subject to BPA's GRSPs. Transmission service over Federal Columbia River Transmission System facilities shall be charged under the applicable transmission rate schedule. Ancillary services shall be available under, or at charges consistent with, the Ancillary Products and Services (APS) rate schedule.

This rate schedule supersedes the Surplus Firm Power (SP-93) and Emergency Capacity (CE-95) rate schedules. Rates under contracts that contain charges that escalate based on rates listed in this rate schedule shall include applicable transmission charges. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's Billing Procedures and/or as agreed to in purchase agreements.

SECTION II. RATES, BILLING FACTORS, AND ADJUSTMENTS

For each product, the rate(s) for each product along with the associated billing factor(s) are identified below. Applicable adjustments, charges, and special rate provisions are listed for each product. This rate schedule contains four subsections, corresponding to the products offered under this rate schedule:

Section II.A. Firm Power.

Section II.B. Supplemental Control Area Services.

Section II.C. Shaping Services.

Section II.D. Reservation and Rights to Change Services.

A. FIRM POWER

1. RATES AND BILLING FACTORS

1.1 Contract Rate

1.1.1 Demand Charge

The charge for demand shall be $0.87 per kilowatt per month in all months of the year, *multiplied by*
the Contract Demand unless otherwise agreed by BPA and the Purchaser.

1.1.2 Energy Charge

The total monthly charge for energy shall be the sum of (1) and (2):

(1) the applicable HLH rate for that month, *multiplied by* the Purchaser's HLH Contract Energy unless otherwise agreed by BPA and the Purchaser, and

(2) the applicable LLH rate for that month, *multiplied by* the Purchaser's LLH Contract Energy unless otherwise agreed by BPA and the Purchaser.

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	49.63 mills/kWh	46.45 mills/kWh
January - March	50.39 mills/kWh	47.25 mills/kWh
April	44.74 mills/kWh	42.73 mills/kWh
May - June	24.36 mills/kWh	21.21 mills/kWh
July	29.94 mills/kWh	26.09 mills/kWh
August	42.68 mills/kWh	37.06 mills/kWh

1.2 Flexible Rate

Demand and/or energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the Purchaser. Billing factors shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Energy Return Surcharge	II.H.
Reactive Power Charge	II.O.
Unauthorized Increase Charge	II.R.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

B. SUPPLEMENTAL CONTROL AREA SERVICES

1. RATES AND BILLING FACTORS

The charge for Supplemental Control Area Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Supplemental Control Area Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Energy Return Surcharge	II.H.
Reactive Power Charge	II.O.
Unauthorized Increase Charge	II.R.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

C. SHAPING SERVICES

1. RATES AND BILLING FACTORS

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Adjustments, Charges, and Special Rate Provisions are described in the GRSPs. Relevant sections are identified below.

2.1 Rate Adjustments

Rate Adjustment	***Section***
Energy Return Surcharge	II.H.
Reactive Power Charge	II.O.
Unauthorized Increase Charge	II.R.

2.2 Special Rate Provisions

Special Rate Provisions	***Section***
Cost Contributions	II.D.

D. RESERVATION AND RIGHTS TO CHANGE SERVICES

1. RATES AND BILLING FACTORS

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing factor(s), pursuant to the agreement between BPA and the Purchaser.

The rate(s) and billing factor(s) for Reservation and Rights to Change Services shall be as established by BPA or mutually agreed by BPA and the Purchaser.

2. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

There are no additional adjustments, charges, or special rate provisions for the Reservation and Rights to Change Services.

SCHEDULE APS-96
ANCILLARY PRODUCTS AND SERVICES

SECTION I. AVAILABILITY

This rate schedule is available for ancillary services necessary to support the firm or non-firm delivery of power from resources to loads using the Federal Columbia River Transmission System (FCRTS) facilities. The ancillary services available under this rate schedule are: Energy Imbalance; Control Area Reserves for Resources; Control Area Reserves for Interruptible Purchases; Load Regulation; and Transmission Losses. These services are defined in section III.A of BPA's General Rate Schedule Provisions (GRSPs). This schedule also is available for ancillary services of a similar nature as BPA may be ordered to make available by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k).

This rate schedule also is available for discounted rates for ancillary services, as applicable, pursuant to section II.A of BPA's GRSPs.

Sales under this schedule are made subject to BPA's GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to BPA's GRSPs and Billing Procedures.

SECTION II. RATES AND BILLING FACTORS

For each service, the rate(s) and associated billing factor(s) are identified below. Applicable adjustments and special rate provisions are listed for each service. This rate schedule contains five subsections, corresponding to the services offered under this rate schedule:

Section II.A. Energy Imbalance

Section II.B. Control Area Reserves for Resources

Section II.C. Control Area Reserves for Interruptible Purchases

Section II.D. Load Regulation

Section II.E. Transmission Losses

A. ENERGY IMBALANCE

The rates below for Energy Imbalance apply to uses of the FCRTS where there are differences between the hourly scheduled amounts and the hourly metered amounts of power deliveries to load and from resources within the BPA control area. The rates shall not apply to scheduled transmission of power using the FCRTS that is not delivered to load or does not originate from resources within the BPA control area.

1. RATES FOR POSITIVE DEVIATIONS

The Purchaser shall pay BPA the applicable rates for Positive Deviations as provided below.

1.1 Rates for Positive Deviations within Energy Imbalance Band

1.1.1 Demand Charge for Generation Capacity

$0.87 per kilowatt per month of Billing Demand.

1.1.2 Energy Rate

The energy rate shall not exceed the rates below:

Applicable Months	***HLH Rate***	***LLH Rate***
September - December	18.60 mills/kWh	17.50 mills/kWh
January - March	19.00 mills/kWh	17.80 mills/kWh
April	16.80 mills/kWh	16.10 mills/kWh
May - June	9.20 mills/kWh	8.00 mills/kWh
July	11.30 mills/kWh	9.80 mills/kWh
August	16.10 mills/kWh	13.90 mills/kWh

1.2 Rate for Positive Deviations Greater than the Energy Imbalance Band

1.2.1 Demand Charge for Generation Capacity

$0.87 per kilowatt per month of Billing Demand.

1.2.2 Energy Rate

100 mills per kWh.

2. BILLING FACTORS FOR POSITIVE DEVIATIONS

2.1 Billing Factors for Positive Deviations within the Energy Imbalance Band

2.1.1 Billing Demand for Generation Capacity

The billing demand shall be the Positive Deviation that occurs during the hour of the Monthly Federal System Peak Load.

2.1.2 HLH Billing Energy

If the direction of the monthly HLH Energy Imbalance account is positive, then the billing energy shall be the Net Monthly HLH kilowatthours of Positive Deviation within the Band.

2.1.3 LLH Billing Energy

If the direction of the monthly LLH Energy Imbalance account is positive, then the billing energy shall be the Net Monthly LLH kilowatthours of Positive Deviation within the Band.

2.2 Billing Factors for Positive Deviations Greater than the Energy Imbalance Band

2.2.1 Billing Demand for Generation Capacity

The billing demand shall be the Positive Deviation less 1.5 percent of the scheduled transaction that occurs during the hour of the Monthly Federal System Peak Load.

2.2.2 HLH Billing Energy

The billing energy shall be the total monthly HLH kilowatthours of energy greater than the +1.5 percent Energy Imbalance Band on any HLH.

2.2.3 LLH Billing Energy

The billing energy shall be the total monthly LLH kilowatthours of energy greater than the +1.5 percent Energy Imbalance Band on any LLH.

3. CREDIT OR PAYMENT FOR NEGATIVE DEVIATION ENERGY IMBALANCE

BPA shall credit or pay the Purchaser, as applicable, for Negative Deviations as provided below.

3.1 Energy Credit or Payment for Negative Deviations within the Energy Imbalance Band

If BPA determines the Negative Deviation was an Intentional Deviation and/or if BPA is in Spill Condition during same billing period as Negative Deviation occurs, the credit or payment for Negative Deviations is zero for the billing month. Otherwise, the credit or payment shall be equal to the applicable rates in effect in section A.1.1.2 of this rate schedule.

3.2 Energy Credit or Payment for Negative Deviations Greater than the Energy Imbalance Band

If BPA determines the Negative Deviation was an Intentional Deviation and/or if BPA is in Spill Conditions during same billing period as Negative Deviation occurs, the credit or payment for Negative Deviations outside the +1.5 percent Energy Imbalance Band shall be zero for the billing month. Otherwise the credit or payment shall not exceed:

Applicable Months	***HLH Credit or Payment***	***LLH Credit or Payment***
September - December	9.30 mills/kWh	8.70 mills/kWh
January - March	9.50 mills/kWh	8.90 mills/kWh
April	8.40 mills/kWh	8.00 mills/kWh
May - June	4.60 mills/kWh	4.00 mills/kWh
July	5.60 mills/kWh	4.90 mills/kWh
August	8.00 mills/kWh	7.00 mills/kWh

4. BILLING FACTORS FOR NEGATIVE DEVIATION ENERGY IMBALANCE

4.1 Billing Factors for Negative Deviation within the Energy Imbalance Band

4.1.1 HLH Billing Energy

If the direction of the monthly HLH Energy Imbalance account is negative, then the billing energy shall be the Net Monthly HLH kilowatthours of Negative Deviation within the -1.5 percent Energy Imbalance Band on any HLH.

4.1.2 LLH Billing Energy

If the direction of the monthly LLH Energy Imbalance account is negative, then the billing energy shall be the Net Monthly LLH kilowatthours of Negative Deviation within the -1.5 percent Energy Imbalance Band on any LLH.

4.2 Billing Factor for Negative Deviations Greater than the Energy Imbalance Band

4.2.1 HLH Billing Energy

The billing energy shall be the total monthly HLH kilowatthours of Negative Deviation outside the -1.5 percent Energy Imbalance Band on any HLH.

4.2.2 LLH Billing Energy

The billing energy shall be the total monthly LLH kilowatthours of Negative Deviation outside the -1.5 percent Energy Imbalance Band on any LLH.

B. CONTROL AREA RESERVES FOR RESOURCES

The rates below for Control Area Reserves For Resources apply to all hydroelectric and non-hydroelectric generating resources with a generating capacity of 3 MW or greater located in BPA's control area. The rates do not apply to a resource that has a generating capacity of less than 3 MW (Small Resource); provided however, if the purchaser has multiple Small Resources and the total generating capacity of those multiple Small Resources is greater than 6 MW, then only the first 3 MW of the total generating capacity of those multiple Small Resources is exempt from the rates below.

The rates are available for Full or Partial Service. Full Service shall be provided, unless BPA agrees to provide Partial Service to meet the resource owner's control area reserve obligations. If BPA provides Full Service, the rates and billing factors in sections 1 and 2, respectively, shall apply. If BPA provides Partial Service, the rates and billing factors for the appropriate service in sections 3 and 4, respectively, shall apply.

1. RATES FOR CONTROL AREA RESERVES FOR RESOURCES (FULL SERVICE)

1.1 Rate for Control Area Reserves for Hydroelectric Resources

The rate shall not exceed $0.27 per kilowatt per month of billing demand.

1.2 Rate for Control Area Reserves for Non-Hydroelectric Resources

The rate shall not exceed $0.36 per kilowatt per month of billing demand.

2. BILLING FACTORS FOR CONTROL AREA RESERVES FOR RESOURCES (FULL SERVICE)

2.1 Billing Demand

If BPA receives the appropriate metering information regarding the Purchaser's resource(s), regardless of resource type, then the billing demand shall be determined as specified in section 2.1.1 below. Otherwise, for the Purchaser's hydroelectric resource(s) the billing demand shall be determined in accordance with section 2.1.2, and for the Purchaser's thermal and any other non-hydroelectric resource(s) the billing demand shall be determined in accordance with section 2.1.3.

2.1.1 Billing Demand for Metered Resources

For service applicable to the Purchaser's resource(s) regardless of type for which BPA receives the appropriate metering information, the billing demand shall be the average metered energy for each resource for the billing month.

2.1.2 Billing Demand for Unmetered Hydroelectric Resources

For service applicable to the Purchaser's hydroelectric resource(s) for which BPA does not receive the appropriate metering information, the billing demand shall be the total Resource Capability, as specified in section B.2.1.4, for the Purchaser's hydroelectric resource(s), multiplied by a capacity factor not to exceed 0.60. BPA may agree to a capacity factor other than 0.60 based on the historical and planned operation of the resource(s).

2.1.3 Billing Demand for Unmetered Non-Hydroelectric Resources

For service applicable to the Purchaser's thermal resource(s) and any other non-hydroelectric resource(s) for which BPA does not receive the appropriate metering information, the billing demand shall be the total Resource Capability for the Purchaser's thermal resource(s) and any other non-hydroelectric resource(s), multiplied by a capacity factor not to exceed 0.90. BPA may agree to a capacity factor other than 0.90 based on the historical and planned operation of the resource(s).

2.1.4 Resource Capability

For service under the 1981 Contracts, the Resource Capability, expressed in kilowatts, shall be equal to the peak capability of the Purchaser's Firm Resource(s) specified in the Firm Resources Exhibit, and the peak capability of other resources specified in the Service Charges Exhibit. For 1996 Contracts and all other agreements, the Resource Capability shall be the Monthly Resource Peaking Capability as specified in the Agreement.

3. RATES FOR CONTROL AREA RESERVES FOR RESOURCES (PARTIAL SERVICE)

3.1 Rate for Non-Spinning Operating Reserve

The rate shall not exceed $4.38 per kilowatt per month of billing demand.

3.2 Rate for Spinning Operating Reserve

The rate shall not exceed $5.39 per kilowatt per month of billing demand.

3.3 Rate for Generation Following

The rate shall not exceed $0.02 per kilowatt per month of billing demand.

4. BILLING FACTORS FOR CONTROL AREA RESERVES FOR RESOURCES (PARTIAL SERVICE)

4.1 Billing Demand

The Billing Demand for Control Area Reserves for Resources (Partial Service) shall be the billing demand for the appropriate component of the Control Area Reserves for Resources in accordance with sections 4.1.1, 4.1.2 and 4.1.3 below.

4.1.1 Billing Demand for Non-Spinning Operating Reserves

The billing demand for Non-Spinning Operating Reserves shall be the contract demand.

4.1.2 Billing Demand for Spinning Operating Reserves

The billing demand for Spinning Operating Reserves shall be the contract demand.

4.1.3 Billing Demand for Generation Following

The billing demand for Generation Following shall be determined pursuant to section 2 above.

C. CONTROL AREA RESERVES FOR INTERRUPTIBLE PURCHASES

The rate below for Control Area Reserves for Interruptible Purchases applies to the schedules of all power purchases imported into BPA's control area that are designated as subject to interruption.

1. RATE

The rate shall not exceed 2.87 mills per kilowatthour.

2. BILLING FACTOR

The billing factor shall be the sum of scheduled amounts of Interruptible Purchases per billing month.

D. LOAD REGULATION

The rate below for Load Regulation applies to all retail and plant load within the BPA control area and BPA customer load served by transfer service outside of BPA's control area. If a Purchaser is taking Load Regulation service under multiple rate schedules, the Purchaser shall pay for Load Regulation for its total retail or plant load under only one rate schedule during the Billing Period.

1. RATE

The rate shall not exceed 0.28 mills per kilowatthour.

2. BILLING FACTOR

The billing factor for Load Regulation shall be the measured monthly kilowatthours of the Receiving Party's Total Retail or Total Plant Load.

E. TRANSMISSION LOSSES

The rate below for Transmission Losses applies to all Transmission Losses that occur on the BPA transmission system that are purchased from BPA.

1. RATE

The rate shall not exceed 22.80 mills per kilowatthour.

2. BILLING FACTOR

The billing factor shall be the amount of losses for the billing month calculated as specified in the applicable Agreement.

BPA'S 1996

TRANSMISSION RATE SCHEDULES

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SCHEDULE FPT-96.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-95.1 for all firm transmission agreements which provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission 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 Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

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 and the Secondary System Charge, as applicable and as specified in the agreement.

1. Main Grid Charge

The Main Grid Charge per kilowatt shall be the sum of one or more of the following annual charges as specified in the agreement:

a. Main Grid Distance: $0.0405 per mile
b. Main Grid Interconnection Terminal: $0.42
c. Main Grid Terminal: $0.47
d. Main Grid Miscellaneous Facilities: $2.31

2. Secondary System Charge

The Secondary System Charge per kilowatt shall be the sum of one or more of the following annual charges as specified in the agreement:

a. Secondary System Distance: $0.3980 per mile
b. Secondary System Transformation: $4.35
c. Secondary System Intermediate Terminal: $1.68
d. Secondary System Interconnection Terminal: $1.19

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 with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:

1. During months of the 12-month period for which service is specified, the monthly charge defined in section II.A., and

2. During other months of the 12-month period, 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 for the rates specified in section II. shall be the largest of:

1. The Transmission Demand;
2. The highest hourly Scheduled Demand for the month; or
3. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support FPT transmission service are available under the APS rate schedule.

C. RESERVATION FEE FOR TRANSMISSION CAPACITY

Customers who have requested increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.P. of the General Rate Schedule Provisions.

SCHEDULE FPT-96.3
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-95.3 for all firm transmission agreements which provide application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission 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 Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

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 and the Secondary System Charge, as applicable and as specified in the agreement.

1. Main Grid Charge

The Main Grid Charge per kilowatt shall be the sum of one or more of the following annual charges as specified in the agreement:

a. Main Grid Distance: $0.0405 per mile
b. Main Grid Interconnection Terminal: $0.42
c. Main Grid Terminal: $0.47
d. Main Grid Miscellaneous Facilities: $2.31

2. Secondary System Charge

The Secondary System Charge per kilowatt shall be the sum of one or more of the following annual charges as specified in the agreement:

a. Secondary System Distance: $0.3980 per mile
b. Secondary System Transformation: $4.35
c. Secondary System Intermediate Terminal: $1.68
d. Secondary System Interconnection Terminal: $1.19

B. PARTIAL-YEAR SERVICE

The monthly charge per kilowatt of Billing Demand shall be as specified in section II.A.1 for all months of the year except for agreements with terms 5 years or less and which specify service for fewer than 12 months per year. The monthly charge shall be:

1. During months of the 12-month period for which service is specified, the monthly charge defined in section II.A., and

2. During other months of the 12-month period, 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 for the rates specified in section II.A. shall be the largest of:

1. The Transmission Demand;
2. The highest hourly Scheduled Demand for the month; or
3. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support FPT transmission service are available under the APS rate schedule.

SCHEDULE IR-96
INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IR-95 and is available for transmission of non-Federal power for full-year firm transmission service and nonfirm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The monthly charge shall be A or B.

A. EMBEDDED COST

The monthly charge shall be:

1. $1.000 per kilowatt

2. For Points of Integration (POI) specified in the IR agreement as being short-distance POIs, for which Network facilities are used for a distance of less than 75 circuit miles, the following formula applies:

[0.6 + (0.4 x transmission distance/75)] * $1.000 per kilowatt

Where:

the Billing Demand for a short-distance POI is the demand level specified in the IR 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 serving load of the customer. Short-distance POIs are determined by BPA after considering factors in addition to transmission distance.

B. OPPORTUNITY COST

For increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.

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 Energy Transmission rate, such transmission service shall not contribute to the Billing Demand for the IR rate provided that the customer requests such treatment and BPA approves in accordance with the prescribed provisions in the agreement.

A. EMBEDDED COST

The Billing Demand shall be the largest of:

1. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;
2. The highest hourly Scheduled Demand for the month; or
3. The Ratchet Demand.

B. OPPORTUNITY COST

Billing factors shall be specified in the agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. DELIVERY CHARGE

Increases in IR firm transmission service are subject to the Delivery Charge specified in section II.F. of the General Rate Schedule Provisions.

B. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

C. ANCILLARY SERVICES

Ancillary services that may be required to support IR transmission service are available under the APS rate schedule.

D. RESERVATION FEE FOR TRANSMISSION CAPACITY

Customers who request increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.P. of the General Rate Schedule Provisions.

E. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

SCHEDULE NT-96
NETWORK INTEGRATION TRANSMISSION RATE
(For NT Service Tariff and Certain Full Requirements Customers Under 1996 Contracts)

SECTION I. AVAILABILITY

This schedule is available to Transmission Customers under the Network Integration (NT) Service Tariff and to certain Full Requirements Customers under 1996 Contracts for delivery of Federal and non-Federal power over Federal Columbia River Transmission System Network and Delivery facilities. Terms and conditions of service are specified in the Network Integration Service Tariff and the 1996 Contracts.

This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k).

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The monthly charge will be the sum of A and B.

A. BASE CHARGE

$1.000 per kilowatt per month.

B. TRANSMISSION LOAD SHAPING CHARGE

$0.539 per kilowatt per month.

SECTION III. BILLING FACTORS

A. BASE CHARGE

1. If no Declared Customer-Served Load (CSL) is specified in the customer's NT Service Agreement or 1996 Contract, the monthly Billing Demand for the Base Charge specified in section II.A. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

2. If an amount of Declared CSL is specified in the customer's NT Service Agreement or 1996 Contract, the monthly Billing Demand for the Base Charge specified in section II.A. shall be a. or b:

a. For the billing month, if the sum of the Actual CSLs occurring during Heavy Load Hours (HLH) is greater than or equal to 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Demand shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load, less Declared CSL.

b. For the billing month, if the sum of the Actual CSLs occurring during HLH is less than 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Demand shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

Where:

"Declared Customer-Served Load (CSL)" is the Network Load in megawatts that the customer elects to serve on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement. The customer's Declared CSL is contractually specified for each month.

"Actual Customer-Served Load (CSL)" is the actual hourly amount of the Network Load in megawatts that the customer serves on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement.

B. TRANSMISSION LOAD SHAPING CHARGE

The monthly Billing Demand for the Transmission Load Shaping Charge specified in section II.B. shall be the Network Load on the hour of the Monthly Transmission Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. METERING ADJUSTMENT

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.74.

B. DELIVERY CHARGE

Customers taking service under this rate schedule are subject to the Delivery Charge specified in section II.F. of the General Rate Schedule Provisions.

C. NT UNAUTHORIZED INCREASE CHARGE

If the customer's Actual Customer-Served Load (CSL) is less than its Declared CSL, the NT Unauthorized Increase Charge shall be assessed.

1. RATE

$12.00 per kilowatt per month.

2. BILLING DEMAND

In each billing month on the hour of the Monthly Transmission Peak Load, the Billing Demand shall equal the Declared CSL minus the Actual CSL.

D. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

E. ANCILLARY SERVICES

Ancillary services that may be required to support NT transmission service are available under the APS rate schedule.

F. REDISPATCH CREDIT

When BPA implements redispatch procedures pursuant to the Network Integration Service Tariff, a credit shall be given to the Transmission Customer whose resource is redispatched. The amount of the credit shall be based on the incremental and/or decremental cost(s) submitted by the Transmission Customer, and verifiable opportunity costs, as appropriate, and shall be a credit against the customer's monthly NT bill(s).

G. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Integration Transmission customer under an applicable rate schedule.

H. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. NT customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II. or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

I. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE NTP-96
NETWORK INTEGRATION TRANSMISSION RATE
(For 1981 Contracts)

SECTION I. AVAILABILITY

This schedule is available for delivery of Federal power over Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable to transmission service for power purchased from BPA under 1981 Contracts for customers who have not executed a Network Integration or Point-to-Point Service Agreement providing transmission for their BPA power purchases. Terms and conditions of service will be as provided in the customer's 1981 Contract.

This schedule is applicable to utilities participating in the residential exchange under section 5(c) of the Northwest Power Act pursuant to their Residential Purchase and Sale Agreements (RPSA).

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The monthly charge shall be the sum of A, B, and C.

A. BASE CHARGE

$1.000 per kilowatt per month.

B. TRANSMISSION LOAD SHAPING CHARGE

$0.539 per kilowatt per month.

Direct Service Industries (DSIs) under 1981 Contracts shall not be assessed the Transmission Load Shaping Charge.

C. RESERVED CAPACITY CHARGE

$0.083 per kilowatt per month.

The Reserved Capacity Charge is applicable only to Computed Requirements Customers under the 1981 Contracts who do not waive all or a portion of their Computed Maximum Requirement.

SECTION III. BILLING FACTORS

A. METERED REQUIREMENTS CUSTOMERS

For Metered Requirements Customers under 1981 Contracts, the billing demands shall be:

1. Base Charge

The monthly Billing Demand for the Base Charge specified in section II.A. shall be the Measured Demand for power delivered under the 1981 Contract on the hour of the Monthly Transmission Peak Load.

At those Points of Delivery (PODs) that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Base Charge Billing Demand for Metered Requirements Customers shall equal the highest hourly demand that occurs during the billing month for power delivered under the 1981 Contract at the POD multiplied by 0.74.

2. Transmission Load Shaping Charge

The monthly Billing Demand for the Transmission Load Shaping Charge specified in section II.B. shall be the highest hourly Measured Demand for power delivered under the 1981 Contract during the billing month, measured coincidently across the customer's PODs.

B. COMPUTED REQUIREMENTS CUSTOMERS (CRCs)

1. CRCs Who Do Not Waive Computed Maximum Requirement (CMR)

a. Base Charge

The monthly Billing Demand for the Base Charge specified in section II.A. shall be the highest monthly Heavy Load Hour (HLH) Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the customer's PODs.

b. Transmission Load Shaping Charge

The monthly Billing Demand for the Transmission Load Shaping Charge specified in section II.B. shall be the CMR.

c. **Reserved Capacity Charge**

The monthly Billing Demand for the Reserved Capacity Charge specified in section II.C. shall be the difference between the customer's billing factors for: (1) the Transmission Load Shaping Charge (section III.B.1.b.) and (2) the Base Charge (section III.B.1.a.).

2. CRCs Who Waive All or a Portion of Computed Maximum Requirement (CMR)

a. **Base Charge**

The monthly Billing Demand for the Base Charge specified in section II.A. shall be the CMR minus the declared megawatt amount waived.

b. **Transmission Load Shaping Charge**

The monthly Billing Demand for the Transmission Load Shaping Charge specified in section II.B. shall be the CMR minus the smallest declared megawatt amount waived for any month.

C. DSIs

For DSIs under 1981 Contracts, the monthly Billing Demand for the Base Charge specified in section II.A. shall be the BPA Operating Level for the billing month. If there is more than one BPA Operating Level within a billing month, the billing demand shall be a weighted average of the BPA Operating Levels during the billing month.

D. RESIDENTIAL EXCHANGE

For RPSA utilities, the Billing Demand for the Base Charge and Transmission Load Shaping Charge specified in sections II.A. and II.B., respectively, shall be the demand calculated by applying the load factor, determined as specified in the RPSA, to the energy associated with the utility's residential load for each billing period. Residential load shall be determined in accordance with the provisions of the purchaser's RPSA.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. DELIVERY CHARGE

Customers taking service under this rate schedule are subject to the Utility/DSI Delivery Charges specified in section II.F. of the General Rate Schedule Provisions.

B. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

C. NTP UNAUTHORIZED INCREASE CHARGE

Computed Requirements Customers who exceed their Computed Maximum Requirement shall be subject to the NTP Unauthorized Increase Charge.

1. RATE

$12.00 per kilowatt per month.

2. BILLING FACTOR

For CRCs who do not waive CMR, the Billing Demand shall be the amount by which the customer exceeds its CMR on the hour determined by the NTP Base Charge billing factor.

For CRCs who waive all or a portion of their CMR, the Billing Demand shall be the greatest amount on any HLH during the monthly billing period by which the customer exceeds its CMR minus the declared megawatt amount waived.

SCHEDULE PTP-96
POINT-TO-POINT TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule is available to Transmission Customers under the Point-to-Point (PTP) Service Tariff for Firm Transmission Service for Federal and non-Federal power delivery for one calendar day or longer and for Nonfirm Transmission Service in amounts not to exceed the customer's Transmission Demands. This schedule is applicable to such service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities. Terms and conditions of service are specified in the PTP Service Tariff.

This schedule also applies to Direct Service Industries (DSIs) who execute a 1996 Contract that refers to point-to-point transmission charges but who have not executed a PTP Service Agreement.

This schedule is available also for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k).

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The charge shall be A or B.

A. EMBEDDED COST

1. Annual/Monthly Service

$1.000 per kilowatt per month.

2. Weekly Service

$0.231 per kilowatt per week.

3. Daily Service

$0.046 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.231 times the highest amount in kilowatts reserved in any calendar day during the week.

B. OPPORTUNITY COST

For applications for new service or increases in current service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.

SECTION III. BILLING FACTORS

The Transmission Demands shall be contractually specified.

A. EMBEDDED COST

1. Customers Who Execute a PTP Service Agreement

The Billing Demand for each charge specified in section II.A. shall be the greater of:

a. the sum of the relevant Transmission Demands at the Point(s) of Interconnection for: (i) generating units that are not located within BPA's Control Area, and (ii) generating units that are located within BPA's Control Area but are not subject to redispatch by BPA, or

b. the sum of the relevant Point of Delivery Transmission Demands.

2. DSIs That Have Not Executed a PTP Service Agreement

a. For a DSI that executes a 1996 Contract that refers to point-to-point transmission charges and that has not executed a PTP Service Agreement to wheel the Federal power purchased under the 1996 Contract, the Billing Demand for the Network charge in section II.A.1. shall be the greater of:

(1) the highest monthly Demand specified pursuant to section 10(a) of the 1996 Contract for the contract year; or

(2) the highest transmission Billing Demand for any prior contract year beginning on or after October 1, 1996 (or after the effective date of any reduced Billing Demand pursuant to section III.A.2.c., if applicable).

b. For DSIs that elect the curtailment option, the Billing Demand for the Network charge in section II.A.1. shall be the Billing Demand in section III.A.2.a., above, less the difference between the monthly amount of Demand specified pursuant to section 10(a) of the 1996 Contract and the highest hourly Measured Demand for power delivered during the month.

c. A DSI may give BPA notice of an intent to reduce monthly demands. In order to reduce Billing Demand, such notice must be given at least two (2) years in advance.

B. OPPORTUNITY COST

The billing factor for the rate in section II.B. shall be specified in the Point-to-Point Service Agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. DELIVERY CHARGE

Customers taking service under this rate schedule are subject to the Delivery Charge specified in section II.F. of the General Rate Schedule Provisions.

B. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

C. SHORT-DISTANCE DISCOUNT (SDD)

When a Point of Interconnection (POI) and Point of Delivery (POD) use FCRTS facilities for a distance of less than 75 circuit miles and are designated as being short distance in the PTP Service Agreement, the monthly Transmission Demands for the relevant POI and POD shall be adjusted, for the purpose of computing the monthly bill for annual service, by the following factor:

$$0.6 + (0.4 \times \text{transmission distance}/75)$$

Such adjusted monthly POI and POD Transmission Demands shall be used to compute the billing factors in section III.A.1. to calculate the monthly bill for annual PTP service. The POD Transmission Demand eligible for the SDD may be no larger than the POI Transmission Demand. The distance used to calculate the SDD will be contractually specified and based upon path(s) identified in power flow studies.

D. ANCILLARY SERVICES

Ancillary services that may be required to support PTP transmission service are available under the APS rate schedule.

E. UNAUTHORIZED TRANSMISSION INCREASE CHARGE

Customers who exceed their Point of Interconnection (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the Unauthorized Transmission Increase Charge.

1. RATE

$12.00 per kilowatt per month.

2. BILLING FACTOR

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its Transmission Demands at each POD and POI, to the extent practicable. For each hour, BPA will sum these amounts that exceed Transmission Demands: a) for all PODs, and b) for all POIs. The Billing Demand for the monthly billing period shall be the greater of the highest one-hour POD sum or highest one-hour POI sum.

F. RESERVATION FEE FOR TRANSMISSION CAPACITY

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service are subject to the Reservation Fee for Transmission Capacity specified in section II.P. of the General Rate Schedule Provisions.

G. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Point-to-Point Transmission customer under an applicable rate schedule.

H. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

I. REDISPATCH CREDIT

When BPA implements redispatch procedures pursuant to the PTP Service Tariff, a credit shall be given to the Transmission Customer whose resource is redispatched. The amount of the credit shall be based on the incremental and/or decremental cost(s) submitted by the Transmission Customer, and verifiable opportunity costs, as appropriate, and shall be a credit against the customer's monthly PTP bill(s).

J. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE RNF-96
RESERVED NONFIRM TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule is available to Transmission Customers under the Point-to-Point Transmission Service Tariff for Short-Term Nonfirm (STNF) Transmission Service that is reserved and/or scheduled daily, weekly, or monthly for delivery of Federal and non-Federal power. This schedule is applicable to such service over Federal Columbia River Transmission System (FCRTS) Network. Terms and conditions of STNF Transmission Service are specified in the Point-to-Point Transmission Service Tariff.

This schedule is available for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k).

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

SECTION II. RATE

A. MONTHLY SERVICE

The charge shall not exceed $1.000 per kilowatt per month.

B. WEEKLY SERVICE

The charge shall not exceed $0.231 per kilowatt per week.

C. DAILY SERVICE

The charge shall not exceed $0.046 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.231 times the highest amount in kilowatts reserved in any calendar day during the week.

SECTION III. BILLING FACTORS

The monthly Billing Demand for each charge specified in section II. shall be the greater of:

a. the sum of the relevant Transmission Demands at the Point(s) of Interconnection for (i) generating units that are not located within BPA's Control Area, and (ii) generating units that are located within BPA's Control Area but are not subject to redispatch by BPA, or

b. the sum of the Point of Delivery Transmission Demands.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support STNF Transmission Service are available under the APS rate schedule.

C. UNAUTHORIZED TRANSMISSION INCREASE CHARGE

Customers who exceed their Point of Interconnection (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the Unauthorized Transmission Increase Charge.

1. RATE

$12.00 per kilowatt per month.

2. BILLING FACTOR

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its Transmission Demands at each POD and POI, to the extent practicable. For each hour, BPA will sum these amount(s) that exceed Transmission Demands: a) for all PODs, and b) for all POIs. The Billing Demand for the monthly billing period shall be the greater of the highest one-hour POD sum or highest one-hour POI sum.

D. INTERRUPTION OF SHORT-TERM NONFIRM SERVICE

If STNF Transmission Service is interrupted, the rates in section II. shall be prorated over the total hours in the period (month, week, day) to give credit for the hours of such interruption.

E. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE ET-96
ENERGY TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule ET-95 and is available for Hourly Nonfirm Transmission Service of Federal and non-Federal power between points within the Pacific Northwest using Federal Columbia River Transmission System (FCRTS) facilities excluding the Southern Intertie and Eastern Intertie. Terms and conditions of Energy Transmission service are specified in the Point-to-Point Transmission Service Tariff.

This schedule is available for transmission service of a similar nature ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k).

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

SECTION II. RATE

The charge shall not exceed 2.52 mills per kilowatthour.

SECTION III. BILLING FACTORS

The Billing Energy for the charge under section II.O. shall be the monthly sum of scheduled kilowatthours.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support ET transmission service are available under the APS rate schedule.

C. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE IS-96
SOUTHERN INTERTIE TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IS-95 and is available for Firm and Nonfirm Transmission Service on the Southern Intertie. Terms and conditions of service are specified in the Point-to-Point (PTP) Transmission Service Tariff or, for customers who executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The rates below apply to both north-to-south and south-to-north transactions.

A. FIRM TRANSMISSION RATE

This rate is the successor to the Firm Transmission Rate in section II.B. of the IS-95 Rate Schedule.

The charge shall be 1 or 2.

1. EMBEDDED COST

a. Annual/Monthly Service

$1.274 per kilowatt per month.

b. Weekly Service

$0.294 per kilowatt per week.

c. Daily Service

$0.059 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.294 times the highest amount in kilowatts reserved in any day during the week.

2. OPPORTUNITY COST

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.1.

B. SHORT-TERM NONFIRM TRANSMISSION RATE

1. MONTHLY SERVICE

The charge shall not exceed $1.274 per kilowatt per month.

2. WEEKLY SERVICE

The charge shall not exceed $0.294 per kilowatt per week.

3. DAILY SERVICE

The charge shall not exceed $0.059 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.294 times the highest amount in kilowatts reserved in any day during the week.

C. HOURLY NONFIRM TRANSMISSION RATE

The charge shall not exceed 2.54 mills per kilowatthour.

This rate is the successor to the Nonfirm Transmission Rate in section II.A. of the IS-95 Rate Schedule.

SECTION III. BILLING FACTORS

A. FIRM AND SHORT-TERM NONFIRM TRANSMISSION

The Billing Demand for each charge specified in sections II.A.1. and II.B. shall be the greater of: 1) the sum of the relevant Point of Interconnection Transmission Demands that correspond to the current billing month, or 2) the sum of the relevant Point of Delivery Transmission Demands that correspond to the current billing month. For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Demand shall be as specified in the agreement.

The billing factors for Firm Transmission Service under section II.A.2. shall be specified in the agreement.

B. HOURLY NONFIRM TRANSMISSION

For Hourly Nonfirm Transmission Service under section II.C., the Billing Energy shall be the monthly sum of the scheduled kilowatthours.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support IS transmission service are available under the APS rate schedule.

C. UNAUTHORIZED TRANSMISSION INCREASE CHARGE

Customers who exceed their monthly Point of Interconnection (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the Unauthorized Transmission Increase Charge.

1. Rate

$12.00 per kilowatt per month.

2. Billing Factor

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its Transmission Demands at each POD and POI, to the extent practicable. For each hour, BPA will sum these amounts that exceed Transmission Demands: a) for all PODs, and b) for all POIs. The Billing Demand for the monthly billing period shall be the greater of the highest one-hour POD sum or highest one-hour POI sum.

D. INTERRUPTION OF SERVICE

If Short-Term Nonfirm Transmission Service is interrupted, the rates in section II.B. shall be prorated over the total hours in the period (month, week, day) to give credit for the hours of such interruption.

E. RESERVATION FEE FOR TRANSMISSION CAPACITY

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service will be subject to the Reservation Fee for Transmission Capacity specified in section II.P. of the General Rate Schedule Provisions.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE IM-96
MONTANA INTERTIE TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule is available for Firm and Nonfirm Transmission Service on BPA's share of Montana Intertie transmission capacity. Terms and conditions of service are specified in the PTP Transmission Service Tariff. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

A. FIRM TRANSMISSION RATE

The charge shall be 1 or 2.

1. EMBEDDED COST

a. Annual/Monthly Service

$1.234 per kilowatt per month.

b. Weekly Service

$0.285 per kilowatt per week.

c. Daily Service

$0.057 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.285 times the highest amount in kilowatts reserved in any calendar day during the week.

2. OPPORTUNITY COST

For applications for new firm service or increases in current firm service, Opportunity Costs may be charged if those costs are higher than the rates in section II.A.1.

B. SHORT-TERM NONFIRM RATE

1. MONTHLY SERVICE

The charge shall not exceed $1.234 per kilowatt per month.

2. WEEKLY SERVICE

The charge shall not exceed $0.285 per kilowatt per week.

3. DAILY SERVICE

The charge shall not exceed $0.057 per kilowatt per day.

The total charge in any one calendar week shall be no more than the product of $0.285 times the highest amount in kilowatts reserved in any calendar day during the week.

C. HOURLY NONFIRM TRANSMISSION RATE

The charge shall not exceed 3.56 mills per kilowatthour.

SECTION III. BILLING FACTORS

A. FIRM AND SHORT-TERM NONFIRM TRANSMISSION

The Billing Demand for each charge specified in section II.A.1. and II.B. shall be the greater of: 1) the sum of the relevant Point of Interconnection Transmission Demands that correspond to the current billing month, or 2) the sum of the relevant Point of Delivery Transmission Demands that correspond to the current billing month.

The billing factors for Firm Transmission Service under section II.A.2. shall be specified in the agreement.

B. HOURLY NONFIRM TRANSMISSION

For Hourly Nonfirm Transmission Service under section II.C., the Billing Energy shall be the monthly sum of the scheduled kilowatthours.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support IM transmission service are available under the APS rate schedule.

C. UNAUTHORIZED TRANSMISSION INCREASE CHARGE

Customers who exceed their monthly Point of Integration (POI) or Point of Delivery (POD) Transmission Demand on any hour shall be subject to the Unauthorized Transmission Increase Charge.

1. RATE

$12.00 per kilowatt month.

2. BILLING FACTOR

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its Transmission Demands at each POD and POI, to the extent practicable. For each hour, BPA will sum these amounts that exceed Transmission Demands: a) for all PODs, and b) for all POIs. The Billing Demand for the monthly billing period shall be the greater of the highest one-hour POD sum or highest one-hour POI sum.

D. INTERRUPTION OF SERVICE

If Short-Term Nonfirm Transmission Service is interrupted, the rates in section II.B. shall be prorated over the total hours in the period (month, week, day) to give credit for the hours of such interruption.

E. RESERVATION FEE FOR TRANSMISSION CAPACITY

Customers who request new or increased firm transmission service under this rate schedule and want to reserve transmission capacity to accommodate such service will be subject to the Reservation Fee for Transmission Capacity specified in section II.P. of the General Rate Schedule Provisions.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II. are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA §212

If, after review by FERC, this rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. §824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to this rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective, however, only prospectively from the date of the final FERC order granting final approval of this rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under this rate schedule prior to the effective date of such prospective modification.

SCHEDULE IE-96
EASTERN INTERTIE TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes IE-95 and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), for nonfirm transmission service on the portion of Eastern Intertie capacity above BPA's firm transmission rights. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The charge shall not exceed 1.68 mills per kilowatthour.

SECTION III. BILLING FACTORS

The Billing Energy shall be the monthly sum of the scheduled kilowatthours, unless otherwise specified in the agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support IE transmission service are available under the APS rate schedule.

SCHEDULE TGT-96
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule TGT-95 and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be either a surplus or a deficit. Such surpluses or deficits for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from nonfirm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower will be the unit rate.

If the government provides firm transmission service in its section of the Montana [Eastern] Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by the government for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer. During an estimated 1- to 3-year period following the commercial operation of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500-kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge.

However, starting 1 month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

A. NONFIRM TRANSMISSION CHARGE:

This charge will be filed as a separate rate schedule, the Eastern Intertie (IE) rate, and revenues received thereunder will reduce the amount of revenue to be collected under the Intertie Charge below.

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE:

$$\text{Intertie Charge} = \left[((\text{TAC}/12)-\text{NFR}) \times \frac{(\text{CR-EC})}{\text{TCR}}\right]$$

SECTION III. DEFINITIONS

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500-kV Transmission line including terminals, and prior to extension of the 500-kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs which are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by the government on account of any reduction in Transmission Demand, termination or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Nonfirm Revenues, which are equal to: (1) the product of the Nonfirm Transmission Charge described in II(A) above, and the total nonfirm energy transmitted over the Townsend-Garrison line segment under such charge for such month; plus (2) the product of the Nonfirm Transmission Charge and the total nonfirm energy transmitted in either direction by the Government over the Townsend-Garrison line segment for such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500-kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I; and (2) the Government's firm capacity requirement. The Government's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer which is the product of: (1) the ratio of investment in the Townsend-Broadview 500-kV transmission line to the investment in the Townsend-Garrison 500-kV transmission line; and (2) the capacity which the Government obtains in the Townsend-Broadview 500-kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

SCHEDULE MT-96
MARKET TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule MT-95 and is available for transmission service for transactions using Federal Columbia River Transmission System facilities pursuant to the Western Systems Power Pool (WSPP) Agreement. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The charge shall be determined in advance by BPA. The charge shall be based on the duration of the proposed transaction and shall not exceed the following rates.

A. HOURLY RATE

The maximum charge shall be 6.5 mills per kilowatthour where the total hourly revenues from a given transaction during a calendar day shall not exceed the product of the Daily rate and the maximum demand scheduled during such day.

B. DAILY RATE

The maximum charge shall be $.105 per kilowattday where the total demand charge revenues in any consecutive 7-day period shall not exceed the product of the Weekly rate and the highest demand experienced on any day in the 7-day period.

C. WEEKLY RATE

The maximum charge shall be $.52 per kilowattweek.

D. MONTHLY RATE

The maximum charge shall be $2.27 per kilowattmonth.

SECTION III. BILLING FACTORS

The billing factors shall be specified in advance by BPA, as to representing the transmission service use or reservation.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support MT transmission service are available under the APS rate schedule.

SCHEDULE UFT-96
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule UFT-95 unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA's Billing Procedures and GRSPs.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once in each Contract Year, BPA shall determine the following data for the facilities which have been constructed or otherwise acquired by BPA and which are used to transmit electric power:

1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used divided by the sum of Transmission Demands. The annual cost per kilowatt of Transmission Demand for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

The annual cost per kilowatt of facilities listed in the agreement which are owned by another entity, and used by BPA for making deliveries to the transferee, shall be determined from the costs specified in the agreement between BPA and such other entity.

SECTION IV. DETERMINATION OF BILLING DEMAND

Unless otherwise stated in the agreement, the factor to be used in determining the kilowatts of Billing Demand shall be the largest of:

A. The Transmission Demand in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month, the Measured Demand being adjusted for power factor; or

C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. REACTIVE POWER CHARGE

Customers taking service under this rate schedule are subject to the Reactive Power Charge specified in section II.O. of the General Rate Schedule Provisions.

B. ANCILLARY SERVICES

Ancillary services that may be required to support UFT transmission service are available under the APS rate schedule.

SCHEDULE AF-96
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule is available to customers who execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs). Bills shall be rendered and payments due pursuant to BPA’s Billing Procedures and GRSPs.

SECTION II. RATE

The charge is the sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA shall be specified in the agreement as either:

1. A lump sum advance payment;
2. Advance payments pursuant to a schedule of progress payments; or
3. Other payment arrangement, as determined by BPA.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs pursuant to BPA's Billing Procedures.

BPA’S 1996

GENERAL RATE SCHEDULE PROVISIONS

FOR POWER AND TRANSMISSION RATES

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF REVISED RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

These 1996 wholesale power and transmission rate schedules and General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC). Bonneville Power Administration (BPA) has requested that FERC make these rates and GRSPs effective on October 1, 1996, for customers who are billed by BPA on a calendar month basis and on the first day of the first billing month following that date for all other customers. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These 1996 wholesale power and transmission rate schedules and the GRSPs associated with these schedules supersede BPA's 1995 rate schedules (which became effective October 1, 1995) to the extent stated in the Availability section of each 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 Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales 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 (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

These 1996 rate schedules do not supersede any previously established rate schedule which is required, by agreement, to remain in effect.

If a provision in an executed agreement is in conflict with a provision contained herein, the former shall prevail.

C. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

D. Late Payment Provisions

Bills not paid in full on or before close of business on the due date shall be subject to an interest charge of one-twentieth percent (0.05 percent) applied each day to the unpaid amount. This interest charge shall be assessed on a daily basis until such time as the unpaid amount is paid in full.

Remittances will be accepted without assessment of the charges referred to in the preceding paragraph provided payment was received on or before the due date. The due date is the 20th day after the issue date of the bill unless the 20th day is a Saturday, Sunday, or Federal holiday, in which case the due date is the next business day. 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 previously accrued charges under such contract.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Ancillary Services Rate Discount

BPA may offer discounted rates for ancillary services available under the APS rate schedule and for Load Regulation, which also is available under the PF, IP and NR rate schedules. Discounts may be offered to reflect cost variations or to match rates available from a third party, consistent with FERC policy, *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Final Rule,* 61 Fed. Reg. 21,540 (1996), FERC Stats & Regs. ¶ 31,036 (1996) (FERC Order 888). Discounts shall be posted on the Open Access Same-Time Information System (OASIS) and will be implemented consistent with the Standards of Conduct.

B. Calculated Energy Capacity

Calculated Energy Capacity (CEC) is the amount of energy load (aMW) that a DSI could consume at a particular separately metered facility when that facility is operating at full capacity. It is the billing factor for DSI Load Shaping. BPA determines CEC for each separately metered facility based on historical DSI energy use and changes in plant technology. A separately metered facility may be an entire plant when there is only one BPA meter at that plant, or it may be a portion of a plant when there are multiple BPA metering points to that plant. BPA will revise the CEC for a particular separately metered facility on an as-needed basis, as any of the factors used in its calculation changes. BPA will provide the CEC to be applied during an Annual Billing Cycle to the customer in writing 30 days prior to the start of the cycle.

C. Conservation Surcharge (PF/NR only)

The Conservation Surcharge, where implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current conservation surcharge policy, and the customer's power sales contract with BPA. The PF and NR rate schedules are subject to the Conservation Surcharge.

D. Cost Contributions

BPA has made the following resource cost determinations:

1. The forecasted average cost of resources available to BPA under average water conditions is 19.14 mills per kilowatthour.

2. The approximate cost contribution of different resource categories to each rate schedule is as follows:

Rate Schedule	*Resource Cost Contribution*		
	Federal Base System	**Exchange**	**New Resources**
PF-96	83.95%	16.05%	0%
IP-96	0%	94.70%	5.30%
NR-96	0%	94.70%	5.30%
FPS-96	0%	94.70%	5.30%

E. Curtailment Charge (IP only)

Curtailment charges are charges assessed for power and transmission demand charges pursuant to section 9 of a DSI's 1981 Contract for failure to purchase an amount of power equal to 75 percent of the DSI's Operating Demand.

F. Delivery Charge

Transmission customers taking service under the PTP, NT, and NTP rate schedules and transmission customers increasing their firm service under the IR rate shall pay a Delivery Charge for service over Utility and DSI Delivery Facilities.

1. Delivery Charges

a. DSI

Service over DSI Delivery facilities is charged at the Use-of-Facilities rate.

b. Utility

For service over Utility Delivery facilities (i.e., service at voltages below 34.5 kV), the charge is $0.750 per kilowatt per month.

2. Utility Delivery Charge Billing Factors

The billing factor for transmission customers taking service under the PTP and NT rate schedules and for increases in firm service under the IR rate is specified in section 2.a., below. The billing factor for NTP customers, with the exception of Computed Requirements Customers (CRCs) under certain conditions, is also shown in section 2.a, below. The billing factor in section 2.a. applies to CRCs who, during Heavy Load Hours (HLHs), do not purchase power under 1981 Contracts. The billing factor for CRCs under the NTP rate schedule who purchase power under 1981 contracts during HLHs is specified in section 2.b., below.

a. All Transmission Customers Except Computed Requirements Customers Who Do Not Purchase Power Under 1981 Contracts During HLHs

The monthly billing demand for the charge specified in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as Utility Delivery facilities.

b. Computed Requirements Customers Who Purchase Power Under 1981 Contracts During HLHs

The monthly billing demand for the charge specified in section 1.b. shall be the total load at the Points of Delivery specified as Utility Delivery facilities that occurs on the hour of the highest monthly HLH Measured Demand for power delivered under the 1981 Contract, measured coincidentally across the customer's PODs. For CRCs who do not waive CMR, this is the same hour that is determined by the NTP Base charge billing factor.

3. Other Provisions

a. Metering Adjustment

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand under section 2.a. shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.74.

b. Utility Delivery Charge Billing Factor Adjustment

The monthly Utility Delivery billing factors in section 2 shall be adjusted for customers who pay for Utility Delivery facilities under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

G. Deviation Adjustment

The Deviation Adjustment applies to Partial Requirements Purchasers and may apply to Full Requirements Purchasers under the 1996 Contract.

1. Monthly Application of Deviation Adjustment

Deviation is the difference between the quantity of power that was actually taken from BPA (Measured Energy) and the quantity the customer is entitled to receive under its Contract Obligation. If a customer's Measured Energy exceeds its Contract Obligation, the deviation is a positive deviation. If its Measured Energy is less than its Contract Obligation, the deviation is negative. The customer is allowed a limited amount of deviation from its Contract Obligation without incurring an Unauthorized Increase Charge or an adjustment for take-or-pay obligations; this Authorized Deviation is specified in the customer's power sales contract. When the customer's deviation for an hour, day, or month exceeds the limit allowed under the contract, the excess deviation is unauthorized. Unauthorized Negative Deviations are treated as take-or-pay amounts, added to the Measured Energy, and billed at the appropriate rate. Unauthorized Positive Deviations are subtracted from the Measured Energy and billed at the Unauthorized Increase Charge.

2. Annual Application of the Deviation Adjustment

The *Annual Billing Cycle* is the 12 months beginning with the customer's first monthly power bill for deliveries starting on or after October 1.

a. Rate Period Excess Purchases

If, at the end of each Annual Billing Cycle, BPA determines that the Purchaser has taken more power under the PF, IP, or NR rate than its actual Total Retail Load or Total Plant Load for the previous year, then the Purchaser shall be subject to the Unauthorized Increase Charge for all such excess purchases. This power shall be treated as an Unauthorized Positive Deviation, subtracted from the Measured Energy for the last month or months of the Annual Billing Cycle, and billed at the Unauthorized Increase Charge.

b. Unreturned Diverted Power

If, at the end of each Annual Billing Cycle, the Purchaser has not taken return of all of its Diverted Power for the year, then the Purchaser shall be subject to the Unauthorized Increase Charge for all Diverted Power that was not returned to the Purchaser's system during the year. This power shall be treated as an Unauthorized Positive Deviation, subtracted from the Measured Energy for the last month or months of the Annual Billing Cycle, and billed at the Unauthorized Increase Charge.

H. Energy Return Surcharge (PF/NR/FPS only)

Any purchaser:

1. who preschedules in accordance with sections 2(a)(4) and 2(c)(2) of Exhibit E of the 1981 Contract and who returns, during a single offpeak hour, more than 60 percent of the difference between that Purchaser's Billing Demand and Computed Average Energy Requirement for the billing month, or

2. who purchases capacity under the FPS rate schedule and returns more than 60 percent of its Contract Demand for the billing month during a single offpeak hour, and is subject to the Energy Return Surcharge

shall be subject to the following charge for each additional kilowatthour so returned:

- 2.44 mills per kilowatthour for the months of September - December;
- 2.42 mills per kilowatthour for the months of January - March;
- 3.27 mills per kilowatthour for the month of April;
- 3.79 mills per kilowatthour for the months of May - June;
- 4.11 mills per kilowatthour for the month of July;
- 4.91 mills per kilowatthour for the month of August.

FPS purchasers are subject to the Energy Return Surcharge stated above unless their agreement with BPA specifically provides otherwise.

I. Guaranteed Delivery Charge (NF only)

A surcharge of 2.00 mills per kilowatthour of Billing Energy is applied whenever BPA guarantees delivery of nonfirm energy to a Purchaser under the NF Standard rate or Market Expansion rate.

J. Local Stability Reserves Adjustment (IP/IPG/VI only)

A credit of 1.48 mills per kilowatthour shall be applied to the Purchaser’s Billing Energy for any customer that provides local stability reserves pursuant to the Bellingham Area Load Tripping Scheme. No credit shall be applied to those purchases subject to unauthorized increase charges.

K. Low Density Discount (PF/NR only)

1. Basic LDD Principles

A predetermined discount shall be applied each billing month to the charges for all power (excluding transmission services) purchased under the PF and NR rate schedules by eligible purchasers as defined in section 2, below. The discount shall be calculated on an annual basis and shall become effective with the first billing period in the calendar year.

a. <u>The KWh/Investment Ratio</u>

The KWh/Investment (K/I) ratio is calculated by dividing the Purchaser's total electric energy requirements during the previous calendar year by the value of the Purchaser's depreciated electric plant (excluding generation plant) at the end of such year. The Purchaser's total electric energy requirements include firm sales, nonfirm sales to firm retail loads, sales for resale, and associated losses. For the 5-year rate period, the Purchaser's total electric energy requirements exclude the 1996 calendar year level of nonfirm sales to nonfirm retail loads. Nonfirm energy load is electric load that is subject to interruptions or curtailment on short notice at any time for any condition, including economic and physical conditions such as power shortages and transmission limitations. The Purchaser will report nonfirm sales to nonfirm retail loads for the period January 1, 1996, through December 31, 1996, to BPA by June 30, 1997. This 1996 level of nonfirm sales to nonfirm retail loads will not be included in calculations of the K/I ratio for the 5-year rate period. Beginning January 1, 1997, however, amounts of nonfirm sales to nonfirm retail loads above the 1996 level will be included to calculate the Purchaser’s K/I ratio.

b. <u>The Consumers/Mile of Line Ratio</u>

The Consumers/Mile of Line (C/M) ratio is calculated by dividing the average number of consumers (annual and seasonal consumers with residential, industrial, commercial, and irrigation accounts, but excluding the average number of consumers associated with separately billed services for water heating, electric space heating, and security lights) during the previous calendar year by the average number of pole miles of distribution line for such year, calculated by halving the sum of the end-of-year pole mile figures for the previous year and the current 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 average annual data provided in the Purchaser's financial and operating reports that they submit periodically to BPA (usually monthly or quarterly). In calculating these ratios, BPA shall compile the data submitted by the Purchaser based on the Purchaser's entire electric utility system in the Pacific Northwest and, for Purchasers with service territories that include any areas outside the Pacific Northwest, BPA shall compile data submitted by the Purchaser separately on the Purchaser's system in the Pacific Northwest and on the Purchaser's entire electric utility system inside and outside the Pacific Northwest. BPA will apply the eligibility criteria and discount percentages to the Purchaser's system within the Pacific Northwest and, where applicable, also to its entire system inside and outside the Pacific Northwest. The Purchaser's eligibility for the LDD will be determined by the lesser amount of discount applicable to its Pacific Northwest system or to its combined system inside and outside the Pacific Northwest. BPA, in its sole discretion, may waive the requirement to submit separate data for the customer with a small amount of its system outside the Pacific Northwest. Results of the calculations shall not be rounded. Retroactive billing for the LDD may be required if the data are not available by the January billing date.

Customers who have not provided BPA with all four requisite pieces of annual data (see 1.a. and 1.b, 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. LDDs 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.

2. Eligibility Criteria

To qualify for a discount, the Purchaser must meet all six of the following eligibility criteria:

a. the Purchaser must serve as an electric utility offering power for resale;

b. the Purchaser must agree to pass the benefits of the discount through to the Purchaser's consumers within the region served by BPA;

c. the Purchaser's average retail rate for the reporting year must exceed the average applicable Priority Firm Power rate for the qualifying period by at least 10 percent. For Calendar Year (CY) 1996, the average Priority Firm Power rate shall be the average of the PF-95 Preference rate for 9 months and the PF-96 Preference rate for 3 months. For CY 1997, the average Priority Firm Power rate shall be the PF-96 Preference rate;

d. the Purchaser's K/I ratio (Ratio 1.a) must be less than 100;

e. the Purchaser's C/M ratio (Ratio 1.b) must be less than 12; and

f. the Purchaser must qualify for a discount based on the criteria in section 3, below.

3. Discounts

The Purchaser shall be awarded the lesser of the following discounts beginning October 1, 1996, which for any year shall not differ from the Purchaser's previous year's discount by more than one-half of one percent (see below):

a. 7 percent, or

b. the sum, not to exceed 7 percent, of the two potential discounts for which the Purchaser qualifies, based on the following table:

LDD Percentage Discount Table

Percentage Discount	*Applicable Range for kWh/Investment (K/I) Ratio*	*Applicable Range for Consumers/Mile (C/M) Ratio*
0.0%	$35.0 \leq X$	$12.0 \leq X$
0.5%	$31.5 \leq X < 35.0$	$10.8 \leq X < 12.0$
1.0%	$28.0 \leq X < 31.5$	$9.6 \leq X < 10.8$
1.5%	$24.5 \leq X < 28.0$	$8.4 \leq X < 9.6$
2.0%	$21.0 \leq X < 24.5$	$7.2 \leq X < 8.4$
2.5%	$17.5 \leq X < 21.0$	$6.0 \leq X < 7.2$
3.0%	$14.0 \leq X < 17.5$	$4.8 \leq X < 6.0$
3.5%	$10.5 \leq X < 14.0$	$3.6 \leq X < 4.8$
4.0%	$7.0 \leq X < 10.5$	$2.4 \leq X < 3.6$
4.5%	$3.5 \leq X < 7.0$	$1.2 \leq X < 2.4$
5.0%	$X < 3.5$	$X < 1.2$

4. LDD Phase-In Adjustment

If the Purchaser satisfies eligibility criteria 2.a.-2.e, above, and the discount calculated above differs from the existing discount by more than ½ of 1 percent, the applicable discount will be:

a. the existing discount plus ½ percent if the calculated discount exceeds the existing discount; or

b. the existing discount minus ½ percent if the calculated discount is less than the existing discount.

The foregoing formula will be applied each successive Fiscal Year until the then-current calculated discount is fully phased in.

If the Purchaser fails to satisfy eligibility criteria 2.a.-2.e. above, the applicable discount will be zero.

5. Additional Adjustment for Very Low Densities

If a Purchaser's C/M ratio is 3 or less and its K/I ratio is 26 or less, *after* determination of the discount pursuant to sections 3 and 4 above, an additional ½ percent shall be added to the Purchaser's discount, but the total discount shall not exceed 7 percent. In subsequent years, the ½ percent added to the discount pursuant to this section shall not be included when determining the applicable discount in section 4 above.

L. NF Rate Cap

1. Application of the NF Rate Cap

The NF Rate Cap defines the maximum nonfirm energy price for general application. At no time shall the total price for BPA's nonfirm energy, including any applicable service charges or rate adjustments, sold under any applicable rate schedule exceed the NF Rate Cap. The level of the NF Rate Cap is based on a 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 October 1, 1987.

2. Monthly Customer Notification of the Value of the NF Rate Cap

Prior to the beginning of each calendar month, BPA shall determine the effective NF Rate Cap for that month. BPA is obligated to provide advance notification of the NF Rate Cap level to purchasers of nonfirm energy. This notification requirement does not apply if BPA does not intend to offer Nonfirm Energy at prices above BPA's Average System Cost (BASC) at any time during a month. BPA shall give the notification to the purchasers at least 10 calendar days prior to the first day of any calendar month in which the NF Rate Cap is expected to apply. BPA shall also maintain, on file for public review, a record of the NF Rate Cap by month throughout the 12-year period that 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 + [0.30 * (DEC - BASC)]

where:

BASC = BPA's Average System Cost
DEC = The Decremental Fuel Cost

4. Determination of BPA’s Average System Cost (BASC)

BPA’s Average System Cost is calculated by dividing BPA’s Total System Costs by BPA’s Total Annual System Sales, where:

a. *BPA's Total System Costs* are 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* are the sum of all BPA's system firm and nonfirm energy sales forecasted each general rate case for the applicable test period.

BASC shall be redetermined in each 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. For this rate period BASC has been determined to be 27.11 mills per kilowatthour.

5. Determination of the Decremental Fuel Cost (DEC)

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. All quantities are to be rounded to the nearest tenth of a mill in making the calculation.

The monthly decremental fuel cost shall be calculated using the following formula:

DEC = [(MGP * WGU) + (MOP * WOU)] / (WGU + WOU)

where:

MGP	=	the monthly California gas price
WGU	=	historical gas use in California
MOP	=	the monthly California petroleum price
WOU	=	historical petroleum use in California

a. <u>Determination of MGP, the Monthly California Gas Price</u>

MGP = 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 <u>Electric Power Monthly</u> (EPM) published by the Energy Information Administration (EIA), U.S. Department of Energy.

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:

i. 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 MGPs were reported and rounded to the nearest one-tenth of a cent;

ii. 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 MGPs were reported and rounded to the nearest one-tenth of a cent; and

iii. dividing the average monthly California gas price in "i" above, by the average monthly California gas price in "ii" 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 kilowatthour.

b. <u>Determination of WGU, Historical Gas Use in California</u>

WGU = CGU * HGU

where:

CGU = the monthly net gas-fired generation, expressed in gigawatthours, for California in the most recent monthly issue of EPM published by the EIA, U.S. Department of Energy.

HGU = the historical relationship between gas consumption 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:

i. 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;

ii. 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; and

iii. dividing the average consumption of gas in California for the month t as determined in “i” above by the average consumption of gas for the month r as determined in “ii” above and rounding to the nearest one-tenth, or three significant places.

c. Determination of MOP, the Monthly California Petroleum Price

MOP = AOP * HOP / 10

where:

AOP = same as AGP except the input data is for the average petroleum price (as opposed to the gas price).

HOP = same as HGP, except the data is for the petroleum price (as opposed to the gas price).

10 = the same conversion factor as used for converting the gas data.

d. Determination of WOU, Historical Petroleum Use in California

WOU = COU * HOU

where:

COU = the same as CGU except the data for monthly net petroleum-fired generation is used instead of the gas data.

HOU = the same as HGU, except the data for petroleum consumption is used instead of the gas data.

6. Changes in Data Sources

In the event that the data used to compute the NF Rate Cap become unavailable, BPA may identify and substitute other data sources for the purpose of calculating the monthly NF Rate Cap. As a result of this data substitution, it also may be necessary to modify the NF Rate Cap methodology to achieve an NF Rate Cap that is substantially equivalent in rate level to that which would have resulted from continued use of the data described in section 5, above.

BPA shall notify interested parties of its intent to substitute data sources or to substitute data sources and change the NF Rate Cap methodology at least 120 days prior to the billing month in which the change would become effective. In this notification, BPA shall explain the reason(s) for the proposed changes and describe its proposed alternative. Interested persons will have until close of business three weeks from the date of the notification to provide comments. Consideration of comments and more current information may cause the final data sources and the final NF Rate Cap methodology to differ from BPA's initial proposal. BPA shall notify all affected parties, and those parties that submitted comments, of its final determination 90 days prior to the billing month in which the new NF Rate Cap parameters (data sources/methodology) become effective.

M. Operating Reserves Adjustment (IP/IPG/VI only)

The energy charges stated in the IP-96 rate schedules reflect a 2.73 mills per kilowatthour credit for the operating reserves a DSI provides to BPA pursuant to its power sales contract. If a DSI chooses not to provide operating reserves, a billing adjustment will be made to remove the effect of the credit.

N. Phase-In Mitigation

The phase-in mitigation is available for Full or Metered Requirements Preference customers. Phase-in mitigation does not apply to PF power purchased under a Residential Purchase and Sale Agreement or an Exchange Transmission Credit Agreement.

1. Eligibility Criteria

To qualify for the phase-in mitigation, a purchaser must:

a. be a Full Requirements customer of BPA as designated in the 1996 Contract, or a Metered Requirements customer of BPA as designated in the 1981 Contract;

b. agree to purchase all power from BPA for 5 years under one or more of BPA's 5-year rate schedules; and

c. have a rate increase greater than 9 percent for all BPA purchases, rounded to the nearest one-tenth of a percent, based on the determination in section 2 below.

2. Determination of Rate Increase for Phase-In Mitigation

The percentage rate increase faced by a Full or Metered Requirements purchaser will be calculated as follows:

a. Apply all applicable 1993 rate schedule (PF, NR, etc.) charges to the individual customer's FY 1997 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

b. Apply all applicable 1996 rate schedule (PF, NR, transmission, etc.) charges to the individual customer's FY 1997 expected BPA purchases, as forecasted in the 1996 rate case by BPA.

c. If the value of 2.b minus the value of 2.a, divided by 2.a, is greater than 9 percent, rounded to the nearest tenth of a percent, the customer may notify BPA by letter to their Account Executive to phase in the 1996 rate increase. Such notice must be received by BPA by September 1, 1996. Purchasers may not apply for mitigation after that time.

3. Rate Adjustment

If the purchaser meets the eligibility criteria and requests BPA to phase in its 1996 rate increase, beginning October 1 of each year BPA will limit the monthly increase in the customer's bill to 9 percent in the first year, with additional 9-percent increments in each subsequent year over the effective period of the 1996 5-year rates.

The adjustment will be based on the difference between: (1) the purchaser's total monthly payment assuming the 1993 rates for the billing month were applied to power purchases for that month; and (2) the purchaser's total monthly payment under the 1996 rates for that month. In the first year, if the difference between the two is equal to or less than 9 percent, no adjustment will be made to the purchaser's monthly bill. If the difference between the two is greater than 9 percent, an adjustment will be made such that the monthly bill to that customer will reflect an increase equal to 9 percent. In subsequent years, no adjustment shall be made if the difference between (1) and (2) above is less than or equal to 18 percent in the second year, 27 percent in the third year, 36 percent in the fourth year, and 45 percent in the fifth year.

O. Reactive Power Charge

1. Description of the Reactive Power Charge

A Purchaser that purchases power under BPA's wholesale power rate schedules or transmission service on the Federal Columbia River Transmission System (FCRTS) under BPA's transmission rate schedules shall be charged for its Reactive Power requirements for such power or transmission service as described in this section, unless otherwise specified in an agreement existing prior to October 1, 1995.

The Reactive Power Charge replaces the Power Factor Adjustment provision included in BPA's 1995 wholesale power rate schedules. Purchasers previously granted Power Factor Adjustment waivers under BPA's prior wholesale power rate schedules shall be subject to the Reactive Power Charge.

If a Purchaser is taking delivery of real power at a point of delivery or point of integration under multiple rate schedules, the Purchaser will pay for its Reactive Power requirements at that point as if it is taking delivery under only one rate schedule. Each point of integration and point of delivery shall be monitored and billed independently for determining the Purchaser's total Reactive Power requirements and all associated billing factors, including the Reactive Deadband.

The charges for a Purchaser's Reactive Power requirements under this subsection shall be subject to the provisions of BPA's Billing Procedures.

2. The Purchaser's Reactive Power Requirements

The Purchaser's Reactive Power requirements shall be measured at each point of delivery and at each point of interconnection where the metered real power (MW) flow is unidirectional and the Purchaser is taking delivery of real power, either Federal or non-Federal. For points of interconnection, the metered real power flow must be unidirectional on all hours during the billing month.

3. Conditions for Application of the Reactive Power Charge

a. Measured Data

The Reactive Power Charge will apply to only the Purchaser's Reactive Power requirements for which measured data exist.

b. Purchaser's Generating Resource Connected to the FCRTS

The Reactive Power Charge shall apply to points of integration where a Purchaser's generating resource is directly connected to the FCRTS, *unless* the Purchaser's generating resource is either:

i. a synchronous generator equipped with a voltage regulator, or

ii. equipped with Reactive Power control devices that comply with BPA's applicable interconnection standards.

Such resource must actively support the voltage schedule at the point of integration at all times when the resource is in service, as determined by BPA, for this exemption to apply. Generating resources that do not satisfy the above criteria shall not be exempt from the Reactive Power Charge.

c. Bidirectional Real Power Flow

The Reactive Energy Charge will *not* be applied, and no new Ratchet Demand for Reactive Power will be established, at a specific point if the metered real power (on an hourly integrated basis) flows from the Purchaser's system to the FCRTS at that point for as little as one hour during the billing period. However, the Purchaser will still pay any previously incurred demand ratchet charges. The direction of the real power flow will be determined based on metered quantities, not on scheduled quantities.

d. Service by Transfer

Points of delivery that are served by transfer over another utility's transmission system will not be subject to the Reactive Power Charge unless (1) the transferor imposes a reactive power charge on BPA for serving such Purchaser's load or (2) there are BPA Network facilities between the Purchaser's points of delivery and the transferor's system.

e. Specific Points Exempt from the Reactive Power Charge

The Reactive Power Charge will *not* apply to the following points:

Nevada-Oregon Border (NOB)
Big Eddy 500kV
Big Eddy 230kV
John Day 500kV
Malin 500kV
Captain Jack 500kV
Garrison 500kV
Townsend 500kV

f. Special Circumstances

The Purchaser may submit requests to BPA for consideration of unique circumstances. BPA will evaluate the request and may make arrangements with the Purchaser to address the special circumstances.

4. Rate

BPA will bill the Purchaser for Reactive Power at each point each month as follows:

a. Reactive Demand

$0.08 per kVAr of lagging reactive demand in excess of the Reactive Deadband during HLH in all months of the year.

$0.06 per kVAr of leading reactive demand in excess of the Reactive Deadband during LLH in all months of the year.

No charge for leading reactive demand during HLH.

No charge for lagging reactive demand during LLH.

b. Reactive Energy

0.53 mills per kVArh for all lagging reactive energy in excess of the Reactive Deadband during all HLH of all months of the year.

0.53 mills per kVArh for all leading reactive energy in excess of the Reactive Deadband during all LLH of all months of the year.

No charge for leading reactive energy during HLH.

No charge for lagging reactive energy during LLH.

5. Billing Factors

a. Reactive Deadband

The Reactive Deadband (measured in kVAr) is used to determine the Reactive Billing Demand, Reactive Billing Energy, and Ratchet Demand for Reactive Power.

The Reactive Deadband for the billing periods commencing with the effective date of this provision through September 30, 1999, is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 33 percent (equivalent to a 0.95 power factor). The Reactive Deadband for each billing period after September 30, 1999, is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 25 percent (equivalent to a 0.97 power factor).

The Reactive Deadband for either HLH or LLH:

i. is computed once per billing period,

ii. does not vary during the billing period,

iii. is based on the maximum hourly integrated metered real power demand during that billing period, and

iv. is applied to both reactive demand and reactive energy.

b. <u>Reactive Billing Demand</u>

The Purchaser's Reactive Billing Demand shall be calculated independently for lagging Reactive Power and leading Reactive Power at each point for which a Reactive Power Charge is assessed.

All reactive demands shall be established in the particular Peak Period (HLH) or Offpeak Period (LLH) hour at each point during which the Purchaser's maximum applicable reactive demand is placed on BPA, regardless of the time of the real power peak at each point.

All reactive demand at each point shall be established on a non-coincidental basis, regardless of whether the Purchaser is billed for real power or transmission at such point on a coincidental or non-coincidental basis, *unless* otherwise specified in the agreement between BPA and the Purchaser, *or* coincidental billing is, in BPA's sole determination, more practical for BPA.

There will be separate reactive demands for lagging (HLH) and leading (LLH) demands. The Purchaser's Reactive Billing Demand for each point for the billing month shall be the *larger* of:

i. the largest measured reactive demand in excess of the Reactive Deadband during the billing period, *or*

ii. the Ratchet Demand for Reactive Power.

The Ratchet Demand for Reactive Power is equal to 100 percent of the largest measured reactive demand in excess of the Reactive Deadband during the preceding 2-year, 11-month period. The Ratchet Demand for Reactive Power for the 2-year, 11-month period preceding October 1, 1996, will be set at zero. Each point shall have a separate Ratchet Demand for lagging (HLH) and leading (LLH) reactive demand.

c. Reactive Billing Energy

The Purchaser's Reactive Billing Energy at each point shall be the sum of the hourly integrated metered reactive energy, in excess of the Reactive Deadband, delivered at such point during the billing period. (This quantity is the sum of the absolute values in excess of the Reactive Deadband, *not* the net value created by summing the positive/lagging reactive energy and the negative/leading reactive energy.)

6. Additional Adjustments

a. Resetting of the Ratchet Demand

BPA shall reset the Ratchet Demand to zero for either the HLH or LLH period for the Purchaser's Reactive Power for any point of delivery or point of interconnection if BPA determines that the following criterion is met:

The Purchaser has reduced its Reactive Power demand to 25 percent or less of its real power demand (i.e. has maintained at least a 0.97 power factor) at such point on all hours, in the respective diurnal period (HLH or LLH), for a 12-month continuous period following the setting of the ratchet.

b. Adjustment for Reactive Losses

Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand and Reactive Billing Energy.

P. Reservation Fee for Transmission Capacity

1. Conditions for Application of Reservation Fee

The Reservation Fee is available to customers who enter into an agreement for firm transmission service and want to postpone taking such service until a later date. The Reservation Fee will reserve transmission capacity for one year. A transmission customer can request yearly extensions up to a total reservation period of five (5) years. If during the reservation period, another customer requests service which can only be satisfied out of the reserved capacity, then the customer with the reservation must agree to pay the full monthly charge for the firm transmission service. Payment of the full charge becomes effective on the date when service under the competing request was to become effective. In the event the customer with the reservation elects to release the reserved capacity, the Reservation Fees paid for the current and past years will be forfeited.

2. Reservation Fee

The Reservation Fee shall be a nonrefundable fee equal to one month's charge for firm transmission service for each year or fraction of a year in which the customer chooses to postpone service. The Reservation Fee shall be paid in a lump sum within 30 days of the date the agreement is executed, and, for yearly extensions, within 30 days of the beginning of the extension. The Reservation Fee shall be assessed annually until transmission service begins or the reservation period ends, whichever occurs first. The Reservation Fee shall be specified in the executed agreement for transmission service.

3. Billing Factors

The billing factors shall be the same as the type of transmission service requested, as determined pursuant to the applicable transmission rate schedule.

Q. Transitional Service--Application of Rates During Initial Operation Period

Under the 1981 Contract, and as specified in BPA's Billing Procedures, BPA may agree to bill the purchaser for Transitional Service. Transitional Service shall apply to DSIs having new, additional or reactivated plant facilities, and utility purchasers serving industrial purchasers with power purchased from BPA. Transitional Service will not be available under the 1996 Contract.

If the purchaser requests billing on a Daily Demand basis pursuant to its power sales contract and if BPA agrees to such billing, the kilowatt Billing Demand for the billing month shall be based on one of the following billing methods, as agreed to by BPA and the purchaser, based on load characteristics and consistent with the procedures outlined in BPA's Billing Procedures. If for any reason agreement is not reached on a billing method, #1 below shall serve as a default billing method. Reactive power will continue to be billed normally.

1. <u>Weighted Monthly Average of Daily Billing Demand</u>

The Billing Demand for each day is the maximum metered amount for any hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

2. Weighted Monthly Average of Daily HLH Billing Demand

The Billing Demand for each day is the maximum metered amount for any HLH hour of that day. For the negotiated transitional period, each day's Billing Demand is averaged with the Billing Demand of every other day in the transitional period to compute the transitional period average. For the remaining period of the billing month, if any, the Billing Demand is the highest of the daily maximum metered amounts. To compute the Billing Demand for the month, the average Billing Demand for the transitional period and the Billing Demand for the remaining period are averaged, weighting each average by the number of days in each period.

R. Unauthorized Increase Charge

If specified in the applicable rate schedule, BPA shall apply the charge for Unauthorized Increase to any purchaser taking demand and energy in excess of its contractual entitlement.

1. Charge for Unauthorized Increase

a. Demand Charge: Demand Charge from applicable power rate schedule.

b. Energy Charge: 100 mills per kWh in all months of the year.

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 shall apply the amount of Unauthorized Increase related to demand and the amount of Unauthorized Increase for energy to each hour of integrated or scheduled demand unless otherwise specified in the purchaser's contract.

a. Unauthorized Increase in Demand

That portion of any Measured Demand that 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;

2. to a type of power that the purchaser acquires from sources other than BPA and that BPA delivers during such hour; or

3. to an authorized deviation or allowable increase in service (specified in the 1996 Contract) from the purchaser’s Contract Obligation,

shall be billed:

1. in accordance with the provisions of the "Relief from Overrun" exhibit to the 1981 Contract; or

2. at the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the Purchaser's power sales contract.

b. Unauthorized Increase in Energy

The amount of Measured Energy during a billing month that exceeds the amount of energy the purchaser is contractually entitled to take during that month and which cannot be assigned:

1. to a class of power BPA delivers during such month pursuant to contracts between BPA and the purchaser;

2. to a type of power the purchaser acquires from sources other than BPA and which BPA delivers during such month; or

3. to an authorized deviation or allowable increase in service (specified in the 1996 Contract) from the purchaser’s Contract Obligation,

shall be billed:

1. in accordance with the provisions of the "Relief from Overrun" exhibit to the 1981 Contract; or

2. at the rate for Unauthorized Increase if such exhibit does not apply or is not a part of the purchaser's power sales contract.

c. Application of Annual Deviation Adjustments

Amounts of Measured Energy that are identified as Rate Period Excess Purchases, or Unreturned Diverted Power, shall be billed at the Unauthorized Increase Charge during the last month or months of the Annual Billing Cycle.

S. Utility Factor

For utility purchasers under the 1981 Contract with no Industrial Exemption, charges for Full Load Shaping and Load Regulation are multiplied by a utility-specific, annual Utility Factor. For utility purchasers under the 1981 Contract who select an Industrial Exemption, the Full Load Shaping charge is multiplied by an Adjusted Utility Factor that is calculated monthly. An Industrial Exemption does not affect the Utility Factor for Load Regulation.

The Utility Factors to be used for billing will be developed annually based on historical data provided by the customers to BPA. Previous calendar year data (January 1-December 31) will be used to develop a Utility Factor that will be in effect for the following fiscal year (October 1 - September 30). The customer shall submit its end of calendar year Financial and Operating Report and Generation Report (if applicable). BPA will develop a customer's Utility Factor once it has received all necessary data from the customer (usually in April). If a customer has not submitted the required data by June 1, BPA will prepare an estimate of the customer's historical annual Total Retail Load for the previous calendar year, after consultation with the customer, and prepare the Utility Factor from that estimate. Completed Utility Factors will be provided to the customers. The first effective year for Utility Factors coincides with the first year of implementation of the new rate structure: October 1, 1996-September 30, 1997. Historical data from the previous calendar year (January 1, 1995-December 31, 1995) will be used to develop the Utility Factor for this first year.

The Load Shaping and Load Regulation Utility Factors are calculated alike, with the exception that for the Utility Factor applied to Full Load Shaping and the Adjusted Utility Factor, New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract are excluded from the calculation of Total Retail Load. For each Metered Requirements customer, the utility factor calculation uses the customer's annual historical BPA purchases as the divisor. For each Actual Computed Requirements customer, the Utility Factor calculation uses the customer's annual historical Computed Energy Maximum as the divisor. Utility Factors are calculated as follows:

Load Regulation

For Metered Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load for the previous calendar year ÷ BPA energy purchases for the previous calendar year. The result of this calculation is capped at 6.

For Computed Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load for the previous calendar year ÷ Computed Energy Maximum for the previous calendar year. The result of this calculation is capped at 6.

Full Load Shaping

For Metered Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load, excluding New Large Single Loads served by dedicated resources pursuant to section 8(e) of the 1981 Contract, for the previous calendar year ÷ BPA energy purchases for the previous calendar year. The result of this calculation is capped at 6.

For Computed Requirements Customers:
The Utility Factor for the applicable fiscal year = customer Total Retail Load, excluding New Large Single Loads served by dedicated resources pursuant to section 8(e) of the 1981 Contract, for the previous calendar year ÷ Computed Energy Maximum for the previous calendar year. The result of this calculation is capped at 6.

Full Load Shaping with an Industrial Exemption (Adjusted Utility Factor)

For Metered Requirements Customers:
The Adjusted Utility Factor for the month =
(one-twelfth of the customer's previous calendar year Total Retail Load, excluding New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract, minus the Industrial Exemption load forecast for the current month) ÷
(one-twelfth of the customer's BPA purchases for the previous calendar year minus the Industrial Exemption load forecast for the current month).

For Computed Requirements Customers:
The Adjusted Utility Factor for the month =
(one-twelfth of the customer's previous calendar year Total Retail Load, excluding New Large Single Loads served with dedicated resources pursuant to section 8(e) of the 1981 Contract, minus the Industrial Exemption load forecast for the current month) ÷
(one-twelfth of the customer's total Computed Energy Maximum for the previous calendar year minus the Industrial Exemption load forecast for the current month).

SECTION III. DEFINITIONS

A. Products and Services Offered by BPA

1. Ancillary Services

Ancillary Services are those services necessary to support the transmission of electric power from resources to load while maintaining reliable operation of the FCRTS. Ancillary services include: Energy Imbalance, Control Area Reserves for Resources, Control Area Reserves for Interruptible Purchases, Load Regulation, and Transmission Losses. Ancillary services are available under the APS-96 rate schedule.

2. Construction, Test and Start-Up, and Station Service

Power for the purpose of *Construction, Test and Start-Up, and Station Service* for a generating resource or transmission facility shall be made available to eligible purchasers under the Priority Firm Power, New Resources Firm Power, and Firm Power Products and Services rate schedules.

Construction, test and start-up, and station service power must be used in the manner specified below:

a. Power sold for construction is to be used in the construction of the project.

b. 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.

c. Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Purchaser may use station service power for start-up, shut-down, normal operations, and operations during a shut-down period.

d. Power sold for construction, test and startup, and station service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

3. Control Area Reserves for Resources

Control Area Reserves for Resources are the control area services necessary to back up generation located in BPA's control area. Control Area Reserves for Resources provides the generation following needs and operating reserves obligations required for the generation in BPA's control area or by the transmission provider for the remainder of the delivery hour.

4. Control Area Reserves for Interruptible Purchases

Control Area Reserves for Interruptible Purchases are the non-spinning operating reserve obligations provided by BPA for interruptible energy delivered to BPA's control area. Interruptible energy is defined as energy deliveries that can be interrupted by the delivering control area or transmission provider during the delivery hour.

5. Control Area Services

Control Area Services are services that BPA provides to the Purchaser for real-time fluctuations in loads and resources during the delivery hour. With these services, BPA will deliver power in amounts that change automatically in response to changes in loads or resource output located in BPA's control area. These services meet the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP) for regulating margin and spinning and non-spinning operating reserves. In addition, BPA also may provide similar services to loads and resources outside BPA's control area. The general category, Control Area Services, includes:

a. Control Area Reserves for Resources;

b. Control Area Reserves for Interruptible Purchases;

c. Load Regulation;

d. Eccentric Load Following;

e. Supplemental Control Area Services

f. Interconnected Operation Services

g Other control area services.

6. DSI Non-Take-or-Pay Option

Purchase of the *DSI Non-Take-or-Pay Option* allows a DSI customer, for a fee, to purchase power under the IP rate without a take-or-pay obligation. To purchase this product, the Purchaser must have signed a 1996 Contract for specified amounts of non-take-or-pay load. The charge for this product is assessed per kilowatthour of the Purchaser's Billing Energy.

7. Eccentric Load Following

Eccentric Load Following provides instantaneous (second-to-second) regulation of firm power supply for a Purchaser's actual real-time eccentric load within the hour. An eccentric load is defined as any specific cyclic customer or consumer load with the ability to change periodically more than 50 MW in level at a rate of greater than 50 MW per minute, regardless of the duration of this change. Eccentric Load Following is included in Load Regulation service.

8. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with transmission to a load located in BPA's control area or from a generation resource located within BPA's control area. BPA allows an hourly Energy Imbalance Band of +/- 1.5 percent of the scheduled transaction (with a required minimum band of +/- one megawatt) to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transactions.

> *Positive Deviation* occurs on any hour when BPA delivers more energy to the Receiving Party at the Point of Delivery than BPA receives from the Delivering Party at the Point of Integration.
>
> *Negative Deviation* occurs on any hour when BPA receives more energy from the Delivering Party at the Point of Integration than BPA delivers to the Receiving Party at the Point of Delivery.

Energy Imbalance applies only to Points of Integration and/or Points of Delivery associated with generation resources and loads located within BPA's control area. Energy imbalances at interconnections between BPA's control area and other control areas shall be in accordance with the NERC and WSCC guidelines regarding control area operations.

BPA will establish and maintain separate accounts for HLH and LLH Positive and Negative Deviations for both within and outside the Energy Imbalance Band. The accounts shall be settled at the close of each billing month. For deviations occurring within the Energy Imbalance Band, the rate is applied to the Net Monthly Deviation, which is the difference between the Positive and Negative HLH and LLH deviations for the month.

9. Firm Capacity without Energy

Firm Capacity without Energy is a product available under the PF-96 and NR-96 rate schedules to Computed Requirements customers who hold 1981 Contracts. Customers who buy this product may take power from BPA during HLH and must return the associated energy within 24 hours. This product is also offered under the FPS rate schedule with delivery and return provisions that may differ from those available under the 1981 Contract.

10. Firm Power

Firm Power available at the FPS rate is defined as firm energy with capacity, firm energy without capacity, and/or firm capacity that BPA may make available to the purchaser at BPA's discretion. Energy associated with the delivery of firm capacity must be returned to BPA either before or after delivery of the capacity and in a manner consistent with the agreement between BPA and the Purchaser.

Firm Power may be used either for resale or direct consumption by purchasers both inside and outside the United States. Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP). Firm Power is also available for various unbundled products, including:

a. Power supplied for emergency use;

b. Replacement of lost generation during forced outages;

c. Replacement of lost generation during planned outages;

d. Displacement of higher-cost firm capacity resources which are otherwise available to meet the purchaser's load;

e. Supplemental non-spinning operating reserves; and

f. Other purposes.

11. Firm Transmission Service

Under the Point-to-Point Service Tariff, *Firm Transmission Service* is Long-Term Firm Transmission Service and Short-Term Firm Transmission Service over the FCRTS that is reserved and/or scheduled on a firm basis and that is of the same priority as that of BPA's firm use.

Long-Term Firm Transmission Service is reserved and/or scheduled for a term of one (1) year or more and is of the same priority as that of BPA's firm use of the FCRTS.

Short-Term Firm Transmission Service is reserved and/or scheduled for a minimum duration of one (1) calendar day up to one (1) year and is of the same priority as that of BPA's firm use of the FCRTS.

12. Fixed Curtailment Fee

The *Fixed Curtailment Fee* gives a DSI purchasing take-or-pay energy under a 1996 Contract the right to curtail its plant load below the sum of (1) its take-or-pay obligation and (2) any amount of non-Federal service the customer identifies at the time it elects this curtailment option. The Fixed Curtailment Fee is assessed per kilowatthour of Curtailed Energy.

13. Generation Following

Generation Following is the instantaneous (second-to-second) regulation of the supply of firm power that BPA provides to follow variations in customers' resources *within* the hour.

14. Hourly Nonfirm Transmission Service

Under the Point-to-Point Service Tariff, *Hourly Nonfirm Transmission Service* is Nonfirm Transmission Service over the FCRTS that is scheduled for a Preschedule Period on an hourly basis and that is of the same priority as that of BPA's nonfirm use of the FCRTS.

15. Industrial Exemption

Industrial Exemption is available to customers purchasing Full Load Shaping under the 1981 and 1996 Contracts. Industrial Exemption allows a customer to exempt certain industrial loads from load shaping charges. The exempted industrial load must be separately metered. BPA will not charge for the industrial exemption, but the utility will be required to pay for the actual load shaping BPA provides the exempt load through a separate billing factor and rate. If the exempt load loses its exemption, the industrial load becomes part of the customer's load for calculating the billing factor for Full Load Shaping, and the Utility Factor is used (rather than the Adjusted Utility Factor) to determine the charge for Full Load Shaping. The charge for load shaping for exempted loads is assessed for any (positive or negative) variations from the monthly forecast; the Purchaser also pays the applicable rate for the power delivered. The customer will be charged for (1) the absolute value of the difference between the monthly Industrial Exemption forecast for HLH and the Measured Energy for the Industrial Exemption load for the HLH, plus (2) the absolute value of the difference between the monthly LLH Industrial Exemption forecast and the Measured Energy for the Industrial Exemption load for the LLH.

For each exempted industrial load, the customer must supply BPA with forecasts of monthly HLH and LLH energy at least two months prior to the start of the billing month. The monthly energy forecasts are used to determine the billing factor and to perform a predictability test. The predictability test compares forecasted and actual total monthly energy amounts to determine whether the facility continues to qualify for the Industrial Exemption. If the energy use falls outside of a +1/-5 percent band from the energy forecast for more than 1 month out of any 6-month period, the facility will lose its Industrial Exemption qualification. The monthly power bill outlining a failure of the predictability test will serve as notice that a subsequent failure within the next 5 months will result in losing the exemption. The load will be disqualified for Industrial Exemption, and Full Load Shaping charged, as of the beginning of the second month in which the exempt industrial load fails the predictability test.

16. Industrial Firm Power

Industrial Firm Power is electric power that BPA will make continuously available to a direct-service industrial (DSI) purchaser subject to the terms of the Purchaser's power sales contract with BPA. Deliveries may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA. Adjustments as provided in the Purchaser's power sales contract shall be made for power restricted to provide reserves.

17. Load Regulation

Load Regulation is the instantaneous (second-to-second) regulation of the supply of firm power that BPA provides to follow variations in customers' loads *within* the hour. The amount of Load Regulation provided is related to the customer's retail or plant load. Load Regulation includes service to provide Eccentric Load Following. BPA may offer discounted rates for Load Regulation available under the APS, PF, IP and NR rate schedules pursuant to section II.A of these GRSPs.

18. Load Shaping

Full Load Shaping provides additional or reduced firm power for the monthly difference between a utility purchaser's actual and forecasted retail loads. Load shaping does not cover changes in purchase amounts due to resource operations. *DSI Load Shaping*, available to DSIs under a 1996 Contract only, provides additional firm power or relief from take-or-pay for a variation of up to 15 percent in a DSI customer's actual plant loads above or below forecasted plant operations.

A separate product, *Partial Load Shaping*, is available to Planned Computed Requirements customers under their 1981 Contracts and to Partial Requirements customers under the 1996 Contracts who forecast their Total Retail Load and their BPA purchases. Partial Load Shaping allows the Purchaser to specify an amount of load shaping it will purchase. If the Purchaser's retail load exceeds its forecast, BPA will provide additional demand and energy, limited to the amount specified by the customer. If the Purchaser's retail load is lower than forecast, BPA will relieve the take-or-pay obligation up to the amount of load shaping specified.

19. New Resource Firm Power

New Resource Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available:

a. for any New Large Single Load, and

b. for firm power purchased by investor-owned utilities (IOUs) pursuant to power sales contracts with BPA.

New Resource Firm Power is to be used to meet the Purchaser's actual firm load within the Pacific Northwest. Deliveries of New Resource Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

New Resource Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. New Resource Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP).

20. Nonfirm Energy

Nonfirm Energy is energy that 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 sold primarily under the Nonfirm Energy rate schedule, NF-96. Nonfirm energy also may be supplied under the NF-96 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. 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.

21. Nonfirm Transmission Service

Under the Point-to-Point Service Tariff (PTP Tariff), *Nonfirm Transmission Service* is Short-Term Nonfirm and Hourly Nonfirm Transmission Service over BPA's FCRTS that is scheduled on an as-available basis and is subject to interruption. Nonfirm Transmission Service is also available in conjunction with reservations of Firm Transmission Service for any term subject to the conditions set forth in Section 14.1 under the PTP Tariff.

22. Non-Spinning Operating Reserve

Non-Spinning Operating Reserve is that portion of the Operating Reserve that does not meet the definition of Spinning Reserve. Generally, non-spinning operating reserve is that portion of operating reserves capable of serving load on a sustained basis within 10 minutes. The Northwest Power Pool requires that each control area maintain a non-spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

23. Operating Reserve

Operating Reserve is the unloaded generating capacity, interruptible load, or other on-demand rights that the customer is able to access within ten (10) minutes of a power system disturbance and that are capable of being used to serve load on a sustained basis for up to one (1) hour. Operating reserves includes both spinning reserves and non-spinning operating reserves. The Northwest Power Pool requires that each control area maintain an operating reserve obligation equal to at least 5 percent of all hydro and 7 percent of all thermal and other non-hydro on-line generation within the control area.

24. Power Supplied for Emergency Use

Power Supplied for Emergency Use is electric energy and/or capacity that has been supplied by BPA under the FPS rate schedule:

a. for use during an emergency on the Purchaser's system, or

b. following an emergency to replace energy secured from sources other than BPA during such emergency.

Mutual emergency assistance may be provided under exchange agreements, and payment for that power made in accordance with the terms of those agreements.

25. Priority Firm Power

Priority Firm Power is electric power (capacity, energy, or capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the residential exchange under section 5(c) of the Northwest Power Act may purchase Priority Firm Power pursuant to their Residential Purchase and Sale Agreements (RPSA). Priority Firm Power is not available to serve New Large Single Loads. Deliveries of Priority Firm Power may be reduced or interrupted as permitted by the terms of the Purchaser's power sales contract with BPA.

Priority Firm Power is guaranteed to be continuously available to the Purchaser during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and *force majeur* events. Priority Firm Power is power where BPA agrees to provide operating reserves in accordance with the standards established by the North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP).

26. Reservation and Rights to Change Services

Reservation and Rights to Change Services include the ability to reserve the right to change future deliveries of firm power, firm energy, capacity, unbundled power products, shaping service, and/or features of these deliveries. These services are available under the FPS-96 rate schedule. These services may include:

a. Reservation fees for put or call options;

b. Changes to energy return provisions;

c. Rights to change notice provisions;

d. Preschedule change services; and

e. Other purposes.

27. Reserve Power

Reserve Power is firm power sold to a Purchaser:

a. in cases where the purchaser's power sales contract states that the rate for Reserve Power shall be applied;

b. to provide service when no other type of power is deemed applicable; or

c. to serve the Purchaser's firm power loads under circumstances in which BPA does not have a power sales contract in force with the purchaser.

Deliveries of Reserve Power may be reduced or interrupted either as a result of an uncontrollable force or when necessitated by emergencies, system maintenance requirements, or other factors related to continuity of service.

28. Residential Purchase and Sale Agreement (RPSA) Power

RPSA Power is power BPA sells to a Purchaser pursuant to the Purchaser's Residential Purchase and Sale Agreement (RPSA) with BPA. Under section 5(c) of the Northwest Power Act, BPA "purchases" power from each RPSA customer at that utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities. The amount of power purchased and sold is equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm customers.

29. Shaping Services

Shaping Services are services provided by BPA to a Purchaser to shape the output of the Purchaser's resource (or purchase) to the Purchaser's load. These services may include accepting and returning energy including load factoring, storage, advance delivery, energy return, and seasonal storage and exchange. Shaping services may be provided on an hourly, daily, weekly, monthly, seasonal, or other basis, and may include advance delivery of the resource (or purchase) to the load. Shaping services are available under the FPS rate schedule on a firm or nonfirm basis and may or may not be packaged with other power products.

30. Short-Term Nonfirm Transmission Service

Under the Point-to-Point Service Tariff, *Short-Term Nonfirm Transmission Service* is Nonfirm Point-to-Point Transmission Service over the FCRTS that is reserved and/or scheduled daily, weekly, or monthly for renewable terms of not more than 30 days each and that is of the same priority as that of BPA's nonfirm use of the FCRTS.

31. Shortage Power

Shortage Power is energy, or energy with capacity, provided by BPA to a Purchaser to serve such purchaser's regional load under circumstances where the Purchaser is in danger of curtailing firm load even though the Purchaser is operating all available resources and exercising all contractual rights to firm power to the maximum level feasible. In the event of a state-ordered or regionwide load curtailment, a power deficiency is deemed to exist for those Purchasers whose power supply condition is in part causally related to the State(s)-initiated load curtailment.

32. Spinning Reserve

Spinning Reserve is the unloaded generating capacity of a system's firm resources that is the portion of Operating Reserve that is synchronized to the power system and provides additional energy as required to be immediately responsive to system frequency. The Northwest Power Pool requires that each control area maintain a spinning reserve obligation equal to a minimum of 50 percent of its operating reserve obligation.

33. Supplemental Control Area Services

Supplemental Control Area Services may be used to support control areas of utilities other than BPA and their control area service obligations. These services, which may include load regulation, control area reserves, interconnected operations services, and others, are available under the FPS-96 rate schedule.

34. Transitional Service

Transitional Service is service that BPA provides to a DSI or utility customer that has a large industrial load that is being brought on-line. The load may be a new industrial plant, a major addition to an existing industrial plant, or reactivation of an existing industrial plant or major portion thereof. Pursuant to its agreement with the customer, BPA will serve the load and calculate the customer's monthly Billing Demand to account for the daily variations in the industrial load. To receive this service, the BPA customer must meet the eligibility requirements set forth in BPA's Billing Procedures.

35. Transmission Losses

Transmission Losses are the real power losses associated with the transmission of power over the FCRTS. The loss factor that represents the amount of losses for a specific transaction is included in the wheeling agreement, the rate schedule, or the tariff. The rates for a transmission customer purchasing Transmission Losses appear in the APS-96 rate schedule.

36. Transmission Service

As used in the MT rate schedule, *Transmission Service* is as defined in the Western Systems Power Pool Agreement.

37. Variable Industrial Power

Variable Industrial Power is Industrial Firm Power that is sold at the VI-96 rate, consistent with the terms and conditions of the Variable Rate Contract between BPA and the Purchaser.

B. Definition of Rate Schedule Terms

1. 1981 Contract

The *1981 Contract* refers to the initial power sales contracts that BPA executed with its Pacific Northwest customers pursuant to the requirements of sections 5(b) and 5(d) of the Northwest Power Act. Most of these contracts were executed in 1981, but some are dated 1984 or later. For purposes of these rate schedules, any such contract that provides for power deliveries to begin prior to October 1, 1996, is referred to for convenience as a 1981 Contract.

2. 1996 Contract

Contracts for the sale of firm power to Pacific Northwest customers pursuant to the requirements of sections 5(b) and 5(d) of the Northwest Power Act are termed the *1996 Contracts* if they provide for power deliveries to begin on or after October 1, 1996.

3. Actual Customer-Served Load

Actual Customer-Served Load is the actual hourly amount of the Network Load in megawatts that the customer serves on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement or 1996 Contract.

4. Adjusted Measured Energy

Adjusted Measured Energy is the Measured Energy for the month under the applicable PF, NR, IP, or IPG rate *less* any Unauthorized Positive Deviations *plus* any Unauthorized Negative Deviations for the hour, day, or month.

5. Adjusted Utility Factor

The *Adjusted Utility Factor* modifies the Full Load Shaping rate for utility customers purchasing under a 1981 Contract that have an Industrial Exemption. The Adjusted Utility Factor is calculated and applied monthly based on the Purchaser's average historical load and its forecast exempt industrial load for the month. For Metered Requirements customers, the calculation also is based on their BPA purchases for the last year. For Computed Requirements customers, the calculation also is based on their Computed Energy Maximum for the last year. See section II, Utility Factor.

6. Annual Billing Cycle

The *Annual Billing Cycle* is the 12 months beginning with the customer's first monthly power bill for deliveries in the first billing month starting on or after October 1.

7. Authorized Deviation

Authorized Deviation is the limited amount of Deviation from Contract Obligation that a Purchaser is allowed under its 1996 Contract without incurring an Unauthorized Increase Charge or an adjustment for take-or-pay obligation. *Authorized Positive Deviation* is the limited amount the Purchaser's Measured Energy may exceed the Purchaser's Contract Obligation on an hour, day, or month without incurring an Unauthorized Increase Charge. *Authorized Negative Deviation* is the limited amount the Purchaser's Measured Energy may be less than the Purchaser's Contract Obligation on an hour, day, or month without an adjustment to the Measured Energy for take-or-pay obligation.

8. Auxiliary Demand *{1981 DSI Contract}*

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. Auxiliary Power is power in excess of the DSI's Operating Demand. 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 1981 Contract.

BPA shall make Auxiliary Power available to Industrial Firm Power purchasers under the Industrial Firm Power rate schedule.

9. Billing Demand (Energy)

The Purchaser's *Billing Demand (Energy)* is the amount of capacity (energy) to which the demand (energy) charge specified in the rate schedule is applied. When the rate schedule includes charges for several products, there may be a Billing Demand (Energy) quantity for each product. BPA establishes Billing Demand and Billing Energy quantities for both active power (kilowatts and kilowatthours) and reactive power (kilovars and kilovarhours). Billing Demand (Energy) may be adjusted for certain outages (providing the Purchaser an Outage Credit or authorized negative deviation) as specified in the Purchaser's agreement with BPA and pursuant to BPA's Billing Procedures.

At any POD that has an unbalanced phase current problem, BPA shall calculate the Billing Demand by multiplying the largest of the adjusted Integrated Demands on any phase at the time of the applicable monthly system peak hour by three. BPA may continue this billing procedure until the Purchaser has made the necessary system corrections.

10. BPA Operating Level *{1981 DSI Contract}*

The *BPA Operating Level* is, for the purpose of these rate schedules and GRSPs, an hourly amount of 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.

Each DSI must request service from BPA for each billing month in accordance with the terms of its power sales contract. The requested level of service under the 1981 Contract 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 provide, a level of service for the Offpeak Period that differs from 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 during any single hour exceeds the BPA Operating Level for that hour shall be subject to an Unauthorized Increase Charge for each kilowatt and kilowatthour of unauthorized increase associated with each such overrun.

11. Calculated Energy Capacity

Calculated Energy Capacity is the billing factor for DSI Load Shaping. BPA's estimate of Calculated Energy Capacity is based on the amount of energy load (aMW) that a DSI would consume at a particular separately metered facility when that facility is operating at full capacity.

12. Composite Rate

The *Composite Rate* applies to PF-96 Purchasers under 1981 and 1996 Contracts. Only customers whose average annual energy loads during the 5-year period, as forecasted by BPA, are 25 average annual MW or less are eligible to purchase at this rate. The composite rate is a weighted average rate that takes into account the relative cost of typical quantities of each product purchased, including generation demand and energy, load shaping, and load regulation.

13. Computed Average Energy Requirement *{1981 Utility Contract}*

For Computed Requirements customers, the *Computed Average Energy Requirement* shall be determined as specified in the Purchaser's 1981 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 customers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for Planned Computed Requirements customers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for Contracted Computed Requirements customers.

For Planned Computed Requirements customers purchasing Partial Load Shaping, the Computed Average Energy Requirement shall be adjusted by the lesser of (1) the absolute value of the Purchaser’s actual Total Retail Load *minus* the Purchaser’s forecasted Total Retail Load, or (2) the Partial Load Shaping Purchase Amount. For variations above forecast, the adjustment shall be added to CAER; for deviations below forecast, the adjustment shall be subtracted from CAER.

14. Computed Energy Maximum *{1981 Utility Contract}*

The *Computed Energy Maximum* equals the Computed Average Energy Requirement (CAER) multiplied by the number of hours in the billing month.

15. Computed Maximum Requirement *{1981 Utility Contract}*

The Purchaser’s *Computed Maximum Requirement* is the maximum amount of power that BPA is obligated to deliver to the Purchaser during the HLH of a month. The Computed Maximum Requirement is defined in section 17(g)(1) of the Purchaser’s 1981 Contract as the greater of the Purchaser’s Computed Peak Requirement and its Computed Average Energy Requirement unless the terms of section 7 (“Allocation Provisions in the Event of Planning Insufficiency”) apply. The Purchaser may waive its right to schedule a portion of its Computed

Maximum Requirement, as specified in an agreement between BPA and the Purchaser.

16. Computed Peak Requirement *{1981 Utility Contract}*

For Computed Requirements customers, the *Computed Peak Requirement* shall be determined as specified in the Purchaser's 1981 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 customers;

b. sections 16, 17(a), and 17(f), as adjusted by other sections of the contract, for Planned Computed Requirements customers; and

c. sections 16 and 17(b), as adjusted by other sections of the contract, for Contracted Computed Requirements customers.

For Planned Computed Requirements customers purchasing Partial Load Shaping, the Computed Peak Requirement shall be adjusted by the lesser of (1) the absolute value of the Purchaser's actual Total Retail Load *minus* the Purchaser's forecasted Total Retail Load, or (2) the Partial Load Shaping Purchase Amount. For variations above forecast, the adjustment shall be added to CPR; for deviations below forecast, the adjustment shall be subtracted from CPR.

17. Computed Requirements Customer *{1981 Utility Contract}*

A *Computed Requirements Customer* is a Purchaser of Priority Firm and/or New Resource Firm Power who is designated as a Computed Requirements Customer by the terms of its 1981 contract.

18. 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 applicable 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."

19. Contract Energy

Contract Energy is the maximum number of kilowatthours that BPA agrees to make available subject to any limitations included in the applicable contract between BPA and the Purchaser. Contract Energy may refer to an energy purchase from BPA or to an amount of energy that BPA agrees to transmit over the FCRTS. For the purpose of these GRSPs, Contract Energy is deemed to refer to any contractual or other reference to Contract Demand as expressed in kilowatthours.

20. Contract Obligation

A customer's *Contract Obligation* is a function of a customer's purchase of products under its 1996 Contract. A customer's Contract Obligation for a month, day, or hour is determined from its purchase commitment or resource commitment, its Total Retail Load or Total Plant Load if purchasing any Load Shaping products, and any minimum or maximum scheduling limits for any hour. The actual description of the Purchaser's Contract Obligation is provided in the Purchaser's 1996 Contract.

21. Control Area

A *Control Area* is the electrical (not necessarily geographical) area within which a controlling utility operating under all North American Electric Reliability Council standards has the responsibility to adjust its generation on an instantaneous basis to match internal load and power flow across interchange boundaries to other Control Areas.

22. Curtailed Demand *{1981 DSI Contract}*

A *Curtailed Demand* is the number of kilowatts of Industrial Firm Power during the billing month that results from a DSI's request for such power in amounts less than the Operating Demand therefor. Each purchaser of Industrial Firm Power may curtail its demand according to the terms of its 1981 Contract (which permits up to three levels of Curtailed Demand each month).

23. Curtailed Energy

Curtailed Energy is the billing factor for the Fixed Curtailment Fee and is equal to the reduction(s) in the DSI customer's purchase of energy from BPA due to the Purchaser exercising its contractual right to curtail.

24. Declared Customer-Served Load

Declared Customer-Served Load (Declared CSL) is the Network Load in megawatts that the customer elects to serve on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement or 1996 Contract. The customer's Declared CSL is contractually specified for each month.

25. 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.

26. Delivering Party

The entity supplying the capacity and/or energy to be transmitted at Point(s) of Interconnection.

27. Deviation *{1996 Contract}*

Deviation is the difference between the quantity of power that was actually taken from BPA (Measured Energy) and the quantity of power the customer is entitled to receive under its Contract Obligation.

28. Direct Assignment Facilities

Direct Assignment Facilities are facilities that have been or are constructed (or caused to be constructed) by BPA for the sole use and benefit of facilitating a request for service. The costs of such facilities may be directly assigned to the Transmission Customer requesting the service in accordance with applicable FERC policy. The cost of Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer.

29. Direct Service Industry (DSI) Delivery

The *DSI Delivery* segment is that segment of the FCRTS that provides service to DSI customers at voltages of 34.5 kV and below.

30. Diverted Power

Diverted Power is PF, NR, or IP Firm Power delivered at the customer's request and for the purpose of storage or exchange, but not resale, to points of delivery other than the Points of Delivery serving the customer's Total Retail Load or Total Plant Load.

31. Eastern Intertie

The *Eastern Intertie* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

32. Electric Power

Electric Power is electric peaking capacity (kilowatts) and/or electric energy (kilowatthours).

33. Federal Columbia River Transmission System

The *Federal Columbia River Transmission System* (FCRTS) is the transmission facilities of the Federal Columbia River Power System, which include all transmission facilities owned by the government and operated by BPA, and other facilities over which BPA has obtained transmission rights.

34. Federal System

The *Federal System* is the generating facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability. "BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer which may be scheduled by BPA;

b. which BPA may use under contract or license; or

c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

35. Full Requirements Customer *{1996 Contract}*

A *Full Requirements Customer* is a customer that has been designated by BPA as a Full Requirements Customer under the terms of its 1996 Contract. Full Requirements Customers are those purchasers under 1996 Contracts: (a) with no resource; or (b) that have contracted for services with BPA for their resource(s) so that the purchaser retains Full Requirements status.

36. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the Peak Period (6 a.m. to 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable)). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

37. Integrated Demand

Integrated Demand is the quantity derived by mathematically “integrating” kilowatthour deliveries over a 60-minute period.

38. Intentional Deviation

Intentional Deviation, for the purpose of determining credit or payment for Negative Deviations under the Energy Imbalance rate, is defined as the intentional creation by the purchaser of a difference between the hourly scheduled amount and the hourly metered (actual delivered) amount associated with transmission to a load located in BPA’s control area or from a generation resource located within BPA’s control area. A deviation will be deemed intentional by BPA if the following patterns occur: 1) chronic Negative Deviations received during multiple hours in a row or at specific times during the day; 2) chronic Positive Deviations received during either winter storm or HLH with corresponding Negative Deviations in LLH; 3) chronic Negative Deviations during LLH or otherwise lightly loaded system conditions; particularly when the purchaser does not respond by adjusting schedules for future days to attempt to correct for these tendencies.

39. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the Offpeak Period (10 p.m. to 6 a.m. Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable)).

40. Main Grid

As used in the FPT rate schedule, the *Main Grid* is that portion of the Network facilities with an operating voltage of 230 kV or more.

41. Main Grid Distance

As used in the FPT rate schedules, *Main Grid Distance* is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

42. Main Grid Interconnection Terminal

As used in the FPT rate schedules, *Main Grid Interconnection Terminal* refers to Main Grid terminal facilities that interconnect the FCRTS with non-BPA facilities.

43. Main Grid Miscellaneous Facilities

As used in the FPT rate schedules, *Main Grid Miscellaneous Facilities* refers to switching, transformation, and other facilities of the Main Grid not included in other components.

44. Main Grid Terminal

As used in the FPT rate schedules, *Main Grid Terminal* refers to the Main Grid terminal facilities located at the sending and/or receiving end of a line, exclusive of the Interconnection terminals.

45. Measured Demand

The Purchaser's *Measured Demand* is that portion of its Metered or Scheduled Demand purchased from BPA under the applicable rate schedule. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Demand for PF, NR, or IP power as applicable. The portion of the total Measured Demand so assigned shall constitute the Measured Demand for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

In determining Measured Demand for any Purchaser who experiences an outage as defined in the Purchaser's agreement with BPA and in BPA's Billing Procedures, BPA shall exclude any abnormal Integrated Demand due to, or resulting from:

a. emergencies or breakdowns on, or maintenance of, the Federal System Facilities; and

b. emergencies on the Purchaser's facilities to the extent Bonneville determines that such facilities have been adequately maintained and prudently operated.

Partial interruptions shall be converted to an equivalent outage of total Measured Demand.

46. Measured Energy

The Purchaser's *Measured Energy* is that portion of its Metered or Scheduled Energy that is purchased from BPA under the applicable rate schedule during a particular diurnal period (HLH or LLH) in a billing period. If more than one class of power is delivered to any point of delivery, the portion of the measured quantities assigned to any class of power shall be as specified by contract. Any delivery of Federal power not assigned to classes of power delivered under other agreements shall be included in the Measured Energy for PF, NR, or IP power as applicable. The portion of the total Measured Energy so assigned shall constitute the Measured Energy for each such class of power. Any residual quantity, after determination of the Purchaser's contractual entitlement at a particular rate, is considered "unauthorized." Unauthorized increases are billed in accordance with the provisions of these GRSPs.

47. Metered Demand

The *Metered Demand* in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered to a purchaser:

a. at each point of delivery for which the Metered Demand is the basis for determination of the Measured Demand,

b. during each time period specified in the applicable rate schedule, and

c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accordance with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the Purchaser.

48. 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 applicable agreement and delivered to a purchaser:

a. at all points of delivery for which metered energy is the basis for determination of the Measured Energy, and

b. during any billing period.

49. Metered Requirements Customer

A *Metered Requirements Customer* is a customer that has been designated as such under the terms of its 1981 Contract.

50. Minimum HLH (LLH) Contract Obligation

The Minimum HLH (LLH) Contract Obligation is 99 percent of the customer's Monthly Contract Obligation for HLH (LLH) energy minus any adjustments specified in the contract for the occurrence of specific operational events.

51. Montana Intertie

The *Montana Intertie* is the regional double-circuit 500 kV transmission intertie from Broadview Substation to Garrison Substation.

52. Monthly Federal System Peak Load

Monthly Federal System Peak Load is the peak load on the Federal System during a customer's billing month, determined by the largest hourly integrated demand produced from system generating plants in BPA's control area and scheduled imports for BPA's account from other control areas.

53. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the peak loading on the Federal transmission system during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's control area and metered flow into BPA's control area.

54. Negative Deviation

Negative Deviation under the 1996 Contract is the difference between the Purchaser's Contract Obligation and Measured Energy on the hour, day, or month, where the Purchaser's Measured Energy is less than its Contract Obligation. *Negative Deviation* under the Energy Imbalance service occurs on any hour when BPA receives more energy from the Delivering Party at the Point of Integration than BPA delivers to the Receiving Party at the Point of Delivery.

55. Network (or Integrated Network)

The *Network* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest.

56. Network Load

Network Load is the Load of a Transmission Customer, including the entire load of all Member Systems designated pursuant to Section 6 of the Network Integration (NT) Service Tariff. Network Load includes the retail energy load during any given time period plus distribution losses and system power requirements. A Transmission Customer's Network Load shall not be reduced to reflect any portion of such load served by the output of any generating facilities owned, or generation purchased, by the Transmission Customer, its Member Systems, or other customers it serves under the NT Tariff.

57. Network Upgrades

Network Upgrades are modifications and/or additions to transmission-related facilities that are integrated with and support BPA's transmission system to satisfy, at least in part, an Application for transmission service as well as provide for the general benefit of users of such transmission system.

58. Northern Intertie

Northern Intertie describes a subset of Network facilities that interconnect the FCRTS to Canada. Northern Intertie facilities were formerly identified as a separate FCRTS segment, but are now subsumed in the Network segment.

59. Offpeak Period

The *Offpeak Period* (or LLH) includes all hours that do not occur during the Peak Period. Thus, the Offpeak Period consists of the hours from 10 p.m. to 6 a.m., Monday through Saturday, and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

60. Operating Demand *{1981 DSI Contract}*

The *Operating Demand* is that demand which is established by each DSI in accordance with section 5(b) of the DSI's 1981 Contract. Unless the DSI has requested, and BPA has granted, an Auxiliary Demand, the Operating Demand establishes a limit with respect to:

a. the hourly demand that the purchaser may impose on BPA; and

b. the total amount of energy during a billing month that the DSI is entitled to purchase from BPA.

61. Opportunity Cost

Opportunity Cost is the net loss of revenue or the net increase in generation cost caused by displacing one transaction with another when the transmission system is so constrained that both transactions cannot be handled at the same time. Loss of revenue resulting from competition shall not be included in the determination of the Opportunity Cost. Opportunity Cost shall be determined consistent with FERC policy.

62. Partial Load Shaping Purchase Amount

Partial Load Shaping Purchase Amount means the absolute value in megawatthours per hour of positive or negative variations from forecast purchased by the Purchaser. The *Partial Load Shaping Purchase Amount for the month,* the billing factor for Partial Load Shaping, is the Partial Load Shaping Purchase Amount times the hours in the month.

63. Partial Requirements Customer *{1996 Contract}*

A *Partial Requirements Customer* is a Purchaser (utility, Federal agency, or DSI) that is designated as a Partial Requirements Customer by the terms of its 1996 Contract. A Purchaser under any 1996 Contract that does not specifically identify a customer as Full Requirements or Partial Requirements shall be considered to be a Partial Requirements Customer. Partial Requirements Customers are those purchasers under 1996 Contracts that are responsible for managing the operation of generation resources or purchases to serve their Total Retail Load or Total Plant Load in specific amounts.

64. Peak Period

The *Peak Period* (or HLH) includes the hours from 6 a.m. to 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). There are no exceptions to this definition; that is, it does not matter whether the day is a normal working day or a holiday.

65. Phase-In Mitigation

Phase-In Mitigation is available to Full and Metered Requirements Preference Purchasers who are purchasing their firm requirements under one or more of BPA's 5-year rate schedules and whose FY 1997 rate increase for BPA purchases is at least 9 percent. If the purchaser meets the eligibility criteria and requests that BPA phase in its rate increase, BPA will limit the Purchaser's annual rate increase to 9 percent each year for the 5-year period.

66. Point of Delivery (POD)

A *Point of Delivery* is the contractual interconnection point where power is delivered to the customer. Typically, a point of delivery is located at a substation site, but it could be located at the change of ownership point on a transmission line.

67. Point of Integration (POI)

A *Point of Integration* is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point to receive system power from the customer.

68. Point of Interconnection (POI)

A *Point of Interconnection* is a point where the facilities of two entities are interconnected.

69. Positive Deviation

Positive Deviation under the 1996 Contract is the difference between the Purchaser's Measured Energy and Contract Obligation on the hour, day, or month, where the Purchaser's Measured Energy exceeds its Contract Obligation. *Positive Deviation* under the Energy Imbalance service occurs on any hour when BPA delivers more energy to the Receiving Party at the Point of Delivery than BPA receives from the Delivering Party at the Point of Integration.

70. Purchaser

Pursuant to the terms of an agreement and applicable rate schedule(s), a *Purchaser* contracts to pay BPA for providing a product or service.

71. Ratchet Demand

The *Ratchet Demand* in kilowatts or kilovars is 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. When the Ratchet Demand is used as a billing factor, BPA shall have specified the following information in the appropriate rate 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 that will be used to calculate the Ratchet Demand.

72. Reactive Power

Reactive Power is the out-of-phase component of the total voltamperes in an electric circuit. Reactive Power has two components: reactive demand (expressed in kilovars or kVAr) and reactive energy (expressed in kilovarhours or kVArh).

73. Receiving Party

The entity receiving the capacity and/or energy transmitted by BPA to Point(s) of Delivery.

74. Restricted Demand *{1981 DSI Contract}*

Restricted Demand is the number of kilowatts of Industrial Firm Power that results when BPA has restricted delivery of such power for one clock-hour or more. BPA makes such restrictions pursuant to the terms of the DSI's power sales contract with BPA. In a given billing month, there are as many possible levels of Restricted Demand for a DSI as the number of restrictions.

75. Scheduled Demand

The *Scheduled Demand* in kilowatts is the largest of the hourly demands at which electric energy is scheduled for transmission on the FCRTS for delivery to a purchaser:

a. to each system for which Scheduled Demand is the basis for determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining Billing Demand.

76. Scheduled Energy

The *Scheduled Energy* in kilowatthours shall be the sum of the hourly demands at which electric energy is scheduled for delivery to a purchaser:

a. for each system for which scheduled energy is the basis for determination of the Measured Energy, and

b. during any billing period.

Scheduled amounts are deemed delivered for the purpose of determining Billing Energy.

77. Secondary System

As used in the FPT rate schedules, *Secondary System* is that portion of the Network facilities with an operating voltage between 69 kV to less than 230 kV.

78. Secondary System Distance

As used in the FPT rate schedules, *Secondary System Distance* is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

79. Secondary System Interconnection Terminal

As used in the FPT rate schedules, *Secondary System Interconnection Terminal* refers to the terminal facilities on the Secondary System that interconnect the FCRTS with non-BPA facilities.

80. Secondary System Intermediate Terminal

As used in the FPT rate schedules, *Secondary System Intermediate Terminal* refers to the first and final terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

81. Secondary Transformation

As used in the FPT rate schedules, *Secondary Transformation* refers to transformation from Main Grid to Secondary System facilities.

82. Southern Intertie

The *Southern Intertie* is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting 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 the 500 kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000 kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

83. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Negative Deviations under the Energy Imbalance rate, exists when any one or more of the following conditions exist or events occur on the BPA system: high flows and full reservoirs; flood control implementation; spill priority implementation procedures; spill due to lack of Federal load; spill past unloaded turbines; minimum generation requirements; increased spill due to storage; BPA is not accepting Coordination storage due to lack of storage or a specified flow requirement. Discretionary spill, where BPA may choose whether to spill does not constitute a Spill Condition.

84. Total Plant Load

Total Plant Load means a DSI customer's total electrical energy load at facilities eligible for BPA service during any given time period whether the customer has chosen to serve its load with BPA power or non-Federal power.

85. Total Retail Load

For utilities, *Total Retail Load* is the customer's regional retail energy load during any given time period plus distribution losses and the customer's system power requirements. No distinction is made between load that is served with BPA power and load that is served with power from other sources. For DSIs, Total Retail Load is called Total Plant Load.

86. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable Agreement.

87. Transmission Customer

A *Transmission Customer* is an Eligible Customer that executes an Network Integration (NT) or Point-to-Point (PTP) Service Agreement or receives service under the NT Tariff or PTP Tariff.

88. Transmission Demand

Transmission Demand is the maximum amount of capacity and/or energy that BPA agrees to transit for the transmission customer over BPA's Federal Columbia River Transmission System between the Point(s) of Interconnection/Integration and the Point(s) of Delivery. Transmission Demand shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

89. Unauthorized Deviation

Unauthorized Deviation under the 1996 Contract is the amount of Deviation in excess of the Authorized Deviation on any hour, day, or month, and the amount of Rate Period Excess Purchase and Unreturned Diverted Power during an Annual Billing Cycle. *Unauthorized Positive Deviations* are amounts of Measured Energy in excess of the Contract Obligation that exceed the limits allowed for Authorized Deviation on any hour, day, or month, and the amount of Rate Period Excess Purchases and Unreturned Diverted Power. Unauthorized Positive Deviations are subtracted from Measured Energy and billed at the Unauthorized Increase Charge. *Unauthorized Negative Deviations* are amounts of Measured Energy less than the Contract Obligation that exceed the limits allowed for Authorized Deviation on any hour, day, or month. Unauthorized Negative Deviations are treated as take-or-pay amounts, added to the Measured Energy, and billed at the appropriate PF, NR, or IP rate.

90. Utility Delivery

The *Utility Delivery* segment is that segment of the FCRTS that provides service to utility customers at voltages below 34.5 kV.

91. Utility Factor

The *Utility Factor* modifies the charges for Full Load Shaping and Load Regulation for customers purchasing under a 1981 Contract. The Utility Factor is calculated and applied annually based on historical data for the Purchaser's Total Retail Load. For Metered Requirements customers, the calculation also is based on their energy purchases from BPA. For Computed Requirements customers, the calculation also is based on their Computed Energy Maximum.