B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Wholesale Power Rate Adjustment Proceeding (WP-07)

ADMINISTRATOR'S FINAL RECORD OF DECISION

July 2006

WP-07-A-02

BONNEVILLE POWER ADMINISTRATION

2007 Wholesale Power Rate Adjustment Proceeding (WP-07)

Administrator's Final Record of Decision

PART 1 OF 2

COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBTUMMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)

MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative

PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company

UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

This page intentionally left blank.

1.0 INTRODUCTION

This Record of Decision (ROD) contains the decisions of the Bonneville Power Administration (BPA), based on the record compiled in this rate proceeding, with respect to the adoption of power rates for the three-year rate period commencing October 1, 2006, through September 30, 2009. This "2007 Wholesale Power Rate Adjustment Proceeding" is designed to establish replacement rate schedules and General Rate Schedule Provisions (GRSPs) for those that expire on September 30, 2006. This power rate case also establishes the General Transfer Agreement (GTA) Delivery Charge for the period of October 1, 2007, through September 30, 2009. BPA's Power Subscription Strategy and Record of Decision (Subscription Strategy), as well as other Agency processes, provide much of the policy context for this rate case and are described in Section 2.

This ROD follows a full evidentiary hearing and briefing, including an Oral Argument before the BPA Administrator. Sections 3 through 18, including any appendices or attachments, present the issues raised by parties in this proceeding, the parties' positions, BPA staff positions on the issues, BPA's evaluations of the positions, and the Administrator's decisions. Parties had the opportunity to file briefs on exceptions to the Draft ROD, before issuance of this Final Record of Decision.

1.1 Procedural History of this Rate Proceeding

1.1.1 Issue Workshops

Prior to the release of its Initial Proposal, BPA sponsored workshops on a variety of issues related to its ratemaking. The workshops covered topics including proposed rate design, revenue requirement, risk management, and inter-business line issues. These workshops were held so BPA and interested parties could develop a common understanding of the issues, generate ideas, and propose alternative solutions to issues in specific areas when possible. Conducting these issue workshops prior to the development of the Initial Proposal enabled BPA to freely exchange ideas and comments, relevant to rate issues, with its customers without the constraints of the prohibition on *ex parte* communication that go into effect at the onset of the formal rate proceeding. The *ex parte* prohibition went into effect on November 8, 2005, with the publication of the notice of BPA's proposed 2007 Wholesale Power Rate Adjustment Proceeding in the Federal Register, and ends with the issuing of this ROD. The Initial Proposal incorporated many of the ideas and solutions arising from these workshops, and this ROD reflects them where appropriate.

1.1.2 Rate Proceeding

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839e(i) (Northwest Power Act), requires that BPA's wholesale power rates be established according to specific procedures. These procedures include, among other things, issuance of a notice in the Federal Register announcing the proposed rates; one or more field hearings; the opportunity to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. This proceeding is governed by BPA's rules for general rate proceedings contained in the *Procedures Governing Bonneville Power Administration Rate Hearings,* 51 Fed. Reg. 7611 (1986) (hereinafter, Procedures). The Procedures implement the Section 7(i) requirements.

On November 8, 2005, BPA published a Notice of Proposed Wholesale Power Rate Adjustment Proceeding in the Federal Register (FRN), 70 Fed. Reg. 67685 (2005). BPA's 2007 wholesale power rate proceeding began with a prehearing conference on November 21, 2005. At that prehearing conference, the Hearing Officer issued an order establishing the schedule for this rate proceeding and an order concerning data request procedures adopting the electronic discovery procedures proffered by BPA and the parties. That same day, the Hearing Officer also issued orders granting petitions to intervene and adopted a service list for BPA's 2007 Wholesale Power Rate Adjustment Proceeding. The Hearing Officer granted petitions to intervene and/or amended the service list on several subsequent occasions, including February 17, 2006, and February 24, 2006.

BPA's 2007 Initial Rate Proposal, filed on November 21, 2005, was supported by prefiled, written testimony and studies sponsored by 55 witnesses. Clarification on BPA's Initial Proposal occurred on December 5 and 6, 2005. Direct testimony was filed by the parties on January 20, 2006. The parties filed their prehearing briefs on January 25, 2006. Clarification on the parties' direct testimony occurred on January 30, 2006.

On February 8, 2006, BPA filed a motion asking to submit supplemental testimony that would modify its Initial Proposal (Supplemental Proposal). This modification was necessary in light of recent Federal Energy Regulatory Commission (FERC) cases regarding generation input costs for generation supplied reactive power and voltage control. By order dated February 10, 2006, the Hearing Officer granted BPA's motion. As a result, this Supplemental Proposal was incorporated into this 7(i) proceeding on a parallel path. On February 10, 13, 22, and 28, 2006, the Hearing Officer issued various orders revising the schedule with respect to the Supplemental Proposal in this rate proceeding. Following discovery, the parties filed their direct cases with respect to the Supplemental Proposal on March 6, 2006, and clarification was conducted the following day, March 7, 2006. The parties filed rebuttal testimony on March 21, 2006, which was followed by cross-examination on March 24, 2006, all with respect to the Supplemental Proposal.

On March 3, 2006, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases not including the Supplemental Proposal. Clarification on the litigants' rebuttal testimony occurred on March 7 and 8, 2006. Written discovery of BPA's and the parties' direct and rebuttal cases occurred consistent with the Hearing Officer's schedule throughout the hearing. Because BPA's rebuttal case contained a new element for the risk mitigation package, parties were provided the opportunity to file sur-rebuttal testimony on this issue on March 13 and March 14, 2006. BPA responded to over 600 data requests concerning its Initial Proposal and its rebuttal testimony. Cross-examination took place on March 20 and 24, 2006, and the parties submitted initial briefs on April 17, 2006. Oral argument before the Administrator was held on April 26, 2006, at which time the Supplemental Proposal was incorporated with the rest of the rate case. The Draft ROD was issued to parties on June 2, 2006. On June 16, 2006, the parties submitted briefs on exceptions in response to the Draft ROD.

For interested persons who do not wish to become parties to the formal evidentiary hearings, BPA's Procedures provide opportunities to participate in the ratemaking process by submitting oral and written comments. (*See* Section 1010.5 of BPA's Procedures.) BPA took oral and written comments at transcribed field hearings conducted throughout the region between November 29, 2005, and December 7, 2005, in six locations: Idaho Falls, Idaho; Kalispell, Montana; Tacoma and Spokane, Washington; and Springfield and Portland, Oregon. BPA received and considered nine written comments submitted during the participant comment period, which officially ended on February 13, 2006. The comment period for the Supplemental Proposal ran from February 13, 2006, through March 6, 2006. BPA received and considered three written comments submitted during the Supplemental Proposal participant comment period. BPA also received several written comments after the end of the official comment period but prior to the issuance of the Draft ROD and the Administrator chose to include these late comments in the record and consider them. The transcribed field hearings and the comments from these rate case participants are part of the record upon which the Administrator bases his decisions. All rate case exhibits (including testimony, studies, and documentation), witness qualifications, motions, and orders for the WP-07 Wholesale Power Rate Adjustment Proceeding can be viewed at https://secure.bpa.gov/ratecase.

This ROD is based on the Administrator's consideration of the entire rate case record, including oral and written comments discussed in Section 18. This ROD was published on July 17, 2006.

[Note: On occasion, certain rate case parties consolidated for the purposes of filing a brief or brief on exceptions on one or more issues where such parties shared the same thinking. Each different consolidated group of parties, termed "joint parties," was given an alpha-numeric designation (*e.g.*, JP1, JP2, JP3) by the rate case clerk for the purposes of being considered, collectively, an official rate case party. For convenience, we have identified all of the entities that comprise each of the joint parties on the list of Commonly Used Acronyms that is included in this ROD.]

1.1.3 Waiver of Issues by Failure to Raise in Briefs

While the parties raised many issues in their briefs, there were a number of other 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. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve the matter at issue. Issues not properly raised will be decided based on BPA's stated position in the record.

However, parties need only to specifically raise the issues in either their initial brief or, if timely, brief on exceptions in order to preserve the issue. While a party may desire to reassert the issue for other reasons, it is not necessary to reassert the issue in its brief on exceptions in order to avoid waiving the issue.

1.2 Legal Guidelines Governing Establishment of Rates

1.2.1 Statutory Guidelines

The Flood Control Act of 1944 (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 of the Flood Control Act 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. *Id.*

The Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission System Act), contains requirements similar to those of the Flood Control 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.

In addition to the Bonneville Project Act of 1937 (Bonneville Project Act), the Flood Control Act, and the Transmission System Act, the Northwest Power Act provides numerous rate directives. Section 7(a)(1) 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. 16 U.S.C. § 839e(a)(1). 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 paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are derived.

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 of 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"); *Aluminum Company of America v. Central Lincoln Peoples' Utility District,* 467 U.S. 380, 389 (1984) ("The Administrator's interpretation of the Regional Act is to be given great weight"); *Department of Water and Power of the City of Los Angeles v. 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"); *Public Power Council v. Bonneville Power Admin.*, (No. 04-73240) (9th Cir April 4, 2006).

1.3 FERC 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 Department of Energy--Bonneville Power Admin.,* 13 F.E.R.C. ¶ 61,157, 61,339 (1980). The Commission may not modify power rates proposed by the Administrator, but may only confirm, reject, or remand them. *United States Department of Energy--Bonneville Power Admin.,* 23 F.E.R.C. ¶ 61,378, 61,801 (1983). 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 (1997).

1.3.1 Firm Power Rates

With respect to FERC review of rates under the Northwest Power Act, FERC reviews BPA rates to determine 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) with respect to transmission rates, to ensure the rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2). *See United States Department of Energy--Bonneville Power Admin,* 39 F.E.R.C. ¶ 61,078, 61,206 (1987). The limited FERC review of 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).

1.3.2 Inter-Business Line Charges

BPA is forecasting certain inter-business line costs and unit costs that will be used as inputs for the transmission and ancillary services rates BPA develops in its separate transmission rate proceeding. BPA's current transmission rates were approved by FERC through FY 2007 and contain formula rates for some ancillary services that will be adjusted based on the inter-business line costs established in this power rate case. BPA will hold another transmission rate proceeding, beginning later this year, to establish transmission and ancillary services rates for FY 2008-2009.

Under Section 212(i) of the Federal Power Act (FPA), 16 U.S.C. § 824k(i), BPA transmission rates applicable to transmission service ordered by the Commission shall meet the existing requirements of the law applicable to BPA transmission rates except that no BPA transmission rates shall be unjust, unreasonable, or unduly discriminatory or preferential. This standard does not apply to any of BPA's transmission rates except for rates for FERC-ordered transmission. At the request of BPA, however, the Commission has reviewed transmission rates established in 7(i) proceedings under this standard, so that BPA knows that the rates meet the standard for FERC-ordered transmission. *See United States Department of Energy--Bonneville Power Admin.,* 80 F.E.R.C. 61,118, at 61,370 (1997). BPA is not establishing any transmission rates in this proceeding. Therefore, it will not be submitting the rates to FERC under the just and reasonable standard. That standard does not apply to any of the rates in this proceeding.

2.0 OVERALL POLICY CONTEXT

2.1 Introduction

In the FRN announcing the rate case, BPA explained that it had undertaken four major public consultation and review processes in the past five years. These processes are the Regional Dialogue and the Policy for Power Supply Role for FY 2007-2011 (Near-Term Policy), the Power Function Review (PFR), Post-2006 Conservation Program Structure Proposal, and the Transmission Rate Case. 70 Fed. Reg. 67687-67688 (2005). In addition, on June 30, 2005, BPA released *Bonneville Power Administration's Service to Direct-Service Industrial (DSI) Customers for Fiscal Years 2007-2011 – Administrator's Record of Decision* (DSI ROD). *Id.* at 67689-67690. A *Supplement to Administrator's Record of Decision on Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (Supplemental DSI ROD) was issued by the Administrator on June 1, 2006. These last two RODs further clarify BPA's decisions for service to DSIs. The FRN explained that the rate case would implement policy decisions reached in each of these processes, where appropriate.

2.2 Subscription

On December 21, 1998, BPA issued the Power Subscription Strategy and Record of Decision (Subscription Strategy). The Subscription Strategy reflected BPA's position on the equitable distribution of Federal power for FY 2002-2011. The Subscription Strategy was the culmination of a multi-year public process that established BPA's plan for the availability of Federal power post-2001, the products from which customers could choose, and an outline of the contracts and pricing framework for those products. *Id.* at 67687.

The Subscription Strategy provided a marketing framework for the WP-02 power rate case. The WP-02 power rate case developed the rates and rate schedules necessary for the products and contracts that were developed through Subscription. However, the rates established in the WP-02 power rate proceeding applied to only the first five years of the 10-year Subscription contracts (through September 30, 2006) and must now be replaced. The Subscription contracts continue to be the basis for the contractual relationship between BPA and nearly all of its firm power customers. *Id.*

2.3 Firm Power Products and Services Rate Schedule

In addition to establishing successor rates for the Subscription contracts, BPA is proposing the successor to the Firm Power Products and Services (FPS) rate schedule. The FPS rate schedule is available for the purchase of surplus firm power and other products and services for use inside and outside the Pacific Northwest (PNW). The FPS rate schedule and associated GRSPs were initially established for a 10-year period running from October 1, 1996, to September 30, 2006. The rate schedule and GRSPs were slightly modified in 2000 through a 7(i) process (FPS-96R). The FPS rate schedule is used primarily for the sale of surplus firm power and related products. If BPA does not replace the FPS schedule, BPA would lack a rate schedule to sell surplus power in the West Coast wholesale energy markets. *Id.*

2.4 Regional Dialogue and the Policy for Power Supply Role for Fiscal Years 2007-2011 (Near-Term Policy)

The Regional Dialogue process began in April 2002 when a group of BPA's PNW electric utility customers submitted a "joint customer proposal" to BPA that addressed both near-term and long-term contract and rate issues. Since then, BPA, the Northwest Power and Conservation Council (NPCC), customers, and other interested parties have worked on these near- and long-term issues. Considering the depth and complexity of many of these issues, BPA concluded it was not practical to resolve all issues before the start of the 2007 rate period. Therefore, BPA determined that it would address the issues in two phases. The first phase of the Regional Dialogue addressed issues that had to be resolved in order to replace power rates that expire in September 2006. The second phase will address long-term issues and is expected to be implemented through new power sales contracts and in a future rate case before new power sales contracts go into effect. *Id*.

BPA issued the Near-Term Policy and Record of Decision on February 4, 2005. The Near-Term Policy resolved certain outstanding issues prior to the start of the FY 2007-2009 rate period. Issues decided in the Near-Term Policy ROD affecting assumptions used in this rate case include the following: (1) BPA will apply the lowest-cost PF rates to its public agency customers whose contracts contain the lowest-cost PF rate guarantee throughout the remaining term of the Subscription power sales contracts; (2) BPA will limit the duration of the next rate period to three years, from FY 2007-2009; (3) public customers whose contracts do not contain a guarantee of the lowest cost-based PF rates for FY 2007-2011 will receive the same rate treatment in the FY 2007-2011 period as customers whose contracts contain this guarantee, as long as such customers signed a new contract or amendment by June 30, 2005, extending the term of the agreement through 2011; (4) any new or existing public customer whose contract expires in 2006 may select from any of the standard products except Complex Partial (Factoring), Block with Factoring, or Slice; and (5) BPA resolved not to offer contract amendments that would allow changes in the power products and services purchased under a customer's 10-year Subscription contract. *Id.* at 67687-67688.

BPA's Subscription contracts and amendments with the region's six Investor-Owned Utilities (IOUs) require the Agency to provide 2,200 aMW (average megawatts) of power or financial benefits to the residential and small-farm consumers of these customers during FY 2007-2011. BPA signed agreements in late May 2004 with all six regional IOUs that provide certainty in the amount and manner that benefits will be provided to their residential and small-farm consumers under their Subscription contracts for FY 2007-2011. These agreements provide certainty by defining benefits based on a methodology that uses independent market prices in calculating the financial benefits, and establishing a floor of $100 million and a cap of $300 million per year. *Id.* at 67688.

2.5 Service to Direct Service Industries

On February 4, 2005, BPA sent a letter to customers and constituents describing a public process to solicit comments on certain issues related to service by BPA to its remaining DSI customers that had not been finally decided in the Near-Term Policy ROD, published the same day. The issues on which BPA was seeking additional public comment were: 1) the actual level of service benefits it should provide to the DSIs; 2) the eligibility criteria it should apply in determining which DSIs would qualify for such service benefits; and 3) the mechanism or mechanisms it should use to deliver those service benefits. BPA's letter outlined a straw proposal on each of these issues. The culmination of this public process was the publication of the DSI ROD on June 30, 2005.

In the DSI ROD, BPA tentatively decided that it would offer a surplus power sales contract to each of its remaining three aluminum company DSI customers, totaling in aggregate 560 aMW, at a capped cost of $59 million per year, and a 17 aMW surplus power sales contract to its one remaining non-aluminum DSI customer, which would not be subject to the cost cap. The DSI ROD indicated that BPA would attempt to structure the delivery of service benefits through a contractual arrangement that included the public utility in whose service area the DSI is located. Because of the financial risks inherent in providing actual power, and in order to meet the known and capped cost prerequisite, BPA concluded that the default mechanism for providing benefits to the DSI aluminum companies would be financial payments, calculated by monetizing the value (relative to expected market prices) of each company's below-market surplus power sales contract, resulting in an equivalent financial value of up to $12/MWh (or $59 million annually) on each megawatt-hour allocated to each aluminum company. This formed the basis for the assumptions for service to the DSI in the WP-07 Initial Proposal. (*See* Gustafson, *et al*., WP 07 E-BPA-17.) Nevertheless, the final decision regarding whether benefits would be provided through these financial payments or through physically delivered power, along with other implementation details, was left to the contract negotiations.

On November 28, 2005, BPA made available for public review and comment the *Draft Prototype – Block Power Sales Agreement* (Smelter Prototype). The Smelter Prototype is the draft surplus firm power sales contract BPA proposed for delivered service benefits to the DSI aluminum companies during FY 2007-2011. The Smelter Prototype was the result of several months of negotiations among BPA, the DSIs, and several of the public utility partners. A separate prototype was developed for Port Townsend Paper. On June 1, 2006, BPA issued the Supplemental DSI ROD. The Supplemental DSI ROD addressed public comments on the draft DSI contracts, including comments on whether certain additional flexibilities should be provided to the DSIs under the contracts. While total annual benefits available to the aluminum company DSIs is $59 million, BPA believes the decisions in the Supplemental DSI ROD will result in a reasonable probability that actual payments to the DSIs will not exceed the $53 million dollar level of benefits projected in BPA's Initial Proposal. The Supplemental DSI ROD formed the basis for assumptions about DSI service in the WP-07 final rate studies and does not change the assumptions in the Initial Proposal.

2.6 Power Function Review

In January 2005, BPA initiated an extensive and in-depth process to examine the Power Business Line's (PBL) program levels. This PFR provided customers and constituents with significant opportunities to provide input into the policy choices that drove program projections to be used in BPA's Initial Power Rate Proposal. The PFR focused on nine major cost areas including Army Corps of Engineer (COE) and Bureau of Reclamation (Reclamation) operation and maintenance costs and capital investments, Columbia Generating Station (CGS) operation and maintenance costs and capital investments, conservation program costs, fish and wildlife program expenses and capital investments, internal operations costs charged to power rates, renewable program costs, transmission acquisition costs, Federal and Non-Federal debt service and debt management, and risk mitigation packages and tools. (70 Fed. Reg. 67688 (2005); *see also*, Homenick, *et al.*, WP-07-E-BPA-10 at 3.) Two main areas, debt service and management and risk mitigation, were discussed but not decided in the PFR. 70 Fed. Reg. 67688 (2005).

With few exceptions, the PFR close-out letter formed the basis for BPA's forecast of program spending levels in the Initial Proposal. (*See* Homenick, *et al.*, WP-07-E-BPA-10 at 3-4.)

BPA committed to revisit many of the program areas between initial and final proposals. This follow-on process, called PFR II, began in January 2006 as a continuation to the PFR held in 2005. The goal of this second phase was to ensure that the cost levels used in setting BPA's power rates for FY 2007-2009 were as low as possible, consistent with carrying out BPA's mission. The results of the PFR II process formed the basis for updates to the program level forecasts used in the final rate case studies. *Id.* at 11.

See Section 4, Revenue Requirement, in this ROD for a description of the PFR process.

2.7 Post-2006 Conservation Program Structure Proposal

In the fall of 2004, BPA established a post-2006 conservation workgroup. The conservation workgroup was composed of over 65 utility representatives and conservation stakeholders. The purpose of the workgroup was to discuss and develop BPA's conservation program for the post-2006 time frame. In January 2005, the workgroup provided BPA with recommendations and comments on how BPA should design its conservation program. 70 Fed. Reg. 67688-67689 (2005).

On March 28, 2005, BPA issued its Post-2006 Conservation Program Structure Proposal for review during a 30-day comment period. BPA received 56 comments on the proposal. On June 28, 2005, BPA issued its response to the comments along with its final decision on the design and scope of the Post-2006 proposal. *Id.*

The proposal describes the approach of the conservation programs that BPA will offer during the FY 2007-2009 timeframe. The decisions in the Post-2006 proposal were used as inputs in the development of BPA's WP-07 Initial and Final Rate Proposals. *Id*.

2.8 Transmission Rate Case

BPA is committed to marketing its power and transmission services separately in a manner that is modeled after the regulatory initiatives adopted in 1996 by FERC to promote competition in wholesale power markets. FERC's initiatives in Orders 888[1] and 889[2] directed public utilities

---

[1] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pubic Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities Reg-Preamble, FERC Stats & Regs 1991–96, para. 31,036 (1996).

[2] Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, Reg-Preamble, FERC Stats & Regs 1991–96, para. 31,035 (1996).

regulated under the FPA to separate their power merchant functions from their transmission reliability functions; unbundle transmission and ancillary services from wholesale power services; and set separate rates for wholesale generation, transmission, and ancillary services. Although BPA was not required by law to follow FERC's regulatory directives that promote competition and open access transmission service, BPA elected to separate its power and transmission operations and unbundle its rates in a manner consistent with the directives concerning open access transmission service. BPA develops its transmission rates in separate proceedings from its power rates. 70 Fed. Reg. 67689 (2005).

On February 2, 2005, BPA's Transmission Business Line (TBL) initiated a rate case to establish transmission rates for the FY 2006-2007 transmission rate period. Prior to the initiation of that rate case, TBL held several public meetings with customers over the period July through September, 2004, to discuss transmission costs, revenues, and rate design issues for the FY 2006-2007 rate period. The customers expressed interest in meeting with TBL to develop a settlement for the FY 2006-2007 rate period. TBL continued meetings with customers between October and early December 2004, resulting in a Settlement Agreement. TBL's initial rate proposal reflected the terms of the Settlement Agreement. *Id.*

On June 20, 2005, BPA issued the Final Transmission Proposal - Administrator's Record of Decision that adopted the transmission and ancillary services rates as reflected in the Settlement Agreement. FERC issued final approval of these TBL rates on September 29, 2005. The TBL rate case settlement established formula rates for ancillary services and some transmission rates that incorporate ancillary services. For FY 2007, these formula rates will be affected by the pricing of generation inputs to ancillary services that will be determined in this PBL rate case. The pricing of generation inputs to ancillary services determined in this rate case also will be a factor in TBL's rates in FY 2008-2009. *Id.*

On February 13, 2006, BPA issued the Supplemental Proposal revising BPA's forecast of revenues from the TBL to the PBL to remove the inside the band cost associated with the FERC-approved *AEP* methodology (*American Elec. Power Serv. Corp.*, 88 FERC ¶61,141 at 61,457 (1999)) for FY 2008 and 2009 from the generation cost allocation for Generation Supplied Reactive and Voltage Control (GSR) described in the Initial Proposal. (*See* ROD, Section 7; Bermejo, *et al.*, WP-07-E-BPA-28 at 1.)

2.9 Financial and Policy Objectives

BPA's six previous major financial and policy objectives helped shape this rate proposal. Those objectives are: 1) a rate design that meets BPA's financial standards, including meeting a 92.6 percent three-year Treasury Payment Probability (TPP) (which is equivalent to a 95 percent two-year TPP); 2) lowest possible rates, consistent with sound business principles including statutory obligations; 3) lower, but adjustable, effective rates rather than higher, but stable rates; 4) a risk package that includes only those elements BPA believes it can rely upon; 5) reserve levels that are not built up to unnecessarily high levels; and 6) allocation of costs and credits to customers based upon product choice to the extent possible. BPA notes that these objectives are interdependent and require BPA to balance competing objectives against each other when developing its overall rate design strategy. The Final Proposal reflects BPA's success in balancing these competing objectives. Effectively dealing with the financial risks that BPA faces was one of the most substantive issues in the WP-07 rate case. Anticipating this, BPA began having risk workshops as part of the PFR process. These workshops continued through the spring and summer of 2005 and served two purposes. First, the workshops helped BPA's customers and other interested parties to have a better understanding of the risks BPA faces, how BPA models those risks, and the implications of various risk mitigation strategies. Second, the workshops provided useful input to BPA as it developed the Initial Proposal. Sections 5 and 6 of this ROD deal with the many issues surrounding risk that were raised in the course of this rate proceeding.

2.10 Partial Resolution of Issues

While rate cases tend to be contentious, during this 7(i) process, BPA and the rate case parties displayed an uncommon ability on a number of occasions to work together toward a common purpose. This collaboration began with the workshops prior to the start of the 7(i) and continued through settlement discussions after cross examination. These efforts produced a number of successful results. As described in Section 6, BPA, with the support and assistance of its customers developed liquidity tools that allowed BPA to reduce rates. In addition, the Partial Resolution of Issues further demonstrates a collaborative effort among BPA, its public power customers, the IOUs, Tribes and interest groups to resolve a number of rate case issues. The parties recognized this collaborative effort that shaped this rate case. For example, WPAG noted that in the rate case "BPA rate staff and the other parties demonstrated the ability to put aside their positions and deal with each other in an interest-based manner." (WPAG Br. WP-07-M-68 at 7.) This 7(i) process demonstrates what is possible when BPA and parties work together collaboratively.

At the request of parties to the WP-07 rate proceeding, BPA and the parties held four publicly noticed settlement discussions to discuss rate design and risk-related issues. These discussions occurred on February 3, February 8, February 14, and February 22, 2006. The intention was to determine if all parties could come to agreement on a set of issues, thereby limiting the contested issues in this rate proceeding, as well as limiting the workload associated with the rest of the rate proceeding. (*See* Evans, *et al.,* WP-07-E-BPA-31 at 1-2.)

BPA and the parties agreed to support, or to not oppose, the resolution of some conditions to the FPS rate schedule, design of the Low Density Discount, treatment of revenue credits from Operating Reserves, Priority Firm Power (PF) rate design and a few Slice issues involving the treatment of particular costs. In addition, BPA and the parties agreed to support, or to not oppose, the nonprecedential nature of the treatment of decisions in this rate case related to Section 7(b)(2) of the Mid-Columbia resources, conservation, uncontrollable events, and secondary revenues counted as reserves. Attachment 1, Partial Resolution of Issues, describes in detail the resolution regarding these issues. BPA's negotiating team supported the resolution of the issues as set forth in Attachment 1 as a reasonable compromise to the different points of view presented in the discussions and recommend that the Administrator adopt this resolution in the Record of Decision for this rate proceeding. (*See* Evans, *et al.,* WP-07-E-BPA-31 (E1).)

As part of this agreement, BPA and the parties agreed that the Brattebo, *et al.*, WP-07-E-JP6-01, testimony, and related exhibits filed by the IOUs, would not be submitted into evidence. In addition, with regard to the issues included in the Partial Resolution of Issues, the parties agreed to five conditions. They agreed not to file rebuttal testimony, not to cross-examine witnesses, and not to raise these topics in briefs in this rate proceeding. In addition, they would not raise these issues with FERC or in any appeal to the Ninth Circuit Court of the rates adopted in this proceeding that are established consistent with this resolution. (*See* Evans, *et al.,* WP-07-E-BPA-31 at 2-3.)

BPA also explained during the settlement discussions that it intended to propose some changes to the National Marine Fisheries Federal Columbia River Power System Biological Opinion Adjustment (NFB Adjustment) in light of issues raised in some parties' direct cases. As part of the Partial Resolution of Issues in this proceeding, BPA and the parties agreed to allow the parties to offer sur-rebuttal testimony on any proposed changes to the NFB Adjustment. (*Id.* at 3.)

Most of the parties referred to the Partial Resolution of Issues as a partial settlement. Because, unlike normal settlement documents, there was no signed document binding the resolution of these issues, BPA chose to refer to this document as a "Partial Resolution of Issues" of rate case issues.

2.10.1 Partial Resolution of Issues

Issue 1

Whether the Administrator should accept the staff recommendation to adopt the Partial Resolution of Issues in the Record of Decision for this rate proceeding.

Parties' Positions

The PNW IOUs support the Partial Resolution of Issues and recommend that the Administrator adopt it in the Record of Decision. (IOU Br., WP-07-M-67 at 4.) NRU supports the partial settlement and believes it reflects reasonable resolutions of those issues between and among BPA and its customers. (NRU Br., WP-07-M-61 at 2-3.) NWEC/SOS fully endorses the partial settlement. (NWEC/SOS Br., WP-07-M-64 at 2.) The PNGC group "generally supports" the partial settlement of issues with the exception of "Section 1 that adheres to the 7(b)(2) issues and that the PNGC Group neither supports nor opposes." (PNGC Br., WP-07-M-70 at 6.) Public Power Council (PPC) "does not oppose the Partial Resolution of Issues." (PPC Br., WP-07-M-65, at 1, n. 2.)[3] Springfield Utility Board (SUB) supports the Partial Resolution of Issues. (SUB Br., WP-07-M-66 at 2.) The Western Public Agencies Group (WPAG) utilities did not oppose this compromise rate design proposal as a group. A number of individual WPAG utilities did not take a position on the compromise rate design proposal, and the Clark Public Utilities commissioners, acting in their individual capacities and not as representatives of Clark Public Utilities, filed comments in the public comment process pointing out the severe financial impacts of the compromise rate design proposal on the residents of Clark County, Washington. (WPAG Br., WP-07-M-68 at 7, n. 1.)

[3] PPC is joined on its brief in whole by NRU and Cowlitz PUD.

In the JP11 testimony (*See* Brawley, *et al*., WP-07-E-JP11-02 at 1-2.) several utilities summarized their positions on the Partial Resolution of Issues. Cowlitz County Public Utility District (Cowlitz) supports the partial settlement as a compromise package but takes no position on the individual issues. In particular, Cowlitz understands BPA's position on the Section 7(b)(2) issues in the package, but Cowlitz stands by the JP1 testimony (*see* Saleba, *et al.*, WP-07-E-JP1-01), which it co-sponsored. City of Tacoma and Grant County PUD No. 2 support Sections 2 (FPS Rate Schedule), 4 (Operating Reserves Credit), and 5 (Rate Design), and do not oppose the remainder of the package. The following utilities support Sections 2, 4, 5, as well as Section 6 (Slice), and do not oppose the remainder of the package: Seattle City Light, Pend Oreille County PUDs No. 1, Eugene Water and Electric Board, Benton County PUD, and Franklin 1 in County PUD No. 1. Grays Harbor County PUD No. 1 supports Sections 2, 4, 5, and 6. PNGC supports Sections 2, 3, 4, 5, and 6, and does not oppose the remainder of the package. PNGC qualifies its support for Section 2 and its support or non-opposition to other parts of the package by stating PNGC "reserves and adheres to the position reflected in its testimony (*see* Reiten and Lovely, WP-07-E-PN-01), on matters of DSI 'service benefits' and rates." (*See* Draft ROD, Section 13.) Finally, Douglas County PUD does not oppose the partial settlement.

The Tribes (Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively) participated in the settlement discussions and found the partial settlement acceptable and recommended that the Administrator incorporate it into final rates. The Tribes will not oppose the partial settlement. (Sheets, *et al.*, WP-07-E-CR/NAYA-02 at 8.)

BPA's Position

BPA believes the resolution is a reasonable compromise to the different points of view presented in the discussions and recommends adoption. (*See* Evans, *et al.*, WP-07-E-BPA-31 (E1).)

Evaluation of Positions

Many of the parties segregated the Partial Resolution of Issues into parts that they support and parts that they do not support but will not oppose. There were no parties who opposed the Partial Resolution of Issues. Consistent with the Partial Resolution of Issues, no parties opposed the settlement in testimony nor raised any of these issues in cross examination or in their briefs except as discussed in Section 10, Section 7(b)(2) Rate Test. BPA continues to believe that the resolution of the specific issues as described in the Partial Resolution of Issues (*see* Evans, *et al.*, WP-07-E-BPA-31), is a reasonable compromise package for those issues.

Decision

BPA adopts the Partial Resolution of Issues.

2.11 Overall Rate Levels

Issue 1

Whether BPA's proposed rates are too high.

Parties' Positions

PPC, and WPAG, ICNU and NRU, as well as SUB through adopting PPC's brief, maintain that BPA's proposed rates are too high and BPA can and should reduce them. (*See* PPC Br., WP 07 M 65 at 2-7; WPAG Br., WP-07-M-68 at 3-6; NRU Br., WP-07-M-61 at 3; SUB Br., WP-07-M-66 at 3.)

PPC states that BPA's current power rates, without CRACs (Cost Recovery Adjustment Clauses), are roughly parallel to historical levels, and with CRACs, preference customers paid as much as 46 percent more than the base rate. (*See* PPC Br., WP-07-M-65 at 3.) They state that BPA's proposed base rate is approximately 31.1 mills/kWh. (*Id.*) They maintain that customers were expecting a rate decrease and BPA's [Initial] Proposal resulted in an increase of around 13 percent over FY 2006 rates. PPC further argues that BPA's customers are experiencing hardship because of BPA's "climbing" rates. (*Id.* at 4.) PPC acknowledges that BPA must set rates that recover its costs; however, PPC contends that BPA's proposed rates are higher than necessary and suggest a variety of ways to lower them. (*Id.* at 4-5.) One area is liquidity tools - PPC "understands and expects that BPA will incorporate the direct pay arrangement with Energy Northwest (EN) into this Draft Record of Decision." (*Id.* at 5.) PPC notes that customers and BPA have outlined some ways that BPA can capture the benefits of these tools if they become available after the Final Record of Decision on rates. (*Id.*) PPC urges BPA to do this. PPC also makes several suggestions to changes to the CRAC that it believes will lower rates. These include adoption of the "may" language similar to that provided for in the SN CRAC, inclusion of a CRAC rebate mechanism, adoption of expense category limits, and a commitment in the GRSPs to engage in cost cuts before, or concurrent with, the implementation of a CRAC. (*Id.* at 6.) The third area, which PPC supports, is to incorporate updated information indicating an increase in expected revenues, specifically to not include a cap on FY 2006 net secondary revenues. (*Id.* at 6-7.) PPC suggests actions for BPA to take to control its costs or otherwise reduce rates. PPC "expects BPA to do everything it can to find and implement reasonable measures to allow lower rates in the FY 2007-2009 period." (*Id.* at 7.)

WPAG raises similar arguments. It contends that "the proposed rates for service to preference customers contained in BPA's initial rate proposal were too high, and they can and should be substantially reduced by the conclusion of this rate proceeding. (WPAG Br., WP-07-M-68 at 3.) WPAG states that now that BPA's financial crisis has passed, customers expected that this rate case would deliver rate reductions reflecting BPA's improved financial circumstances and that the rates in the Initial Proposal are a "severe disappointment to preference customers." (*Id*. at 3-4.) WPAG suggests that this rate case presents BPA with an opportunity to demonstrate that its "stated commitment to keeping costs as low as possible" in this rate period, and in the post-2011 period can be counted on by preference customers. (*Id*. at 5.) WPAG's specific recommendations to BPA are to: carefully examine the need for, and amount of, Planned Net Revenues for Risk (PNRR); reflect the full amount of cost reductions achieved through the Direct Pay agreement with EN rather than using some of those cost reductions as increased working capital; include the full amount of FY 2006 secondary revenues when determining the final PF rate; make every effort to implement the Treasury note liquidity tool prior to the Final Record of Decision in this rate case; capture in the final PF rate all cost savings and revenue enhancements identified in the PFR processes; and reassess "whether starting a new subsidy payment program to the DSIs makes sense in light of the proposed level of the PF rate and the likelihood of additional costs being imposed on BPA through the ESA litigation." (*Id*. at 6.)

On the other hand, the Tribes are concerned that BPA's rate proposal "has given more weight to its policy of keeping its rates as low as possible and less weight to the concerns of salmon or fulfilling Federal treaty obligations." (JP13 Br., WP-07-M-69 at 7.) The issue of fulfilling Federal treaty obligations is addressed in Section 17 of this ROD. In their brief on exceptions, the Tribes contend that while "BPA states that it understands the Tribes' concerns regarding the fish and wildlife costs…BPA does not describe how it has addressed those concerns." (JP13 Br. Ex., WP-07-M-77 at 6.) They also suggest that BPA has not properly balanced its focus on "minimizing rates" with the need to address the costs and risks it faces. They state that BPA has not analyzed the impacts on the economy, especially the benefits of salmon restoration activities that restore a harvestable fishery, in anything close to a comprehensive evaluation. They conclude that this results in an unacceptable increased risk that BPA will defer either its payments to the Treasury or fish and wildlife protections. (*Id*., at 6 - 7.)

<u>BPA's Position</u>

BPA strives to ensure that power rates are as low as possible, consistent with sound business principles including meeting its statutory obligations. 16 U.S.C. § 839e(a)(1). BPA also understands the Tribes' desire for BPA to spend more on fish and wildlife restoration. BPA's response to both of these concerns is basically the same. Most of BPA's rates are cost-based and must be set to recover costs. (*See* Andrews, *et al.,* WP-07-E-BPA-30 at 2.) BPA costs are established outside the confines of a 7(i) rate proceeding. (*Id*.)

<u>Evaluation of Positions</u>

Several of the specific suggestions made by PPC and WPAG are dealt with elsewhere in the ROD. Treatment of new and potential liquidity tools and suggested changes to the CRACs are discussed in Section 6, Risk Mitigation. Discussions about incorporating expense reductions identified through the PFR processes are discussed in Section 4, Revenue Requirement. WPAG's discussion on service to the DSIs (WPAG Br., WP-07-M-68 at 6.) is dealt with in Section 17, Procedural Matters.

In rebuttal testimony, BPA agreed that "removal of the cap on secondary revenue is reasonable for the final study. BPA will not be relying on a capped forecast of FY 2006 net secondary revenues in its Final Proposal." (*See* Normandeau, *et al.,* WP-07-E-BPA-33.) The good fortune BPA is experiencing so far this year – with above average hydro conditions and healthy market prices – is a benefit to the region and helps bring overall rate levels down in the final studies, all else being equal.

Regarding WPAG's request that BPA carefully examine the need for Planned Net Revenues for Risk (PNRR), just as BPA did in the Initial Proposal, this ROD reflects decisions the Administrator is making that represent a risk package necessary to achieve BPA's TPP target of 92.6 percent. The actual amount of needed PNRR is included in the final rate case studies.

With respect to the overall discussion about the hardship and disappointment on the part of customers in reaction to the Initial Proposal, BPA is sympathetic to these concerns. BPA is committed to keeping its power rates as low as possible, consistent with sound business principles including meeting its statutory obligations. (*See* Andrews, *et al.,* WP-07-E-BPA-30 at 2.) On the other hand, the Tribes desire BPA to spend more on fish and wildlife restoration. (JP13 Br., WP-07-M-69 at 7.) BPA understands the Tribes' concerns regarding the fish and wildlife costs and believes these issues were dealt with in the PFR process. BPA can understand the Tribes' concerns without necessarily agreeing with them and that is the case here. The fact that the Tribes *desire* BPA to make additional expenditures does not necessarily result in an unacceptable increased risk that BPA will defer either Treasury payments or fish and wildlife protections. With regard to the views of both customers and Tribes, BPA must recover its costs. BPA's costs, with a few exceptions, are determined outside of a rate case proceeding.

Rate levels in BPA's Initial Proposal resulted from BPA's best forecasts of costs, sales, risks, and other factors at that time. While customers may have been disappointed at those rate levels, they were set at a level necessary to achieve the Agency TPP target of 92.6 percent for a three-year rate period. Final rates are set, based on the record, including updated financial information, to meet the TPP target of 92.6 percent.

The Tribes' concern that BPA has not prepared socioeconomic analysis of salmon restoration expenditures is misplaced in this rate case. None of BPA's ratemaking directives require the type of analysis the Tribes are requesting. This issue is discussed in Section 17.1.

Decision

BPA's proposed rates are neither too high nor too low; they are set to recover costs.

3.0 LOAD RESOURCE

3.1 Introduction

The Load Resource Study represents the compilation of the loads, sales, contracts, and resource data necessary for developing BPA's wholesale power rates. The Load Resource Study is described in the Load Resource Study, WP-07-FS-BPA-01. Documentation of the results is presented in the Load Resource Study Documentation, WP-07-FS-BPA-01A. The Load Resource Study is also described in the direct testimony of Hirsch, *et al.*, WP-07-E-BPA-11, and the rebuttal testimony of Hirsch, *et al.*, WP-07-E-BPA-32.

The Load Resource Study results are used to: (1) provide data to determine resource costs for the Revenue Requirement Study, WP-07-FS-BPA-02; (2) provide data to derive billing determinants for the revenue forecast in the Wholesale Power Rate Development Study (WPRDS), WP-07-FS-BPA-05; (3) provide load and resource data for use in the Risk Analysis Study, WP-07-FS-BPA-04; and (4) provide Pacific Northwest (PNW) regional hydro data for use in the secondary revenue forecast for the Market Price Forecast Study, WP-07-FS-BPA-03.

The Load Resource Study includes the following interrelated components: (1) a forecast of the Federal system load obligations comprised of BPA's power sales contract (PSC) obligations and other additional BPA contract obligations; (2) Federal system resource estimates that include the output from hydro and other generating resources purchased by BPA and other BPA contract purchases; (3) the Federal system load resource balance that relates Federal sales, loads and contract obligations to the Federal generating resources and contract purchases; (4) total Pacific Northwest regional hydro resources; and (5) estimated power purchases eligible for 4(h)(10)(C) credit.

For the calculation of the final rates, the Load Resource Study was updated as described below.

3.2 Federal System Load Obligations

The Federal system load obligation forecast is composed of the various components.

3.2.1 Power Sales Contract Obligations

BPA updated the Federal system PSC obligation forecast that is composed of customer group sales forecasts for public body and cooperative utilities and Federal Agencies (Public Agencies), DSIs, IOUs, and other BPA PSC obligations. The Public Agency PSC forecast is based on the sum of the individual load forecasts that BPA produces for, or obtains from, each of its public utility and Federal agency customers. These forecasts begin as annual projections of total retail load that are shaped to reflect monthly variation using historical relationships and peak energy use. The Federal system PSC forecast was also reduced for conservation savings. (*See* Load Resource Study, WP-07-FS-BPA-01 at 5-7.)

Slice product sales are estimated as 22.63 percent of the Slice resource stack. The Slice resource stack was revised to reflect a new hydro regulation study. The Slice resource stack was also modified to reflect the expiration of BPA's Idaho Falls' Bulb Turbine acquisition contract on September 30, 2006. The amount of Slice product available for delivery is dependent on Federal system operating decisions, hydro production that varies by water conditions, and generation from non-hydro Federal resources and other specified contracts. (*Id*. at 6.)

BPA projects no actual power deliveries to the IOUs and estimates one DSI sale through a public utility by means of an FPS contract of 17 aMW. (*Id*. at 6.)

3.2.2 Other BPA Contract Obligations

BPA's other contract obligations, comprised of contracts not defined under BPA's firm requirements PSC obligations, were updated since the Initial Proposal. These obligations include contract sales to utilities, marketers, and power commitments under the Columbia River Treaty. (*See* Load Resource Study, WP-07-FS-BPA-01 at 10-11.)

No party raised issues regarding the Federal System Load Obligation forecast.

3.3 Federal System Resource Forecast

BPA markets power from generating resources that include Federal and non-Federal hydro projects, other generating projects, and other hydro-related contracts. The Federal system resource forecast includes BPA's purchased output from generating projects and other contract purchases and exchanges which were revised since the Initial Proposal.

3.3.1 Regulated Hydro

Federal system regulated hydro resource estimates are derived from a hydro regulation study that estimates generation under 50 water conditions using the operating provisions of the Pacific Northwest Coordination Agreement (PNCA). The power and non-power power operating characteristics that affect the seasonal shape and magnitude of the hydro system generation was updated since the Initial Proposal. (*See* Load Resource Study, WP-07-FS-BPA-01 at 11-13.)

Specific aspects of the power and non-power requirements in the updated hydro regulation study include, but are not limited to:

- Surface Passage Improvements: Incorporation of information concerning the timing of installation, testing, and full implementation of surface passage improvements at COE's projects on the lower Columbia and lower Snake Rivers.

- Fall Chinook Transport Study: Updates relating to juvenile transportation effectiveness at several of the COEs' Little Goose, McNary, and The Dalles projects on the lower Columbia and lower Snake Rivers using input provided from regional forums planning research. Spill requirements for the Lower Snake Fall Chinook Transport Study are scheduled for FY 2006-2008. For FY 2009, these spill requirements are not assumed since BPA expects the study to conclude after three years, in FY 2008.

- Court-Ordered Spill Operations: Incorporation of the 2006 court-ordered spill operations for FY 2007-2009 due to the status of the 2004 Biological Opinion remand process and the likelihood that the 2006 court-ordered operations will continue through the rate period.

- Residual Hydro Load: Updates to the projected regional loads for FY 2007-2009 used in the hydro regulation model that are consistent with those published in the 2004 White Book.

Detail of the power and non-power requirements for the hydro regulation study for FY 2007-2009 are presented in the WP-07 Final Study, Load Resource Study Documentation, WP-07-FS-BPA-01A, Sections 2.9.1 through 2.9.3, at 110-130.

3.3.2 Independent Hydro

Federal system Independent Hydro resource estimates were updated to reflect the expiration of the Idaho Falls' Bulb Turbine acquisition contract on September 30, 2006. (*See* Load Resource Study, WP-07-FS-BPA-01 at 11-13.)

3.3.3 Non-Utility Generation

Federal system Non-Utility Generation (NUG) resource estimates were revised to reflect the removal of the Fourmile Hill Geothermal project. The Fourmile Hill Geothermal project was previously included in FY 2009; however the start date for the project was revised from October 1, 2008, to October 1, 2009, which is outside the rate period. (*See* Load Resource Study, WP-07-FS-BPA-01 at 11-13.)

3.3.4 Augmentation Purchases

BPA's Augmentation Purchases keep the Federal system in load resource balance on an annual basis over the rate period under 1937 critical water conditions. Augmentation Purchases were updated to cover changes in BPA's loads, contracts, and resources for the rate period. (*See* Load Resource Study, WP-07-FS-BPA-01 at 11-13.)

Issue 1

Whether BPA properly considered operation of the FCRPS based on the 2004 Biological Opinion and any further river operations changes that may be imposed on the system due to court order.

Parties' Positions

The Tribes support BPA's hydro operations assumptions and note that BPA's risk mitigation mechanisms need to be revised so they are robust enough to address other non-power requirements and costs. (JP 13Br., WP-07-M-77 at 7.)

PPC believes that BPA should not alter its assumptions for the entire rate period to match current hydro operations for 2006. (PPC Ex. Br., WP-07-M-78 at 11, joined by PNGC, ICNU, Cowlitz.) PPC acknowledges there is a substantial likelihood that hydro operations in FY 2007-2009 will be different from those set forth in the 2004 Biological Opinion, what the actual operations turn out to be still is uncertain. (*Id*.) PPC believes a prudent approach to addressing any changes in cost would be to rely on the mechanisms (NFB Adjustment and Emergency NFB Surcharge) created in this proceeding specifically to account for those changes by collecting the costs that are actually incurred. (*Id*.) If BPA now assumes hydro operations will be identical to current operations, the benefit of these tools will be undermined. (*Id.*) If BPA continued to assume hydro operations in accordance with the 2004 Biological Opinion, however, any discrepancies in actual operations, including the situation where current operations persist, would be addressed by the operation of the NFB Adjustment and/or NFB Surcharge. (*Id*.)

BPA's Position

BPA will incorporate non-power requirements, as they may be agreed upon at the time BPA makes the final hydro regulation studies resulting from the 2004 Biological Opinion Remand process. (Hirsch, *et al.*, WP-07-E-BPA-32 at 2.) The hydro modeling assumptions represent BPA's best available information on power and non-power requirements, including the 2006 court-ordered spill in the hydro operations assumed for FY 2007-2009.

BPA believes the operations under these hydro requirements are a reasonable assumption for the rate period because the assumed fish and wildlife hydro operations in the initial proposal do not reflect the anticipated hydro operations for FY 2007-2009. Therefore it is reasonable to model the 2006 hydro operating requirements, at a minimum, as a base for the rate period. BPA indicated that it would update the hydro regulation studies over time to include adopted changes in fish mitigation measures as they become available.

Evaluation of Positions

BPA incorporates the best available information concerning hydro system operating requirements expected to be in effect during the rate period. This requires BPA to consider many factors. For example, hydro operations take into account Biological Opinions, legal challenges to the Biological Opinions, and ongoing processes intended to resolve those legal challenges. PPC admits there is a "substantial likelihood" that hydro operations in FY 2007-2009 will be different from those set forth in the 2004 Biological Opinion. (PPC Br. Ex., WP-07-M-78 at 11.) Therefore, given this uncertainty, it is prudent and reasonable for BPA to model hydro operations based on the 2006 court-ordered operations for the FY 2007-2009 rate period.

BPA disagrees with PPC that the benefit of the NFB Adjustment and Surcharge will be undermined if current hydro operations are assumed. These risk tools were not intended to collect for changes in operations or programs that were known by BPA going into the rate period. The NFB Adjustment and Surcharge were designed to address conditions that BPA cannot currently forecast or model due to a wide range of possible outcomes that may result from future court-related decisions in the FY 2007-2009 rate period. The NFB Adjustment and Surcharge were created to specifically address the financial impact of court-related changes to hydro operations or programs that occur after the Final Studies. (Lovell and Normandeau, WP-07-E-BPA-34 at 2-3.) Consequently, there will be no decrease in the value or benefit of these risk tools over the rate period. Therefore, it is reasonable and prudent that BPA's final load resource study and rates reflect changes in hydro operations that have occurred since BPA's Initial Proposal.

Decision

BPA properly considered operation of the FCRPS based on the 2004 Biological Opinion and any further river operations changes that may be imposed on the system due to court order. BPA's Final Study reflects the changes described in Section 3.3.1.

3.4 Federal System Load Resource Balance

The Federal system load resource balance compiles the updated monthly energy of BPA's resources, which includes hydro and non-hydro resources, and contract purchases; less BPA's load obligations, which are comprised of BPA's PSC obligations and other contract obligations. This determines BPA's monthly and annual energy load resource balance. If BPA's resources are greater than load obligations under 1937 critical water conditions, BPA has firm surplus energy. Conversely, if BPA's resources are less than load obligations, then BPA will have to augment with power purchases to meet Federal system energy deficits. (*See* Load Resource Study Documentation, WP-07-FS-BPA-01A, Section 2.3, at 11.)

No party raised issues regarding the Federal system load resource balance estimates..

3.5 Pacific Northwest Regional Hydro Generation

The total PNW regional hydro resource generation estimates that includes regulated, independent, and NUG hydro projects were revised to include the previously discussed power and non-power requirement changes. (*See* Load Resource Study Documentation, WP-07-FS-BPA-01A, Section 2.7, Tables 2.7.1 through 2.7.3, at 104-106.)

No party raised issues regarding the total PNW regional hydro resource generation projections.

3.6 Power Purchase Estimate for 4(h)(10)(c) Credit

BPA ratepayers are not required to pay for costs allocated to non-power uses of the dams. These non-power uses include flood control, irrigation, recreation, and fish and wildlife. The Northwest Power Act provides a methodology for BPA to annually recoup the portion of costs associated with fish measures that should be allocated to other non-power uses of the dams via 4(h)(10)(C) credits against BPA's Treasury payment. The 4(h)(10)(C) power purchase credit estimate was recalculated using the previously discussed updated power and non-power requirements incorporated in the hydro regulation study. (*See* Load Resource Study Documentation, WP-07-FS-BPA-01A, at 108.)

No party raised issues regarding the power purchase estimate for 4(h)(10)(C) credit.

4.0 REVENUE REQUIREMENT

4.1 Introduction

The Wholesale Power rates are designed to recover the costs of the generation function only. The Revenue Requirement Study, WP-07-FS-BPA-02, determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including the repayment of the Federal investment in hydro generation, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest; other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; cost to the PBL, if necessary, of purchasing transmission services; and all other generation-related costs incurred by the Administrator pursuant to law. (*See* Revenue Requirement Study, WP-07-FS -BPA-02.)

4.2 Revenue Requirement Development

BPA has developed the revenue requirement in conformance with the financial, accounting, and ratemaking requirements of DOE's Order No. (RA 6120.2.) BPA determines the revenue requirement separately for generation and transmission.
United States Department of Energy-Bonneville Power Admin., 26 FERC ¶ 61,096 (1984).

The revenue requirement was developed using a cost accounting analysis comprised of the following three components.

- Repayment studies to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment studies are conducted for each year of the four-year rate test period and include a 50-year repayment period.

- Operating expenses and minimum required net revenues for each year of the rate test period.

- Annual PNRR based on the risks identified and quantified, the TPP standard, and other risk mitigation tools.

With these three parts, the revenue requirement is set at the lowest revenue level necessary to fulfill cost recovery requirements and objectives.

RA 6120.2 requires that BPA demonstrate the adequacy of proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test and repayment period. The revised revenue test demonstrates that revenues from proposed wholesale power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment periods. *Id*. In this proceeding, rate test period costs are indeed demonstrated to be recovered with a very high confidence level. In the Final Studies, the risks are quantified and analyzed, and risk mitigation measures designed to achieve a 92.6 percent probability that planned payments to Treasury are recovered on time and in full over the three-year period.

4.3 Spending Level Development

The development of program levels reflected in BPA's WP-07 Revenue Requirement Study began early in the FY 2002-2006 rate period. BPA began to impose spending reductions in FY 2002 in response to the financial effects of the West Coast energy crisis, followed by strict cost management. This process continued with the 2002 Financial Choices public process, which focused on developing options for resolving an expected $860 million net revenue shortfall for the FY 2002-2006 rate period. BPA built on these efforts with the Power Net Revenue Improvement Sounding Board (Sounding Board), which met ten times from November 2003 to June 2004. The primary purpose of the Sounding Board was to identify $100 million in cost reductions and revenue enhancements in FY 2004 and 2005. The sounding board exceeded its goal by $11 million. In addition to these public processes, BPA has met regularly with customer and constituent groups, such as the Customer Collaborative, to provide updates on the Agency's financial condition in an effort to promote greater financial transparency.

The development of the specific program levels in this proposal occurred primarily in two forums, the Regional Dialogue process and the two phases of the PFR.

4.3.1 Regional Dialogue

The first phase of the Regional Dialogue process reached some conclusions that had a direct effect on financial issues (*see* Near-Term Policy ROD, Section 2.4). The Near-Term Policy recommended that BPA should cap its net expense for facilitating renewable resource development at $21 million per year. It also recommended that BPA provide service to DSIs at a known quantity and capped cost which would be determined in a separate DSI ROD. In the DSI ROD, published on June 30, 2005, the Administrator tentatively determined that the DSI benefit would be capped at $59 million per year through 2011. The Supplemental DSI ROD confirmed that the total annual benefits available to the DSIs would be $59 million. (*See* Near-Term Policy ROD, Section 2.5.)

The Near-Term ROD also provided that BPA would continue to focus on promoting financial transparency, allow for public input on Agency costs, and demonstrate management of those costs including engaging customers in the PFR to discuss spending levels that will be used to set power rates for the FY 2007-2009 rate period.

4.3.2 Power Function Review

BPA began the PFR process in January 2005 with the first of a series of 19 technical and management customer workshops and public workshops held throughout the region. The PFR was designed to provide an opportunity for customers and constituents to examine, understand, and provide input on BPA's cost projections that form the basis of the Revenue Requirement

Study for the WP-07 wholesale power rate case. The PFR workshops focused on the projected capital investments and operations and maintenance costs of the major programs that affect wholesale power rates. The workshops examined the projected spending levels of: CGS, COE, and Reclamation direct fundings, conservation, renewables, fish and wildlife, Power Business Line internal operations, transmission purchases and ancillary services program; BPA corporate costs, risk mitigation, and Federal and non-Federal debt management. Where appropriate, the Near-Term Policy decisions were incorporated in the PFR spending level projections.

BPA held a series of separate public workshops throughout the region on the fish and wildlife costs in addition to and concurrent with the PFR. Additionally, BPA participated in numerous meetings with the NPCC, States, Tribes, other constituents, and customers beginning in 2004 to get input on the appropriate approach to program spending, a potential Program-level Memorandum of Agreement (MOA) for FY 2007-2009, and the appropriate level of funding. The comments gathered in these forums were used to inform the forecast of FY 2007-2009 fish and wildlife spending levels incorporated in the PFR.

Based on comments received during the PFR process, BPA changed some of its forecasts of program costs. The final PFR report, which is included in Appendix A of the Revenue Requirement Study, reflects an average annual expense reduction of $96 million from the initial estimate of $2,674 million. The close-out report included average annual expenses of $2,577 million with capital investments averaging $206 million per year. (*See* Revenue Requirement Study, WP-07-FS-BPA-02, Appendix A.) The changes made during the PFR include, among other things, an $8 million average annual decrease due to expected efficiencies for Internal Operations charged to power, a $4 million average annual increase in the Fish and Wildlife Direct Program expense, a $4 million annual decrease in transmission acquisition expenses due to a revised GTA wheeling forecast, and a $22 million average annual decrease in CGS operations and maintenance costs.

In addition to changes in spending levels, BPA agreed to conduct an additional public process to further review program spending levels concurrent with this rate proceeding so that any resulting reductions in spending levels could be incorporated in the Final Revenue Requirement Study. This second phase of the PFR is known as PFR II.

PFR II began after the publication of the Initial Proposal. BPA held a series of public workshops in early 2006. The workshops again focused on each of the major power expense categories in an effort to identify additional reductions. This process also provided a forum to review other non-cost issues that could affect power rates such as BPA's on-going efforts to develop liquidity tools. The change in expenses that resulted from PFR II has been incorporated in the final Revenue Requirement Study. (*See* Homenick, *et al*., WP-07-E-BPA-10 at 11.)

4.4 Amortization of Conservation Acquisition Investments

Issue 1

Whether the amortization period for conservation acquisition investments made after FY 2006 should be extended from five years to 20 years.

Parties' Position

A group of joint parties argued that BPA should apply a 20-year amortization period to new conservation acquisition investments starting in FY 2007. (Brattebo, *et al.*, WP-07-E-JP9-03 at 13[1].) The joint parties argued that BPA's survey of industry practices on conservation amortization policies shows that there is no clear agreement on the appropriate period. Moreover, a shorter amortization period may "erode customer support of BPA's capitalized conservation activities, because it increases the costs of these investments." (*Id.*)

BPA's Position

BPA's conservation program is designed to meet BPA's conservation targets consistent with the Fifth Power Plan of the NPCC. The NPCC identified 15 years as the composite median life for conservation investments installed after FY 2006. (Andrews, *et al.*, WP-07-E-BPA-30 at 12.) BPA can also consider a variety of other factors including industry practice to determine the appropriate amortization period. (Leathley, *et al.*, WP-07-E-BPA-08 at 11.) BPA selected five years as the appropriate amortization period based on its review of industry practice and its assessment of the effect on BPA's Federal borrowing authority.

Evaluation of Positions

The joint parties argued that BPA should use a 20-year amortization period for all conservation investments made after FY 2006. (Brattebo, *et al.*, WP-07-E-JP9-03 at 13.) Based on a review of industry practices and other considerations, BPA has deemed the five-year amortization period as the most appropriate for conservation acquisition investments for the FY 2007-2009 period. (Leathley, *et al.*, WP-07-E-BPA-08 at 11.) BPA follows Generally Accepted Accounting Principles (GAAP) which provides criteria for establishing amortization periods. Financial Accounting Standard (FAS) 71, "Accounting for the Effects of Certain Types of Regulation," enables BPA to capitalize and amortize conservation investments as regulatory assets. (*Id.* at 10.) When determining the appropriate useful life of capital investments, FAS 142, "Goodwill and Other Intangible Assets," allows BPA to consider a variety of factors, including industry practice. (*Id.* at 11.)

BPA's conservation program is designed to implement its portion of the Fifth Power Plan of the NPCC. The NPCC identified 15 years as the composite median life for conservation investments installed after FY 2006. (Andrews, *et al.*, WP-07-E-BPA-30 at 12.)

The parties argue that BPA's survey of industry practice is incomplete and that it does not support a five-year amortization period. For example, the survey did not include Seattle City Light, which uses a 20-year amortization period. (Brattebo, *et al.*, WP-07-E-JP9-03 at 13.) However, BPA's review of industry practices was not intended to be, nor was it represented as being, all-inclusive. Nevertheless, the survey results run counter to the parties' position even if one includes Seattle City Light. Most utilities appear to expense the cost of their investments in

[1] The group consisted of Alcoa, Avista, PGE, ICNU, NRU, PacifiCorp, PNGC, PPC, and WPAG. Three of the parties (Avista, PacifiCorp, and PGE) did not support the panel testimony on conservation amortization.

the year the investment is made, and almost none of the utilities examined use an amortization period longer than ten years. (*See* WP-07-E-JP9-03B.)

In addition to industry practice, BPA considered the effect of the amortization period on the Agency's access to capital. BPA has a limited ability to borrow funds from the U.S. Treasury. While not preserving BPA's borrowing authority to the extent expensing conservation investments would, a five-year amortization period has a smaller negative impact on BPA's borrowing authority than would a 15-year or 20-year period. (Andrews, *et al.*, at 13; WP-07-E-JP9-03B; BRA Br., WP-07-M-30 at 12-13.) With a five-year period, the Agency's use of borrowing authority will peak at $160 million in the fifth year after which principal will be repaid in amounts equal to new investments. A 15-year period, by contrast, will peak in the 15th year at $480 million. (*See* PFR II technical workshop handout, http://www.bpa.gov/power/pl/review/02-13-2006_workshop_handout.pdf)

These three major points are important markers for BPA. First, the amortization period available to BPA is shorter than what the customers proposed. Second, the predominant industry practice is to use very short amortization periods for conservation investments, often to the point of expensing the cost of the investments. Third, a short, five-year amortization period helps to preserve BPA's access to capital, without which BPA could not invest in conservation or other activities.

Decision

BPA will adopt a five-year amortization period for conservation acquisition investments made after FY 2006.

5.0 RISK ANALYSIS

5.1 Introduction

BPA's operating environment is filled with numerous uncertainties, and thus the rate-setting process must take into account a wide spectrum of risks. This is carried out in two distinct steps: a risk analysis step, in which the distributions or profiles of operating and non-operating risks are defined; and a risk mitigation step, in which different measures are tested to assess BPA's ability to recover its costs in the face of this uncertainty. RiskMod and the Non-Operating Risk Model (NORM) are used in the risk analysis step for this rate proposal, while the ToolKit model is used to test the effectiveness of risk mitigation options. (Risk Analysis Study, WP-07-FS-BPA-04; Risk Analysis Study Documentation, WP-07-FS-BPA-04A.)

The objective of the Risk Analysis is to identify, model, and analyze the impacts that key risks have on BPA's net revenue (revenues less expenses). The impacts of operational risks are quantified through the use of the RiskMod, and non-operational risks are quantified through the use of NORM. The results from the Risk Analysis are subsequently used in the ToolKit model to evaluate the impact that certain risk mitigation measures have on reducing BPA's net revenue risk, so that BPA can develop rates that cover all of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period. In addition to its use in the Risk Analysis Study, WP-07-FS-BPA-04, RiskMod is used to calculate the average surplus energy revenues and power purchase expenses reported in the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05.

5.2 RiskMod Model

The RiskMod model quantifies the impact that various Federal load, Federal resource, and wholesale spot market price conditions have on BPA's net revenue. It calculates net revenue using monthly data for HLH and LLH electricity generation, firm loads, surplus energy sales, and power purchases. Monthly HLH and LLH energy values are calculated using load and resource data from the Load Resource Study, WP-07-FS-BPA-01. Monthly HLH and LLH hydro generation amounts for each of the 50 historical water years are estimated by the Hourly Operating and Scheduling Simulator (HOSS) model, which estimates the ability of the FCRPS to shape hydro generation between HLH and LLH under system operational constraints.

Net revenues are calculated using PNW HLH and LLH spot market prices estimated by the AURORA model, (Market Price Forecast Study, WP-07-FS-BPA-03), expense data, IOU Residential Exchange Program (REP) settlement benefit payments, and DSI benefits payments computed by the Rate Analysis Model (RAM), and various revenue data from the Revenue Forecast component of the Wholesale Power Rate Development Study (WP-07-FS-BPA-05). (*See* Risk Analysis Study, WP-07-FS-BPA-04; Risk Analysis Study Documentation, WP-07--FS-BPA-04A.)

5.3 Non-Operating Risk Model

NORM is an analytical risk tool that was developed to capture risks other than operational risks in the rate-setting process. It was first introduced as part of the May 2000 Power Rate Proposal and further developed for the current rate proposal. NORM models the non-operating risks of the generation function, as well as the risks related to the Corporate costs that are covered by the generation function. Transmission function risks are not included in this analysis; however, NORM includes the generation function expense uncertainty for transmission services. NORM models uncertainty in expenses, as well as uncertainty in some revenue and cash. Whereas RiskMod is used to quantify risks having to do with various economic and generation resource capability variations, NORM is used to model the impact on expected costs associated with risks surrounding projections of non-operations-related revenue or expense levels associated with the generation function in the revenue requirement. The output from NORM, along with the output from RiskMod, is used by the ToolKit model to assess the TPP. (Risk Analysis Study, WP-07-FS-BPA-04; Risk Analysis Study Documentation, WP-07-FS-BPA- 04A.)

5.4 Treasury Payment Probability

One of BPA's primary risk mitigation goals is to meet BPA's TPP standard. This standard for a three-year rate period is 92.6 percent for the risks, financial reserves, and tools attributed to the PBL. (Leathley, *et al.*, WP-07-E-BPA-08 at 1-17.)

The TPP is the probability that a business line will have sufficient financial reserves to cover all of the scheduled payments to the Treasury that have been assigned to it during the course of a rate period, given the risks identified in RiskMod and NORM, and the available risk mitigation tools. BPA's 10-Year Financial Plan, adopted in 1993 and still in effect, specifies that BPA shall set rates to achieve a 95 percent TPP in each two-year rate period. (1993 ROD, WP-93-A-02 at 68-72.) Since FY 2002, the transmission and generation functions have set their rates separately, and BPA has determined that if each function separately meets the TPP standard with their respective rates and the reserves attributed to that business line, the Agency TPP requirement will have been met. BPA has calculated that a 92.6 percent TPP for a three-year rate period is equivalent to the two-year 95 percent TPP specified in the 10-Year Financial Plan. (Risk Analysis Study, WP-07-FS-BPA-04 at 3.)

5.5 ToolKit

The ToolKit is an Excel 2003® spreadsheet that is used to evaluate PBL's ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. ToolKit reads in data from two external files, one each from RiskMod and NORM.

More specifically, the ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to generation. It registers a deferral of a Treasury payment when these reserves fall below the level of "Liquidity Reserves" entered on the main page of the ToolKit. The amount of liquidity that BPA has determined is needed is discussed further in Section 6 of this ROD. The ToolKit is run for 3000 "games" or iterations. The number of those games, where each of the three years in the rate period ends with at least the required level of PBL reserves, is divided by 3000 to calculate the TPP. (*Id.* at 3.)

5.6 Treasury Payment Probability

Issue 1

Whether BPA's TPP standard of 92.6 percent assures repayment on a current basis.

Parties' Positions

The Tribes maintain that even with a TPP standard of 92.6 percent over the three-year rate period, BPA still assumes a 7.4 percent probability that it will not be able to repay the U.S. Treasury on time and in full. (JP13 Br., WP-07-M-69 at 33.) BPA could have selected a higher TPP goal to provide greater assurance of payment to the U.S. Treasury. (*Id*. at 34.)

PPC supports BPA's rejection of arguments that its risk package does not maintain an adequate TPP. (PPC Br., WP-07-M-65 at 14.) PPC contends that the Tribes' ToolKit analysis is flawed and produces meaningless results. (*Id*. at 14-15.) PPC urges BPA to disregard the Tribes' arguments and maintain the comprehensive risk mitigation package that is currently in the proposal. (*Id*. at 15.)

In their brief on exceptions, the Tribes contend that the current TPP standard, in combination with the other assumptions and risk mitigation mechanisms, does not provide a reasonable assurance of Treasury repayment on a current basis as asserted by BPA. (JP13 Br. Ex., WP-07-M-77 at 9.)

BPA's Position

While the Tribes frame the issue as one where BPA's TPP standard does not assure repayment on a current basis, BPA believes the Tribes are actually arguing for a different TPP standard than that which BPA adopted in its 10-Year Financial Plan. In that document, BPA adopted a 95 percent two-year TPP. The 92.6 percent for the three-year rate period is the equivalent value. (Normandeau, *et al.*, WP-07-E-BPA-14 at 3.) It has never been BPA's objective to have a 100 percent probability of repaying Treasury. Such a standard would require rates that are prohibitively high. (Normandeau, *et al.*, WP-07-BPA-33 at 4.) BPA's financial and policy objectives require BPA to balance competing objectives against each other when developing its overall rate design strategy. (Leathley, *et al.,* WP-07-E-BPA-08 at 5.)

Evaluation of Positions

In both their initial brief and brief on exceptions, the Tribes essentially argue for the adoption of a different TPP standard. Although the Tribes never specify what an acceptable TPP standard would be, they note that "BPA starts with some probability that it will not be able to make a Treasury payment in its base case." (JP13 Br. Ex., WP-07-M-77 at 9.) The Tribes do not believe the current TPP standard, in combination with the other assumptions and risk mitigation tools, provides a reasonable assurance of meeting BPA's obligation to the Treasury. (*Id*.)

BPA must consider and balance its responsibilities to keep rates as low as possible while ensuring its ability to carry out its legally mandated responsibilities required under the Northwest Power Act in a sound and business-like manner. Relying on the 10-Year Financial Plan provides a benchmark by which the Agency is able to set rates at a reasonable level to assure that the Treasury payment will be made on time and in full for each year of the rate period. It has never been BPA's intent to have a 100 percent TPP. Such a standard would require rates to be prohibitively high and inconsistent with BPA's competing obligations to keep rates as low as possible consistent with sound business principles.

In every rate case since 1993, BPA has balanced setting sustainable rate levels with achieving the TPP at the full level set in the 10-Year Financial Plan. For the FY 2007-2009 rate period, BPA expects to meet the TPP level consistent with the 1993 10-Year Financial Plan.

The Tribes' comment appears to focus on their contention that BPA uses overly optimistic fish and wildlife cost assumptions and the effectiveness of some of the risk mitigation tools to cover these costs, rather than on the adoption of the 92.6 percent TPP standard. The issues regarding the fish and wildlife cost assumptions and risk tools are addressed elsewhere in this ROD. *See* sections 6 and 17.

<u>Decision</u>

BPA's current TPP standard of 92.6 percent provides for a reasonable assurance of repayment on a current basis and conforms to the current standard set in the 10-Year Financial Plan.

<u>Issue 2</u>

Whether BPA should revise its TPP standard to account for games differently where there are multiple versus single deferrals over the same rate period.

<u>Parties' Positions</u>

The Tribes contend that BPA underestimates the risks it faces by treating games that defer payments to the Treasury in more than one year during the rate period the same as games where there is a single deferral. (JP13 Br., WP-07-M-69 at 34.) They maintain that the consequences of multiple deferrals are much more significant than a single deferral. (*Id.*)

In their brief on exceptions, the Tribes contend that treating ToolKit games with multiple deferrals the same as games with a single deferral is unreasonable and understates the risks BPA faces. (JP13 Br. Ex., WP-07-M-77 at 10.) They note that some of the testimony stricken from the record supports their contention that senior BPA management has serious concerns about multiple deferrals. (*Id.*)

BPA's Position

BPA believes that the Tribes are arguing for a different definition of the TPP standard, perhaps a calculation of the percentage of years in the set of games in which there is no deferral, or a metric that weights more heavily second deferrals than first deferrals in a game. (Normandeau, *et al*., WP-07-E-33 at 4.) These are not unreasonable definitions, but they are no more reasonable than the definition BPA has been using for over 10 years. (*Id*.) If BPA were to adopt an alternate definition, BPA would then need to determine what the appropriate numerical standard would be and there is no reason to assume that such a standard would be 95 percent over a two-year rate period. BPA believes it is calculating TPP appropriately and there is no basis for adopting a standard different from the one adopted in the 10-Year Financial Plan. (*Id*.)

Evaluation of Positions

BPA and the region defined TPP in 1992 as the probability of BPA making its annual U.S. Treasury payments within a rate period in full and on time. (1993 ROD, WP-93-A-02, at 68.) BPA remained consistent when it addressed the issue of multiple-year deferrals in the May 2000 Record of Decision. (May 2000 ROD, WP-02-A-02, at 7-11.) The May 2000 ROD made several key points to support its argument – all of which BPA continues to reiterate. BPA believes that the current TPP methodology adheres to a stringent standard for making its annual payments to Treasury. (*Id.)* The May 2002 ROD supports this assertion by pointing to historical on-time and in-full payments since the adoption of the methodology, acknowledging that multiple deferrals are inevitable and the Risk Analysis methodology is explicitly designed to capture the effects of key risks on net revenues, and clarifying that any games that have any deferrals in them whatsoever fail the test – even if ToolKit shows that, in that game, BPA will have paid off the debt incurred by that deferral by the end of the rate period. (*Id.*)

The Tribes also support NWEC/SOS's calculation that of the 3,000 games, 221 runs had deferrals and 54 of those had multiple deferrals. (Weiss, WP-07-E-JP8-01 at 9.) While this is true, this represents less than 2 percent of the total games (54/3000 = .018 or 1.8 percent). The sum of the average deferrals in each of the three years is $8.7 million; this sum comprises both deferred interest and deferred principal payments. Deferred interest payments for FY 2007-2009 are repaid later in the rate period. Therefore, the impact of deferrals on average ending reserve levels can be no more than, and is probably less than, $8.7 million. (WP-07-FS-BPA-04A at 148.) Thus, viewed from the standpoint of expected impact, the fact that deferrals occur in 7.4 percent (221/3000 = .0736 or ~ 7.4 percent) of the games or that multiple deferrals occur in roughly 2 percent of the worst cases is not an indication that the method of calculating TPP is exposing BPA to undue risk.

The Tribes' concern over the potential political risk associated with multiple Treasury deferrals during the rate period as compared to a single Treasury deferral is not supported by any evidence on the record. Furthermore, the stricken testimony does not support the Tribes' argument that BPA has serious concerns about multiple deferrals. The statements by Paul Norman, Senior Vice President for BPA's PBL referenced by the Tribes discuss a generic concern regarding BPA's ability to meet its Treasury payment in a particular year, FY 2006, if a specific operational regime were adopted. The statement does not mention the concept of multiple deferrals and was presented to the court in an entirely different context from this rate case. Mr. Norman's statement was not designed to inform the court about the TPP standard applicable to rate-setting, as is the issue here, but only informs the court about the impact of increased cost on a particular year. These are very different matters and the Tribes reliance on the statement is misplaced.

Decision

BPA will not revise its TPP standard to account for games differently where there are multiple versus single deferrals over the same rate period.

Issue 3

Whether BPA is meeting its TPP goal if it experiences additional fish and wildlife costs.

Parties' Positions

The Tribes contend that BPA's risk mitigation package is not sufficient to meet the TPP goal if one assumes an additional $100 million per year in fish and wildlife costs. (JP13 Br., WP-07-M-69 at 49.) In the Tribes' sur-rebuttal testimony, they state they ran the ToolKit model after increasing the cost assumptions in one of the cells by $100 million. (*Id.*) The results of this analysis showed a drop in the TPP from 92.6 to 81 percent. (*Id.*)

The Tribes argue that BPA cannot point to the NFB Adjustment as a mechanism for maintaining the TPP goal because it did not conduct a TPP analysis of the NFB Adjustment. (JP13 BR., WP-07-M-69 at 35.) The Tribes contend that they performed several different analyses to test the effectiveness of the NFB Adjustment and each demonstrated that additional fish and wildlife costs reduced the TPP below the goal of 92.6 percent TPP. (*Id.* at 36.) The Tribes also argue that their analysis raises fundamental questions about the overall effectiveness of the NFB Adjustment. (*Id.* at 37.)

PPC petitions BPA to reject arguments that its risk package does not maintain an adequate TPP. The Tribes and NWEC/SOS argue that the potential of higher fish and wildlife costs during the rate period increases uncertainty that compromises BPA's TPP goals. (PPC Br., WP-07-M-65 at 14.) In response to this criticism, PPC pointed out that the Tribes' and NWEC/SOS's analysis suffered from a serious flaw and produced incorrect results. (*Id.*) PPC notes that BPA proposed the Emergency NFB Surcharge to address some of the Tribes' concerns about the ability of BPA to quickly collect cash in response to uncertain future events. (*Id.*)

In their brief on exceptions, the Tribes continue to argue that BPA's risk mitigation tools are not sufficient to meet the TPP goal if it experiences higher costs. (JP13 Br. Ex., WP-07-M-77 at 12.) They contend:

> BPA's proposal does not meet the costs of implementing the Columbia River Basin Fish and Wildlife Program or the cost uncertainties of implementing a new Biological Opinion and recovery plans. BPA's Proposal has turned a blind eye toward its cost risks by

> eliminating the range of fish and wildlife costs from the previous rate case that was designed to address some of the uncertainty associated with BPA's future obligations. *See* WP-07-E-BPA-08, page 12 line1 through page 14, line 23.
>
> BPA will have to address these future fish and wildlife costs whether it has included them in this proposal or not. By not adequately addressing these costs and uncertainties in its Proposal BPA has unacceptably increased the risks that it will not be able to meet all of its costs and assure timely repayment to the Treasury.

(JP13 Br. Ex., WP-07-M-77 at 8.)

BPA's Position

BPA believes the Tribes' ToolKit analysis is flawed. In their direct case, the Tribes raised a concern that if BPA had additional fish and wildlife expenses, the result would lower the TPP. (Sheets, *et al*., WP-07-E-CR/NZ/YA-01 at 2.) BPA took note of this matter and designed the Emergency NFB Surcharge (NFB Surcharge) to address the fact that the dollars associated with the NFB Adjustment are not collected until the following year. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) The NFB Surcharge was specifically designed to address a possible reduction in TPP that resulted from this delay in the receipt of the cash. (*Id.*) This issue is addressed in Section 6 of this ROD. The analysis described by the Tribes in their sur-rebuttal testimony merely repeats the analysis without in any way accounting for the revenues associated with the NFB Surcharge that would be received in the same fiscal year that the cost are incurred.

In addition, the analysis improperly assumes that the increase in costs has a 100 percent chance of occurring. BPA believes that through the combination of the PNRR, CRAC, NFB Adjustment and NFB Surcharge, BPA will be able to address the risks associated with increases in fish and wildlife expenses. (*Id.*) BPA has done a risk analysis (NORM) around some of the fish and wildlife program costs. (Risk Analysis Study, WP-07-FS-BPA-04.) To the extent that BPA's operations are impacted by changes in spill and flow requirements to meet fish and wildlife obligations, the combination of PNRR, CRAC, NFB Adjustment and NFB Surcharge will address these costs. (*Id.*) To the extent BPA must look beyond those risk tools to meet its fish and wildlife obligations, BPA always retains the option of initiating a new rate case. (*Id.*)

Evaluation of Positions

BPA made a decision to not model the expense and revenue uncertainties associated with potential future court-related actions to the FCRPS 2004 Biological Opinion due to lack of information available for future events, whether interim changes or a new Biological Opinion altogether. (Normandeau, *et al*., WP-07-E-BPA-14 at 13.) To address the very real uncertainty related to BPA's future fish and wildlife obligations, BPA initially proposed the NFB Adjustment. The Tribes noted in their direct case that BPA may not be able to maintain its TPP standard. (Sheets, *et al*., WP-07-E-CR/NZ/YA-01 at 54-55.)

BPA acknowledged in its rebuttal testimony that the time lag in the recovery of cash through a NFB Adjustment of up to one year does prevent the NFB Adjustment from providing the TPP support in those years when BPA's reserves are low. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) In response to this problem, BPA proposed the NFB Surcharge. The NFB Surcharge is designed to address the time lag between when BPA incurs the cost and the receipt of the dollars during those years when BPA's reserves are low. (*Id.*) In years when the reserve levels are high, the delay or lag in the receipt of the cash does not impact BPA's ability to make the payment to Treasury

The Tribes' analysis of the NFB Surcharge in their sur-rebuttal testimony was stricken from the record. (Order, WP-07-O-30.) The Tribes have sought to reinstate this testimony; however, as noted in Section 17.1, the Administrator has elected to not reinstate this testimony for the reasons stated there. As a result, there is little or no analysis on the record from which the Tribes can argue that BPA cannot maintain its TPP standard.

In their sur-rebuttal testimony, the Tribes nevertheless still maintain that BPA's risk package fails to meet the TPP standard. However, the Tribes' TPP analysis fails to account for the addition of the NFB Surcharge revenues. In response, the Tribes first point out that they made a good faith effort to model the uncertainty. (JP13 Br., WP-07-M-69 at 38.) This does not prove or disprove the Tribes' argument. The Tribes' modeling fails for precisely the reason that BPA chose to not include these unpredictable events. A good faith effort that fails to include a significant rate design change still produces invalid results. The Tribes' also argue that there is no uncertainty around the range of potential costs that might result from a court-ordered action or new Biological Opinion. (*Id.*) They argue that the costs will either be there or not. This argument ignores the objective of risk mitigation, which is to set rates to recover costs and provide ways to adjust rates for uncertainties that BPA faces in the FY 2007-2009 rate period, including FCRPS 2004 Biological Opinion litigation. In the case of the FCRPS 2004 Biological Opinion risk, the level is not important because the NFB Adjustment and NFB Surcharge are not capped. In either case, both mechanisms can recover the total cost if needed.

The third point the Tribes make is that BPA has made no effort to analyze whether BPA can maintain its TPP standard. This argument is equally invalid. Since both mechanisms (NFB Adjustment and NFB Surcharge) are not capped, and can fully recover the related costs, the question becomes one of timing. Will the costs be recovered in full prior to the end of the fiscal year when a Treasury payment is due? The proposed NFB Surcharge specifically addresses this issue if the Agency Within-year TPP is forecast to be less than 80 percent for that fiscal year. If the Agency Within-year TPP is 80 percent or greater, the costs are picked up through the CRAC in the next fiscal year. Therefore, if the costs are fully recovered through the NFB Surcharge within the fiscal year that the costs are incurred, then there is no need to model the risk because meeting the TPP standard will be held harmless.

The Tribes' concerns in their brief on exceptions that BPA has not met its TPP standard arise in large part from the Tribes' belief that BPA will experience greater fish and wildlife costs than forecast. As noted in section 17 of this ROD, the level of BPA's fish and wildlife costs is an issue outside the scope of this proceeding. Those cost projections were developed during the PFR and were deemed to be a matter outside the scope of this proceeding in the FRN. 70 Fed. Reg. 67,685, at 67,689 (2005). However, as noted by BPA during the PFR, the Tribes' fish and wildlife cost assumptions were based upon estimates developed by CBFWA and were found to be based upon imprecise estimates and extrapolation and sought funding for fish and wildlife mitigation measures that are not attributable to the Federal hydro system. (*See* section 17.1, Issue 5, footnote 6.) As a consequence, BPA rejected the assumptions and developed its rates based upon what it believed to be reasonable estimates of its future fish and wildlife costs. While there is some uncertainty surrounding these costs, BPA is confident it will cover these costs through its risk mitigation tools (PNRR, CRAC, NFB Adjustment and NFB Surcharge) or, if necessary, a new rate case.

Given that the risk package is designed specifically to address BPA's FCRPS fish and wildlife obligations, the risk of missing a Treasury payment has been mitigated.

Decision

The NFB Surcharge is designed to address increases in BPA's fish and wildlife obligations such that the risk of missing a Treasury payment is mitigated. BPA designed its rate proposal to cover the costs associated with meeting its fish and wildlife obligations, including possible additional fish and wildlife costs, while meeting its TPP goal.

5.7 Fish and Wildlife Uncertainties

Issue 1

Whether BPA's fish and wildlife spending is adequate to implement the Northwest Power and Conservation Council's Columbia River Basin Fish and Wildlife Program and ESA obligations.

Parties' Positions

The Tribes contend that BPA's fish and wildlife spending is inadequate to fully implement the NPCC's Columbia River Basin Fish and Wildlife Program. (JP13 Br., WP-07-M-69 at 12-13.) Although much of the Tribes' evidence supporting this conclusion was stricken from the record, the Tribes state that BPA did no analysis to evaluate whether it has met its fish and wildlife obligations. (*Id*. at 13.) The Tribes maintain that BPA's ability to meet its fish and wildlife obligations is a critical issue in the remand of the Biological Opinion. (*Id.* at 13.)

BPA's Position

Much of the Tribes' stricken testimony and exhibits directly challenge the policy decisions and budget assumptions that were made in, and as part of, the PFR. The PFR spending level assumptions were developed through a lengthy public process that had input from a variety of interested parties, including the Tribes. These spending level assumptions represent a reasonable forecast of the fish and wildlife expense levels. The Administrator has separately addressed the request by the Tribes to reinstate this testimony in Section 17.1 and has determined the Hearing Officer did not err when he struck this testimony. As a result, there is little evidence on the record to support the Tribes' conclusions that BPA's budgets are inadequate to meet its obligations.

As noted in Section 17.1, the Tribes' submission of testimony and exhibits supporting alternative spending levels for fish and wildlife programs is completely contrary to the allowable scope of the proceeding as defined in the FRN. The Administrator's direction to the Hearing Officer in the FRN is absolutely clear in this respect. The Hearing Officer was thereby directed in the FRN to "exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit the appropriateness or reasonableness" of BPA's decisions on spending levels developed in the PFR. 70 Fed. Reg. 67,685, 67,688 (2005).

Nevertheless, BPA believes its rate design, including the use of CRACs, provides reasonable assurance that BPA will meet its fish and wildlife obligations. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) With respect to the FCRPS 2004 Biological Opinion litigation exposure, BPA proposed the NFB Surcharge and NFB Adjustment to the CRAC cap to cover any unanticipated or unknown fish and wildlife costs. While there are, in theory, fish and wildlife costs that could exceed the capability of these risk tools, BPA has assured parties that it will meet its fish and wildlife funding responsibilities and retains the option of starting a new rate case if necessary. (*Id*.)

Evaluation of Positions

The stricken testimony the Tribes rely upon to argue that BPA's fish and wildlife program level is inadequate and involves the same matters that the Tribes raised during the PFR. In general, the testimony Sheets, *et al*. WP-07-E-CR/NZ/YA-01, page 18, line 4 through page 48, line 19, recites the same CBFWA materials that the Tribes presented to BPA in their comments to the PFR. Because the testimony was properly stricken, there is little on the record to support the conclusion advocated by the Tribes. Even if the testimony were reinstated, the Tribes' argument lacks merit.

The Tribes assert that BPA has performed no analysis to evaluate whether BPA has met its fish and wildlife obligations. BPA believes it has made adequate plans and preparations to meet these obligations.

The attachments to Columbia River Inter-Tribal Fish Commission's CRITFC) Exhibit WP-07-E-CR-01DD include links to two letters[1] (totaling 36 pages) in which BPA analyzed and rebutted CBFWA's draft cost estimates as well as the funding proposals of the Yakama Nation and CRITFC. In addressing these proposals, BPA found that:

> the draft CBFWA proposal was based on imprecise estimates and extrapolation; it sought funding for a considerable amount of mitigation that is not attributable to the impacts of the federal hydropower system and not BPA's responsibility; it did not meaningfully consider the effects of the proposal in BPA's customers and their rates; and it did not account for the limits to BPA's available capital (for borrowing from the U.S. Treasury).

[1] WP-07-E-CR-O1DD, link http://www.efw.bpa.gov/Integrated_Fish_and_Wildlife_Program/YINCRITFCLetterandAttachments.pdf, at page 2.

Given the issues associated with the CBFWA analysis, there is no basis to believe that BPA costs will mirror these estimates. Furthermore, given the risk mitigation package contained in BPA's proposal, it should be able to meet its fish and wildlife obligations.

BPA believes its risk package provides reasonable assurance that BPA will meet its fish and wildlife obligations. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) BPA separated the treatment of the risks associated with FCRPS 2004 Biological Opinion litigation from its treatment of all other risks. BPA modeled and forecast the non-ESA risks and used the traditional risk mitigation tools (reserves/liquidity, PNRR and a CRAC) to achieve a 92.6 percent TPP. It should be noted that BPA's risk analysis in this proceeding was more rigorous than in prior rate proceedings. In particular, BPA's NORM analysis was modified and expanded to more comprehensively analyze BPA's costs. (Wagner, *et al*., WP-07-E-BPA-12 at 33.) The NORM analysis includes an examination of BPA fish and wildlife O&M costs, as well as its fish and wildlife capital expenditures. (*Id.*)

BPA treated the fish and wildlife cost risk associated with the FCRPS 2004 Biological Opinion litigation outside of the risk analysis outlined above. To address the FCRPS 2004 Biological Opinion litigation exposure, BPA proposed the NFB Surcharge and NFB Adjustment to cover any unanticipated or unknown fish and wildlife costs arising during the rate period. Rather than modeling these potential cost increases, BPA elected to collect for these costs after the impact of the changes to program level expenses and operations were understood and qualified.

All total, BPA has a multilayered risk mitigation package that effectively covers its risk exposure, including those associated with fish and wildlife costs resulting from the FCRPS 2004 Biological Opinion litigation.

Decision

BPA's fish and wildlife spending level was adopted outside of this rate case in the PFR and meets BPA's obligations under the NPCC's Columbia River Basin Fish and Wildlife Program and ESA.

Issue 2

Whether BPA has adequately addressed the uncertainties associated with BPA's fish and wildlife obligations.

Parties' Positions

The Tribes contend that BPA's rate proposal does not adequately address the uncertainties associated with its fish and wildlife obligations. (JP13 Br., WP-07-M-69 at 23.) Although much of the testimony supporting their position was struck by the Hearing Officer, the Tribes contend that there will be additional costs beyond that which BPA has forecast in the rate case and in addition BPA has not evaluated these uncertainties. (*Id*. at 24.)

BPA's Position

BPA believes its proposed rate design provides reasonable assurance that BPA will meet its fish and wildlife obligations for FY 2007-2009. (Lovell and Normandeau, WP-07-E-BPA-34 at 12.) With respect to the 2004 FCRPS Biological Opinion litigation exposure, BPA has proposed the NFB Surcharge and NFB Adjustment to the CRAC cap to cover any unanticipated or unknown fish and wildlife costs. (*Id.*) BPA has assured parties that it will meet its fish and wildlife funding responsibilities, whatever they may be. (*Id.*)

The NFB Adjustment is designed to address uncertainty surrounding the 2004 FCRPS Biological Opinion litigation. In rebuttal testimony, BPA proposed, in specific response to the testimony of these parties, the NFB Surcharge. (*Id.*) BPA does not believe there is significant exposure to additional financial impacts in any other ongoing fish-related litigation. (*Id.*)

In the event other litigation introduces additional fish and wildlife mitigation and recovery actions for BPA, those will be dealt with first by considering the priorities of projects funded through the NPCC Fish and Wildlife Program. (*Id.*) In addition, BPA intends to manage those financial impacts as they become known through regular cost control efforts with customers and constituents. (*Id.*) Even though these financial impacts are not modeled, the CRAC would be able to recover them if the CRAC is not already collecting up to its cap. (*Id.*) Finally, BPA could choose to address such increased financial impacts through a new rate case, if necessary. (*Id.*)

Evaluation of Positions

The Tribes' argument is based upon a similar foundation as other issues previously addressed in this section, namely, that BPA will have higher fish and wildlife costs than assumed in the rate case. Rather than arguing that the budgets are inadequate, the Tribes have recharacterized the argument as one where BPA has failed to address the "uncertainties" surrounding its fish and wildlife obligations. BPA has addressed the uncertainty surrounding fish and wildlife through the combination of its risk analysis and risk tools (PNRR, CRAC, NFB Adjustment and NFB Surcharge). For these reasons and those previously stated, BPA has addressed the uncertainty associated with its fish and wildlife obligations.

Decision

BPA adequately addressed the uncertainties associated with BPA's fish and wildlife obligations.

6.0 RISK MITIGATION

6.1 Introduction

The results from the risk analysis are used in ToolKit to evaluate the impact that certain risk mitigation measures have on reducing BPA's net revenue risk, so that BPA can develop rates that cover all of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period. By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. 16 U.S.C. § 839 e(a)(1). For this reason, BPA measures its potential for recovering costs in terms of probability of being able to make Treasury payments on time (also known as Treasury Payment Probability or TPP).

In its 1993 rate filing, BPA established a long-term policy for meeting its obligations for repaying the U.S. Treasury. (1993 ROD, WP-93-A-02 at 68-72.) At that time, two repayment probability goals were set: one short-term and one longer-term. The short-term goal was to ensure a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. (*Id.*) The longer-term goal, described in the 10-Year Financial Plan, was to maintain that 95 percent rate period standard for five consecutive two-year rate periods. (*Id.*) BPA continues to adhere to these 10-year Financial Plan objectives for the 2007 Rate Case.

This TPP standard was established as a rate period standard; that is, it focuses upon the percentage of time BPA successfully makes all of its payments to Treasury over the entire rate period rather than setting numerical goals for year-to-year performance. (*Id*. at 70.)

For the WP-07 power rate case, BPA is measuring the TPP for three years. The three-year TPP of 92.6 percent is the equivalent of the 95 percent two-year standard from the 10-year Financial Plan. (Risk Mitigation Study, WP-07-FS-BPA-04 at 2-3.) The methodology employed in the ToolKit model is consistent with an emphasis on full rate period success in recovering all costs, including lowest priority Treasury payments. (*Id.* at 38-76.) While ToolKit calculates sequential year-end financial reserve balances for a number of alternative simulations (or games) of the rate period under different risk conditions, it counts games (or full rate periods), not years, in calculating TPP percentages. (*Id.* at 38-39.)

BPA uses ToolKit to test the effectiveness of various risk mitigation measures as part of a rate package that meets its financial and policy objectives including the three-year 92.6 percent TPP goal. These risk mitigation measures include starting financial reserves, the CRAC, PNRR, and DDC. (Risk Analysis Study*,* WP-07-FS-BPA-04 at 39-44.)

In addition, BPA provided policy guidance for the WP-07 Power rate case risk mitigation package. Those guidelines are described in the testimony of Leathley, *et al.*, WP-07-E-BPA-08 at 1-17, and reiterated in Section 2.9 in this ROD.

Although the risk mitigation methodology for the this rate proceeding displayed many similarities with previous rate cases, it also contains a number of new features.

- The NORM model is more advanced and includes a number of new non-operating risks. (Risk Analysis Study, WP-07-FS-BPA-04 at 24.)

- The NFB Adjustment to the CRAC cap addresses cost uncertainties associated with the ongoing FCRPS 2004 Biological Opinion litigation. BPA has chosen to not model these uncertainties, or forecast possible outcomes, but instead develop mechanisms to mitigate the actual costs, if and when they occur. (*Id.*)

In addition BPA made enhancements to the risk mitigation package as a result of issues raised by parties in the rate case.

- The NFB Surcharge was introduced to address the same uncertainties as the NFB Adjustment but to account for the TPP impact caused by the up-to-one-year lag in revenues collected through the CRAC. The NFB Surcharge is implemented if two criteria are met: (1) the Agency Within-year TPP is below 80 percent; and (2) a court-related decision associated with the FCRPS 2004 BiOp has been made for that fiscal year that decreases the expected PBL net revenue. (WP-07-E-BPA-34 at 2.)

- As a result of developing new sources of liquidity between the Initial and Final Studies, BPA is proposing to revise its Liquidity Reserve Level (formerly known as Working Capital) to address a change in the shape of BPA's annual cash stream. (WP-07-E-BPA-33 at 11.)

BPA remains firmly committed to meeting its TPP objective and to providing the lowest possible rates within sound business principles, two goals supported by many parties in their testimony. To that end, BPA's proposed risk mitigation package in the Initial Proposal set the CRAC and DDC thresholds, in combination with the level of PNRR, to produce a result that achieved the TPP objective and maintained an acceptable balance between the posted rate (before any CRACs or DDCs are applied) and the three-year average "effective" rate after including the expected value CRACs and DDCs. The resulting expected rates for each year of the rate period strike a reasonable balance between rate volatility and low rates.

6.2 Liquidity Tools

Issue 1

Whether BPA should incorporate Direct Pay of Energy Northwest's annual operating and debt service expenses into the Final Studies.

Parties' Positions

PPC urges BPA to incorporate Direct Pay of EN's obligations into its assumptions when calculating final rates. (PPC Br., WP-07-M-65 at 5.) (PPC is joined on its brief by NRU, Cowlitz PUD, ICNU, and PNGC. SUB also adopted the PPC brief. For the purposes of Section 6, all of these parties are collectively referred to herein as "PPC.") PPC believes this is appropriate given the Internal Revenue Service Letter Ruling regarding the lack of a tax impact of this program, allowing BPA to take advantage of this liquidity tool. (*Id*.) PPC contends that incorporation of Direct Pay will lower rate levels from those in the Initial Proposal. (*Id*.)

WPAG also proposed that BPA account for the full amount of cost reduction from Direct Pay into rates. (WPAG Br., WP-07-M-68 at 6.)

In their briefs on exceptions, WPAG and PPC support incorporating the EN Direct Pay program and recognition of the cash flow advantages it produces in the final PF rate. (WPAG Br. Ex., WP-07-M-81 at 8; PPC Br. Ex., WP-07-M-78 at 4.)

BPA's Position

BPA will include liquidity tools in the Final Studies if they can be prudently relied upon at the time the Final Studies are completed. (Normandeau, *et al*., WP-07-E-BPA-33 at 12; Andrews, *et al.*, WP-07-E-BPA-30 at 8.)

BPA will incorporate a liquidity tool, such as Direct Pay into the Final Studies by appropriately adjusting the liquidity reserve level in ToolKit. (*Id.*) The liquidity reserve level sets the threshold at which BPA counts a Treasury miss when reserves fall below that threshold.

Evaluation of Positions

The critical element to implementing the Direct Pay option was whether BPA's change to a Direct Pay mechanism would affect the tax exempt nature of the bonds. On March 6, 2006, BPA received a Letter Ruling from the IRS indicating that the proposed change did not negatively affect the tax exempt nature of the bonds. Subsequent to the ruling, BPA entered into agreements with EN to begin directly paying their obligations.

Because of the IRS ruling, and the agreeents with EN, BPA can reasonably rely upon the availability of this liquidity tool and will incorporate the impacts in its calculation of rates in the Final Studies. BPA will also consider the ramifications of Direct Pay on BPA's cash position within the fiscal year, because Direct Pay changes the shape of BPA's cash flow.

Decision

BPA will incorporate Direct Pay of Energy Northwest obligations into the Final Studies.

Issue 2

Whether BPA should adjust the Power Business Line Liquidity Reserve Level to account for the full effect of the change from Net Billing to Direct Pay of Energy Northwest obligations.

Parties' Positions

WPAG argues that BPA should reflect the full amount of the cost reductions achieved through the Direct Pay agreement with EN, rather than accounting for some of the increased reserves as increased Working Capital (liquidity reserves). (WPAG Br., WP-07-M-68 at 6.)

BPA's Position

BPA agreed that the rate benefit of available liquidity tools should be accounted for in rates in order to lower PNRR or to reduce the CRAC collection amount. (Normandeau, *et al*., WP-07-E-BPA-33 at 12.) BPA noted the following:

> In general, assuming that the information is available in time to be included in the Final Studies, BPA would incorporate the liquidity tool(s) into the Final Studies by appropriately adjusting the liquidity reserve level in ToolKit. The liquidity reserve level sets the threshold at which BPA counts a Treasury miss when reserves fall below that threshold. For the Initial Proposal, this was set at $50M for PBL. Generally speaking, other sources of liquidity can substitute for financial reserves for meeting BPA's liquidity needs. This means that the amount of reserves set aside for liquidity needs can be reduced, and some amount of reserves can be freed up to be used to increase TPP. This results in a reduction in the cost of risk in the form of lower PNRR and/or a reduction in the CRAC collection amount.

(*Id.* at 12.)

BPA raised the issue that moving from Net Billing to Direct Pay would shift BPA's cash flow pattern and result in the need to reassess BPA's liquidity reserve requirements for PBL. (*Id.* at 13.) BPA also indicated that it would reassess PBL's Liquidity Reserve Level in the event that one or more liquidity tools become available in time for completion of the Final Studies to ensure the TPP calculation remains at 92.6 percent. (*Id.*)

> It should be noted while many of the liquidity tools BPA is pursuing have a simple effect of increasing the liquidity available to BPA; the proposal for Direct Pay of Energy Northwest (EN) has two effects. One effect is to increase BPA's supply of liquidity by freeing up money that would under Net Billing be held by Energy Northwest on September 30; the other effect is to increase BPA's need for liquidity by changing the shape of BPA's cash flow through the year. The latter effect would require BPA to increase the liquidity reserve level above the current $50 million to adjust for the major shift in BPA's cash flow pattern and the associated shift in BPA's cash obligations throughout the year. The increase in BPA's need for liquidity would be more than off-set by the benefit of additional liquidity made available through Direct Pay. All of the estimates BPA has made of the rate benefits of Direct Pay have included the impacts of both of these effects.

(*Id.*)

Direct Pay also changes BPA's monthly cash flow.

> This is because BPA's responsibilities to EN under Direct Pay reflect the actual shape of EN's monthly operating cash requirements instead of the effect of the net billing agreements. EN is required to make two large bond payments during its fiscal year, one in December and one in July. These debt payments can range from $100M to $200M, depending on whether the EN budget has been refinanced through the Debt Optimization Program. For the other 10 months of its fiscal year, its operating cash requirements are more or less level. If BPA implements Direct Pay, it will be required to make these two debt payments out of the Bonneville Fund, whereas before, EN would have made the payments out of the cash it had collected from the net billed participants. BPA will also have to make all cash payments to EN one month in advance of its operating need date; this means BPA will have to make these debt payments in November and June to allow EN time to make the debt payments to the Bond Trustee.

(*Id*. at 13-14.)

BPA's cash flow under Direct Pay changes dramatically when compared to Net Billing, particularly in the spring and summer months. Therefore, BPA is concerned about having sufficient cash to meet EN's cash requirements in the May to June time frame. Alternatively, liquidity risk is lower for the November/December period. Additionally, due to the change in cash flow, BPA would have approximately $200 million more cash (liquidity) at the beginning of each fiscal year than it would have had under Net Billing. The flip side of this is that by the end of May under Direct Pay, BPA's total cash outflows to EN for the previous twelve months will be identical to those under Net Billing, meaning that this liquidity cash advantage has decreased to zero. Also in the May/June time frame, BPA's cash inflow from its power revenues under Net Billing is almost identical to that under Direct Pay because by this time, virtually all Net Billing obligations have been met. Therefore, BPA's June payment to EN, which would include a large debt payment, is made in the month where BPA no longer has the extra liquidity cash from Direct Pay and where Bonneville's cash inflows are virtually identical to what they would have been under Net Billing. This is not the case in December. (*Id.* at 14.) BPA said that its preliminary analysis indicated the Liquidity Reserve Level would need to increase as a result of Direct Pay compared to Net Billing.

> BPA has done some preliminary analysis of this issue and has estimated that the increase in liquidity reserve level during the May to June time frame could range from $125 to $200 million. BPA will update this analysis for the Final Studies. BPA is likely to assume in its Final Studies to increase its $50 million liquidity cash need to between $175 and $250 million when computing power rates under Direct Pay if no other liquidity tools are available. The combined effect of Direct Pay and this change in liquidity reserve level still provides the potential for a rate reduction in the PF rate because there is still a large positive net liquidity benefit from Direct Pay, even after accounting for this increase in cash liquidity needs. (*Id.* at 15.)

Evaluation of Positions

BPA worked closely with parties to identify and develop additional sources of liquidity prior to and throughout this rate proceeding. (Risk Analysis Study, WP-07-FS-BPA-04 at 51.) A number of liquidity sources were pursued and Direct Pay is considered reliable enough to be included at this time, in the Final Studies because of the IRS ruling and the agreements with EN. Additionally, incorporating Direct Pay into the Final Studies required BPA to consider the change in the shape of BPA's cash flow within each fiscal year of the FY 2007-2009 rate period.

Prior to BPA implementing Direct Pay, EN received revenue to cover about 80% of its annual (July through June) operating expenses in the first five months of its net billing cycle (June through October). This put a burden on BPA early in its fiscal year, since most of its power revenues were going to EN during this critical time frame. Under Net Billing, over $200 million above EN's current needs were accumulated at EN by September 30. This accumulation was gradually released, in effect, to BPA following the end of the Net Billing cycle during the winter and spring, providing extra liquidity during the spring.

WPAG proposed that BPA should reflect the full amount of the cost reductions achieved through the Direct Pay agreement with EN, rather than using some of those cost reductions as increased working capital (now known as liquidity reserve level). WPAG's reference to cost reductions is misleading. Direct Pay does not result in cost reductions but moves some cash receipts from spring to September, making it easier for BPA to make its year-end Treasury payment. However, this change increases liquidity risk in the spring. Regardless, WPAG is not challenging the appropriate level of liquidity reserves that BPA should carry. Rather, WPAG's argument focuses entirely on the rate impact of Direct Pay. If BPA were to adopt WPAG's proposal and not adjust the Liquidity Reserve Level and choose to use the full benefit of Direct Pay just to lower rates, then BPA would be at risk of missing payments to vendors or to the Treasury in months when reserves are depleted. It is fiscally imprudent to ignore the cash flow impacts that result from Direct Pay. BPA has a legal obligation to pay its creditors and must manage financial reserves in a manner that places a high probability of meeting these obligations.

BPA's analysis indicated the Liquidity Reserve Level would need to increase because of dramatic cash flow changes in the spring and autumn months resulting from Direct Pay. BPA is concerned about having sufficient cash to meet the EN obligations in the November/December and June/July time frames. By the end of June under Direct Pay, BPA's cash inflow from power revenues under Net Billing is almost identical to that under Direct Pay because virtually all Net Billing obligations will have been met and virtually all of the Net Billing power revenue would come to BPA. Therefore, BPA's large June cash outflow, due to EN's scheduled debt payment, is made from the Bonneville Fund in a month where there is no longer any additional liquidity resulting from Direct Pay. This is not the case in November. By the end of November under Direct Pay, BPA's cash inflow from its power revenues under Direct Pay have significantly increased compared to that under Net Billing. Therefore, BPA's November large cash outflow, due to EN's scheduled debt payment, is made from the Bonneville Fund in a month where there is significant additional liquidity resulting from Direct Pay, assuming the cash was not used to make the Treasury Payment. (*Id.* at 14.)

BPA's analysis indicates that the liquidity reserve level should increase to between $175 million and $250 million. (Normandeau, *et al.*, WP-07-E-BPA-33 at 15) At this time, BPA believes that the appropriate level of liquidity reserves given the change in cash flow due to Direct Pay is $175 million. This amount can be reduced appropriately if BPA assumes any customers participate in the Flexible PF Rate Program as discussed in Issue 3 of this section.

Decision

BPA will adjust the PBL liquidity reserve level to $175 million as a consequence of the change from Net Billing to Direct Pay.

Issue 3

Whether BPA will incorporate other sources of liquidity into the Final Studies.

Parties' Positions

PPC urges the Administrator to consider all other potential liquidity tools that promise a similar ability to reduce rates, if and when they become available. (PPC Br., WP-07-M-65 at 5.)

In its brief on exceptions, WPAG supports implementing the PF rate liquidity program (Flexible PF Rate Program), and including language in the GRSPs to permit the benefits of this program to be reflected in the final PF rate. (WPAG Br. Ex., WP-07-M-81 at 8.)

BPA's Position

BPA stated that it intends to include in its Final Studies any of the liquidity tools that BPA determines it can rely on with confidence. (Andrews, *et al.*, WP-07-E-BPA-30 at 8.) BPA will include liquidity tools in the Final Studies if they can prudently be relied upon at the time the Final Studies are completed. (Normandeau, *et al*., WP-07-E-BPA-33 at 12.)

BPA will incorporate a liquidity tool, such as Direct Pay, into the Final Studies by appropriately adjusting the liquidity reserve level in ToolKit. (*Id.*) The liquidity reserve level sets the threshold at which BPA counts a Treasury miss when reserves fall below that level. For the Initial Proposal, this was set at $50 million for PBL. (*Id.*)

BPA's need for liquidity is increased by the changed shape of its cash flow under Direct Pay. But, if other liquidity tools become available, BPA's supply of liquidity would also increase. If other liquidity tools can supply as much incremental liquidity as is required by Direct Pay, BPA would not need to increase the liquidity reserve level. If such tools can provide more incremental liquidity than Direct Pay requires, BPA may be able to set a lower liquidity reserve level. (*Id*. at 15.)

Evaluation of Positions

BPA and customers recently developed the Flexible PF Rate Program as part of an ongoing endeavor to identify additional sources of liquidity. The Program is intended to increase BPA's liquidity by shaping power revenues to cover extraordinary cash flow requirements. This allows BPA to lower the liquidity reserve level used to assess Treasury payment in ToolKit due to freed-up cash that would otherwise be unavailable under the higher reserve level requirement. The overall effect of additional sources of liquidity is a reduction in the need for cash reserves which reduces the amount of PNRR included in base rates to maintain those reserves. BPA will offer the Flexible PF Rate Program to non-Slice purchases under the Flexible PF Rate Option.

The actual amount of liquidity available through the Flexible PF Rate Program remains uncertain and cannot be fully relied upon until contracts are completed later this summer. Based on the interest shown by customers, BPA believes there is a high likelihood of successfully completing contracts shortly after the ROD is published. BPA set a deadline of June 9, 2006, for customers to formally indicate strong interest in this program. The amount of liquidity supported by written commitments provided by customers by that date has informed the Administrator on the amount of additional liquidity available through this program. The Administrator evaluated the commitments and concluded that he will reduce the liquidity reserve level from $175 million to $89 million in setting final rates. Additional liquidity from this program or from other sources can be accounted for through the CRAC contingent mechanism described in Issue 7 of Section 6.3.

Because final contract amendments will not be concluded before the final rate calculation, BPA is proposing a one-time adjustment of the CRAC and Divided Distribution Clause (DDC) Thresholds, in August of 2006, to account for the possibility that less liquidity is generated than was assumed at the time final rates were set. If less liquidity is generated, then the CRAC will be made more likely to trigger through a higher Accumulated Modified Net Revenue (AMNR) Threshold and/or the DDC will be made less likely through a higher AMNR trigger. This will ensure that rates are set to maintain the 92.6 percent target after the final amount of liquidity ultimately made available through this program is known.

Rather than propose a contingent recalculation mechanism for this program, BPA pre-calculated several possible adjusted CRAC and DDC Thresholds to show how rates could be higher if customers' enrollment in the program is less than that assumed in the Final Studies. BPA believes this will encourage customers to participate in this program. BPA is also taking this approach because the record includes proposals only to reduce rates if additional liquidity tools become available, and does not allow for rates (or the proposed rate mechanisms) to be adjusted upward if the source of additional liquidity is not realized.

BPA will add the following language to Sections D and F of the GRSPs to account for the one-time change to the CRAC and DDC Thresholds to account for changes in the Flexible PF Rate Program in August of FY 2006:

One-Time Adjustment of the CRAC/DDC Thresholds Due to Lower Enrollment in the Flexible PF Rate Program

In the WP-07 Final Studies, BPA included an estimate of $125 million of participation in the Flexible PF Rate Program using the Flexible PF rate option. The additional liquidity assumed by BPA to be available was included in the calculation of the base rates and in establishing the CRAC/DDC Thresholds to achieve a minimum three-year TPP of 92.6 percent. Since this source of liquidity is uncertain, BPA will reassess the final amount after August 25, 2006, and adjust the CRAC/DDC Thresholds to maintain the TPP of 92.6 percent if the final amount of enrollment in the Flexible PF Rate Program is less than that assumed in the Final Studies.

(1) **Determining the actual enrollment in the Flexible PF Rate Program**

The following conditions must be satisfied prior to August 26, 2006.

(a) The Customer and BPA have each signed a formal agreement (contract) establishing the Customer as a participant in the Flexible PF Rate Program for the duration of the FY 2007-2009 rate period.

(b) The customer has secured and provided to BPA a letter of credit, stand-by letter of credit, or other mutually agreed-to form of liquidity guarantee, with a financial institution providing BPA with the assurance of payment under the terms of the Flexible PF Rate Program.

(2) **Adjusting the CRAC/DDC Thresholds for a Lower Enrollment Amount in the Flexible PF Rate Program**

If a lower amount of Flexible PF revenue is available than was assumed in the WP-07 Final Studies, then the CRAC/DDC Thresholds will be adjusted upward to account for the lower amount, after this new amount is rounded down to the nearest $20 million. The CRAC/DDC Thresholds will be adjusted to the predetermined levels as specified in Table C.

Table C Adjusted CRAC Thresholds for Reduced Flexible PF Revenues [Dollars in Millions]						
Flexible PF Participation	**Equiv. Amt. of Reserves**	**PBL Liquidity Reserves**	**CRAC Thresholds**			
			Equiv. in Reserves	**Thresholds in AMNR**		
				2007	**2008**	**2009**
125.0	**86.3**	**88.7**	**750.0**	**-151.2**	**-52.9**	**48.2**
120.0	82.9	92.1	753.0	-148.2	-49.9	51.3
100.0	69.1	105.9	783.0	-118.2	-19.7	81.8
80.0	55.2	119.8	814.0	-87.2	11.7	113.3
60.0	41.4	133.6	832.0	-69.2	30.0	131.6
40.0	27.6	147.4	857.0	-44.2	55.7	156.8
20.0	13.8	161.2	877.0	-24.2	76.4	177.0
0.0	0.0	175.0	905.0	3.8	105.7	205.0

Table E Adjusted DDC Thresholds for Reduced Flexible PF Revenues [Dollars in Millions]						
Flexible PF Participation	**Equiv. Amt. of Reserves**	**PBL Liquidity Reserves**	**DDC Thresholds**			
			Equiv. in Reserves	**Thresholds in AMNR**		
				2007	**2008**	**2009**
125.0	**86.3**	**88.7**	**1,050.0**	**148.8**	**247.1**	**348.2**
120.0	82.9	92.1	1,050.0	148.8	247.1	348.3
100.0	69.1	105.9	1,050.0	148.8	247.3	348.8
80.0	55.2	119.8	1,050.0	148.8	247.7	349.3
60.0	41.4	133.6	1,050.0	148.8	248.0	349.6
40.0	27.6	147.4	1,050.0	148.8	248.7	349.8
20.0	13.8	161.2	1,050.0	148.8	249.4	350.0
0.0	0.0	175.0	1,050.0	148.8	250.7	350.0

In addition, in order to implement the Flexible PF Rate Program, BPA will make the following addition to the GRSPs for the Flexible Rate Option:

> Notwithstanding the effective dates of the PF rate and associated GRSP's, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate Program by purchasing under the Flexible PF Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

It is important to note that the primary objective of the Flexible PF Rate Program is to provide customers with an effective rate that is lower than it otherwise would be without the Program. To this end, BPA has assumed a level of participation in the Program when setting the base rate. In addition, BPA will adjust the CRAC thresholds to in light of the actual participation in the program. The combination of these factors is the consideration for the customer's participation in this program and will be reflected in their contracts

Decision

BPA will incorporate into its Final Studies the Flexible PF Rate Program. BPA will lower the liquidity reserve level to $89 million which corresponds to the assumed level of customer participation in the Flexible PF Rate Program. BPA will include in the GRSPs a mechanism for adjusting the CRAC and/or DDC Thresholds upward to account for the actual amount of additional liquidity produced through August of 2006, if it is lower than the amount assumed in the Final Studies. Notwithstanding the effective dates of the PF rate and associated GRSP's, any rights and obligations of BPA and a customer arising out of the customer's election to purchase under the Flexible PF Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

6.3 CRAC and DDC Design

Issue 1

Whether BPA should adjust the thresholds for triggering the CRAC and DDC to account for changes since the Initial Proposal.

Parties' Position

No party raised an issue regarding this matter in their respective initial briefs.

In their briefs on exceptions, NRU, WPAG, and PPC supported the decision to adjust the CRAC and DDC reserve thresholds to $750 million and $1,050 million respectively. (NRU Br. Ex., WP-07-M-76 at 2; WPAG Br. Ex., WP-07-M-81 at 8; PPC Br. Ex., WP-07-M-78 at 9.) NRU believes that the draft decision serves the NRU utilities' desire for low base rates with a level of stability. (NRU Br. Ex., WP-07-M-76 at 3.) The CRAC and DDC Thresholds produce a lower base rate level and the adjusted thresholds do not appear to produce unacceptably frequent or large rate adjustments during the rate period. (*Id.*) WPAG similarly believes that the trade-off between a slightly higher likelihood of a CRAC triggering during the rate period in order to achieve a lower base rate, combined with a relatively low likelihood of a DDC, is a fundamentally sound approach. (WPAG Br. Ex., WP-07-M-81 at 7.) PPC also believes that the balance achieved between low rates and an acceptable level of volatility is achieved by the $750/$1,050 million threshold levels for the CRAC and DDC. (PPC Br. Ex., WP-07-M-78 at 9).

BPA's Position

For the Initial Proposal, BPA determined that the AMNR equivalent to $500 million in PBL year-end cash reserves was an appropriate CRAC threshold level because it represented an appropriate balance or compromise between a lower threshold that would trigger less frequently but require higher PNRR, and a higher threshold with higher total CRAC revenues but a lower level of PNRR. (Normandeau, *et al.*, WP-07-E-BPA-14 at 9.) BPA noted this issue in the Draft ROD.

Evaluation of Positions

As the decisions in this ROD indicate, there have been some significant changes to BPA's rate proposal since the Initial Proposal. One of the primary changes relates to the assumptions regarding liquidity tools. In the Initial Proposal, BPA stated "[a]t this time, BPA does not have a sufficient level of confidence to include the liquidity tools under development in the risk mitigation package for the Initial Proposal. Should one or more of these tools become available between the Initial and Final Proposal, then the tool may be included in the risk mitigation analysis performed for the Final Proposal." (*Id*. at 19.)

Since then, and as reflected in this ROD, the Direct Pay of EN's obligations has become a reality and will be incorporated into the assumptions for Final Studies. (*See* Section 6.2 for further discussion) As further noted in this ROD, a consequence of assuming Direct Pay is an increase in BPA's need for liquidity, and therefore in the Liquidity Reserve Level, due to changes in BPA's cash flow during the year.

The increase in the level of liquidity reserve level from $50 million to $175 million also adjusts the point from which it measures a "missed" Treasury payment for purposes of the ToolKit analysis. This means that with Direct Pay a "missed" Treasury payment will be any scenario which ends with less than $175 million in reserves.

When BPA issued the Draft ROD, there had not yet been a determination of the amount of participation in the Flexible PF Rate Program to count towards BPA's liquidity need. Since the Draft ROD, the Administrator concluded he can effectively reduce PBL's liquidity reserves to $89 million to account for the additional source of liquidity.

The collective impact of all of these changes also tips the balance BPA attempted to achieve between higher but stable rates and lower more volatile rates when it set the CRAC threshold. This choice involved setting a threshold high enough so that there was an acceptably low level of PNRR (which directly impacts base rate levels) but not so high that the frequency of the CRAC triggering made rates unduly volatile. BPA adopted a financial reserve equivalent threshold of $500 million because it represented the appropriate balance between the level of PNRR and frequency of the CRAC triggering at that time. (*Id.* at 9.)

Because Direct Pay changes the cash flow profile, the AMNR Threshold equivalent of $500 million cash reserve level assumed in the Initial Proposal no longer strikes the same balance between these two competing objectives. Maintaining cash reserves equivalent to

$500 million, given the change in BPA cash flows, would require significantly more PNRR, resulting in higher base rates.

A further concern with the CRAC threshold level is the appropriate balance between base rates and the expected frequency of CRACs and DDCs. One of the drivers for estimating the frequency of the CRAC triggering, particularly in the first year of the rate period, is the level of starting reserves for the rate period. In the Initial Proposal, BPA's ToolKit analysis showed an expected value of starting rate period PBL reserve level of $380 million and a CRAC triggering in FY 2007 38 percent of the time. (Risk Analysis Study, WP-07-E-BPAFS-BPA-04A at 149.) Since that analysis was performed, PBL's secondary energy sales have been better than forecast and the expected value of PBL starting reserves for the rate period based on the Second Quarter Review are $895 million. The increase in PBL reserves is the combined result of better than expected modified net revenues (MNR) due to better than expected net secondary revenues in FY 2006 and additional cash reserves resulting from Direct Pay. The MNR improvement reflects a real improvement in PBL's financial performance. The Direct Pay effect is purely a change in cash flow and not a change in PBL's financial performance.

As a consequence, using the Initial Proposal threshold assumption of an AMNR equivalent of $500 million cash reserves for the CRAC in the final rate calculations would result in a CRAC triggering significantly less frequently than it did under the Initial Proposal threshold and PNRR would also be significantly higher. This continues to be the case with the additional liquidity available from the Flexible PF Rate Program. Therefore, assuming the change in BPA cash flows and starting reserves, maintaining the threshold at the $500 million level would result in relatively higher base rates and a CRAC that rarely triggers. This result is inconsistent with the balance BPA attempted to achieve in the Initial Proposal. The CRAC was not designed as a tool of last resort, but rather as a rate design mechanism that allows BPA to keep base rates relatively lower, but effective rates would be less stable than they might otherwise be. The proposed increase in the CRAC and DDC Thresholds balances the policy objectives discussed in Section 2 of this ROD.

To regain the balance achieved with the Initial Proposal, BPA will raise the CRAC threshold to be the AMNR equivalent of $750 million. This threshold level allows the PNRR to be relatively lower and increases the frequency of triggering the CRAC compared to the PNRR level threshold in the Initial Proposal.

Under the Initial Proposal, BPA established an AMNR equivalent of $800 million in cash reserves for the DDC Threshold. This level was chosen because it was considered high enough above the CRAC threshold to allow a reasonable deadband between the CRAC and DCC. (Normandeau, *et al.*, WP-07-E-BPA-14 at 16.) The size of the deadband directly results in relative rate stability. BPA is maintaining the $300 million difference between the two thresholds by proposing to raise the DDC Threshold to an AMNR equivalent in cash reserves of $1,050 million. This maintains a balance which results in a reduced need for PNRR and balances the frequency of the CRAC and DDC in the next rate period.

The objective in maintaining this balance does not change with the inclusion of additional liquidity from the Flexible PF Rate Program. A relative balance between PNRR and the CRAC and DDC is important and therefore the thresholds for the CRAC and DDC should be changed to the AMNR equivalent in PBL financial reserves of $750 million and $1,050 million respectively.

Decision

BPA will adjust the CRAC and DDC Thresholds to the AMNR equivalent of PBL financial reserves of $750 million and $1,050 million, respectively, to account for the changes since the Initial Proposal.

Issue 2

Whether BPA should provide a rebate mechanism in the CRAC design to return money to customers if BPA's AMNR exceeds the established CRAC threshold level.

Parties' Positions

PPC proposed that the CRAC design should include a rebate mechanism to return excess revenues to customers prior to the DDC triggering. To the extent it reduces the overall expected rates during the rate period, it should be part of the rate package because PPC contends that it will guard against an "over-accumulation of customers' dollars." (PPC Br., WP-07-M-65 at 11.) WPAG similarly believes the proposed CRAC should contain a rebate mechanism if BPA's financial results turn out to be materially better than when the CRAC was imposed. (WPAG Br., WP-07-M-68 at 10.) WPAG contends that if customers are asked to shoulder an extra financial burden when BPA needs help, these customers should also share the benefit, in the form of reduced rates, when BPA experiences a financial recovery. (*Id*. at 10-11.) WPAG's proposal would include a rebate mechanism similar to the current one used with the SN CRAC. (*Id.* at 11.)

In their brief on exceptions, the Tribes support the decision to not have a CRAC refund mechanism. (JP13 Br. Ex., WP-07-M-77 at 15.)

BPA's Position

BPA argued that the CRAC Rebate is unnecessary to reduce the "over-accumulation" of customer dollars. (Normandeau, *et al.,* WP-07-E-BPA-33 at 19.) The CRAC Rebate would tend to add an unnecessary element to BPA's risk package and provide little added benefit (*Id.*) The DDC sufficiently serves the purpose of returning reserves that are not necessary to maintain BPA's financial stability to its customers. (*Id.*) Additionally, adding the rebate mechanism will have the offsetting effect of increasing the PNRR resulting in higher base rates. (*Id.*)

Evaluation of Positions

The CRAC Rebate proposal by PPC and WPAG is intended to provide customers with some measure of protection against a perceived over-collection of revenues through the CRAC. In theory, the concept of a CRAC Rebate makes some sense. The underlying purpose of the CRAC is to return BPA to a better financial footing. Because the CRAC is calculated based upon the prior year's financial results and is assessed to rates in the subsequent year, and if PBL's AMNR in that next fiscal year turn out to be significantly better than the threshold, some or all of the CRAC may be perceived to not have been needed. However, the purpose of BPA's risk mitigation package, including the CRAC and the DDC, is to maintain financial health, not merely to avert catastrophe.

While the CRAC Rebate in concept may have a logical foundation, there are problems with the nature of PPC and WPAG proposal and the rate impacts such a proposal would bring. As noted by BPA, the mechanism would introduce an additional element to an already complex rate design. (Normandeau, *et al*., WP-07-E-BPA-33 at 19.) Furthermore, the CRAC Rebate would provide little additional benefit to customers over that which is already being provided via the DDC. (*Id*.) The DDC will return excess reserves to customers in the event that BPA reaches certain specified financial standards.

Finally, somewhat ignored by the customer groups is the negative effect that the proposal would have on the base rates paid by customers. The calculated amount of PNRR would go up if a CRAC Rebate is provided. (*Id.*) Given the concerns expressed by these same groups about the impact of higher rate levels, adding a second mechanism to return dollars to customers that would also raise the base rate is counter-productive. (*See* Early, *et al.*, WP-07-E-JP9-01 at 1-3.)

In addition, there are some practical matters that would seem to make the impact of this approach relatively limited in scope. Because of the strong financial outlook for FY 2006, the probability that a CRAC will trigger for FY 2007 is very low. Therefore, it is not likely that a CRAC Rebate would be available until FY 2009, and then only if there is a CRAC in FY 2008. There is no opportunity to rebate revenues for a FY 2009 CRAC because it is the last year in the rate period. Any CRAC revenues would be incorporated into the rate analysis used in the next power rate-setting process. Given the redundant and limited nature of this proposal, the level of added complexity it would introduce, and the related increase to the base rate, a rebate mechanism for the CRAC is not reasonable at this time.

Decision

BPA will not include a rebate mechanism in the CRAC design to return money to customers if BPA's AMNR exceeds the established CRAC threshold level.

Issue 3

Whether BPA's proposed CRAC should include expense category limits.

Parties' Positions

PPC argues that BPA should include caps on particular expense categories before calculating the CRAC. (PPC Br., WP-07-M-65 at 11.) While PPC appreciates the efforts BPA has made to control spending, their fear is that the CRAC could become an outlet for potential Agency overspending. (*Id.* at 12.) A cap on such expenses prior to calculating a CRAC would limit the Agency's ability to collect revenues to cover this uncontrolled spending.

WPAG also argues that the CRAC should account for spending limits. (WPAG Br., WP-07-M-68 at 8.) Their proposal was made to ensure that voluntary decisions by BPA to spend beyond the levels assumed in the rate case did not trigger a CRAC rate increase. (*Id*. at 8-9.) The improved transparency of BPA financial decisions provides customers with increased understanding of BPA's financial circumstances but provides no real protections against spending decisions BPA makes. (*Id*. at 9.)

In their brief on exceptions, the Tribes support the decision to not limit the recovery of expenses through the CRAC for specific expense categories. (JP13 Br. Ex., WP-07-M-77 at 15.)

WPAG argues that BPA should adopt spending limits on cost categories for purposes of triggering the CRAC. (WPAG Br. Ex., WP-07-M-81 at10.) WPAG contends that the strong support for this among preference customers shows that BPA has not adequately addressed the customers' concerns. (*Id*.) WPAG further argues that added transparency did not adequately address overspending concerns and that spending limits should be focused on budget areas that BPA controls. (*Id*.) WPAG notes that in exchange for giving in on the cost limits, BPA does not need to go through a 7(i) proceeding to trigger the CRAC. (*Id*.)

BPA's Position

BPA noted in its testimony that a number of expense categories agreed to under the SN CRAC were not truly "controllable" and that if BPA were to agree to caps in the future it would likely be for a more narrow set of categories. Furthermore, BPA believes the expense caps found in the SN CRAC were adopted because of a lack of transparency with regard to BPA's costs. (Normandeau, *et al.*, WP-07-E-BPA-33 at 18.) Since that time, BPA has increased the level of information available regarding its finances through numerous processes that have helped BPA control, reduce, and be accountable for costs. (*Id.*) BPA believes these processes have been successful at answering the customers' desire for effective cost control.

Evaluation of Positions

WPAG and PPC believe the cost cap proposal sends a clear message that customers want BPA to take responsibility for expense changes that occur throughout the rate period – particularly upward changes. (WPAG Br., WP-07-M-68 at 8; PPC Br., WP-07-0M-65 at 11; WPAG Br. Ex., WP-07-M-81 at10.) WPAG believes that added transparency does not adequately address overspending concerns and that spending limits should be focused on budget areas that BPA controls. (*Id*.) In the past, WPAG and PPC's proposal may have provided added incentive to control actual costs to budgeted levels. However, BPA's track record of managing costs at or below budgeted levels has been very good in recent years, and the added incentive of cost caps is not needed to maintain that focus.

If all of BPA's costs were completely within BPA's control, the notion of holding BPA fully responsible for increased expenses might be an appropriate one. A problem, however, arises when budget overruns are the product of events over which BPA has little or no control. While WPAG suggests that the caps should focus on budget areas BPA has some control over, this does not avoid the problem. Even with areas over which BPA can exercise some cost control, circumstances still can arise that necessitate spending beyond the forecast levels. It is therefore prudent for BPA to have the flexibility to adjust rates to fully recover unexpected costs within the rate period.

The request for transparency is also a very valid request. Without transparency, BPA's customers have no reason to believe that BPA's budget is slim or, for that matter, fat laden. BPA has acknowledged this prior shortfall and has implemented several processes to close this gap. Many customers have praised BPA on these efforts, while BPA has simultaneously reiterated its commitment to maintain and expand the progress that has been made. Provided all parties keep these lines of communication open, the concerns over BPA's budget will be addressed. (*See* Section 4 for further discussion on PFR.)

In addition to the financial impacts that cost caps place on BPA's budget, there are also operational side effects that arise under such a proposal. Customers have pointed out in discussions that the spending limits should be by category and should not include the ability to shift dollars from one category to another. This would severely limit BPA's ability to manage its business within sound business principles.

Another challenge with cost caps involves timing. In some instances, the total amount needed for a program will not be known until after the rate proposal has been filed. This is true for conservation and renewables. For example, the Conservation Rate Credit (CRC) expense depends on customer choices that do not need to be made until after the rate filing. These choices could move funds from the CRC to the renewable program. It is also true that some of the commitments in PFR, *e.g.*, internal operations, are managed to a three-year average, which could not be done with an annual cap.

In the end, this proposal does not protect customers from expense program increases and over-runs. BPA is obligated to recover its costs and will do so either in the current rate period or, if those costs are not recovered in the current rate period, as part of the next rate-setting process. Costs should be recovered on a current basis if reasonably possible. Furthermore, this proposal would reinforce a notion of poor cost management and lack of transparency that more recent endeavors by BPA do not support.

Decision

BPA will not limit the recovery of revenues through the CRAC for specific expense categories or limit the amount recoverable for overall spending.

Issue 4

Whether BPA should implement a provision that requires it to seek cost reductions before or concurrent with implementation of any CRAC.

Parties' Positions

PPC argues that BPA's proposed CRAC should include an Agency commitment to seek cost reductions before, or concurrently with, implementation of any CRAC. (PPC Br., WP-07-M-65 at 12.)

In their briefs on exceptions, NRU, WPAG, and PPC support the decision to adopt in the GRSP a commitment to seek actions that might advert or mitigate the need for a CRAC before or concurrent with implementation of any CRAC. (NRU Br. Ex., WP-07-M-76 at 5; WPAG Br. Ex., WP-07-M-81 at 8; PPC Br. Ex., WP-07-M-78 at 6.)

BPA's Position

BPA believes any cost caps or controls are unnecessary because of BPA's continued efforts over the past three years to successfully reduce costs and increase transparency. (Normandeau, *et al.*, WP-07-E-BPA-33 at 18.) Staff did not directly address the customer's proposal to include a commitment to seek cost reductions before or concurrent with the implementation of the CRAC in testimony.

Evaluation of Positions

PPC encouraged BPA to commit to reduce costs, as BPA's customers would in the event that a CRAC or other cost increase where imposed on them. (PPC Br., WP-07-M-65 at 12.)

In the 2002 GRSPs, the FB CRAC included a general commitment to seek ways to mitigate a possible rate increase prior to implementing the FB CRAC:

> If accumulated net revenues at the end of a fiscal year are within $150 million of the FB CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for the causes of BPA's financial decline compared to the rate case plan, and propose a prioritized list of potential actions to avert or mitigate the need for FB CRAC in future years. BPA shall conduct a public comment period on these actions to avert or reduce a potential FB CRAC rate adjustment by the following October.

(2002 General Rate Schedule Provisions, Revised May 2004)

BPA agrees that a similar provision to seek ways to avert or to mitigate a CRAC is an appropriate action but does not agree that it is necessary to explicitly require the Agency to seek cost reductions, considering that the major drivers of the need for the CRAC are generally outside of BPA's control.

BPA agrees to include new proposed language and will follow section II.D.3.a.(2) of the GRSPs:

(2) Actions to mitigate the need for the CRAC

If PBL accumulated modified net revenues at the end of a fiscal year are within $150 million of the CRAC threshold for the subsequent year, BPA will prepare and post on its Web site an analysis for the causes of BPA's financial decline compared to the rate case forecast, and propose a prioritized list of potential actions to avert or mitigate the need for a CRAC. BPA shall conduct a comment period on these actions to avert or reduce a potential CRAC rate adjustment by the following October.

Decision

BPA will not specifically commit to seeking cost reductions prior to triggering a CRAC, however, BPA will adopt GRSPs that commit to a process to avert or mitigate the need for the CRAC in the following year.

Issue 5

Whether BPA should adopt PPC's proposal to modify the timing of the CRAC and DDC notice.

Parties' Positions

PPC proposes a modification of the timing of the CRAC notice made by customers to conduct the CRAC process earlier, in August, to continue the process in the FY 2002-2006 GRSPs. (PPC Br., WP-07-M-65 at 13.) PPC believes this change will provide value by giving customers a preliminary look at the next year's power rates as early as is practical. (*Id.*)

In their briefs on exceptions, NRU, WPAG, and PPC support the decision to provide customers with preliminary notice of a potential CRAC and DDC adjustment in August. (NRU Br. Ex., WP-07-M-76 at 5; WPAG Br. Ex., WP-07-M-81 at 9; PPC Br. Ex., WP-07-M-78 at 7.)

BPA's Position

BPA indicated in rebuttal testimony that it is willing to modify the GRSPs in the Final Studies and include a preliminary forecast in August of the rate adjustment along with having the final rate announcement on or about September 1, as is stated in the current GRSPs. (Normandeau, *et al.*, WP-07-E-BPA-33 at 19.)

Evaluation of Positions

PPC's recommendation that BPA provide customers with a preliminary forecast in August has merit. This additional time would benefit customers by providing them added time for their own rate-making efforts. It would also allow customers and interested parties to obtain answers to any questions they may have about a rate increase due to the CRAC. BPA's original intent for changing the process to later in September was to allow for the most complete financial information to be available before calculating the CRAC or DDC adjustments (if any). The experience in the FY 2002-2006 rate period has led to a number of post-third-quarter changes to the rate analysis to account for events in July and August that were not part of the third-quarter review. These are the types of changes that BPA wants to include in the rate calculation that would be presented to customers in September. However, BPA is willing to include an August preliminary rate adjustment forecast along with having the final rate announcement on or about September 1. (Normandeau, *et al.*, WP-07-E-BPA-33 at 19.)

The following modified text will replace section II.D.3 of the GRSPs:

> In August prior to beginning of each year of the rate period, the Administrator will determine whether the expected value of the AMNR forecast at the end of that fiscal year is below the CRAC Threshold. If the AMNR is forecasted to fall below the CRAC Threshold, the Administrator will propose, by the end of August, to assess a cost recovery adjustment to applicable rates for power deliveries beginning in October.
>
> Customers will be notified, on or about September 1, of the percentage increase applicable to the base, if any, due to the CRAC. The rates used to calculate the customers' bills for the following October through September will reflect the CRAC increase.

The following modified text will replace section II.D.3.a.(2) of the GRSPs:

> BPA shall complete a forecast of current fiscal end-of-year AMNR ~~prior to the beginning of the next fiscal year~~ in August of each year. BPA shall notify all customers and rate case parties by the end of August~~ around mid-September~~, in each FYs 2006-2008 (prior to the beginning of the next fiscal year) if the expected value of AMNR is forecast to fall below the CRAC Threshold for the that fiscal year and, if so, the extent to which BPA intends to adjust rates due to the CRAC. Notification will be posted on BPA's website and will include the AMNR based on audited results, for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Revenue Amount, and the forecast of the CRAC Percentage. The notice shall also describe the data and assumptions relied upon by BPA for the AMNR determination. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available from BPA for review upon request.
>
> In early September ~~Prior to the end of each fiscal year~~of any year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA staff shall conduct a public forum to explain the AMNR forecast, the calculation of the CRAC Amount and the CRAC Percentage, and to demonstrate that the CRAC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.
>
> On or about September 30 of any fiscal year in which the AMNR is forecasted to fall below the CRAC Threshold, BPA will post to the BPA website the final calculation of the percentage adjustment to each product and the dollar

adjustment to each benefit subject to the CRAC as described above. This will include any National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] (NFB) Adjustment to the CRAC calculation.

BPA will also similarly modify the timing of the DDC to maintain consistency between the two August processes.

The following modified text will replace section II.G.2 of the GRSPs:

> In August prior to beginning of each year of the rate period, the Administrator will determine whether the expected value of the AMNR forecast at the end of that fiscal year is above the DDC Threshold. If the AMNR is forecasted to be above the DDC Threshold, the Administrator will propose, by the end of August, to assess a dividend distribution adjustment to applicable rates for power deliveries beginning in October.
>
> Customers will be notified, on or about September 1, of the percentage decrease applicable to the base, if any, due to the DDC. The rates used to calculate the customers' bills for the following October through September will reflect the DDC decrease.

The following modified text will replace section II.G.2.a.(2) of the GRSPs:

> BPA shall complete a forecast of current fiscal end-of-year AMNR ~~prior to the beginning of the next fiscal year~~ in August of each year. BPA shall notify all customers and rate case parties by the end of August ~~around mid-September~~, in each FYs 2006-2008 (prior to the beginning of the next fiscal year), if the expected value of AMNR is forecast to be above the DDC Threshold for that fiscal year and, if so, the extent to which BPA intends to adjust rates due to the DDC. Notification will be posted on BPA's website, and will include the audited AMNR for the prior fiscal year, the forecast of end-of-year AMNR, the calculation of the Dividend Amount, and the forecast of the DDC Percentage. The notice shall also describe the data and assumptions relied upon by BPA. Such data, assumptions, and documentation, if non-proprietary and/or non-privileged, shall be made available by BPA for review upon request.
>
> In early September ~~Prior to the end of each fiscal year~~of any year in which the AMNR is forecast to be above the DDC Threshold, BPA staff shall conduct a public forum to explain the AMNR forecast, the calculation of the Dividend Amount and the DDC Percentage, and to demonstrate that the DDC has been implemented in accordance with these GRSPs. The forum will provide an opportunity for public comment.

> No later than September 30 of any fiscal year in which the AMNR is forecasted to be above the DDC Threshold, BPA will post to the BPA website the final calculation of the adjustment (as a percentage) to each product and benefit subject to the DDC as described above.

Decision

BPA will change the GRSPs to provide a preliminary notice in August of each year if a CRAC or DDC is anticipated.

Issue 6

Whether BPA should adopt the proposal to include the Administrator's discretion to lower the CRAC based on a forward-looking TPP analysis.

Parties' Positions

PPC argues that the CRAC should include language giving the Administrator the discretion to reduce or eliminate a CRAC while still maintaining its financial goals if circumstances justify such action. (PPC Br., WP-07-M-65 at 8.) The discretionary language would allow the Administrator to reduce or eliminate the CRAC if subsequent events make the CRAC unnecessary. (*Id*. at 9.) In addition, if liquidity tools become available after the Final Studies are completed, such a provision could be used to incorporate the benefit of such a tool into the calculation of any CRAC. (*Id*.) PPC found BPA's rejection of discretionary language for the CRAC peculiar considering that BPA was willing to consider the discretionary language for the purpose of integrating future liquidity sources into rates. (*Id*.) Furthermore, PPC argued that BPA's justification for rejecting discretionary language was not satisfactory considering BPA's inconsistent approach. (*Id.* at 10.)

In their briefs on exceptions, NRU, WPAG, and PPC support the decision to adopt language that gives the Administrator discretion to lower a CRAC based on certain PBL TPP levels. (NRU Br. Ex., WP-07-M-76 at 5.) (WPAG Br. Ex., WP-07-M-81 at 9.) (PPC Br. Ex., WP-07-M-78 at 5.)

The Tribes believe the decision to adopt language that gives the Administrator discretion to lower a CRAC will unacceptably reduce BPA's ability to repay Treasury. (JP13 Br. Ex., WP-07-M-77 at 16.) However, the Tribes note that they would support the addition of language that allows the Administrator to increase the amount collected under the CRAC if circumstances warranted. (*Id*.)

BPA's Position:

BPA rejected the inclusion of discretionary language that would allow the Administrator to lower the CRAC if circumstances warranted. (Normandeau, *et al.*, WP-07-E-BPA-33 at 18.) The discretion, referred to as the "may" language, was first adopted with the SN CRAC in FY 2003. BPA does not consider that the current circumstances justify including such language with the CRAC because the SN CRAC was a risk mechanism of last resort in the current rate period and was not intended to recover lost revenues or return the Agency to its traditional 95 percent two-year TPP standard. (*Id.*) Since the CRAC proposed for the FY 2007-2009 rate period is not designed as a tool of last resort but instead as an integral part of maintaining the Agency standard of 92.6 percent TPP for three years, it is not prudent to include discretion. Furthermore, the CRAC is designed to account for actual financial performance and not to adjust for future needs in either direction. (*Id.*) BPA also believes that a formula-based mechanism makes the calculation clear and transparent and allows the Agency and the region to focus on other issues during the rate period. (*Id.*)

BPA did agree with PPC testimony that future sources of liquidity, at least in part, could be included in the CRAC calculation if discretionary language was adopted. (*Id.* at 16.)

Evaluation of Positions

BPA's position on the surface might be considered contradictory, but when considered in context of the parties' arguments it is not. BPA argued against PPC's proposal because the concept of the CRAC was designed to account for past financial results. The CRAC was not intended to be based on forecasts of future revenues or expenses since such forecasts are often the focus of controversy. On the other hand, the fact that the fruits of the work and effort by BPA and customers to develop alternate sources of liquidity that are not likely to be available in time to be incorporated into base rates does require some type of mechanism to make future rate adjustments in a manner that accounts for the additional liquidity available to BPA. It is in this context that BPA agreed with PPC that discretionary language or some type of contingent mechanism could appropriately account for future liquidity and could produce a rate benefit to customers if a CRAC were triggered.

PPC's proposal to provide a provision in the GRSPs that gives the Administrator some discretion to lower or eliminate the CRAC in the event there are factors that would lead to the conclusion that the need for the CRAC is lessened or eliminated has merit. While the SN CRAC was a risk mechanism of last resort, the "may" language included in the GRSPs provided a tool that allowed the Administrator to look ahead to the remaining fiscal years of the rate period and determine whether any or all of the CRAC was needed to help BPA maintain its financial standing. Furthermore, the ability to apply discretion is firmly tempered by the requirement to maintain the equivalent three-year TPP of 92.6 percent. This requirement protects the TPP from departing from the standard in the 10-year Financial Plan as applied in the rate case. As a result, the Administrator is prepared to adopt language in the GRSPs to provide discretion when implementing the CRAC.

The Tribes' argument for giving the Administrator the discretion to raise the CRAC amount if circumstances dictate is not necessary. BPA believes it has either modeled the risks and accounted for them through risk mitigation tools (reserves/liquidity, PNRR or CRAC) and as to possible changes to fish and wildlife costs, put in place risk mitigation tools designed specifically to address changes to these costs (NFB Adjustment or Surcharge). This multi-layered package mitigates the risks BPA faces in the coming rate period.

The following language is proposed to be inserted into section II.D.2.a.(2) of the GRSPs:

> The Administrator may elect at his discretion to reduce the CRAC rate adjustment. If the Administrator so elects, BPA will recalibrate the caps and the thresholds for the CRAC for later years to maintain the equivalent three-year PBL TPP of 92.6 percent based on then-current information. He shall then inform the customers of his decision during the workshops. The three-year TPP standard for reducing the FY 2007 CRAC is 92.6%, the two-year TPP standard for reducing the FY 2008 CRAC is 95.0%, and the one-year TPP standard for reducing the FY 2009 CRAC is 97.5%.

Decision

BPA adopts the proposal to include the Administrator's discretion to lower the CRAC based on the PBL TPP.

Issue 7

Whether BPA will incorporate a contingent mechanism to account for future liquidity tools that become available after the 2007 Rate Case has concluded.

Parties' Positions

PPC's position is that it understands and expects that BPA will incorporate Direct Pay into the Final Studies in order to decrease rates from the Initial Proposal levels. (PPC Br., WP-07-M-64 at 5.) PPC also believes that the inclusion of the discretionary language, contingent recalculation, or other such mechanism is needed to allow BPA to capture the benefits of other liquidity tools that become available after the Final Proposal. (*Id.*)

In their briefs on exceptions, NRU, WPAG, and PPC support the decision to adopt discretionary and contingent mechanisms to account for any future liquidity tools that may become available during the rate period. (NRU Br. Ex., WP-07-M-76 at 5.) (WPAG Br. Ex., WP-07-M-81 at 9.) (PPC Br. Ex., WP-07-M-78 at 5)

BPA's Position

BPA agreed with PPC that the rate benefit of additional liquidity tools should be considered in order to lower PNRR or a reduction in the CRAC collection amount. (Normandeau, *et al.*, WP-07-E-BPA-33 at 12.)

Generally speaking, other sources of liquidity can substitute for financial reserves for meeting BPA's liquidity needs. (*Id.*) This means that the amount of reserves set aside for liquidity needs can be reduced, and some amount of reserves can be freed up to be used to increase TPP. (*Id.*) This results in a reduction in the cost of risk in the form of lower PNRR and/or a reduction in the CRAC collection amount. (*Id.*)

BPA, in support of PPC testimony, agreed that the Administrator has the ability in the ROD to accommodate the availability of liquidity tools after the Final Studies by adopting discretionary language into the CRAC methodology or consider some type of contingent recalculation. (WP 07-E-BPA-33 at 16.)

BPA will include, in the Final Studies, only those liquidity tools that can be prudently relied upon at that time to be available when needed. (Normandeau, *et al*., WP-07-E-BPA-33 at 12.) BPA intends to include in its Final Studies any of these liquidity tools that BPA determines it can rely on with confidence. (Andrews, *et al*., WP-07-E-BPA-30 at 8.) However, BPA does share the opinion that, if feasible, rate-reducing ability should be reflected when liquidity tools become available after the Final Studies. (Normandeau, *et al*., WP-07-E-BPA-33 at 12.) Two methods in particular could be used to provide the benefits of additional liquidity, the inclusion of the "may" language or a contingent recalculation. (*Id.* at 16.)

<u>Evaluation of Positions</u>

The parties urged BPA to include additional sources of liquidity that arise following the completion of the Final Studies. BPA is proposing to adopt a contingent mechanism that would adjust the CRAC and/or DDC Thresholds for future years of the rate period if additional liquidity becomes available later in the rate period.

As noted in the BPA's rebuttal testimony, BPA and customers were working on four different liquidity tools that had not been fully realized at that time. (Andrews, *et al*., WP-07-E-BPA-30 at 8.) Since filing that testimony, as noted above, the Direct Pay of EN costs is being implemented and will be incorporated into Final Studies. Additionally, as discussed in detail in Section 6.2, the liquidity available through the Flexible PF Rate Program will be assumed for Final Studies, consistent with the decision described there. If additional liquidity becomes available between the Final Studies and the deadline for completing the contracts under the Flexible PF Rate Program, BPA will incorporate the additional liquidity through the contingent mechanism described here.

One of the remaining available liquidity tools, a note from the U.S. Treasury, is still not sufficiently reliable to include at this time and as a result, this tool will not be factored into the calculation of final rates. However, it is possible that this liquidity tool may become available after Final Studies are completed. If this occurs, BPA will account for access to this tool. PPC suggests that this be done through a contingent recalculation of the CRAC parameters. BPA agreed earlier in the Draft ROD to include in the GRSPs language that gives the Administrator the discretion to reduce or eliminate a CRAC if this is possible while maintaining PBL's TPP. This provision can be used to incorporate not just the prospects of improvement in the revenue and expense levels in the remaining fiscal years but also additional liquidity that might become available after Final Studies have been completed. Unfortunately, this approach benefits rates only if there is a CRAC and does not provide for adjusting the DDC thresholds to recognize additional liquidity and the reduced need to maintain higher cash reserves. As a result, BPA is proposing that a second discretionary and contingent mechanism be adopted that allows the Administrator to choose to adjust the CRAC and DDC Thresholds if additional sources of liquidity become available after the Final Studies are completed.

Deferring the payment date on BPA's advanced amortization payments is no longer under consideration in that it no longer has value now that BPA has adopted Direct Pay and BPA's worst liquidity risk no longer occurs at the start of the fiscal year.

The following language will be inserted into Sections D and F of the GRSPs account for changes in PBL's liquidity needs, resulting in adjustments to the CRAC and DDC Thresholds in August of each year:

Contingent Recalculation of the CRAC/DDC Thresholds if additional sources of liquidity are acquired in FY 2006, 2007, or 2008.

The Thresholds for the CRAC/DDC will be recalculated if the Administrator determines, in his sole determination, both that BPA has received sufficient assurance after the WP-07 Record of Decision (ROD) has been issued that an additional source of liquidity has become available to BPA, and that the additional source of liquidity warrants recalculation of the Thresholds. For this purpose, an additional source of liquidity includes amounts available under the Flexible PF Rate Program in excess of the $125 million used in final rate studies; however, additional liquidity, available under the Flexible PF Rate Program will in no case serve to reduce PBL's minimum liquidity reserve level, used to calculate a Treasury miss, below $50 million.

(a) Conditions occurring after the WP-07 ROD but before the beginning of FY 2009.

If additional sources of liquidity are obtained in time to include in the calculation of the CRAC/DDC for FY 2007, FY 2008, or FY 2009, then the CRAC/DDC Thresholds will be recalculated for the remaining whole fiscal years of the rate period. The revised Thresholds will be applied to the CRAC/DDC calculations for the remaining years of the rate period.

(b) Determining the Change in the CRAC/DDC Thresholds

BPA shall account for the change in liquidity by adjusting the liquidity reserve requirement in the WP-07 Final Study version of ToolKit. The thresholds for the CRAC/DDC will be established based on the same 92.6% three-year Agency TPP criterion used to set rates in the WP-07 rate proceeding. No other update will be included in the contingent recalculation of the CRAC/DDC Threshold.

The Adjusted CRAC/DDC Thresholds will be in effect for the remaining years in the rate period.

Decision

BPA will incorporate a contingent recalculation of the CRAC and DDC Thresholds to account for liquidity tools that become available after the 2007 Rate Case has concluded. This contingent recalculation will be at the Administrator's discretion.

Issue 8

Whether the CRAC, DDC, and NFB Surcharge GRSP language reflects the effects of the cap and floor on IOU REP Settlement benefits under the IOU REP Settlement agreements and DSI contract caps in calculating the amounts to be distributed through upward or downward rate and benefit adjustments.

Parties' Positions

The IOUs argue that the CRAC, DDC, and NFB Surcharge should reflect the effects of the caps and floors on IOU REP Settlement benefits under the IOU REP Settlement agreements in calculating the amounts to be distributed through upward or downward rate and benefit adjustments. (IOU Br., WP-07-M-67 at 4.) The IOUs also believe that the NFB Surcharge should reflect the caps on DSI customer benefits under the DSI contracts in calculating the amounts to be generated through surcharge or benefit reductions. (*Id.*)

BPA's Position

BPA supports the IOU's position. (Normandeau, *et al*., WP-07-E-BPA-33 at 21.) The proposed CRAC and DDC GRSP language was clarified to reflect BPA's view that IOU REP Settlement Benefits under the IOU REP Settlement agreements should be included in the calculation of the amounts to be distributed under the CRAC and DDC. (*Id.*) The proposed NFB Surcharge GRSP language is consistent with the IOU REP Settlement and DSI benefits. (BPA Br., WP-07-M-59 at A-5.)

Evaluation of Positions

Both the IOUs and BPA agree that the CRAC, DDC and NFB Surcharge should reflect the effects of the caps and floors under the IOU REP Settlement Agreements. (IOU Br., WP-07-M-67 at 4; Normandeau, *et al*., WP-07-E-BPA-33 at 21.) Both parties also agree that the NFB Surcharge should reflect the effects of the caps on DSI customer benefits under the DSI contracts. (*Id.*)

The following text was proposed by BPA in rebuttal testimony to replace Section II.D.1.c:

> The CRAC percentage will be the lowest percentage that, when applied to HLH and LLH Energy and Load Variance, generates additional net revenue (additional PF revenue combined with possible reductions in IOU REP Settlement benefits) in the amount required by the CRAC formula.

(*Id.*)

The following text will replace Section II.F.1.c:

> The DDC percentage will be the lowest (smallest negative) percentage that, when applied to HLH and LLH Energy and Load Variance, generates reduced net revenues (reduced PF revenue combined with possible increases in IOU REP Settlement benefits) in the amount required by the DDC formula.

(*Id.*)

After much deliberation between BPA and the parties, the amended NFB Surcharge GRSP language was proposed by BPA:

> **a. Calculating IOU and DSI Portions of the Surcharge Amount**
> For the purpose of determining the Adjusted Surcharge Amount, a determination will be made of the portion of the Surcharge Amount to be realized from a reduction, if any, in the benefit payments to the IOUs and DSIs. Such reduction, if any, results from an increase in the rate used to calculate IOU and DSI benefits and will be realized by reducing the payments to the IOUs and DSIs during the months for which the Surcharge is billed to PF loads subject to the Surcharge.
>
> Calculation and application of the Surcharge as applied to IOU REP Settlement benefits will be subject to the cap and floor on IOU benefit amounts under IOU REP Settlement Agreements. Calculation and application of the Surcharge as applied to DSI benefits will be subject to the cap on DSI benefit amounts under the DSI agreements.
>
> For the purpose of determining the Adjusted Surcharge Amount, IOU and DSI benefits will be recalculated through adjustment of the PF rate used to calculate benefits under the IOU REP Settlement Agreements and the PF rate used to calculate the DSI benefits until the sum of:
>
> (1) the increased revenue that would be realized from a Surcharge on PF and other products subject to the Surcharge; and
>
> (2) the calculated reduction (in light of the annual effects of the cap and floor on IOU REP Settlement benefits and cap on DSI benefits) in IOU REP Settlement benefits and DSI benefits, if any, (less the effect of this reduction on the Slice True-up Adjustment Charge) that would result from such Surcharge
>
> equals the Surcharge Amount.
>
> Any reduction in IOU or DSI benefits determined as described above will be reflected in benefit payments for the same months during which the monthly Surcharge bill is sent out.

Decision

BPA will include language in the GRSPs for the CRAC, DDC, and Emergency NFB Surcharge that incorporates the effects of the IOU REP Settlement caps and floors and the DSI contract caps.

6.4 NFB Adjustment to the CRAC

Issue 1

Whether BPA should adopt the trigger language contained in the GRSPs for the NFB Surcharge for the NFB Adjustment.

Parties' Position

PPC notes that through settlement discussions related to the provisions of the NFB Surcharge, BPA and customers developed a somewhat different definition of a "trigger event" than that proposed with the NFB Adjustment. (PPC Br., WP-07-M-64 at 13.) Even though the circumstances to trigger both the NFB Surcharge and the NFB Adjustment are intended to be the same, the GRSPs use different definitions of a "trigger event" for the two rates provisions. (*Id.*) PPC proposes that BPA adopt the definition for the trigger event used with the NFB Surcharge. (*Id.*)

In their briefs on exceptions, NRU, WPAG, and PPC support the decision to adopt the same definition of "Trigger Event" for use in both the NFB Adjustment to the CRAC and the NFB Surcharge. (NRU Br. Ex., WP-07-M-76 at 5; WPAG Br. Ex., WP-07-M-81 at 9; PPC Br. Ex., WP-07-M-78 at 7.)

In their brief on exceptions, the Tribes state that they oppose the change to the original NFB Surcharge trigger language because it further limits BPA's ability to trigger the NFB Surcharge. (JP13 Br. Ex., WP-07-M-77 at 16.)

BPA's Position

In BPA's Initial Proposal GRSPs, the trigger definition for the NFB Adjustment is:

> b. Triggering the NFB Adjustment
>
> The NFB Adjustment will address changes in financial results due to the anadromous fish portion of Fish and Wildlife cost categories only when those impacts result from changes in FCRPS Endangered Species Act (ESA) compliance as required by a court order (including court-approved agreements), an agreement related to litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA. Financial impacts include foregone revenue, power purchases, direct program expense, fish and wildlife credits, Corps of Engineers and Bureau of Reclamation Operations and Maintenance,

and capital repayment. Financial impacts will be calculated net of estimated 4(h)(10)(C) credits.

(Wholesale Power Rate Schedules and General Rate Schedule Provisions, WP-07-E-BPA-07 at 83-84.)

In the revised NFB Surcharge GRSPs, the trigger definition for the NFB Surcharge is:

(a) A <u>Trigger Event</u> is when one of the following four kinds of events arises and results in changes to BPA's FCRPS ESA obligations compared to those in the Final Studies of the WP-07 BPA rate proceeding as modified prior to this Trigger Event:

1. A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");
2. An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;
3. A new NMFS FCRPS BiOp; or
4. A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

(Order, WP-07-O-33 at 3-4.)

<u>Evaluation of Positions</u>

The definition of a trigger event for the NFB Surcharge was developed during extensive settlement discussions with parties over the NFB Surcharge provisions. In these discussions BPA and parties proposed to modify the definition of a trigger event to more accurately capture potential outcomes of court-related FCRPS 2004 BiOp events. In order to have a common definition of a trigger event, the NFB Adjustment GRSPs should be modified to use the definition trigger event contained in the NFB Surcharge. A common definition will reduce confusion and potential conflict regarding what is and is not a trigger event.

The Tribes contend that the definition of a "trigger event" in the NFB Surcharge somehow limits BPA's ability to trigger the NFB Surcharge. (JP13 Br. Ex., WP-07-M-77 at 16.) Unfortunately, the Tribes do not explain how or why the language with the NFB Surcharge limits BPA. The intent behind the trigger definition related to the NFB Surcharge negotiated with the Tribes and other parties during settlement discussions was to provide greater clarity and understanding about what constituted a trigger event and there was no intent to further limit the scope of the definition. It was no BPA's intent to create a substantive difference between the original definition and that proposed with the NFB Surcharge.

<u>Decision</u>

BPA will adopt the trigger definition contained in the NFB Surcharge GRSPs for the NFB Adjustment.

Issue 2

Whether the NFB Adjustment should be revised to include an "Access Fee" to Investor-Owned Utilities and Direct Service Industries.

Parties' Positions

WPAG argues that BPA should consider amending the IOU REP Settlement Agreement in an effort to spread the NFB Surcharge impact equitably across customers and benefit recipients. (WPAG Br., WP-07-M-68 at 12.)

WPAG contends that the NFB Adjustment should apply to all customers receiving benefits from the FCRPS. (*Id.*) WPAG maintains that customers receiving benefits from the FCRPS in the form of cash payments, as opposed to power, may or may not pay any portion of the ESA compliance costs associated with the NFB Adjustment. (*Id.*) If the IOU benefits are above the capped amount after adjusting the PF rate for any NFB Adjustment, then the IOUs do not proportionately share in the increased costs. (*Id*. at 13.)

To remedy this perceived inequity, WPAG proposes that BPA adopt an "access fee" to be charged to customers receiving monetary benefits. (*Id.*) Under this access fee, BPA would collect the proportionate share of the NFB Adjustment from the customers receiving monetary benefits. (*Id.*) To the extent that this proposal is inconsistent with the existing contracts with the IOUs, WPAG recommends negotiating an amendment to those contracts. (*Id*. at 14.)

The IOUs contend that WPAG ignores the fact that the IOUs do not share proportionately in the benefits of the FCRPS. (IOU Br., WP-07-M-67 at 26.) The IOU benefits under the IOU REP Settlement agreements are capped and thus the value of their benefit declines as the value of the benefit that public customers receive increases. (*Id.*)

BPA's Position

BPA testified that WPAG's access fee did not comport with the existing IOU REP Settlement agreements. (Lovell and Normandeau, WP-07-E-BPA-34 at 11.) BPA has attempted to apply the proposed NFB Adjustment equitably, but consistent with the terms and conditions of existing contracts. (*Id.*)

BPA believes that the current proposal does not contain a structural flaw that will not collect any portion of an NFB Adjustment from the IOUs. (*Id.*) WPAG members and the IOUs both face the costs of an NFB Adjustment but in different ways. (*Id.*)

Evaluation of Positions

While the WPAG proposal may have some appeal, implementing it through a rate case is not feasible. The IOU REP Settlement agreements provide that their benefits shall be calculated using a methodology that is based upon the difference between the lowest PF rate (as adjusted by a CRAC, NFB Adjustment or NFB Surcharge) and a mark-to-market price derived pursuant to specific provisions in the agreements. The dollar value of the calculation is then multiplied by the approximate 2,200 aMW in the contract to determine the annual dollar value of the benefit. The benefit levels are capped under these agreements at $300 million dollars per year and have a floor of $100 million per year. Therefore, to the extent that the calculated benefits exceed $300 million both before and after any adjustment to the PF rate as the result of an NFB Adjustment, then the IOUs will see no reduction in their benefit levels.

However, the cap on the benefit levels also limits the ability of the IOUs to share in the upside value of the system. There is no corresponding limit on the value of the system to the public customers. As a result, having the IOUs and publics experience the ESA costs in a slightly different fashion is not wholly unreasonable.

Additionally, the proposed access fee is inconsistent with the IOU REP Settlement agreements. Furthermore, to the extent this issue can be addressed, it must be accomplished through bilateral discussions with the IOUs and not in the context of a rate case. While WPAG seems to suggest that BPA will be able to negotiate a change in the terms of the IOU REP Settlement Agreement with the IOUs, the IOUs have shown no willingness to negotiate on this point.

Decision

BPA will not revise the NFB Surcharge to include an "Access Fee" for IOUs and DSIs.

6.5 NFB Surcharge

Issue 1

Whether the NFB Surcharge adequately addresses the issue of the one-year revenue lag created by the NFB Adjustment to the CRAC.

Parties' Positions

The Tribes argue that BPA cannot point to the NFB Adjustment as a mechanism for maintaining the TPP goal because it did not conduct a TPP analysis of the NFB Adjustment. (JP13 Br., WP-07-M-69 at 35.) The Tribes contend that they performed several different analyses to test the effectiveness of the NFB Adjustment and each demonstrated that additional fish and wildlife costs reduced the TPP below the goal of 92.6 percent TPP. (*Id.* at 36.) The Tribes also argue that their analysis raises fundamental questions about the overall effectiveness of the NFB Adjustment. (*Id.* at 37.)

The Tribes argue that BPA has not demonstrated that its revised proposal will meet its TPP goal if it experiences additional Biological Opinion costs. BPA has not demonstrated that the proposed NFB Surcharge will ensure that BPA will be able to repay its debt to the Treasury on a current basis after meeting its costs. (JP13 Br., WP-07-M-69 at 39.) The Tribes maintain there is nothing on the record from BPA that indicates that it can meet its TPP goals with the risk mitigation strategies proposed, including the revised proposal that includes the NFB Surcharge. (*Id.* at 41.)

PPC petitions BPA to reject arguments that its risk package does not maintain an adequate TPP. (PPC Br., WP-07-M-65 at 14.) PPC pointed out that the Tribes and NWEC/SOS's analysis suffered from a serious flaw and produced incorrect results. (*Id.*) PPC notes that BPA proposed the NFB Surcharge to address some of the Tribes concerns about the ability of BPA to quickly collect cash in response to uncertain future events. (*Id.*)

PPC also notes that in response to the NFB Surcharge, the Tribes again raised essentially the same arguments which BPA previously found to be flawed. PPC urges BPA to disregard these arguments for the same reasons, and asserts that BPA's comprehensive response to dealing with these unique risks is certainly more than reasonable and sufficient. (*Id.*)

BPA's Position

BPA made a decision to not model the expense and revenue uncertainties associated with potential future court-related actions to the FCRPS 2004 BiOp due to lack of information available for future events, whether interim changes or a new BiOp all together. (Normandeau, *et al.*, WP-07-E-BPA-14 at 12.) To address the very real uncertainty related to BPA's future fish and wildlife obligations, BPA initially proposed the NFB Adjustment. The Tribes noted in their direct case that BPA may not be able to maintain its TPP standard because of the limitations of the NFB Adjustment. (Sheets, *et al.*, WP-07-E-CR/NZ/YA-01 at 54-55.)

BPA acknowledged in its rebuttal testimony that the time lag in the recovery of cash through a NFB Adjustment of up to one year does prevent the NFB Adjustment from providing the TPP support in those years when BPA's reserves are low. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) In years when the reserve levels are high, the delay or lag in the receipt of the cash does not impact BPA's ability to make the payment to Treasury. (*Id.*) In response to this problem, BPA proposed the NFB Surcharge. The NFB Surcharge is designed to address the time lag between when BPA incurs the cost and the receipt of the dollars during those years when BPA's reserves are low. (*Id.*)

BPA limited the impact of the NFB Surcharge specifically to ESA litigation-related costs of the FCRPS 2004 BiOp. BPA proposed the NFB Surcharge after NWEC/SOS and the Tribes both argued in their direct testimony that BPA's TPP was overstated due to the recovery of NFB related revenues in the next fiscal year. (Normandeau, *et al.*, WP-07-E-BPA-34 at 2-3.) The NFB Surcharge was subsequently modified as the result of joint settlement discussions with parties. The substitute NFB Surcharge GRSPs were placed on the record through Order, WP-07-O-33.

Evaluation of Positions

The Tribes' analysis of the NFB Surcharge in their sur-rebuttal testimony was stricken from the record. (Order, WP-07-O-30.) The Tribes have sought to reinstate this testimony; however, as noted in Section 17, the Administrator has elected not to reinstate this testimony for the reasons stated. As a result, there is little or no analysis on the record from which the Tribes can make this argument.

In their sur-rebuttal testimony, the Tribes nevertheless still maintain that BPA's risk package fails to meet the TPP standard. However, the Tribes' TPP analysis fails to account for the significant rate design change the NFB Surcharge provides. The Tribes first point out that they made a good faith effort to model the uncertainty associated with the fish and wildlife costs. (JP13 Br., WP-07-M-69 at 38.) This attempt to analyze the risk does not prove or disprove the Tribes argument. The Tribes' modeling fails for precisely the reason that BPA chose not to include these unpredictable events. The Tribes improperly assume additional fish and wildlife costs have a 100 percent chance of occurring and fail to model the revenue impacts of the NFB Surcharge. Therefore, this resulted in invalid results. A good faith effort that produces invalid results does not make their argument any more persuasive or more reasonable.

The Tribes also argue that there is no uncertainty around the range of potential costs that might result from a court-ordered action or new BiOp. (*Id.*) They contend that the costs will either be there or not. (*Id.*) This argument ignores the objective of risk mitigation, which is to set rates to recover costs and provide ways to adjust rates for uncertainties that BPA faces in the FY 2007-2009 rate period, including FCRPS 2004 BiOp-related uncertainties. In the case of the FCRPS 2004 BiOp risk, the level is not important because the NFB Adjustment and NFB Surcharge are not capped. In either case, both mechanisms can recover the total cost.

Given that the NFB Surcharge is designed specifically to address BPA's FCRPS 2004 BiOp obligations, the risk of missing a Treasury payment due to this uncertainty has been mitigated.

Decision

The NFB Surcharge adequately addresses the issue of the one-year revenue lag created by the NFB Adjustment to the CRAC.

Issue 2

Whether BPA must conduct a hearing under section 7(i) of the Northwest Power Act prior to implementing a rate adjustment pursuant to the NFB Surcharge.

Parties' Positions

ICNU contends BPA must modify its NFB Surcharge so that it is implemented consistent with section 7(i). (ICNU Br., WP-07-M-72 at 3; ICNU Br. Ex., WP-07-M-83 at 2) ICNU argues the NFB Surcharge as proposed is not a rate, but rather it is a provision in the rate schedules that allows BPA to increase rates. (*Id.*) The rate schedules do not contain the necessary monetary charge or formula for pricing to constitute a rate. (ICNU Br. WP-07-M-72 at 4.) BPA must conduct a section 7(i) hearing prior to implementing the surcharge and it should add a specific methodology to determine when it is appropriate to trigger such a hearing. (*Id.* at 5.)

WPAG argues that the NFB Surcharge as drafted is inconsistent with the provisions of section 7(i). (WPAG Br., WP-07-M-68 at 23.) WPAG believes the current version of the NFB Surcharge leaves the methodology on how the NFB Surcharge will be determined completely up to BPA. (*Id*. at 24.) To remedy this shortcoming, WPAG proposes a public process that begins within 60 days after the submittal of rates to FERC to establish a methodology to determine the Agency Within-year TPP calculation as well as the tools BPA will use to calculate the financial effects due to a trigger event. (*Id*. at 23.) In addition, WPAG raised arguments that the NFB Surcharge was not a rate. This issue is dealt with in Section 17.

NRU similarly argues that there should be a better definition of how the Agency Within-year TPP will be calculated. (NRU Br., WP-07-M-61 at 6) NRU recommends that BPA adopt a proposal similar to that advocated by WPAG, to have a public process initiated within 60 days following the submittal of the rates to FERC to determine the methodology for calculating the Agency Within-year TPP. (*Id.*)

In their briefs on exceptions, NRU, WPAG and PPC support the decision to conduct a public process within 120 days of the filing of rates with FERC to develop a methodology for calculating the Agency Within-year TPP for purposes of triggering and calculating the NFB Surcharge. (NRU Br. Ex., WP-07-M-76 at 5; WPAG Br. Ex., WP-07-M-81 at 9; PPC Br. Ex., WP-07-M-78 at 7.)

WPAG contends that BPA did not propose any language for inclusion in the GRSPs to memorialize the public process to examine the Agency Within-year TPP. (WPAG Br. Ex., WP-07-M-81 at 12.)

ICNU believes the Draft ROD incorrectly concluded that BPA does not need to conduct a 7(i) to implement the NFB Surcharge. (ICNU Br. Ex. WP-07-M-83 at 1.) Contrary to the conclusion in the Draft ROD, unlike the FB CRAC, the NFB Surcharge does not contain sufficient specificity to be considered a valid rate. (*Id*. at 2.) ICNU notes that the Financial-Based (FB) and Load-Based (LB) CRACs were adopted pursuant to settlements with many of BPA's customers. (*Id.*) In contrast the NFB Surcharge was proposed at the end of the current rate proceeding and did not receive a full or comprehensive review. (*Id.*)

BPA's Position

BPA contends that the GRSPs for the NFB Surcharge contain sufficient information for parties to understand how the NFB Surcharge will be calculated and collected.

Evaluation of Positions

There are two separate calculations involved with the NFB Surcharge. BPA must calculate the Agency Within-year TPP and also calculate the NFB Surcharge amount. The separate calculations raise different issues.

ICNU contends that the BPA must conduct a hearing pursuant to section 7(i) of the Northwest Power Act prior to triggering the NFB Surcharge. ICNU argues that the lack of a formula in the

GRSPs, it makes it impossible to assess the validity of the models BPA intends to use in order to assess the amount of the loss. (ICNU Br., WP-07-M-72 at 4.) ICNU points to the LB CRAC and FB CRAC as examples of instances where BPA had specific formulas or financial records that were employed when calculating the rate adjustment. (*Id.*) While the LB and FB CRAC contained the outlines of a formula for calculating the rate adjustment, neither of these adjustment clauses contained the kind of detail sought by ICNU in this case. For example, the FB CRAC calculation requires BPA to forecast Accumulated Modified Net Revenues for the last quarter of the fiscal year. These GRSPs do not provide the specific financial records, computer models, or other documentation BPA would rely upon to conduct this forecast of the last quarter.

By contrast, BPA has provided the same amount of detail on how it will calculate the Financial Effects related to a Trigger Event(s) under the NFB Surcharge and the FB CRAC. The proposed GRSPs provide the following formulae to calculate the financial effects of the NFB Surcharge:

> **Formulae for Calculating the Financial Effects and the Surcharge Amount**
> The calculation of the Financial Effects will be determined as follows making use of the best information available at the time:
>
> Financial Effects =
>
> Expected Value Modified Net Revenue without Trigger Event
>
> Minus
>
> Expected Value Modified Net Revenue with Trigger Event
>
> Where:
>
> (1) The Expected Value Modified Net Revenue without Trigger Event is BPA's projection of what the Modified Net Revenues would be at the end of the fiscal year assuming the Financial Effects of the Trigger Event did not take place. Such projection will be based on actual generation function revenues and expenses to the extent available and forecast results for the remainder of the fiscal year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, including BPA's best estimate of 4(h)(10)(C) credits.
>
> (2) The Expected Value Net Revenue with Trigger Event is the identical projection as made in (1) above except that BPA will assume the Financial Effects of the Trigger Event did take place.
>
> The calculation of the Surcharge Amount will be determined as follows making use of the best information available at the time:

The Surcharge Amount =

Financial Effects

Minus

Expense Changes Borne by Slice Customers

Where:

(1) The Expense Changes Borne by Slice Customers are the estimated costs subject to the Annual True-up Adjustment for Actual Costs, including changes in IOU and/or DSI benefits due to the Surcharge. The portion of the Surcharge Amount allocated to the IOU and DSI customers in determining the Adjusted Surcharge Amount is set forth in subsection E.4 below. The Adjusted Surcharge Amount to be collected from firm power purchasers subject to the Surcharge, excluding the IOU and DSI customers, is set forth in subsection E.5 below.

For comparison, BPA used the following formulae to adjust rates over the last five years. The FB CRAC provisions of the GRSPs provide the following:

Formula for Calculation of the Financial-Based Cost Recovery Adjustment Clause

By August of the fiscal year immediately prior to each fiscal year of the rate period (*i.e.,* FY 2002-2006), a forecast of that end-of-year ANR will be completed. If the ANR at the end of the forecast year falls below the FB CRAC Threshold applicable to that fiscal year, the FB CRAC will trigger, and a CRAC rate increase will go into effect beginning in October of the upcoming fiscal year.

The Revenue Amount will be determined by the following formula:

Revenue Amount is the lower of:

FB CRAC Threshold minus forecasted ANR;

or

The annual Maximum Planned Recovery Amount, shown in Table A below.

Table A: FB CRAC
[Dollars in Millions]

Applicability to Fiscal Year	ANR Calculated at end of Fiscal Year	FB CRAC Thresholds	Maximum FB CRAC Recovery Amounts
2004	2003	-$378	$150
2005	2004	-$204	$150
2006	2005	-$161	$175

Where Revenue Amount is the amount of additional revenue that an increase in rates under FB CRAC is intended to generate during the period the rate increase is effective.

Where FB CRAC Threshold is the "trigger point" for invoking a rate increase under the FB CRAC. The Threshold is pre-specified for the end of FY 2003, 2004, and 2005, in Table A.

Where ANR is generation function net revenues, as accumulated since 1999, at the end of each of the FY 2001-2005. Audited Actual Accumulated Net Revenues (AANR), confirmed by BPA's independent auditing firm, will be used for FY 1999 and 2000, and any subsequent year for which they are available. Unaudited ANR will be used to the extent audited actuals are not available.

The forecast of ANR through the end of each fiscal year will be calculated and used to determine if the threshold has been reached, and what the Revenue Amount is. Net revenues for any given fiscal year are accrued revenues less accrued expenses, in accordance with Generally Accepted Accounting Principles, with the following three exceptions. First, for purposes of determining if the FB CRAC threshold has been reached, actual and forecasted expenses will include BPA expenses associated with EN debt service as forecasted in the WP-02 Final Studies. Second, those actual and forecasted expenses will include BPA expenses associated with payments of benefits to the Investor-Owned Utilities as forecasted in the SN-03 Final Proposal. Third, the impact of adopting Financial Accounting Standard 133, Accounting for Derivative Instruments and Hedging Activities will not be considered in determining if the FB CRAC threshold has been reached. Only generation function revenues and expenses, that is, actual and forecasted revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, will be included in determinations under the FB CRAC. Accrued revenues and expenses of the transmission function are excluded. Impacts of forecasted revenues, positive or negative, from contractual true-up pursuant to the Slice Agreement shall be included in the revenue forecast when determining the FB CRAC. As part of BPA's annual audit process, BPA's independent outside auditing firm will confirm that BPA's ANR determination is consistent with applicable criteria. This confirmation will be made in accordance with additional agreed-upon procedures established by BPA and its independent outside auditing firm after consultation with interested parties.

Where Maximum Planned Recovery Amount is the maximum annual amount planned to be recovered through the FB CRAC. The thresholds for the end of each of FY 2003-2005 will be set to be equal to the thresholds for the SN CRAC each time the SN CRAC thresholds are recalculated.

Once the Revenue Amount is determined, that amount will be converted to the FB CRAC Percentage. The FB CRAC Percentage is the percentage increase in customers' rates (not including any CRACs) in each of the firm power rate schedules listed above. This percentage will be applied to generate the additional FB CRAC revenue.

The FB CRAC Percentage will be determined by the following formula:

FB CRAC Percentage =

Revenue Amount

Divided by

FB CRAC Revenue Basis

Where for FY 2002, the FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC for the fiscal year in which the FB CRAC implementation begins, based on the then-most-current revenue forecast. For FY 2003-2006, FB CRAC Revenue Basis is the total generation revenue (not including any CRACs) for the loads subject to FB CRAC plus Slice loads for the fiscal year in which the FB CRAC implementation begins, based on the then most current revenue forecast. Each non-Slice product's total charge for energy, demand, and load variance will be increased by this FB CRAC percentage amount.

Rate increases under the FB CRAC will be due in 12 monthly payments from November (for the October billing period) through October of the following year.

While the two provisions are different in functionality, the level of detail describing how BPA will calculate the adjustment and tools it will use are remarkably similar. As a consequence, contrary to the positions articulated by ICNU and WPAG, there is sufficient detail in the GRSPs explaining how the Surcharge Amount will be calculated.

The level of detail regarding the Agency Within-year TPP raises different issues.

While there are specifics about how the Agency Within-year TPP will be calculated, it is reasonable to include a public process after BPA submits the rates to FERC to add further specificity. WPAG proposes a public process to begin within 60 days of submitting the rates. (WPAG Br., WP-07-M-68 at 23.) BPA originally believed that conducting a discussion regarding the Agency Within-year TPP prior to the Trigger Event was the more efficient way to proceed. However, parties indicated a clear preference for resolution of the matter earlier than

BPA proposed. There is other conflicting work during this period at BPA that make beginning the process within 60 days impractical. As a result, the rates schedules will be revised to include such a process that will begin within 120 days of submitting the rates to FERC.

In addition, rather than including a discussion of both the methodology for calculating the Agency Within-year TPP and the Financial Effects due to the trigger event, this proposed public process will include only the Agency Within-year TPP methodology. The need for the public process was designed to address the perceived lack of specificity regarding how BPA would calculate the Agency Within-year TPP and the rancor surrounding the triggering of the SN CRAC. The calculation of the Financial Effects cannot be specified as completely because the time available for the Financial Effects calculation may determine the method of calculation.

Late in the process, certain parties raised issues whether the Surcharge is sufficiently specific to not require a new 7(i) hearing. Part of BPA's calculus in proposing the Surcharge, as with other adjustments, was to avoid increasing base rates to anticipate uncertain events, but rather to cover them through adjustment clauses in the event they occurred. Therefore, in the event customers successfully challenge BPA's ability to trigger and implement the NFB Surcharge without conducting a 7(i) hearing, BPA will recalculate the base rates to maintain the 92.6 percent or the equivalent TPP standard for the remaining years in the rate period.

In its brief on exceptions, WPAG contends BPA did not produce any GRSP provision to memorialize the decision to hold the public process. (WPAG Br. Ex., WP-07-M-81 at 12.)

Contrary to WPAG's argument, BPA did include GRSPs to memorialize the public process. Section II, G. 9 of the GRSPs, Appendix A to this ROD contains GRSP language regarding the Agency Within-year TPP methodology. While the language does not mirror the WPAG proposal, it provides a process to develop the Agency Within-year TPP.

ICNU argues the Draft ROD incorrectly concluded that BPA does not need to conduct a 7(i) to implement the NFB Surcharge. (ICNU Br. Ex. WP-07-M-83 at 1.) They contend that contrary to the conclusion in the Draft ROD, the NFB Surcharge does not contain sufficient specificity to be considered a valid rate. (*Id*. at 2) ICNU notes that the FB and LB CRACs were adopted pursuant to settlements with many of BPA's customers who had an understanding of the way it would operate. The NFB Surcharge on the other hand, was proposed at the end of the current rate proceeding and did not receive a full or comprehensive review. (*Id.*)

ICNU contends that, because the FB and LB CRACs are based upon audited results, they contain sufficient detail. (*Id*.) There are two problems with this conclusion. First there is no direct nexus between using audited results and the sufficiency of the detail in the GRSPs for customers to understand how the adjustment will work. The fact that audited results are used in the calculation does not make the rate adjustment sufficiently detailed. Secondly, neither the FB nor LB CRAC actually used "audited" results for the rate adjustment. The FB CRAC, for example, BPA has traditionally used the internal Third Quarter review numbers plus a forecast for the balance of the year. The Third Quarter review is not "audited financial" data. (There is potential for a true-up, however, based on audited results.) Additionally, the GRSPs do not explain exactly how BPA will do its forecast for the balance of the year. While the FB CRAC does provide the opportunity for a true-up to audited results, the LB CRAC does not contain any similar provision.

The level of detail is sufficient for ICNU and others to understand how the amount will be calculated. It is also worth pointing out that while ICNU contends that the FB and LB CRACs were the product of settlement discussions, so was the NFB Surcharge. BPA held over 40 hours of settlement discussions with ICNU and others to discuss this provision of the GRSPs. In light of the extensive discussions on this provision, it is difficult to understand the level of ICNU's concern.

Decision

It is not necessary for BPA to conduct a hearing under section 7(i) of the Northwest Power Act prior to implementing a rate surcharge pursuant to the NFB Surcharge. However, BPA will initiate a public process within 120 days of the filing of rates with FERC to determine the methodology for calculating the Agency Within-year TPP.

Issue 3

Whether BPA should conduct the section 7(b)(2) rate test prior to increasing rates due to the NFB Adjustment and/or the NFB Surcharge.

Parties' Positions

ICNU contends that BPA cannot legally increase its rates pursuant to the Fish Adjustment (NFB Adjustment and NFB Surcharge) without performing the rate test required by section 7(b)(2) of the Northwest Power Act. (ICNU Br., WP-07-M-72 at 5.) In its brief on exceptions, ICNU challenges the Administrator's draft decision that BPA was not obligated to conduct the 7(b)(2) rate step prior to implementing the NFB Adjustment or Surcharge. (ICNU Br. Ex., WP-07-M-83 at 4.) ICNU believes BPA created an artificial distinction between the base rates and adjustment clauses in order to avoid the 7(b)(2) rate test. (*Id.*)

BPA's Position

BPA conducted the section 7(b)(2) rate test in developing BPA's 2007 wholesale power rates. (Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06; Keep, *et al.*, WP-07-E-BPA-27.) BPA is not required to run the section 7(b)(2) rate test a second time when implementing an adjustment clause such as the NFB Adjustment and Surcharge, which do not revisit BPA's established rates. Doing so would require BPA to prepare all the information needed to develop BPA's base rates, which would subvert the purpose of an adjustment clause.

Evaluation of Positions

The NFB Adjustment is an adjustment to the CRAC Maximum Recovery Amount (Cap) designed to mitigate the potentially large financial impact of court-ordered changes in the operation of the hydro system and with the fish and wildlife program costs. (Normandeau, *et al.*, WP-07-E-BPA-14 at 12-13.) An NFB Adjustment results in an upward adjustment to the annual CRAC Cap for any one year in the rate period. (*Id.*) The NFB Adjustment will not affect rates unless the AMNR is below the CRAC Threshold and the CRAC Amount (before comparison to the CRAC Cap) is greater than $300 million for that year. (*Id.*)

A. The Northwest Power Act

ICNU argues that section 7(b)(2) of the Northwest Power Act is a mandatory requirement in the development of BPA's rates, and BPA should adjust its proposed NFB Adjustment and NFB Surcharge to ensure that BPA will perform a section 7(b)(2) rate test when the adjustments are formalized as rates in the section 7(i) process. (ICNU Br., WP-07-M-72 at 6.) Section 7(b)(2), however, must be understood within the context of section 7 of the Act. Section 7 of the Northwest Power Act contains directives for the development of BPA's wholesale power rates. 16 U.S.C. § 839e. Section 7(b) regards the establishment of "a *rate* or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal Agency customers within the Pacific Northwest …." 16 U.S.C. § 839e(b)(1) (emphasis added). This rate is called the Priority Firm, or PF Preference rate. Section 7(b)(2) is used in the development of this rate ("the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal Agency customers."). 16 U.S.C. § 839e(b)(2). Section 7(b)(2) is discussed at length in Section 10 of this ROD.

Section 7(b)(2) is one of numerous provisions in section 7 of the Act that provides direction in establishing BPA's wholesale power rates. These provisions, or "rate directives," with one exception, do not regard the specific components of the rates, such as demand charges, energy charges, unauthorized increase charges, adjustment clauses, or other components of BPA's rates. The exception is section 7(e) of the Act, which addresses these component parts of BPA's rates. 16 U.S.C. § 839e(e). Section 7(e), as discussed in greater detail below, grants BPA broad discretion in the design of its rates. The other rate directives, however, address the establishment of BPA's base rates, primarily the PF, NR, and IP rates. This is also true of section 7(b)(2), which establishes a rate test. If the rate test triggers, certain costs must be allocated to all BPA power sales other than those to preference customers (except in limited circumstances). The section 7(b)(2) rate test is thus conducted in the establishment of the base PF rate and the other base rates. Section 7(b)(2) does not refer to adjustment clauses.

ICNU's argues that BPA must conduct the section 7(b)(2) rate test when implementing the NFB Adjustment and Surcharge. Section 7(b)(2) is only one of many rate directives contained in section 7 of the Northwest Power Act. 16 U.S.C. § 839e. If BPA were required to conduct the section 7(b)(2) rate test when implementing the NFB Surcharge or NFB Adjustment to the CRAC, then BPA would be required to conduct all of the other rate directives as well. This would require BPA to perform all the work needed to develop new base rates, which would make adjustment clauses ineffective. Some of these rate directives follow.

Section 7(b)(1) of the Northwest Power Act prescribes the allocation of costs to the rates for requirements sales to BPA's preference customers and for REP sales to IOUs. 16 U.S.C. § 839e(b)(1). Section 7(b)(1) of the Act provides:

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal Agency customers within the Pacific Northwest, and loads of electric utilities under section 839c(c) of this title. Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 839c(c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1).

Section 7(c) of the Northwest Power Act establishes rate directives for the establishment of rates for BPA's DSI customers:

> The rate or rates applicable to direct service industrial customers shall be established—
> …
>
> for the period beginning July 1, 1985, 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.
>
> The determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account--
>
> the comparative size and character of the loads served, the relative costs of electric capacity, energy, transmission, and related delivery
>
> facilities provided, and other service provisions, and direct and indirect overhead costs,
>
> all as related to the delivery of power to industrial customers, except that the Administrator's rates during such period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.
>
> The Administrator shall adjust such 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).

Section 7(f) of the Northwest Power Act establishes rate directives for BPA's requirements power sales to BPA's IOU customers and for other firm power sold in the Pacific Northwest:

> 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 839c(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).

Section 7(g) of the Act prescribes the allocation of certain costs and benefits:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, 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 chapter, 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 839d of this title, the cost of credits granted pursuant to section 839d of this title, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g).

Although ICNU argues BPA must conduct the section 7(b)(2) rate test in implementing the NFB Adjustment and Surcharge, section 7(b)(2) is no more or less a part of BPA's statutory rate directives than section 7(b)(1), section 7(c), or section 7(f), *etc.* If BPA must conduct the section 7(b)(2) rate test in implementing the NFB Adjustment and Surcharge, then BPA must implement all of the other rate tests under the statutory rate directives as well. But this makes no sense. The establishment of BPA's base rates is fundamentally different from the establishment or implementation of adjustment clauses. BPA develops its base rates in order to have rates that apply to BPA's power sales to all customers. These rates are developed using all of the rate directives of section 7 of the Northwest Power Act. In implementing the NFB Adjustment and NFB Surcharge, however, BPA is addressing only cost recovery, not cost allocation.

The NFB Adjustment and NFB Surcharge do not develop base rates, but are adjustment clauses. For example, one of the most fundamental rate directives is that BPA will allocate to preference customers' rates the Federal base system (FBS) resource costs needed to supply preference loads until such sales exceed the FBS resources. 16 U.S.C. § 839e(b)(1). Thereafter, the preference rate(s) recovers the cost of additional electric power as needed to supply the preference loads, first from Residential Exchange Program power and then from other resources. (*Id.*) Yet the NFB Adjustment and NFB Surcharge do not address this issue at all. Section 7(b)(1) was implemented in developing BPA's base rates. The same is true for section 7(b)(2). In any event, BPA already conducted the 7(b)(2) rate test when BPA developed its 2007 power rates.

B. BPA's Prior Administrative Practice

There can be little dispute that BPA has the authority to establish adjustment clauses to its base rates. Section 7(e) of the Northwest Power Act provides that "[n]othing 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*." 16 U.S.C. § 839e(e) (emphasis added). The purpose of adjustment clauses is to provide a mechanism for adjusting rates in response to changes in BPA's financial condition more rapidly than would be possible through reestablishing base rates. If BPA had to implement all the section 7 rate directives when establishing or implementing adjustment clauses, BPA would never establish adjustment clauses, but would establish only base rates. This is flatly inconsistent with BPA's ratemaking history. BPA has established and implemented adjustment clauses for its base rates for many years. For example, BPA's 1987 wholesale power rates had a CRAC. (*See* 1987 Wholesale Power and Transmission Rate Schedules.) Also, BPA's 1989 wholesale power rates had a CRAC. (*See* 1989 Wholesale Power and Transmission Rate Schedules.) Also, BPA's 1993 wholesale power rates had an Interim Rate Adjustment (IRA). (*See* 1993 Wholesale Power and Transmission Rate Schedules.) BPA's 2002 power rates had an LB CRAC, an FB CRAC, and a Safety Net (SN) CRAC. (*See* 2002 Wholesale Power and Transmission Rate Schedules.) Implementation of these adjustment clauses did not require a section 7(b)(2) rate test. Parties have never established that BPA lacked authority to develop, or was precluded from developing, adjustment clauses. Indeed, parties have previously advocated adjustment clauses as a means to keep rates low because the adjustment clauses serve as a substitute for the inclusion of higher PNRR in rates.

Review of BPA's historical practices also demonstrates that, since 1985, BPA's longstanding legal interpretation and administrative precedent do *not* require BPA to conduct the section 7(b)(2) rate test in establishing single rates. BPA's historical establishment of adjustment clauses was noted earlier. In addition, in 1986, BPA developed the Variable Industrial Power rate schedule VI-86. *U.S. Dep't of Energy – Bonneville Power Admin*., 36 FERC ¶ 61,142 (1986). In 1986, BPA developed the Southern California Edison Contract Formula rate schedule SC-86. *U.S. Dep't of Energy – Bonneville Power Admin*., 36 FERC ¶ 61,350 (1987). In 1987, BPA developed a Surplus Firm Power rate schedule SL-87. *U.S. Dep't of Energy – Bonneville Power Admin*., 40 FERC ¶ 61,350 (1986). In 1990, BPA developed a Pacific Power & Light Company Capacity Contract Formula rate schedule PPL-90. *U.S. Dep't of Energy – Bonneville Power Admin*., 53 FERC ¶ 61,318 (1990). In 1999, BPA revised the Firm Power Products and Services rate schedule FPS-96R. *U.S. Dep't of Energy – Bonneville Power Admin*., 95 FERC 61,082 (2001). In 2000, BPA amended the WP-96 Unauthorized Increase Charge. *U.S. Dep't of Energy – Bonneville Power Admin*., 94 FERC ¶ 62,084 (2001). On January 15, 2003, FERC approved the PNCA-02 rate. *U.S. Dep't of Energy – Bonneville Power Admin*., 102 FERC ¶ 62,030 (2003). In BPA's WP-02 and SN-03 rate hearings, BPA established and implemented the LB, FB and SN CRACs. *U.S. Dep't of Energy – Bonneville Power Admin*., 104 FERC ¶ 61,093 (2003); *U.S. Dep't of Energy – Bonneville Power Admin*., 107 FERC 61,138 (2004). In all of the foregoing circumstances, BPA did not conduct the section 7(b)(2) rate test when establishing single rates or rate adjustment clauses. BPA's longstanding statutory interpretation and administrative precedent therefore do not require BPA to conduct the section 7(b)(2) rate test except when establishing BPA's base rates.

ICNU argues in its brief on exceptions that the court decisions cited by BPA do not address the specific issue in this proceeding and do not stand for the proposition that BPA can somehow ignore the requirements of the 7(b)(2) rate test. (ICNU Br. Ex., WP-07-M-83 at 6.) First, it is true that the authorities cited by BPA did not involve the NFB Adjustment and Surcharge, because BPA has not previously proposed the NFB Adjustment clause prior to the WP-07 rate proceeding. Such authorities are relevant, however, because they establish BPA's consistent and longstanding interpretation of the Northwest Power Act on the issue of adjustment clauses and section 7(b)(2), and also establish BPA's longstanding and consistent administrative practice. Second, as explained at length in this section, BPA has not ignored the requirements of section 7(b)(2). Section 7(b)(2), however, applies to the establishment of base rates and not to adjustment clauses.

C. Section 7(b)(2) and Base Rates

Section 7(b)(2) of the Act is a rate test that is performed for the development of a new rate "for the combined general requirements of [BPA's] public body, cooperative, and Federal Agency customers," that is, a new PF rate. 16 U.S.C. § 839e(b)(2). Therefore, BPA conducts the Section 7(b)(2) rate test only when BPA is establishing a new PF rate. BPA establishes new PF rates only in general rate cases where BPA establishes its base rates. The NFB Adjustment and NFB Surcharge do not establish a new PF rate. BPA's posted power rates are BPA's PF, NR, and IP rates. The NFB Adjustment and NFB Surcharge are adjustment clauses applied to these rates. A rate can exist without an adjustment clause. An adjustment clause cannot exist without a rate.

ICNU argues that the section 7(b)(2) rate test must be performed on BPA's total rates actually charged to customers, not the merely a portion of its overall rates. (ICNU Br., WP-07-M-72 at 6-7; ICNU Br. Ex., WP-07-M-83 at 5.) ICNU argues that BPA must determine whether "the projected amounts to be charged for firm power for the combined general requirements" of preference customers exceed "the power costs" they would pay if BPA was not required to provide power to certain non-preference customers. (*Id.*) ICNU argues this language requires BPA to perform a section 7(b)(2) rate test for the total power costs of preference customers and prevents BPA from circumventing the final impact of the section 7(b)(2) rate test by separating its power costs into base rates and other charges that will be implemented in the future. (*Id.*) These arguments are not persuasive for a number of reasons.

First, BPA performed a 7(b)(2) rate test in the WP-07 rate proceeding, which in conjunction with BPA's Subscription Step, considered all costs BPA forecasts for the rate period. BPA does not know if it will incur costs that will require the implementation of the NFB Adjustment and NFB Surcharge. Indeed, ICNU admits that "[a]t this time, the Section 7(b)(2) test cannot be applied to a final rate that includes the [NFB Adjustment and NFB Surcharge] because it is unclear whether the [NFB Adjustment and NFB Surcharge] will be used to increase rates, or what the total amount of the new rates would be." (ICNU Br., WP-07-M-72 at 6.) Nevertheless, BPA is required to establish rates that recover BPA's total costs. 16 U.S.C. § 839e(a)(1). BPA therefore developed its base rates using section 7(b)(2) and is using an adjustment clause only to recover specified costs that BPA might incur during the rate period in order to ensure that BPA recovers its total costs through rates.

Second, these arguments ignore other language of section 7(b) of the Act and the legislative history of the Act, as noted above. In addition, these arguments ignore BPA's *Section 7(b)(2) Implementation Methodology*. Although section 7(b)(2) refers to the "projected amounts to be charged" for firm power general requirements sales to BPA's preference customers, and "the power costs" for general requirements of such customers incorporating the five assumptions in section 7(b)(2), these terms are synonymous with rates. The *Section 7(b)(2) Implementation Methodology* prescribes, and BPA has always implemented these directives as referring to, two sets of rates: Program Case rates and 7(b)(2) Case rates:

> The implementation of section 7(b)(2) in any given BPA rate proceeding requires two distinct steps. The first step is to compare a projection of BPA *rates developed under all the provisions of the Northwest Power Act*, but without considering the effects of section 7(b)(2) (the program case), with a projection of BPA *rates* developed under the assumptions outlined in section 7(b)(2) (the 7(b)(2) case). *Both projections are of rates applicable to public body, cooperative, and Federal Agency customers (7(b)(2) customers) and are based on the costs of power required to serve the general requirements of those customers over a five-year period.*
>
> If the projected *rates* in the program case are determined to be higher than those in the 7(b)(2) case, then the second step is required. The *rates* for the 7(b)(2) customers being developed in the BPA rate proceedings must be reduced and the difference allocated to other BPA *rates* pursuant to section 7(b)(3) of the Northwest Power Act. This potential reallocation must be made within the framework of sound ratemaking principles and of BPA's statutory obligations.

(*Implementation Methodology,* Appendix C, at 37; emphasis added).

Furthermore, section II.5 of the *Implementation Methodology* defines the 7(b)(2) Case as "[t]he entire process of projecting *rates* for the relevant five-year period under the provisions of section 7(b)(2) of the Northwest Power Act, including specific data, assumptions, and results." (Emphasis added.) Similarly, section II.6 of the *Implementation Methodology* defines the Program Case as "[t]he entire process of projecting *rates* to be charged in the future under the provisions of the Northwest Power Act other than section 7(b)(2), including specific data, assumptions and results." (Emphasis added.) The section 7(b)(2) rate test must be conducted in the development of base rates. The statute and methodology, however, do not mention adjustment clauses. ICNU implies that because the Northwest Power Act does not refer to base rates or adjustment clauses, Congress intended the 7(b)(2) rate test to apply to total power costs and not base rates. (ICNU Br., WP-07-M-72 at 6-7.) This does not follow. The legislative history of section 7(b) establishes that the 7(b)(2) rate test is for establishing the rate for general requirements service for BPA's preference customers. This is the PF rate, not an adjustment clause. As noted above, section 7(b)(2) is one of many rate directives that BPA must implement when establishing rates. Yet BPA does not implement these rate directives when implementing adjustment clauses. Although ICNU describes the section 7(b)(2) rate test in very general terms, it fails to mention that, in order to conduct the rate test, BPA must prepare all the information needed to develop completely new base rates. This would require the development of new base rates and render adjustment clauses superfluous. In other words, to conduct the test, BPA would have to prepare a complete new general rate case filing as opposed to the much more limited information needed to implement an adjustment clause such as the NFB Adjustment and NFB Surcharge. Because this is so, if BPA had to conduct the section 7(b)(2) rate test in order to implement the NFB Adjustment and NFB Surcharge, BPA would not need to establish the NFB Adjustment and NFB Surcharge and BPA would simply develop completely new rates.

In its brief on exceptions, ICNU argues that contrary to BPA's conclusions, the 7(b)(2) rate test does not apply only to the PF rate. (ICNU Br. Ex., WP-07-M-83 at 5.) ICNU argues that Congress contemplated that the general requirements of preference customers could be met with multiple rates. (*Id.*) ICNU argues the Northwest Power Act does not limit the 7(b)(2) rate test to only a base rate or PF rate, but applies to "rate or *rates*" of general application. (*Id.*) This argument is not persuasive. It is correct that BPA can establish "a rate or rates of general application for electric power sold to meet the general requirements of" preference customers. 16 U.S.C. § 839e(b)(1). All such rates, however, are *base PF rates.* BPA develops multiple PF rates that apply to different products. For example, BPA has established different base PF rates such as the Slice rate, the Full Service Product rate, the Actual Partial Service rate, *etc*. (*See* 2007 Wholesale Power Rates Schedules and GRSPs, WP-07-E-BPA-07 at 11.) All of these PF rates are base rates, not adjustment clauses.

D. Previous Customer Positions

In BPA's 2002 supplemental rate case, BPA developed the LB, FB, and SN CRACs. During the proceeding, a diverse group of parties, comprising nearly all of BPA's customers and four regional utility commissions, filed joint testimony and briefs as the "Joint Customers". (This is not the same group of parties comprising the different "Joint Parties" in the WP-07 rate proceeding). The Joint Customers noted that "[t]he JCG proposal [which was incorporated into BPA's supplemental proposal], including the LB, FB, and SN CRACs and the revised DDC, is an integrated package of risk mitigation tools that should be adopted in its entirety. The integrated package directly addresses the financial risks faced by BPA in the rate period . . ." (WP-02 ROD at 2.1-60 citing JCG Br., WP-02-B-JCG-01 at 2.) The JCG expressly stated that CRACs did not require BPA to conduct the section 7(b)(2) rate test a second time:

> The JCG proposal [which was incorporated into BPA's supplemental proposal] only modifies the operation of the contingent rate adjustment mechanisms, and does not revise the base rates adopted in the May ROD. *These modifications do not require the recalculation of the section 7(b)(2) rate test . . . .*

(*Id.*; emphasis added). The Joint Customers reiterated and expounded upon the reason the section 7(b)(2) rate test need not be conducted in establishing the CRACs:

> CRACs are contingent cost recovery clauses that only go into effect to collect additional revenues if certain circumstances develop. BPA has not suggested in any testimony submitted in this proceeding that the base rates adopted in the May ROD be subject to revision. In the first phase of this proceeding, BPA subjected these base rates to all of the statutory tests it deemed necessary to satisfy the requirements of section 7 of the Regional Act, including the various rate tests contained *in sections 7(b)* and (c) of the Regional Act *[which include the section 7(b)(2) rate test]. And since it is only the contingent cost recovery clauses contained in the GRSPs, and not the base rates contained in the rate schedules, that are being modified in the second phase of this proceeding, there is no legal requirement that these rate tests be performed a second time.*

(*Id.;* emphasis added.) The Joint Customers stated their position yet again:

> Some rate case parties have argued that even though BPA has proposed no changes to the base rates contained in the May 2000 ROD, and has focused on what revisions should be made to these contingent rate adjustment provisions, BPA should nevertheless perform for a second time both the section 7(b)(2) rate test and the section 7(c) floor rate calculations. WP-02-DS-06 at 2-7. This argument is in error.
>
> BPA has from time to time in past rate case included contingent rate adjustment clauses in its rates to cover financial contingencies that could not be adequately dealt with in BPA's base rates. The inclusion of these contingent rate adjustment clauses in the GRSPs has never required a second performance of the section 7(b)(2) rate test . . .
>
> By their very nature, contingent rate adjustment clauses deal with financial events whose timing, magnitude, and consequences are difficult or impossible to accurately forecast. For example, in the first year of the rate period augmentation, cost estimates range from $1.0 to $6.5 billion. WP-02-E-JCG-03 at 19. That is why they are dealt with in contingent clauses and not in base rates. *And for the same reason, attempting to perform the section 7(b)(2) rate test and the section 7(c) floor rate calculation based on the possible operation of these contingencies rate adjustment clauses would be, at best, an exercise in speculation, or at worst an excursion into completely subjective matters.*
>
> The purpose of this second phase of the WP-02 proceeding is to provide BPA with the contingent rate mechanism that it needs to ensure recovery of the revenues needed to fulfill its obligations. *The Regional Act does not require that these contingent rate mechanisms individually be evaluated on the basis of the section 7(b)(2) . . . rate test. Rather, these contingent rate adjustment clauses, when combined with base rates, must demonstrate that BPA can ". . . 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* . . . ." 16 U.S.C. § 839e(a)(1).

(*Id.;* emphasis added.)

The foregoing statements show that BPA's belief that adjustment clauses do not require the implementation of the 7(b)(2) rate test is shared by many BPA customers. ICNU argues that the positions taken by customers in the WP-02 proceeding were made in a "non-precedential settlement" of those issues and ICNU did not join the settlement and cannot be bound by it. (ICNU Br. Ex., WP-07-M-83 at 6.) BPA, however, is not claiming that ICNU is bound by the WP-02 settlement. BPA simply notes that the legal analysis performed by the Joint Parties in the WP-02 proceeding concluded that it was not necessary to conduct the 7(b)(2) rate step when implementing adjustment clauses. This conclusion is consistent with BPA's longstanding legal analysis. In summary, it was not appropriate for BPA to conduct the section 7(b)(2) rate test for the LB, FB, and SN CRACs for the following reasons:

(1) CRACs are contingent cost recovery clauses that only go into effect to collect additional revenues if certain circumstances develop.

(2) In the first phase of the WP-02 proceeding, BPA subjected its base rates to the section 7(b)(2) rate test.

(3) Because it is only the contingent cost recovery clauses contained in the GRSPs, and not the base rates contained in the rate schedules, there is no legal requirement that the section 7(b)(2) rate test be performed a second time.

(4) In the past, BPA has included contingent rate adjustment clauses in its rates to cover financial contingencies that could not be adequately dealt with in BPA's base rates, and these contingent rate adjustment clauses have never required a second performance of the section 7(b)(2) rate test.

(5) The Northwest Power Act does not require that LB, FB, and SN CRACs individually be evaluated on the basis of the section 7(b)(2) rate test; rather, the CRACs, when combined with base rates, must demonstrate that BPA can ". . . 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 . . ." 16 U.S.C. § 839e(a)(1).

(*Id.*) The reasons the section 7(b)(2) rate test was not conducted for the development of BPA's LB, FB, and SN CRACs apply equally to the NFB Adjustment and NFB Surcharge.

ICNU argues that BPA cannot ignore the provisions of the rate test merely because they are cumbersome or inconvenient, or would negate the benefits of adjustment mechanisms. (ICNU Br. Ex., WP-07-M-83 at 6.) ICNU has misunderstood BPA's position. BPA is not claiming that it can ignore the 7(b)(2) rate step. Indeed, BPA conducted the rate step in developing BPA's WP-07 rates. Also, the absence of the rate step when implementing the NFB Adjustment and Surcharge is not simply because it would be burdensome or inconvenient. Instead, BPA pointed out that conducting the rate step when implementing adjustment clauses would preclude BPA's establishment of any adjustment clause because it would require virtually all the work of establishing new base rates, which would render an adjustment clause superfluous. Also, BPA's position is that the rate step is only conducted in the establishment of base rates, not adjustment clauses. As ICNU acknowledges, "BPA's enabling statutes . . . allow it to implement adjustment clauses." (*Id.*) This admission is significant. Every adjustment clause involves the collection of some type of costs. Under ICNU's argument, however, the recovery of *any* costs through an adjustment clause would mean those costs had not been reflected in the 7(b)(2) rate step and *every* adjustment clause would require the rate step or would be unlawful. This, however, is contrary to the broad rate design discretion Congress granted BPA in section 7(e) of the Northwest Power Act and the common industry practice of implementing adjustment clauses.

Finally, ICNU argues that because BPA has not implemented the Fish Adjustments and its final rates for preference customers are unknown, it is unclear whether the Section 7(b)(2) rate test would have different results. (ICNU Br. Ex., WP-07-M-83 at 7.) This argument is not well-founded. The costs recovered by the NFB Adjustment and Surcharge are Federal base system costs. As FBS costs, they are included both in the Program Case and the 7(b)(2) Case when conducting the 7(b)(2) rate test. This means the recovery of such costs would have had no effect on the 7(b)(2) rate step.

Decision

BPA is not required to conduct the section 7(b)(2) rate step when implementing the NFB Adjustment and NFB Surcharge.

Issue 4

Whether the NFB Surcharge should be set to recover to a specific reserve level or TPP target rather than for the Financial Effects defined under the Financial Effects calculation.

Parties' Positions

NWEC/SOS argue that the NFB Surcharge trigger should not be based on BiOp related issues but instead should be based solely on a TPP criterion of 80 percent. (NWEC/SOS Br., WP-07-M-64 at 4-5.) They believe that BPA should not artificially limit the effectiveness of the surcharge to litigation-related events and should base the trigger on any event that causes the Agency Within-year TPP to go below 80 percent. (*Id.*) Further, they suggest that the two restrictions imposed on the Surcharge are contrary to sound business principles. (*Id.*) There is no guarantee that if the Surcharge triggers it will collect enough money to help BPA avoid a Treasury deferral, especially when the financial events leading to the trigging of the Surcharge would likely be caused by other events such as a sharp fall in secondary revenues sales or problems with CGS. (*Id.* at 4.) If the NFB Surcharge was allowed to collect enough to return BPA to the TPP criterion, BPA could safely reduce its reserves significantly because in the event additional revenue was necessary, the Surcharge could be implemented quickly. (*Id.* at 5.) Lastly, NWEC/SOS argue for an end of rate period reserves target $100 million or an 80 percent TPP (whichever is higher) in the last year of the rate period regardless of the Financial Effects due to court ordered changes. (*Id*.)

In their brief on exceptions, NWEC/SOS argue that the NFB Surcharge should not be limited to the financial effects of the trigger event, but rather should include the ability to collect an amount that would ensure an adequate TPP or end of rate period reserve level. (NWEC/SOS Br. Ex., WP-07-M-85 at 5-6). NWEC/SOS is concerned that the trigger event could be caused by a variety of circumstance not just the trigger event. (Id. at 6) NWEC/SOS argues that the failure to account for these other circumstances limits the effectiveness of the NFB Surcharge for no apparent reason or gain. (Id.)

In their brief on exceptions, the Tribes also object to BPA's failure to include a provision in the NFB Surcharge that would maintain the TPP rather than just collecting the revenue shortfall that resulted from a trigger event. (JP13 Br. Ex., WP-07-M-77 at 17.)

BPA's Position

BPA limited the impact of the NFB Surcharge to ESA litigation-related costs specifically related to the FCRPS 2004 BiOp. BPA proposed the NFB Surcharge after NWEC/SOS and the Tribes both argued in their direct testimony that BPA's TPP was overstated due to the delay in recovery of NFB related revenues until the next fiscal year. (Normandeau, *et al*., WP-07-E-BPA-34 at 2-3.) The NFB Surcharge was subsequently modified as the result of joint settlement discussions with parties. The substitute NFB Surcharge GRSPs were placed on the record through Order, WP-07-O-33. BPA has proposed that the Surcharge be limited to the Financial Effects defined as:

> Financial Effects of a Trigger Event are changes within the fiscal year to BPA's finances due to a Trigger Event that affects power sales revenues, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, Corps of Engineers and Bureau of Reclamation Operations and Maintenance expenses, and amortization of capital costs when compared with the estimate of the foregoing costs and obligations in the Final Studies of the WP-07 BPA rate proceeding as modified prior to this Trigger Event. These effects are the total effects on the Federal System including the effects borne directly by Slice Customers. (*Id.* at 4.)

To the extent that additional obligations are placed on BPA that are not related to the 2004 FCRPS 2004 BiOp impact, BPA will manage those risks through the other risk tools that are part of this proposal. (Lovell and Normandeau, WP-07-E-BPA-34 at 4.)

Evaluation of Positions

NWEC/SOS argue that the NFB Surcharge trigger should not be based on BiOp related issues but instead should be based solely on a TPP criterion of 80 percent. (NWEC/SOS Br., WP-07-M-64 at 4-5.) While NWEC/SOS do not provide many specifics about this concept, it is clear that this approach would have the NFB Surcharge collect more than the just FCRPS 2004 BiOp related costs. In its brief on exceptions, NWEC/SOS clarify their position and explain that they believe the NFB Surcharge should not be limited to the financial effects of the trigger event, but rather should include the ability to collect an amount that would ensure an adequate TPP or end of rate period reserve level. (NWEC/SOS Br. Ex., WP-07-M-85 at 5-6). Similarly, the Tribes express concern over the ability to maintain the TPP. NWEC/SOS's argument is analogous to contentions they made in their direct testimony related to the NFB Adjustment. There NWEC/SOS argued for what they called a TK CRAC that covered costs beyond just those related to the FCRPS 2004 BiOp. (Weiss, WP-07-E-JP8-01 at 17) The TK CRAC is functionally similar to the NFB Adjustment and Surcharge, but the TK CRAC is significantly broader in scope. Where the NFB Adjustment and Surcharge cover only FCRPS 2004 BiOp related costs, the TK CRAC was designed to cover a broad array of costs. Conversely, rather than covering a large group of costs with an open-ended tool, BPA has divided its risks into two categories. Risks in the first, and largest, category are modeled explicitly and mitigated sufficiently with BPA's proposed risk treatments (CRAC, PNRR, *etc.*) to meet BPA's 92.6 percent TPP standard. Risks in the second category, comprising ESA litigation risks, are not modeled explicitly, and are mitigated separately (through the NFB Adjustment and Surcharge) to ensure the validity of the TPP measured on the basis of the risks in the first category. BPA did this because potential additional FCRPS 2004 BiOp related cost, are unknown and difficult to estimate.

NWEC/SOS believe that BPA's failure to modify the NFB Surcharge to broaden its application is evidence that BPA is adopting a more "risky mechanism" than necessary. (NWEC/SOS Br. Ex., WP-07-M-85 at 6). NWEC/SOS's contention appears to misunderstand the manner in which BPA has addressed those risks not covered by the NFB Surcharge. Rather than covering these through the NFB Adjustment or Surcharge, BPA has modeled these other risks and is mitigating these through a combination of reserves, PNRR and the CRAC. If BPA were to adopt NWEC/SOS' proposal, without modifying other aspects of its risk package, it would be covering the non-ESA risks twice.

NWEC/SOS and BPA have different approaches to addressing financial risks. While the NWEC/SOS approach is reasonable, adopting the proposal would require BPA to restructure its entire risk package to avoid mitigating some risks twice. Because BPA's approach is equally reasonable and given the lack of specificity with the NWEC/SOS proposal, there is no need to change course at this point.

Decision

The NFB Surcharge will collect only the Financial Effects as defined in the NFB Surcharge GRSPs and will not be designed to recover revenues that result in a specific reserve level or TPP.

Issue 5

Whether the NFB Surcharge should be based on a trigger of 95 percent TPP instead of 80 percent because this fails to meet the 92.6 percent TPP goal.

Parties' Positions

The Tribes argue that BPA has not provided any analysis to support the assertion that an 80 percent NFB Surcharge trigger is adequate when reserves are low. The Tribes attempted to use the ToolKit to model their assumptions that produced Treasury deferrals in FY 2007, 2008 and/or 2009. (JP13 Br., WP-07-M-69 at 43.) The Tribes contend that an 80 percent trigger is significantly below the two-year TPP goal of 95 percent and that a TPP this low puts BPA at substantial risk of deferring payments or cutting costs, including and especially fish and wildlife. (*Id.* at 44.) In their brief on exceptions, the Tribes reiterated their request for a 95 percent TPP standard for triggering the NFB Surcharge. (JP13 Br. Ex., WP-07-M-77 at 23.) The Tribes argue that there are several issues with the proposed Surcharge.

First, BPA will collect only the amount of the additional ESA litigation-related costs. (*See* Lovell and Normandeau, WP-07-E-BPA-34 at A-4.) The Tribes contend that if the goal is to minimize the risk of a Treasury deferral, then BPA should trigger an emergency surcharge for any reason if its ability to repay the Treasury is compromised. (*Id.*)

Second, the Tribes note there may be a delay in when BPA collects the funds. BPA proposes to notify rate case parties two weeks after the trigger event occurs, hold a workshop, and then notify customers of the amount to be collected. (*Id.*) The Tribes are concerned that receipt of the surcharge revenues could be delayed by at least two months and potentially more. (*Id.* at 4-5.)

Finally, the Tribes note that BPA has provided no analysis of how the schedule for implementing the surcharge and limits it has adopted will affect its ability to repay the Treasury after meeting its other costs. (*Id.*)

BPA's Position

BPA has limited the trigger to ESA litigation-related costs in the substitute NFB Surcharge GRSPs to specifically address the FCRPS 2004 BiOp uncertainties. (Lovell and Normandeau, WP-07-E-BPA-34 at 2-3.) The NFB Surcharge GRSPs were modified through joint settlement discussions with parties and the substitute NFB Surcharge GRSPs were placed on the record through order WP-07-O-33. BPA was not proposing a mechanism by which to address other risks to the current fiscal year Treasury payments because BPA had already addressed those risks through the proposed risk mitigation package of reserves (including available liquidity), PNRR and the CRAC (including the NFB Adjustment to the CRAC), as described in the Risk Mitigation Study, WP-07-FS-BPA-04 at 4-7.

BPA is attempting to balance the need to raise additional revenues to meet current-year obligations with the complexity of the within-year adjustment and the possible hardship it will cause in the region. (Lovell and Normandeau, WP-07-E-BPA-34 at 5) The 80 percent level for triggering the Surcharge was viewed as the appropriate balance between three-year TPP standard of 92.6 percent and the criteria in the 2001 Hydro Operations Plan for declaring a financial emergency. (*Id.*)

Evaluation of Positions

The Tribes assert that the primary purpose of the NFB Surcharge is to, "…to minimize the risk of a Treasury deferral." (JP13 Br., WP-07-M-69 at 44.) This objective is more far-reaching than BPA intended for the NFB Surcharge. BPA's objective with the NFB Adjustment and Surcharge was to address the uncertainty associated with the ESA litigation-related costs, and only those costs. (*Id.*) The Surcharge was specifically designed to address the fact that BPA would not receive revenues generated by the NFB Adjustment until the year after BPA experienced the Financial Effects of the Trigger Event. With the NFB Surcharge, if BPA needed the revenues during the current fiscal year, the NFB Surcharge allowed BPA to collect these dollars during the current fiscal year rather than having to wait until the next year. (*Id.*) BPA proposed a narrow definition, because all other risks that the Agency modeled were addressed through other aspects of the proposed risk mitigation package, including cash reserves (and available liquidity), PNRR and the CRAC (including the NFB Adjustment to the CRAC) as described in the Risk Analysis Study, WP-07-FS-BPA-04. Those risks, as modeled, have been mitigated under the proposed risk package and result in a three-year TPP of 92.6 percent.

The Tribes raise concerns that it may take as much as two months to begin collecting revenues through the Surcharge. (JP13 Br., WP-07-M-69 at 44.) This delay will be accounted for in the monthly Surcharge Amount levied on customers to be collected prior to the September 30 Treasury payment. This issue does not have any impact on TPP as long as the revenues are received prior to the Treasury payment at the end of the fiscal year. The following excerpt is from the proposed NFB Surcharge GRSPs describing how the monthly surcharge will be calculated to assure that surcharge revenues are received prior to the end of the fiscal year:

> Each Customer Percentage will be multiplied by the Adjusted Surcharge Amount, and divided by the number of billing months payable before the end of the then current fiscal year to determine each customer's Monthly Surcharge, subject to the limit set forth in subsection E.2 above. The Monthly Surcharge will be added to each customer's bill for each billing month payable before the end of the current fiscal year.

(Order, WP-07-O-33 at 8.)

The Tribes argue that BPA has not provided any analysis that supports that the proposed Surcharge assures repayment of Treasury. (JP13 Br., WP-07-M-69 at 44.) BPA asserts that as long as the full Financial Effects are accounted for within the fiscal year that the costs take place, then there will be no impact on TPP. The TPP will be held neutral for those costs and those costs will not result in BPA missing its next scheduled payment. BPA has not conducted any risk analysis based on this logic. The calculation that is designed to ensure that the Financial Effects are correctly accounted for is the following:

Formula for Calculating the Financial Effects and the Surcharge Amount
The calculation of the Financial Effects will be determined as follows making use of the best information available at the time:

Financial Effects =

Expected Value Modified Net Revenue without Trigger Event

Minus

Expected Value Modified Net Revenue with Trigger Event

Where:

(1) The Expected Value Modified Net Revenue without Trigger Event is BPA's projection of what the Modified Net Revenues would be at the end of the fiscal year assuming the Financial Effects of the Trigger Event did not take place. Such projection will be based on actual generation function revenues and expenses to the extent available and forecasted results for the remainder of the fiscal year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, including BPA's best estimate of 4(h)(10)(C) credits.

(2) The Expected Value Modified Net Revenue with Trigger Event is the identical projection as made in (1) above except that BPA will assume the Financial Effects of the Trigger Event did take place

(*Id.* at 6.)

The Tribes are concerned that BPA may choose to reduce costs prior to triggering the Surcharge. (JP13 Br., WP-07-M-69 at 44.) BPA may, in fact, reduce costs when it does not put its legal and statutory obligations at risk. BPA may also choose to conduct another 7(i) process, if it determines the changes are so significant that a new rate case is necessary.

The 80 percent standard represents the appropriate balance between competing objectives. BPA is attempting to balance between the need to raise additional revenues to meet current-year obligations against the complexity of a within year rate adjustment and the possible hardship it will cause in the region. (Lovell and Normandeau, WP-07-E-BPA-34 at 5) The 80 percent level for triggering the NFB Surcharge was viewed as the appropriate balance between three-year TPP standard of 92.6 percent and the criteria in the 2001 Hydro Operations Plan for declaring a financial emergency. (*Id.*)

Decision

The NFB Surcharge trigger will remain at 80 percent and will collect only for ESA litigation-related costs because BPA's proposed risk mitigation package incorporates the necessary risk mitigation features to assure that BPA is maintaining a 92.6 percent TPP for the three-year rate period.

Issue 6

Whether the proposed NFB Surcharge GRSP language contains provisions that require BPA to cut expenses before triggering the NFB Surcharge.

Parties' Positions

The Tribes argue that the revised NFB Surcharge language further limits the ability to trigger for circumstances that neither BPA nor the parties have envisioned at this time. (JP13 Br., WP 07 M-69 at 46-47.) They contend that the revised NFB Surcharge contains language [regarding expense reductions] that implies that BPA must make cost cuts before calculating the Agency Within-year TPP. (*Id.* at 47) This issue was raised for the first time in brief.

BPA's Position

BPA does not believe the provisions of the NFB Surcharge require it to cut costs prior to triggering the NFB Surcharge. If BPA's financial condition is so dire that if a Trigger Event were to occur then the NFB Surcharge would be implemented, it is reasonable to assume that BPA will concurrently be examining its revenues and expenses. In order to most accurately assess Agency Within-year TPP, the analysis should include all relevant updates to BPA's finances, both positive and negative. This would include, among other things, any expense reductions BPA can reasonably rely upon over the balance of that fiscal year.

Evaluation of Positions

The Tribes argue the revised NFB Surcharge further limits BPA's ability to trigger the NFB Surcharge as compared to the version contained in BPA's rebuttal testimony. (JP13 Br., WP-07-M-69 at 47.) They contend that BPA included language in the revised version to consider "expense reductions and revenue increases" when calculating the Agency Within-year TPP. (*Id.*) The Tribes argue that including this "implies Bonneville will make additional cost reductions, including fish and wildlife, before deciding to trigger a surcharge…" (*Id.*)

The Tribes' arguments are misplaced. The Tribes incorrectly conclude that the provision that requires BPA to consider all "expense reductions and revenue increases" when calculating the Agency Within-year TPP, implies that BPA must slash fish and wildlife expenditures or other costs prior to triggering the NFB Surcharge.

When BPA calculates the Agency Within-year TPP it is taking a financial snapshot at a particular point in time. In order for that analysis to most accurately reflect the Agency's financial outlook for the balance of that fiscal year, it is necessary to consider all relevant factors in order to project its ability to make the end of year payment to Treasury. In that regard, BPA added the following definition to provide some clarity:

> (c) The Agency Within-year TPP is the probability that the Agency (i.e., both Power and Transmission) will be able to meet all Agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurred, and which takes into account for the remainder of such fiscal year: (i) all funds reasonably expected to be available to the Agency to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), funds available from Energy Northwest refinancing under the Debt Optimization Program, and **expense reductions and revenue increases,** and BPA's then current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the WP-07 BPA rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, prepayments to Treasury required or called for by the Debt Optimization Program, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.

(Order, WP-07-O-33 at 4; emphasis added.)

Contrary to the Tribes arguments, the inclusion of the highlighted phrase is not intended to force BPA to cut costs prior to triggering the NFB Surcharge, but rather to include any revenue enhancements or expense reductions, along with all other relevant factors, in the calculation of the Agency Within-year TPP. The intent of the provision is to develop as accurate a picture as possible of BPA's finances. If BPA has reduced expenses in a particular area, it logically follows that BPA should consider this fact when it assesses its ability to make the end-of-year payment to the Treasury.

Decision

The proposed NFB Surcharge GRSP language does not contain provisions that require BPA to cut expenses before triggering the NFB Surcharge. The cited language refers to actions BPA may, but need not, take.

Issue 7

Whether the NFB Surcharge GRSPs should include language that allows the Administrator to adjust the NFB Surcharge or remove it entirely if it is subsequently determined to be unnecessary.

Parties' Positions

The Tribes argue that BPA should not include in the substitute NFB Surcharge GRSPs the ability to adjust the surcharge or remove it entirely if it is subsequently determined to be unnecessary.

(JP13 Br., WP-07-M-69 at 47.) They contend that the language could be interpreted to require BPA to remove the surcharge entirely if the NFB Surcharge is set too high or too low after the updated calculation. (*Id.*) They also believe the substitute language lowers the TPP and limits how much can be collected and makes it unlikely that BPA will be able to make all of its Treasury payments on a current basis after meeting costs. (*Id.* at 48.) This specific issue was raised for the first time in brief.

In their brief on exceptions, the Tribes contend that the language in the draft GRSPs that allows BPA to adjust or remove the NFB Surcharge could be read to require BPA to remove the NFB Surcharge if BPA set the amount too high or low or if BPA did not follow the Agency Within-year TPP methodology. (JP13 Br. Ex., WP-07-M-77 at 18.) This could result in BPA removing the Surcharge even though BPA would be entitled to appropriately assess one. (*Id.*)

BPA's Position

The GRSPs for the NFB Surcharge do not require the Administrator to remove the NFB Surcharge if it is subsequently determined that one or more of the provisions in the GRSPs has been met. The purpose of these provisions was to make sure that in the event that the original calculation was done incorrectly or that changes in BPA's finances since the triggering the NFB Surcharge no longer make all or part of the NFB Surcharge necessary.

Evaluation of Positions

Contrary to the Tribes' argument, the NFB Surcharge GRSPs do not require BPA to remove the NFB Surcharge entirely if the NFB Surcharge is set too high or too low. Rather, the GRSPs give BPA the ability to adjust (or remove, if necessary) the NFB Surcharge if BPA experiences such a dramatic improvement in its financial situation after initially implementing the NFB Surcharge. However, BPA agrees that the language in the GRSPs addressing this point is somewhat ambiguous and could be clearer. Therefore, the language will be modified to eliminate this clause since a refund up to the full amount collected would in effect accomplish the same objective but only if the NFB Surcharge is no longer needed to maintain a TPP of at least 90 percent. This modification addresses the Tribes' concern that BPA could arbitrarily eliminate the NFB Surcharge without meeting the prescribed TPP criteria for doing so.

The GRSPs from the Draft ROD will be modified as follows:

> If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to Customers for the amounts over-collected or adjust the Surcharge then in effect for the remainder of the year, if one or more of the following occur:
>
> (1) the Agency Within-year TPP, not including future surcharge payments, is determined at the time of the close-out letter, using the methodology developed pursuant to subsection E.9, to be greater than 90 percent;

(2) an updated Surcharge calculation results in a change compared to the Surcharge calculated in subsection E.7.

(3) in BPA's initial determination to assess the surcharge, BPA did not follow the Agency Within-year TPP methodology established pursuant to subsection E.9.

The provisions under circumstance (1) allow BPA to, among other choices, modify the NFB Surcharge in the event BPA's TPP has improved dramatically. Because BPA's TPP would be not only above the 80 percent trigger but would have increased to greater than 90 percent, emergency circumstances would no longer be deemed to exist. (*Id.* at A-2(b)(ii).)

The ability to adjust the NFB Surcharge for circumstance (2) is designed to address the potential that the original surcharge amount was incorrect or new information or circumstances has resulted in a modification to the adjustment either upwards or downwards.

The ability to adjust the NFB Surcharge for circumstance (3) is designed to address the issue that BPA failed to follow the established Agency Within-year TPP Methodology. If the updated calculation resulted in an increase in TPP above the trigger level of 80 percent, then one of the required trigger criteria was not met and the Administrator would be obligated to stop the NFB Surcharge and return surcharge revenues to customers.

None of these provisions requires the Administrator to "remove" the Surcharge if it is set too high or too low. Rather, there are specific requirements that constrain the Administrator to a specific set of standards when issuing the close-out letter that allow him to adjust the level of the NFB Surcharge.

The Tribes also fail to explain why reducing the NFB Surcharge, if it is deemed unnecessary makes it unlikely that BPA will be able to make all of its Treasury payments on a current basis after meeting its costs. (JP13 Br., WP-07-M-69 at 48.) If BPA's TPP is above 90 percent, then it is not experiencing a situation where cash is so low that the Agency is at risk of missing a Treasury Payment. This is especially true since the TPP criterion is Agency-based rather than based only on cash available to PBL. Furthermore, this does not mean that BPA will not cover its costs over the long run because the CRAC will capture these costs and recover the revenues in the next fiscal year. If the CRAC does not trigger, it is reasonable to assume that the TPP is at an adequately high level to avoid missing a Treasury payment for that fiscal year.

<u>Decision</u>

The NFB Surcharge GRSPs will include language that allows the Administrator to adjust the surcharge. The language will be written to allow downward modifications without complete removal of the surcharge should such correction be necessary.

6.6 Other Risk Mitigation Proposals

Issue 1

Whether BPA should adopt a mid-year hydro surcharge as part of the risk mitigation package.

Parties' Positions

ICNU argued that BPA should include the mid-year surcharge as one of the liquidity tools to produce the lowest possible rates. (ICNU Br., WP-07-M-72 at 7.) ICNU argues that the mid-year surcharge should be used instead of fish adjustments because ICNU considers that the mid-year surcharge provides BPA with greater financial flexibility because it allows BPA to collect additional revenues when the Agency is facing difficult financial times. (*Id.*) The mid-year surcharge would allow BPA to assess expected secondary revenues in the mid-February timeframe and adjust rates for the next 12-months, if revenues were expected to be $150 million or more below the rate case forecast. (*Id.*) Furthermore, BPA did not correctly model the mid-year surcharge because it ignored potential sources of liquidity associated with Debt Optimization (DOP) and customer prepayments. (*Id.*) ICNU argued that BPA should consider these tools available for the purposes of analyzing the benefit of the mid-year surcharge on rates. (*Id.*) ICNU further describes that a detailed set of specific triggers, details and limitations should be included or a 7(i) process conducted to ensure that BPA implements the rate adjustment correctly. (*Id.* at 8.)

In its brief on exceptions, ICNU reiterates its request for BPA to adopt a mid-year hydro surcharge. ICNU contends that such a surcharge would allow BPA to lower rates. (ICNU Br. Ex., WP-07-M-83 at 7)

BPA's Position

BPA argued in rebuttal testimony that the current Net Billing arrangement largely prevents the mid-year hydro surcharge from providing much benefit unless BPA obtains significant new liquidity tools. (Normandeau, *et al*., WP-07-E-BPA-33 at 22.) If BPA obtained other significant new liquidity tools, it would strengthen the mid-year hydro surcharge. But additional liquidity tools would also benefit BPA's proposal. (*Id.* at 23.) BPA's assessment of the mid-year surcharge compared to BPA's proposal, under scenarios with and without additional liquidity, resulted in higher three-year average rates. (*Id.* at 25.)

BPA also pointed out that there remains a tremendous uncertainty in BPA's revenues for the remaining year because there is still tremendous uncertainty in the value and timing of the runoff of the snow pack for the year. As a result, rates would need to be adjusted through a true-up in October to address the actual financial outcome of the year. This creates added complexity to the analysis as well as rate volatility within a fiscal year. (*Id*. at 23.)

BPA also disagreed with ICNU's assessment that BPA's analysis of the mid-year surcharge was flawed because it did not consider all available liquidity tools. (*Id.* at 24.) BPA described the requirements in policy testimony that it would only include liquidity tools that have a reasonable assurance of being available at the time of the Final Studies. (Leathley, *et al*., WP-07-E-BPA-08 at 14-15.)

<u>Evaluation of Positions</u>

BPA's original argument that the mid-year hydro surcharge revenues were lost to net billing is no longer valid. Since the filing of rebuttal testimony, BPA obtained a Letter Ruling from the IRS that has allowed BPA to secure Direct Pay agreements with EN allowing for BPA to change the shape of revenue collection. (*See* discussion in Section 6.2.) While the limitation presented by the Net Billing of EN operating debt service expenses has been removed, the proposal still has serious flaws. BPA's assessment of the mid-year surcharge compared to the CRAC shows that there is greater rate benefit to BPA's CRAC when compared to ICNU's mid-year surcharge under Direct Pay. (Normandeau, *et al*., WP-07-E-BPA-33, Attachment A.)

ICNU has attempted to fashion their proposal as a liquidity tool rather than a risk mitigation mechanism. This is both incorrect and misleading. The mid-year surcharge is not related to BPA's recent efforts to increase liquidity. In fact, ICNU is proposing a complex risk mitigation tool that would require immense staff time and resources if BPA were to adopt ICNU's proposal. There remain numerous questions as to how the methodology would be developed to satisfy parties' needs for a detailed, specific methodology, including controls and limitations as to how BPA would implement and calculate the surcharge or conduct a 7(i). If BPA's experience in the development of the NFB Surcharge in this rate case is an indicator of the detail that parties seek in the effort to fully understand how a risk mechanism is triggered, calculated and implemented, then any attempt by BPA to provide at this late date would likely be met with mistrust. The 7(i) option offers no better of a solution since it would lengthen both the time and resources necessary to implement the proposed surcharge.

ICNU also argues that the mid-year surcharge could replace the NFB Adjustment. This argument ignores the potential increase from direct programs that could result from Trigger Event. The mid-year surcharge would affect only the operational portion of any court-related decision and would not address any of the program-related costs and for that matter any other cost increases that BPA might experience in the next rate period. As a result it cannot replace the NFB Adjustment because it does not sufficiently address the expense risks of potential court-related decisions.

ICNU reiterated its request for a mid-year hydro surcharge in its brief on exceptions. While there is some disagreement over the relative value of the mid-year hydro surcharge, it is difficult to reconcile ICNU's advocacy of this risk tool with its objection to the NFB Surcharge. With the NFB Surcharge, ICNU has repeatedly argued BPA must conduct a 7(i) hearing before implementing the NFB surcharge. (*See* Section 17.3 for discussion of this issue.) BPA disagrees with the need to conduct a 7(i) hearing before implementing the NFB Surcharge. Further, ICNU's position on this point cannot be reconciled with its position on the mid-year hydro surcharge.

ICNU argues the NFB Surcharge does not provide sufficient detail for a customer to understand how BPA is going to calculate the amount. Not only does BPA disagree with ICNU on this point, but ICNU has not provided any proposed language from which BPA or the customers would have any understanding of how this mid-year hydro surcharge would be determined and allocated among customers. Whereas BPA did provide in a GRSP format the basic calculations and processes for which the NFB Surcharge would be conducted, ICNU has provided no formulas or process description. Also, there is no common understanding between BPA and the parties in this rate case about how BPA would calculate a mid-year hydro surcharge.

Decision

BPA will not include a mid-year hydro surcharge mechanism in the risk mitigation package due to the complexity of implementing the mechanism with the current risk package and the lack of clarity in how this risk mitigation mechanism would work.

Issue 2

Whether BPA should consider the real-time secondary revenue credit in a future rate proceeding.

Parties' Positions

NRU does not support the real time secondary revenue credit proposed by WPAG in this rate case but would consider this a possible design in future rates after additional consultation with customers. (NRU Br., WP-07-M-NR-61 at 9.)

In its brief on exceptions, NRU expresses its concern, but not its opposition, with a real-time secondary revenue credit. (NRU Br. Ex., WP-07-M-76 at 4.) NRU's strong recommendation is for BPA to undertake workshops and consultations with customers and interested parties to explore the feasibility of a real-time revenue credit prior to it being proposed in future initial proposals. (*Id*.)

BPA's Position

BPA recognized the potential of a secondary revenue credit proposal in rebuttal testimony, agreeing that potential exists for this option in future rate cases. (Normandeau, *et al*., WP-07-E-BPA-33 at 26.)

Evaluation of Positions

No one is proposing this issue be addressed in this rate proceeding. BPA is encouraged by this proposal since we agree that, if it were implemented correctly, it would mitigate the single largest uncertainty that BPA currently faces. This design would produce a lower effective rate than the Initial Proposal but would do so at the expense of a higher posted rate and potentially more rate volatility. A real-time secondary revenue credit is a proposal that may be feasible in a future rate proceeding.

Decision

BPA may consider a real-time secondary revenue credit in a future rate proceeding and will conduct workshops to explore the feasibility of a real-time revenue credit prior to proposing it in future initial proposals.

Issue 3

Whether BPA violated section 7(n) of the Northwest Power Act by failing to properly analyze the impact of recovery of fish and wildlife costs.

Parties' Positions

NWEC/SOS argue in their brief on exceptions that BPA violated the provisions of section 7(n) of the Northwest Power Act. (NWEC/SOS Br. Ex., WP-07-M-85 at 3) NWEC/SOS contend that the section requires the Administrator to set rates which maintain its TPP standard during the FY 2007-2009 rate period. (*Id.*) NWEC/SOS maintain that BPA's proposal ignores the provisions of 7(n). (*Id*. at 5)

BPA's Position

This issue was not raised previously. BPA has not violated section 7(n) and has met its application to establishing the proposed rates. BPA's rates are being set to recover costs for the FY2007-2009 rate period.

Evaluation of Positions

NWEC/SOS contend that BPA must comply with the provisions of section 7(n) of the NPA. (NWEC/SOS Br. Ex., WP-07-M-85 at 3.) The apparent concern is that BPA is setting rates to pay the Treasury only in full and on time during the rate period. (*Id.*) They contend that 7(n) requires BPA to additionally establish sufficient ending reserve levels so as to maintain a high TPP in the subsequent rate period. (*Id*. at 3-4.)

NWEC/SOS is simply wrong in its assertion that BPA violated section 7(n). Contrary to NWEC/SOS contention, BPA has not violated subsection 7(n) of the Northwest Power Act, which reads as follows:

> Notwithstanding any other provision in this section, rates established by the Administrator under this section shall recover costs for protection, mitigation and enhancement of fish and wildlife, whether under the Pacific Northwest Electric Power Planning and Conservation Act or any other Act, *not to exceed such amounts the Administrator forecasts will be expended during the fiscal year 2002-2006 rate period,* while preserving the Administrator's ability to establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period.

See 2000 Energy and Water Development Appropriations Act, HR 2605 ENR, P.L. 106-60 (emphasis added).

Subsection 7(n) refers to BPA rate-setting for FY 2002-2006 and was limited in its application to the establishment of BPA's WP-02 firm power rates. Consequently, subsection 7(n) is not applicable to setting rates post-2006. Of particular importance, subsection 7(n) was intended to preserve the Administrator's flexibility to build and maintain financial reserves to position BPA to achieve a high confidence level for recovering costs post-2006. As the record demonstrates, BPA is establishing rates to achieve a three-year TPP of 92.6 percent (*See* Risk Analysis Study, WP-07-FS-BPA-04). This equivalent to the five-year 88 percent TPP achieved in the WP-02 rate case (*See* 2002 Final Power Rate Proposal, WP-02-A-02.), which first addressed section 7(n) of the Northwest Power Act. BPA's rates also include specific adjustments—the NFB Adjustment and NFB Surcharge—which specifically apply to recover costs related to fish and wildlife. Therefore, as the record demonstrates, BPA is positioned to achieve a high confidence level for recovering costs during the FY 2007 -2009 rate period, including the impact of recovering of fish and wildlife costs. In addition, BPA is forecasting $823 million of ending rate period power reserves, which is an appropriate level of ending reserves to begin the next rate period.

Decision

BPA did not violate section 7(n) of the Northwest Power Act.

7.0 TRANSMISSION AND INTER-BUSINESS LINE ISSUES

7.1 Introduction

Transmission and inter-business line issues in this rate case include the revenue forecasts for the allocation of generation inputs for the sale of Ancillary Services to the TBL, a segmentation analysis for COE and Reclamation transmission facilities and generation integration costs, and a GTA Delivery Charge. Other transmission expenses issues were included in the PFR and are reflected in the revenue requirement.

The Initial Proposal for generation inputs for Ancillary Services included GSR, Operating Reserves, Regulating Reserves, Energy and Generation Imbalance, Generation Dropping, and Station Service. (Bermejo, *et al*., WP-07- E-BPA-20.) In general, these proposed revenue forecasts for the sale of generation inputs used the same methodologies as were used in the WP-02 rate case. No parties raised issues regarding any of these forecasts in their testimony or briefs.

There was a strong protest by some parties to BPA's proposal for an ORC that would have credited the revenues received for Operating Reserves from TBL to public utility customers that purchased Operating Reserves from TBL. (Bolden, *et al*., WP-07-E-BPA-13 at 14-20.) This issue was resolved in the Partial Resolution of Issues that resulted in some modifications to the Operating Reserves generation input contained in the Initial Proposal. This issue and the modification are explained in more detail in Section 7.3.

During the rate case, BPA issued a Supplemental Proposal for the generation input GSR, based on a recent FERC order and internal BPA discussions. The Supplemental Proposal retained the Initial Proposal generation input forecast for FY 2007, but made a significant modification for FY 2008-2009. (Bermejo, *et al*., WP-07-E-BPA-28; Supplemental Study Reactive Power, WP-07-E-BPA-29(E1).) The Supplemental Proposal and the issues raised by parties regarding the Supplemental Proposal are described in Section 7.2.

The segmentation analysis for COE and Reclamation transmission facilities and generation integration costs allocates generation integration costs related to BPA-owned facilities to the generation revenue requirement. It also removed costs associated with transmission and distribution facilities owned by COE and Reclamation from the generation revenue requirement, as these are properly included in the transmission revenue requirement. (Berdahl, *et al*., WP-07-E-BPA-21.) No parties raised issues related to this segmentation analysis.

The GTA Delivery Charge is a PBL rate for deliveries of power made over third-party transmission systems at low voltages. This rate was set to continue to mirror the TBL Delivery Charge which extends through the end of FY 2007. TBL will set a Delivery Charge in the upcoming TBL rate case for FY 2008-2009. Accordingly, the GTA Delivery Charge will adjust to be consistent with any change in the TBL Delivery Charge resulting from the next TBL rate case. (Pompel and Wiley, WP-07-E-BPA-22.) No parties raised issues related to the GTA Delivery Charge.

WPAG raised an additional issue in its initial brief, suggesting that the NFB Adjustment should apply to generation input costs so that transmission customers pay their share of Endangered ESA costs covered by the NFB Adjustment. (WPAG Br., WP-07-M-68 at 14-15.) This issue is discussed in more detail in Section 7.4.

7.2 Supplemental Proposal for Reactive Power

7.2.1 Introduction

In the Initial Proposal, PBL forecast inter-business line revenues based on the assumption that TBL would continue compensating PBL for GSR inside the band. This forecast applied the FERC-approved *AEP* methodology (*American Elec. Power Serv. Corp.*, 88 FERC ¶ 61,141 at 61,457 (1999)) to allocate a portion of certain generation plant costs to inside the band GSR and included other costs associated with GSR. (Bermejo, *et al.*, WP-07-E-BPA-20 at 2-10.) This was consistent with the approach taken in the last rate case and resulted in a revenue forecast of $24.9 million a year associated with providing GSR inputs to TBL. (*Id.*) The dollar amounts described in this section were those contained in the Supplemental Proposal. These dollar amounts have been modified in the Final Studies.

In Order 2003-A, FERC recognized that non-affiliate generators are not entitled to compensation for GSR inside the band unless the transmission provider is compensating its own generators for GSR inside the band. FERCSR ¶ 31,160, Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-A at Paragraph (P.). 416 and 31,153 (2004). Since the issuance of Order 2003-A, four non-affiliate generators in BPA's control area have filed for GSR rates for seven different generators. Based on settlements that lock in the rate methodology until October 1, 2007, TBL is currently paying these four non-affiliate generators approximately $7.6 million a year. TransAlta Settlement, *TransAlta Centralia Generation L.L.C.*, 111 FERC ¶ 61,087 (2005); *see also* FERC Docket No. ER05-1518. These TBL costs are combined with the GSR generation input cost from PBL and TBL recovers such costs under Schedule 2 of its Open Access Transmission Tariff (OATT).

A FERC opinion issued in October 2005, provided a declaratory order to Entergy stating that by discontinuing payments to its affiliate for GSR inside the band, Entergy would be relieved of its obligation to compensate non-affiliate generators. *Entergy Services Inc.*, 113 FERC ¶ 61,040 at P. 22. Based on this opinion and BPA concerns that more non-affiliate generators may file for GSR rates, BPA decided to change its Initial Proposal. In the Supplemental Proposal, PBL reduced the forecast for GSR compensation from TBL from $24.9 million to $4.464 million for FY 2008-2009. (Bermejo, *et al.*, WP-07-E-BPA-28 at 3.)

For FY 2007, the forecast for GSR revenues would continue to be $24.9 million, consistent with the Initial Proposal. (*Id.*) The $20.4 million that was removed from the Initial Proposal for FY 2008-2009 is the amount associated with compensation for inside the band GSR and losses. (*Id.* at 2-3.) The remaining $4.464 million represents payments for synchronous condensing, which is distinct from inside the band operations and is primarily based on the power consumed by synchronous condensing operations. (*Id.* at 3-4; Bermejo, *et al.*, WP-07-E-BPA-20 at 8-9.)

The impact on power rates from this revised revenue forecast, for inside the band GSR, was limited by assuming that a new outside the band compensation methodology would be in place for FY 2008-2009. Therefore, the revenue forecast for both inside and outside the band GSR was calculated by assuming that PBL would receive between $4.464 million and $20 million, or $12.5 million in expected value, for revenues associated with GSR inputs in FY 2008-2009. (*Id.* at 8-9.) The $20 million was used for purposes of forecasting this expected revenue and was not meant to be a cap on any outside the band methodology proposed in the future. (*Id.* at 10.) This forecast resulted in an increase to the PF rate of 0.18 mills as compared to the Initial Proposal. This change also resulted in a slight increase in the revenue forecast for Regulating Reserves and Operating Reserves because the GSR forecast is deducted from the revenue requirement used in the embedded cost methodology for forecasting Operating Reserves and Regulating Reserves revenues. (*Id*. at 8-9.)

The decision being made in this PBL rate case is whether or not to eliminate revenue from inside the band GSR from PBL's forecast of inter-business line allocations for FY 2008-2009. The rate for the ancillary service GSR for FY 2008-2009 will be established in the next TBL rate case, and the mechanism for discontinuing GSR payments to non-affiliate generators will be through separate filings at FERC, under Section 206 of the Federal Power Act.

The Supplemental Proposal described the rationale for changing the revenue forecast as being the first necessary step to allow TBL to file at FERC to avoid future GSR payments to non-affiliate generators after the provision locking in the rate methodology in the TransAlta Settlement expires. (*Id.* at 7; *see* Bermejo, *et al*., WP-07-E-BPA-38 at 2.) The Supplemental Proposal also describes the rate impacts this change would have on various customer groups. This analysis showed that, as compared to the current level of GSR payments, the Supplemental Proposal would have a negative $6 million impact per year on preference customer's cost of delivered power, but would have a $1 million benefit per year to regional ratepayers. It also projected that if the current non-affiliate generators with GSR rates file for adjustments in 2008, the negative impact of the Supplemental Proposal on preference customers shrinks to $3 million a year, and the benefit to regional ratepayers increases to $4.4 million per year. If a few more non-affiliate generators were to file rates, the Supplemental Proposal to not pay PBL would become a benefit to preference customers. (*Id.* at 6-7; *see* Supplemental Study Reactive Power, WP-07-E-BPA-29(E1), Section 2, Table 1.)

Initially, no non-affiliate generators with filed GSR rates intervened in the WP-07 power rate case. Therefore, in the motion to submit the Supplemental Proposal, PBL requested that interested parties be given another opportunity to intervene, and BPA posted notices and contacted potentially interested entities to ensure that all regional entities were aware of the Supplemental Proposal and the opportunity to intervene. (Motion to Amend Order Establishing Schedule, WP-07-M-15.) The non-affiliate generators that intervened in the supplemental proceeding were TransAlta, Calpine, PPM, and the Northwest Independent Power Producers Coalition (collectively, the IPPs).

Issue 1

Whether BPA has misinterpreted the Entergy Services *decision, other FERC precedents, and BPA statutes with regard to the treatment of costs formerly associated with the allocation of generation plant costs to TBL for inside the band GSR being collected in power rates under the Supplemental Proposal.*

Parties' Position

The IPPs claim that FERC's *Entergy Services* order does not apply to BPA's Supplemental Proposal because BPA has stated that it will continue to receive compensation for GSR costs in its power rates. (JP15 Br., WP-07-M-71 at 9-11; JP15 Br. Ex., WP-07-M-80 at 4.) This issue was raised by independent generators that intervened in the *Entergy Services* case when they claimed that Entergy was still collecting GSR costs through its retail power rates. FERC declined to address this issue because FERC does not have jurisdiction over Entergy's retail rates. *Entergy Services* at P. 18, n. 17. (*See* JP15 Br., WP-07-M-71 at 9.) The IPPs argue that since BPA has admitted it is still receiving compensation for GSR costs through its power rates, the principle of comparability requires BPA to continue compensating non-affiliate generators for GSR, and BPA's Supplemental Proposal is "just an accounting gimmick." (JP15 Br., WP-07-M-71 at 10-11.) In their brief on exceptions, the IPPs also claim that BPA has misinterpreted FERC precedent under Order 2003. The IPPs contend that since BPA receives compensation for synchronous condensing through transmission rates and the rest of the GSR compensation will be collected through power rates, FERC's comparability requirements require BPA to continue to compensate non-affiliate generators. (JP15 Br. Ex., WP-07-M-80 at 4.)

BPA's Position

In the Supplemental Proposal, BPA forecast expected revenues from providing inside the band GSR as a generation input to the TBL. For FY 2007, consistent with FERC precedent through applying the *AEP* methodology, BPA allocated a portion of its electrical plant and other related generation costs to inside the band GSR. (Bermejo, *et al*., WP-07-E-BPA-20 at 4-5.) Based on FERC's Order 2003-A and the *Entergy Services* order, BPA believes that after FY 2007 no generators should be compensated for inside the band GSR and thus in the Supplemental Proposal, BPA forecast no revenues from inside the band GSR for FY 2008-2009. (Bermejo, *et al*., WP-07-E-BPA-28 at 3.) Because the *AEP* methodology is an embedded cost methodology and BPA is required by statute to collect all its costs in its rates, this reduction in cost allocation to generation inputs will cause an increase in power rates. Northwest Power Act, 16 U.S.C. §839e(a)(1). (S*ee* Bermejo, *et al*., WP-07-E-BPA-38 at 2.)

BPA does not believe this is an "accounting gimmick" because the costs at issue are generation costs that must be recovered. In the *Entergy Services* order, FERC focused on compensation under Schedule 2, which is the ancillary service GSR rate set by the transmission provider. *Entergy Services* at P. 24. By forecasting no revenues from allocating GSR inside the band costs to TBL that would be collected through TBL's Schedule 2 rate, BPA will not be charging transmission customers for GSR inside the band. BPA believes that this meets the requirements of comparability and is consistent with FERC precedent as determined in Order 2003, Order 2003-A, and the *Entergy Services* order.

<u>Evaluation of Positions</u>

The IPPs mischaracterized the costs that are allocated to inside the band GSR by the *AEP* methodology as being only GSR costs. The *AEP* methodology is simply a mechanism for allocating some portion of generation costs to inside the band GSR based on the generator's power factor rating. (Bermejo, *et al*., WP-07-E-BPA-20 at 4-8.) These costs are associated with electrical components at the generating facilities that provide both real and reactive power. (*Id.* at 5.) These electric components are essential parts of the generating facility and the cost associated with these components is part of the power revenue requirement. None of these costs are associated with electric components that produce only GSR. (*Id*. at 5.) On the other hand, synchronous condensing costs are incurred exclusively for the purpose of producing GSR and are appropriately collected through transmission rates. (Bermejo, *et al*., WP-07-E-BPA-20 at 8-9.)

In Order 2003, FERC stated that an interconnected generator "should not be compensated for reactive power when operating its Generating Facility within the established power factor range, since it is only meeting its obligation." FERCSR ¶ 31,146, Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003 at P. 546 (2003). FERC did not state that these costs cannot be recovered through power rates and since FERC did hold that GSR operation inside the band is an obligation of the generator, it is reasonable to recover generation obligation costs in power rates.

The independent generators involved in the *Entergy Services* case did raise the issue by claiming that Entergy is compensating its affiliates for reactive capability through its retail rates rather than Schedule 2 of its OATT. *Entergy Services* at P. 18. FERC did not address this issue, but stated in a footnote that "[t]o the extent that protestors raise concerns about Entergy's bundled retail rates, those concerns are merely unsubstantiated allegations, and those rates are beyond the scope of this proceeding." *Entergy Services* at n. 17. The IPPs' claim that the *Entergy Services* order does not apply to BPA because BPA has admitted on the record that not allocating inside the band GSR to inter-business line revenues will increase power rates. (JP15 Br., WP-07-M-71 at 9-11.) In *Entergy Services*, FERC declined to address this issue because Entergy's retail rates are not subject to FERC jurisdiction; however, by declining to address the issue, FERC did not indicate that there is any merit in the argument.

When BPA files at FERC to extinguish the GSR rates of the IPPs, FERC may consider this issue. However, FERC should not find that because BPA's power rates are affected by BPA forecasting less revenue from inter-business line allocations, the IPPs are entitled to compensation for inside the band GSR. In Order 2003, FERC stated that generators should not be compensated for inside the band GSR, and then in Order 2003-A, FERC recognized an exception to this rule, if the transmission provider is compensating its affiliate for inside the band GSR. Order 2003-A at P. 416. The *Entergy Services* case interpreted this exception and recognized that if Entergy was not including the cost of its own generator's inside the band GSR in its Schedule 2 rate, it need not compensate non-affiliate generators for this service.

Entergy Services at P. 22-24. The IPPs' contention that the increase in power rates reflects continued compensation for GSR ignores general rate making principles and misconstrues FERC's holdings in Order 2003-A and *Entergy Services*. Also, the fact that BPA will continue to allocate synchronous condenser costs to transmission rates is consistent with Order 2003-A, *Entergy Services*, and FERC's comparability requirements because synchronous condensing costs reflect actual power consumed to provide GSR and are not associated with inside the band GSR. (Bermejo, *et al*., WP-07-E-BPA-20 at 8-9.)

FERC's determination should focus only on whether the transmission provider is compensating its affiliated generators for inside the band GSR that is collected through the transmission provider's Schedule 2 rate. As FERC stated in Order 2003, all generators are obligated to provide inside the band GSR. Order 2003 at P. 546. Under the *AEP* methodology, some portion of the generators' costs can be attributed to inside the band GSR, but FERC has never required transmission providers to allocate these generation costs to their transmission functions for inclusion in their Schedule 2 rates. Rather, this has always been treated as an option. The IPPs' witness testified in cross-examination that FERC does not require transmission providers to include generation costs in their Schedule 2 rate, in particular PacifiCorp does not include these costs in its Schedule 2 rate, and including generation plant costs in the Schedule 2 rate is left to the discretion of the transmission provider. (Cross-Ex Tr. at page 94, line 17 through page 95, line 3.)

Just as other transmission providers have either chosen to not allocate a portion of their generation cost to inside the band GSR or in the case of Entergy, have decided to change this cost allocation to avoid the exception in Order 2003-A, it is reasonable for BPA to decide to not allocate a portion of its generation cost to inside the band GSR for FY 2008-2009. Other transmission providers are subject to the FERC comparability principles and FERC has not required them to demonstrate that they do not receive compensation for a portion of their generation plant. The comparability principle should be applied to the costs included in Schedule 2 of the OATT. In BPA's Supplemental Proposal, costs of inside the band GSR were be included in the inter-business line allocation and thus will be included as a cost component of Schedule 2 in FY 2007. (Bermejo, *et al*., WP-07-E-BPA-28 at 7.) At the same time, BPA will continue to compensate the IPPs for inside the band GSR at their FERC filed rates. For FY 2008-2009, BPA does not intend to include any costs associated with providing inside the band GSR in its Schedule 2 rate. This is comparable treatment for all generators.

BPA is required by statute to recover its cost, and if the forecast for inter-business line generation inputs is reduced due to the decision to not allocate costs associated with inside the band GSR, this must be reflected in power rates. (Bermejo, *et al*., WP-07-E-BPA-38 at 2-3.) For purposes of forecasting the inter-business line revenues, it is reasonable to assume that FERC will find that not including an allocation for inside the band GSR does not violate the comparability principle.

BPA is required by statute to recover its costs and choosing to not allocate certain generation costs to TBL is not a violation of the comparability principle, and it is not an "accounting gimmick."

Decision

BPA has not misinterpreted FERC precedent, FERC's Entergy Service*s order or BPA statutes with regard to the treatment of generation plant costs.*

Issue 2

Whether Section 211A of the Energy Policy Act of 2005 (EPA '05) precludes BPA from forecasting zero revenues from the allocation of inside the band GSR for FY 2008-2009.

Parties' Position

The IPPs contend that EPA '05 made comparability mandatory and precludes BPA from terminating payments to them for inside the band GSR. (JP15 Br., WP-07-M-71 at 11-12.)

BPA's Position

BPA is not terminating payments to the IPPs in this rate case. In addition, under FERC precedent, a transmission provider need not compensate non-affiliate generators for inside the band GSR if it does not compensate its own generators.

Evaluation of Positions

In this rate case BPA is forecasting the allocation of generation inputs based on reasonable assumptions. (Bermejo, *et al*., WP-07-E-BPA-38 at 2.) It established power rates assuming no allocation to TBL for inside the band GSR in FY 2008-2009. It is not terminating payments to IPPs in this proceeding. This rate case is merely reflecting a forecast of payment based upon a proposed change to TBL practices. In addition, under comparability principles a transmission provider need not compensate non-affiliate generators for inside the band GSR as long as it does not compensate its own generators. Therefore, as long as BPA eliminates all payment for inside the band GSR, it will satisfy comparability. Order 2003-A at P. 416 and 31,153; *Entergy Services* at P. 22-24. Finally, nothing in Section 211A of EPA '05 precludes BPA from changing a rate or revising a revenue forecast.

Decision

Section 211A of EPA '05 does not preclude BPA from forecasting zero revenues from the allocation of inside the band GSR for FY 2009-2009.

Issue 3

Whether BPA is engaging in undue discrimination as defined by the Federal Power Act Section 211A and 212(i) if it eliminates inside the band payments to all generators, but continues to forecast revenues associated with synchronous condensers.

Parties' Position

The IPPs state that the value of reactive power does not vary depending on whether it is produced by synchronous condensers or generating units and BPA is only making this distinction in order to be able to continue collecting synchronous condenser cost when it is not paying non-affiliate generators for GSR. The IPPs contend that this is undue discrimination prohibited by the Federal Power Act Sections 211A and 212(i). (JP15 Br., WP-07-M-71 at 12; JP15 Br. Ex., WP-07-M-80 at 5.) The IPPs state in their brief on exceptions that continuing to pay Federal generators for synchronous condensing while BPA is trying to avoid paying non-affiliate generators for GSR "is nothing more than the arbitrary way in which BPA has decided to recover its own GSR costs." (JP15 Br. Ex., WP-07-M-80 at 5.)

BPA's Position

Synchronous condenser operations are unique to some Federal generators and these operations are distinct from providing inside the band GSR. The costs of these operations are not taken into account in the *AEP* methodology and these operations absorb a significant amount of power. (Bermejo, *et al*., WP-07-E-BPA-20 at 8-9; Bermejo, *et al*., WP-07-E-BPA-28 at 3-4.) Continuing to forecast the inclusion of synchronous condenser costs in the revenues from inter-business line allocations for FY 2008-2009 is not undue discrimination.

Evaluation of Positions

In order to maintain reliability under certain conditions, the transmission operator needs reactive support from generators that would not otherwise be operating due to spill or fish conditions. (Bermejo, *et al*., WP-07-E-BPA-20 at 8-9.) For these purposes some of the Federal hydro units have been modified so that they can be dewatered and run as a motor. This has the effect of producing reactive support, but instead of producing real power these units are consuming real power. (*Id.*) The revenue forecast for synchronous condenser costs include the cost of modifying some of these generation units and the cost of the power consumed by the synchronous condensers. (*Id.* at 9.)

These operations are distinct from any service provided by other generators. Furthermore, in the WP-02 rate case, BPA included synchronous condenser cost as a separate cost allocation from those costs allocated using the *AEP* methodology. The Supplemental Proposal removes costs associated with inside the band GSR revenue from the forecast for FY 2008-2009. Since synchronous condensers are not part of the inside the band provision of GSR, these costs should not be removed from the FY 2008-2009 revenue forecast. Non-affiliate generators are not capable of operating as synchronous condensers and the transmission provider can not call on non-affiliate generators to provide this service. Therefore, it is not undue discrimination to continue compensating PBL for this service while attempting to not compensate non-affiliate generators for inside the band GSR. In Order 2003, FERC recognized that generators should be compensated when the transmission provider asks them to operate outside the established range. Order 2003 at P. 546. When generators are asked to operate as synchronous condensers, they are not even being operated as generators and real power is consumed rather than produced;

therefore, compensation for these operations is reasonable and is not an arbitrary way for BPA to allocate certain costs associated with GSR.

Decision

Forecasting revenues from synchronous condensers while attempting to avoid paying non-affiliate generators for inside the band GSR is not undue discrimination, and the cost of synchronous condensing is appropriately included in the revenue forecast for FY 2008-2009.

Issue 4

Whether the Supplemental Proposal violates the equitable allocation requirement of Section 7(a)(2)(C) of the Northwest Power Act by creating a cross-subsidization of transmission rates in power rates.

Parties' Position

The IPPs state that the Supplemental Proposal will shift $20.4 million of identified GSR costs to power rates. (JP15 Br., WP-07-M-71 at 13-14.) They point out that FERC Order 888-A conclusively determined that GSR must be offered as a discrete ancillary service. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997). The IPPs go on to claim that removing the $20.4 million in identified GSR cost from the forecast inter-business line allocation is a cross-subsidization of TBL rates and customers by PBL rates and customers. (JP15 Br., WP-07-M-71 at 13-14.) The IPPs argue that this cross-subsidization violates the equitable allocation requirement of 7(a)(2) of the Northwest Power Act, because the GSR costs are transmission cost that should be borne by all transmission customers and not just BPA's power customers. (JP15 Br., WP-07-M-71 at 13-14; JP15 Br. Ex., WP-07-M-80 at 5.) The IPPs also compare equitable allocation to comparability and claim that BPA is violating both with the Supplemental Proposal. (JP15 Br., WP-07-M-71 at 13-14.) In their brief on exceptions, the IPPs claim that treating inside the band GSR costs as generation costs collected through power rates, while allocating synchronous condenser costs to transmission rates, runs afoul of FERC rulings and bears no resemblance to sound ratemaking principles. (JP15 Br. Ex., WP-07-M-80 at 5-6.)

BPA's Position

BPA agrees that GSR must be offered as a discrete ancillary service in accordance with Order Nos. 888 or 888-A, as referenced by the IPPs. However, since issuing these orders, FERC has issued an extensive amount of case law and rulemakings describing what cost inputs may be included in the GSR ancillary service rate. The Supplemental Proposal is an acceptable approach under these more recent FERC directives, and although there is a reduction in costs being allocated to TBL for inside the band GSR, which causes an increase in power rates, this is not a cross-subsidization of transmission rates by power customers. The Supplemental Proposal does not violate 7(a)(2)(C) of the Northwest Power Act; all identified transmission cost will be applied to both Federal and non-Federal users of the transmission system equitably. Also, as addressed in Issue 1 above, the Supplemental Proposal does not violate the comparability principle.

Evaluation of Positions

In Order 888, FERC required GSR to be offered as a discrete ancillary service. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,707 (1996). However, FERC provided very little direction on how to price this ancillary service and the *AEP* methodology, which is the industry standard for pricing GSR inside the band, was not approved until 1999. *American Elec. Power Serv. Corp.*, 88 FERC ¶ 61,141 at 61,457 (1999). FERC approved the *AEP* methodology, but as described above in Issue 1, FERC has never required transmission providers to allocate generation costs to GSR.

The more recent FERC precedent regarding compensation for GSR does provide significant guidance as to acceptable approaches for allocating these costs. The *pro forma* Standard Large Generator Interconnection Agreement attached to Order 2003-A establishes the following rule:

> **9.6.3 Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

Order 2003-A at 31,153; *see also* Order 2003-A at P. 416.

The range referred to in this provision is the distinction between inside the band and outside the band GSR. As described above, in the *Entergy Services* case FERC granted Entergy's request for a declaratory order that, pursuant to Order 2003-A, if it no longer compensated its affiliate generators for GSR inside the band, it would not have to compensate non-affiliate generators. *Entergy Services* at P. 22. BPA is relying on this recent FERC direction in the Supplemental Proposal and, as discussed in the Supplemental Proposal, BPA intends to establish a rate methodology to compensate all generators for GSR outside the band. (Bermejo, *et al.*, WP-07-E-BPA-28 at 11.) Consistent with Order 2003-A, any cost for outside the band operations and synchronous condenser cost should be included as inputs for the Schedule 2 ancillary service rate. This approach does not run afoul of FERC rulings, and it is consistent with sound ratemaking principles.

The Supplemental Proposal is not a cross-subsidization of transmission rates by power customers, because the inside the band GSR costs at issue are generation costs and FERC precedent indicates that it is left to the discretion of the transmission provider to decide whether to use the *AEP* methodology to allocate a portion of generation cost for inside the band GSR. (*See* evaluation of Issue 1 above.) The Supplemental Proposal forecast does not include inside the band GSR in the allocation of generation input costs for FY 2008-2009. However, since BPA has cost-based rates and is required by statute to recover its costs, the decision to not allocate generation costs for inside the band GSR must be reflected as slightly higher power rates.

Arguably, the equitable allocation standard in Section 7(a)(2)(C) of the Northwest Power Act is applicable to only transmission rates and is not an appropriate issue for the power rate case. Section 7(a)(2)(C) states, "insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system." 16 U.S.C. § 839e(a)(2)(C). However, since the Supplemental Proposal is forecasting a cost allocation that will be an input to a transmission rate, it should be clarified that the Supplemental Proposal does not violate Section 7(a)(2)(C). As discussed above, the GSR costs addressed in the Supplemental Proposal are generation costs that are allocated only to GSR if the transmission provider decides to compensate its affiliate for inside the band GSR. Under the Supplemental Proposal, this allocation is changing for FY 2008-2009 so that PBL is forecasting that no generation costs will be allocated for inside the band GSR. The power rates reflect this change in allocation, and since these are generation costs in the first place, it is a mischaracterization to refer to them as a transmission cost borne only by BPA power customers.

Generally, equitable allocation is raised as a concern if PBL or PBL's power customers are not paying their share of transmission system costs. However, in this case, the IPPs are claiming that Section 7(a)(2)(C) is being violated because they contend BPA power customers are paying more than their share of the transmission system cost. This is not the case because the Supplemental Proposal is a forecast of the decision to not include inside the band GSR costs from the transmission providers own generators in the Schedule 2 rate for FY 2008-2009. Based on that decision, all identified transmission costs will be included in the Schedule 2 rate and all transmission customers, both Federal and non-Federal, will pay the same rate. Therefore, the Supplemental Proposal is not a violation of Section 7(a)(2)(C).

Decision

The Supplemental Proposal does not create a cross-subsidization of transmission rates by power customers and therefore does not violate Section 7(a)(2)(C) of the Northwest Power Act.

Issue 5

Whether BPA's assumptions regarding the potential for future increases in compensation to non-affiliate generators for inside the band GSR are valid.

Parties' Position

The IPPs, Cowlitz, WPAG, and PNGC question BPA's assumptions regarding other non-affiliate generators that may file for GSR rates in the future. (JP15 Br., WP-07-M-71 at 14-15; Cowlitz, WPAG, and PNGC Br., WP-07-M-63 at 3.) They point out that non-affiliate generators have been able to file for a GSR rate for a couple of years and yet none of the non-affiliate generators that BPA listed in a data response as potentially filing rates has filed. (*See* Cross-Ex Tr., Volume II, at 105, NIPPC Cross-Ex Exhibit No. 2 (NP-BPA-010).) The IPPs assert that the non-affiliate generators BPA identified in its data request are outside of BPA's control area and do not qualify to file a GSR rate to collect from BPA. (JP15 Br., WP-07-M-71 at 15; JP15 Br. Ex., WP-07-M-80 at 2.) Cowlitz, WPAG, and PNGC suggest that these other non-affiliate generators may not file for a GSR rate because such a filing would subject them to greater operational control by BPA. (Cowlitz, WPAG, and PNGC Br., WP-07-M-63 at 3.) As for increases in the rates BPA would have to pay the IPPs that already have GSR rates on file, the IPPs state that BPA should have discussed this concern with them prior to filing the Supplemental Proposal. (JP15 Br., WP-07-M-71 at 16-17; JP15 Br. Ex., WP-07-M-80 at 4.) The IPPs claim that in order "to paper over" the fact that based on the current GSR rates of non-affiliate generators the Supplemental Proposal will result in a rate increase to preference customers, BPA staff have "erected a hypothetical future problem" arising from additional non-affiliate generators filing GSR rates. (JP15 Br. Ex., WP-07-M-80 at 2.) The IPPs also point to the fact that the IOUs that own some of the generators BPA contends may file for GSR rates are supportive of BPA's Supplemental Proposal as evidence supporting the IPP's claim that none of these other generators will file GSR rates. (*Id.*)

<u>BPA's Position</u>

BPA believes there is a potential for all of the non-affiliate generators listed in BPA's data response to file for a GSR rate. (Cross-Ex Tr. at page 112, line 4-7.) There may be several reasons why these non-affiliate generators have not yet filed, but as long as BPA is compensating its affiliate for inside the band GSR, there is a risk that the amount BPA is required to pay non-affiliates for inside the band GSR could increase significantly. (Bermejo, *et al.*, WP-07-E-BPA-28 at 4; *see* Supplemental Study Reactive Power, WP-07-E-BPA-29(E1) Section 2, Table 1.) BPA staff did not erect a hypothetical problem to justify discontinuing payments for inside the band GSR. Rather BPA staff raised concerns about the increasing costs of compensating non-affiliate generators and performed an economic analysis and revenue risk assessment around reasonable assumptions that non-affiliate generators may file GSR rates and what the impacts these potential costs would have on different customer groups in the region. (*Id.*) It is true that some of the non-affiliate generators listed in the data response are not in BPA's control area, but whether this would prevent FERC from approving a GSR rate that is applicable to BPA is an unsettled legal issue.

BPA does not believe the generators listed in the data response are concerned about additional BPA control because these generators already follow BPA's voltage schedule or they will be required to follow BPA voltage schedules at some point in the future. In response to the IPPs assertion that BPA should have discussed its concerns regarding the IPPs raising their GSR rates after FY 2007, BPA had not fully studied the impacts of the *Entergy Services* order and conducted necessary internal discussions prior to the beginning of the rate case, so open communication with the IPPs on this issue outside of the rate case was not an option for BPA.

Evaluation of Positions

All of the generators listed in the data response, except River Road and Cherry Point, are currently connected to BPA transmission facilities. (Cross-Ex Tr. at 108-110.) River Road is currently in PacifiCorp's control area, but there is a process under way that will move River Road into BPA's control area in the near future. Cherry Point is currently under construction, and when it is complete it will be in BPA's control area. (Cross-Ex Tr. at page 110, lines 21-25.) When these events occur, it is reasonable to assume that these generators would file for a GSR rate.

The IPPs referenced FERC's ruling in *Otter Tail Power Company* as precedent for reasoning that non-affiliate generators that are not inside the transmission providers control area are not eligible to be compensated under a GSR rate. *Otter Tail Power Co*., 99 FERC ¶ 61,019 (2002). In a more recent case, FERC held that, for purposes of Schedule 2, a generator's power revenue requirement should be allocated to the zone that it is connected to rather than the zone it is located in. *PJM Interconnection, L.L.C.*, 112 FERC ¶ 61,058 (2005). While the *PJM* order involves an ISO with an established Schedule 2 procedure, the facts of this case may be applicable to the generators listed in BPA's data response that are not in the BPA control area. At best, this could be described as an unsettled legal issue, and if a generator located outside of BPA's control area does file for a GSR rate, BPA may argue that they are not eligible. However, based on the *PJM* ruling it is reasonable to conclude that FERC may approve a GSR rate for one or more of these non-affiliate generators that are interconnected to BPA transmission facilities. The IOU coalition's support of the Supplemental Proposal does not conclusively indicate that these non-affiliate generators would not change their position in the future. The IOU coalition did not elaborate as to why they support the Supplemental Proposal and it is pure speculation on the part of IPPs to attribute a particular motive to their actions. (JP6 Br., WP-07-M-67 at 4.)

Decision

The assumptions BPA made regarding the potential of additional non-affiliate generator filing for GSR rates and increases in already-filed GSR rates are reasonable and should be a consideration in the decision regarding the adoption of the Supplemental Proposal.

Issue 6

Whether the Supplemental Proposal is bad public policy that conflicts with BPA's objectives of promoting the use of non-Federal generation to meet regional load growth.

Parties' Position

The IPPs state that they are having difficulty recovering their investment in the Northwest and BPA's plan, as outlined in the Supplemental Proposal, to deny non-affiliate generators GSR compensation, will add significantly to their present difficulties. At the same time, BPA is contemplating a material change that would lead its customers to rely on non-Federal resources to meet future load growth. The IPPs argue that the Supplemental Proposal is focused on causing a significant loss in revenues to non-affiliate generators and this "is short-term, parochial thinking that can only be hurtful toward long-term regional efforts to promote adequate and reliable power supplies." (JP15 Br., WP-07-M-71 at 17.) The IPPs claim BPA's Supplemental Proposal is not based on concern for ratepayers, but rather that it is about gaining a competitive advantage as a power supplier at the expense of independent power producers. (JP15 Br. Ex., WP-07-M-80 at 3.) The IPPs also point out that they have been seeking some form of GSR compensation from BPA for several years and now BPA is trying to take away most of the results of these efforts through the Supplemental Proposal. (JP15 Br. Ex., WP-07-M-80 at 6-7.) Cowlitz, WPAG, and PNGC state "as a general proposition, unnecessary changes in policies discourage efficient development of any power system." (Cowlitz, WPAG, and PNGC Br., WP-07-M-63 at 3.)

BPA's Position

The Supplemental Proposal is consistent with FERC guidance that inside the band GSR is an obligation of the interconnected generator. In evaluating the policy considerations behind the Supplemental Proposal, BPA was most concerned with the effect this decision would have on the cost of delivered power (both transmission and power rates) for all regional ratepayers. (Bermejo, *et al*., WP-07-E-BPA-28 at 4; Supplemental Study Reactive Power, WP-07-E-BPA-29, Section 2.) While the Supplemental Proposal would have a significant impact on non-affiliate generators that currently have filed rates for GSR, there is both a short- and long-term benefit to regional ratepayers if inside the band GSR is treated as an obligation of the generator rather than a cost to all transmission customers. Establishing policies that keep the cost of delivered power low for regional ratepayers and provide rate stability should promote the efficient use and development of an adequate and reliable power supply in the region. The Supplemental Proposal is a necessary change.

Evaluation of Positions

In evaluating the forecast of GSR allocation in the Supplemental Proposal, BPA looked at the financial impacts to several different ratepayer groups. This analysis indicated that based on current rates paid to non-Federal generators, the Supplemental Proposal would benefit regional ratepayers $1 million a year. If the current non-Federal generators increase their rates, as expected in 2007, the benefit of the Supplemental Proposal to regional ratepayer increases to $4.4 million a year. If additional non-Federal generators file GSR rates, the benefit of the Supplemental Proposal to regional ratepayers is even greater. (Bermejo, *et al*., WP 07-E-BPA-28 at 7; Supplemental Study Reactive Power, WP-07-E-BPA-29(E1) Section 2, Table 1.) As the IPPs note, if BPA is successful in its FERC filings to remove the IPPs' GSR rates, the IPPs would see a significant loss in revenues as compared to the current situation where all generators with filed rates are compensated for inside the band GSR. (*Id*. at page 6, line 23.) However, the IPPs may still be able to receive self-supply described in the TBL tariff.

The WP-02 rate case was the first time that BPA used the *AEP* methodology to forecast an allocation of generation costs to inside the band GSR. (Record of Decision, WP-02-A-02 at 8-1 to 8-2.) At that time, FERC was not accepting filings from non-affiliate generators for GSR rates and recognized only that non-affiliate generators may be due a partial credit for self-supplying GSR. Order 888-A at 30,227-29. The Supplemental Proposal in this rate case is the first time BPA has evaluated the impacts of compensating non-affiliate generators for inside the band GSR in a PBL rate case. Based on the analysis described above, not compensating BPA's own generators, or non-affiliate generators, for inside the band GSR is a benefit to regional ratepayers and a reasonable policy decision. The Supplemental Proposal is not intended to provide a competitive advantage to BPA over non-affiliate generators and there is no competitive advantage where all generators are treated the same in regard to compensation for inside the band GSR. The decision to not allocate cost for inside the band GSR will increase BPA's PF rate, so if anything, this decision hinders BPA's competitiveness.

Decision

The Supplemental Proposal is not bad public policy, and it does not conflict with BPA's other policy initiatives.

Issue 7

Whether BPA should adopt the Supplemental Proposal to forecast revenues from inside the band GSR for only FY 2007 and not for FY 2008-2009, or adopt the Initial Proposal forecasting revenue from inside the band GSR for each year of the rate case.

Parties' Positions

For all the reasons described above, the IPPs oppose the Supplemental Proposal and they believe that the inside the band GSR cost should continue to be allocated to transmission rates. (JP15 Br., WP-07-M-71 at 18.) The IPPs claim the Supplemental Proposal lacks legal, factual and policy justification and asked the Administrator to reappraise the Supplemental Proposal. (JP15 Br. Ex., WP-07-M-80 at 7.) Cowlitz, WPAG, and PNGC oppose the Supplemental Proposal at this time. They reason that based on BPA's analysis of different customer groups, if no other non-affiliate generators file GSR rates, preference customers stand to lose a benefit of $2.9 million a year in their cost of delivered power. Cowlitz, WPAG, and PNGC believe that the possibility of other non-affiliate generators filing rates that would cause the Supplemental Proposal to be a benefit to preference customers is speculative and BPA should wait and reevaluate this policy in FY 2009 when the rate impacts are more certain. (Cowlitz, WPAG, and PNGC Br., WP-07-M-63 at 2-3.) The IOUs support the Supplemental Proposal and recommend that the Administrator adopt it in the Record of Decision. (JP6 Br., WP-07-M-67 at 4.)

BPA's Position

With respect to forecasting revenues from allocating generation input costs to TBL, the Supplemental Proposal is in the best interest of the region. (Bermejo, *et al*., WP-07-E-BPA-28 at 7; Supplemental Study Reactive Power, WP-07-E-BPA-29(E1) Section 2, Table 1.) It is recognized that this forecast is just a first step in a process in which BPA will attempt to extinguish the IPP GSR rates currently on file with FERC, and although FERC precedent indicates that BPA will most likely be successful, extinguishing these rates is not a foregone conclusion. Based on the potential risk of an adverse ruling at FERC, BPA should proceed with the Supplemental Proposal, but if BPA is unable to extinguish the IPPs' GSR rates, BPA may resume allocation of inside the band GSR cost for the remainder of FY 2008-2009 at the FY 2007 input level.

Evaluation of Positions

As discussed above, FERC has indicated that generators should not be compensated for inside the band GSR, unless the transmission provider chooses to compensate its affiliate generators. BPA's analysis indicates that even if no other non-affiliate generators were to file for a GSR rate, there is a benefit to regional ratepayers of discontinuing payments for inside the band GSR. (Supplemental Study Reactive Power, WP-07-E-BPA-29(E1) Section 2 Table 1.) Also, as discussed above there are legal, factual, and policy justifications for the Supplemental Proposal and it is reasonable to forecast no cost allocation associated with inside the band GSR for FY 2008-2009.

As to Cowlitz, WPAG and PNGC's concern that this is not a benefit to preference customers if no other non-affiliate generators would have filed for a GSR rate, it is reasonable to assume that at least some of the other potential non-affiliate generators would file a GSR rate between now and 2009. It would take only a few additional non-affiliate generator GSR rates to change the current benefit to preference customers into a liability.

FERC's *Entergy Services* order may be appealed to the Circuit Court and there are still some outstanding issues in the *Entergy Services* case regarding the potential for a contract right to inside the band GSR compensation. *Entergy Services, Inc v. Cottonwood Energy Co. LP*, 115 FERC ¶ 61,031 (2006). In addition, FERC is evaluating its current reactive power policies, and such policies may change over time. (*See* FERC Staff Report Principles for Efficient and Reliable Reactive Power Supply and Consumption, Docket No. AD05-1 (2005).) In order to demonstrate that BPA is not compensating its own generators for inside the band GSR, it is necessary to proceed with the Supplemental Proposal. BPA will not be able to file to extinguish the IPPs' GSR rates until the spring of 2007 due to FERC rules and the settlement agreement that BPA has with the IPPs. It may take several months to get a definitive ruling from FERC. If it turns out that BPA is unable to extinguish the IPPs GSR rates, BPA could find itself in a situation where it is compensating non-affiliate generators for inside the band GSR, but not compensating its own generators for inside the band GSR. If this situation were to occur, it would be reasonable for BPA to review the impacts on regional ratepayers and consider returning to the FY 2007 allocation for inside the band GSR for the remainder of the power rate period.

Decision

BPA adopts the Supplemental Proposal with the caveat that if BPA is unsuccessful in extinguishing the IPPs' GSR rates for inside the band, BPA may revert to the Initial Proposal forecast allocation for FY 2007 and apply this to the remainder of the power rate period.

7.3 Operating Reserves

7.3.1 Introduction

As part of the Partial Resolution of Issues, BPA staff and the rate case parties supported or did not oppose modifications to BPA's Initial Proposal. Those modifications involved the treatment of revenues received from TBL for Operating Reserves, elimination of the ORC that was in the Initial Proposal, and a reduction in the unit price for Operating Reserves proposed in the Initial Proposal. The specifics of the proposed changes are set forth in Section 2 of this ROD and Evans, *et al*., WP-07-E-BPA-31; Evans, *et al*., WP-07-E-BPA-31(E1). The forecast of revenues from Operating Reserves is determined by multiplying the unit price by the amount of the control area obligation remaining after accounting for self- and third-party supply. (Bermejo, *et al*., WP-07-E-BPA-20 at 12-16.) One of the concerns raised in BPA's Initial Proposal for the ORC was the risk of under-recovery of revenue due to the uncertainty of self- and third-party supply of Operating Reserves. (Bolden, *et al*., WP-07-E-BPA-13 at 15-16.)

Issue 1

Whether BPA should spread the revenues received from Operating Reserves equally over all firm power requirements rates by not implementing the ORC and reduce the unit price for Operating Reserves contained in the Initial Proposal to $5.63/kW per month as proposed in the Partial Resolution of Issues.

Parties' Positions

The IOUs, PNGC, NRU, WPAG, PPC, and SUB either supported or did not oppose the Partial Resolution of Issues negotiated between BPA and the rate case parties. The Partial Resolution of Issues includes a provision that eliminates the ORC, spreads the Operating Reserves revenues equally across all firm power requirements rates, and sets the unit price of Operating Reserves at $5.63/kW per month.

BPA's Position

BPA supports the decision to eliminate the ORC, spread the Operating Reserve revenues evenly across all firm power requirements rates, and lower the unit cost of Operating Reserves to $5.63/kW per month. BPA's Initial Proposal proposed to set the unit cost for Operating Reserves at $6.96/kW per month and the ORC would have allocated the revenues received from Operating Reserves only to those customers that were purchasing Operating Reserves from TBL. In the Partial Resolution of Issues, BPA agreed to lower the unit price, remove the ORC, and allocate the revenues from Operating Reserves evenly across all firm power requirements rates. (Evans, *et al*., WP-07-E-BPA-31 at A-3.)

Evaluation of Positions

The Partial Resolution of Issues states the following with regard to this issue:

> BPA's Initial Proposal contained an Operating Reserves Credit (ORC), which would have forecast zero revenues from operating reserves in the base rates as a revenue credit and provided a line item billing credit to firm power requirements customers that elected to purchase operating reserves from TBL rather than self or third party supply. BPA will establish a per unit cost for operating reserves provided to TBL of $5.63/kW per month, as opposed to the $6.96/kW per month per unit cost in the Initial Proposal. For the final study, BPA will apply the $5.63/kW per month charge to the adjusted forecast of PBL's share of the control area reserves obligation provided by TBL. BPA will allocate the resulting revenues evenly across all firm power requirements rates. This revenue credit will not be dependent on the transmission customer's choice to buy operating reserves from TBL, self-supply, or third-party supply.

(Evans, *et al*., WP-07-E-BPA-31 at A-3.)

The resolution of this issue negotiated between BPA and the rate case parties is proper and reasonable. BPA's intent in the Initial Proposal was to use the ORC to reconcile an inequity that BPA believed had developed between BPA customers that self-supply Operating Reserves and those that purchase Operating Reserves from TBL. (Bolden, *et al*., WP-07-E-BPA-13 at 16-17.) There was very little support from the parties for the Operating Reserve Credit.

BPA uses an embedded cost methodology to establish the unit price for Operating Reserves, based on assumptions for self- and third-party supply. (Bermejo, *et al*., WP-07-E-BPA-20 at 12-14.) The advent of several customers electing to self- and third-party supply Operating Reserves reduced PBL's share of the TBL control area reserve obligation and resulted in costs associated with Operating Reserves being spread to a smaller pool of customers still purchasing from TBL. This smaller pool, combined with other cost drivers, caused a significant increase in the unit price of Operating Reserves. BPA agreed to eliminate the Operating Reserve Credit in conjunction with lowering the unit price because this resulted in less of an impact on those customers that continue to purchase Operating Reserves from TBL. This resolution was acceptable to the rate case parties.

Decision

BPA will eliminate the ORC, allocate Operating Reserves revenues evenly across all firm power requirements rates, and lower the unit cost for Operating Reserves that PBL supplies to TBL to $5.63/kW per month as proposed in the Partial Resolution of Issues.

Issue 2

Whether BPA should shift the risk of under-recovery associated with Operating Reserves from PBL to TBL.

Parties' Positions

In their direct testimony, the Operating Reserve Coalition (JP2) suggested that in order to address the risk of under-recovery of Operating Reserve revenues, PBL should bill TBL for the total cost of supplying Operating Reserves and TBL should manage the risk of under- recovery in its rate design. (Clark, *et al.*, WP-07-E-JP2-01 at 7-8.) Since Operating Reserve issues were part of the Partial Resolution of Issues, this suggestion was not contained in the parties' initial briefs.

BPA's Position

BPA believes there may be some merit in this suggestion. However, rather than shifting all the risk of under- recovery to TBL, it may be appropriate to shift only a portion of this risk to TBL. Based on each business lines' ability to absorb risk, it would be reasonable to allocate 25 percent of any revenue under-recovery to TBL.

Evaluation of Positions

Since Operating Reserve issues were resolved in the Partial Resolution of Issues and no party addressed this issue in an initial brief, BPA believes that the parties have not had an adequate opportunity to address the issue of the business lines sharing any potential under-recovery. Parties should have a full opportunity to address this issue in the TBL rate case.

Decision

Allocating 25 percent of an under-recovery of revenues from Operating Reserves to TBL is reasonable and should be fully addressed in the next TBL rate case.

7.4 Application of the NFB Adjustment to Ancillary Service Inputs

7.4.1 Introduction

BPA forecasts revenues from the allocation of generation inputs in the PBL rate case and TBL uses this allocation to establish its ancillary services rates in the TBL rate case. In the WP-02 rate case, these generation inputs were established for the entire rate period and it was determined that the CRAC adjustments should not apply to the inter-business line charges for this allocation because the PBL and TBL rate cases are staggered and the additional system cost would add unnecessary complexity to the overall risk management program and billing. (Record of Decision, WP-02-A-02 at 8-25 to 8-27.) These same assumptions were relied on in BPA's Initial Proposal in this rate case and no CRAC, DDC, or NFB Adjustment were proposed to apply to generation inputs.

Issue 1

Whether BPA should apply the NFB Adjustment to generation inputs sold to TBL.

Parties' Positions

In its initial brief, WPAG stated that transmission customers benefit from the FCRPS and they should pay a portion of any ESA compliance costs associated with an NFB Adjustment through an adjustment to the generation input cost. (WPAG Br., WP-07-M-68 at 14-15.) WPAG went on to point out that even if TBL does not have an adjustment mechanism in its current rate, this adjustment could be accommodated in the next TBL rate case to cover FY 2008-2009. (*Id.*) WPAG argued that while the revenue contribution from the sale of generation inputs appears small, it will provide some rate relief and as a matter of principle, all customers that benefit from the system should pay these additional costs. (*Id.*)

BPA's Position

The general concept of requiring all customers who benefit from the system pay a share of the costs is reasonable. However, the NFB adjustment may be triggered for a variety of reasons of which only some may be directly related to fish and wildlife program costs that are reflected in generation input methodologies. Of all the generation inputs allocated to TBL, only Regulating Reserves and Operating Reserves include fish and wildlife program costs in the embedded cost methodology. Since the outcome of the court challenges is unknown, it is not possible to evaluate which costs could be put into an adjustment of Operating Reserves and Regulating Reserves. Almost all of the customers that are required to purchase Operating Reserves and Regulating Reserves from TBL are BPA power customers. Applying the NFB Adjustment to these generation input costs would not have the desired effect of spreading NFB Adjustment costs to all transmission customers. The concept of allocating the costs to all that benefit from the system is reasonable, but potential impacts on customers from applying the NFB Adjustment to generation inputs do not appear to warrant the complexities of determining which costs could be passed through.

Evaluation of Positions

Fish and wildlife program costs are not included in the revenue forecast for the generation input allocations of GSR, Energy or Generation Imbalance, Generation Dropping, or Station Service because each of these generation inputs is focused on specific components of the system. However, fish and wildlife program costs are included in the generation input cost allocation for both Operating Reserves and Regulating Reserves. (Bermejo, *et al*., WP-07-E-BPA-20 at 14-15, and 19.) While it is reasonable to allocate direct program-type costs to Operating Reserves and Regulating Reserves, it would be difficult to justify allocating operating expenses, such as spill, to these generation inputs for ancillary services, because operation expenses have a direct impact on the amount of surplus power BPA can market. The relationship between operating expenses and existing capacity obligations is somewhat tenuous. There is a relationship between operating requirements and system capacity, but this is a rather complex relationship that BPA has not specifically analyzed.

Appropriately identified direct program costs associated with an NFB Adjustment could be applied to Operating Reserves and Regulating Reserves. However, the generation input unit price for Operating Reserves was agreed to in the Partial Resolution of Issues and any adjustment mechanism would appear to be in conflict with the terms of the Partial Resolution of Issues. Regulating Reserves are purchased only by transmission customers that have loads in the BPA control area. Only a few transmission customers that are not BPA power customers would be exposed to this pass-through adjustment.

Decision

BPA will not apply the NFB Adjustment to generation inputs for ancillary services sold to TBL.

8.0 WHOLESALE POWER RATE DESIGN

8.1 Introduction

As part of the Partial Resolution of Issues, BPA staff and the rate case parties supported, or did not oppose, proposed modifications to BPA's Initial Proposal on rate design. (Evans, *et al.*, WP-07-BPA-31.) BPA and the parties agreed that BPA would continue, in general, its existing (WP-02) rate design for FY 2007-2009. Aside from the proposed demand, energy, and load variance rates, as addressed below, parties raised no issues regarding the following Initial Proposal rate design elements: (1) discontinuation of the Stepped-Up Multi-Year Block Charge; (2) minor change to the Excess Factoring Charge to eliminate references to the California Power Exchange; (3) minor change to the Unauthorized Increase Charge (UAI) to eliminate references to the California Power Exchange; and (4) continuation of the PF Targeted Adjustment Charge as modified to exempt unanticipated incremental loads less than 1 aMW in a year and to use any monthly surplus power available from the Federal system to serve portions of a Targeted Adjustment Charge (TAC) load. These uncontested rate design elements are adopted as proposed in BPA's Initial Proposal. In addition, in order to implement the Flexible PF Rate Program, as discussed in Section 6.2 of this ROD, BPA made the following addition to the GRSPs for the Flexible Rate Option:

> Notwithstanding the effective dates of the PF rate and associated GRSP's, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate Program by purchasing under the Flexible PF Rate Option will survive and be fully enforceable until such time as they are fully satisfied.

In reviewing resource costs for the Final Studies, BPA noticed inconsistencies in the treatment of resource output and costs in the Wholesale Power Rate Design Study Documentation, WP-07-FS-BPA-05A. The costs of the Cowlitz Falls generating project, the Wauna co-generation project, and the various wind projects had been included in the new resources (NR) resource pool while the energy from such resources had been included in the FBS resource pool. BPA's research of the treatment of these resources in past rate cases indicates that the costs of these resources have always been included in the NR resource pool. In the 7(b)(2) rate test, these resources have always been treated as NR resources. The sole inconsistency has been in the treatment of the energy output, which has been treated as both NR and FBS resources. Therefore, BPA is correcting this inconsistency and treats these resources as NR resources. The Final Studies include both the costs and the energy of the foregoing resources as New Resources.

8.2 Calculation of Demand, Energy, and Load Variance Rates

Issue 1

Whether BPA should adopt the modifications to the Demand, Energy, and Load Variance rates as proposed in the Partial Resolution of Issues.

Parties' Positions

The IOUs, PNGC, NRU, SUB, WPAG, PPC, Cowlitz, Tacoma, Grant County PUD #2, Seattle, Pend Oreille County PUD #1, EWEB, Benton County PUD, Franklin County PUD No. 1, Grays Harbor County PUD No. 1, CRITFC, SOS/NWEC, either support, or do not oppose, the Partial Resolution of Issues negotiated between BPA and the rate case parties. (*See* ROD, Section 2.0) The Partial Resolution of Issues, WP-07-E-BPA-31, at A-3, provides the proposed changes to the Demand, Energy, and Load Variance rates. Most parties to the rate case have indicated that they either support, or do not oppose, the Partial Resolution of Issues, which includes the provisions related to the Demand, Energy, and Load Variance rates.

BPA's Position

BPA supports the proposed changes to the Demand, Energy, and Load Variance rates, as set forth in WP-07-E-BPA-31, at A-3.

Evaluation of Positions

The Partial Resolution of Issues contains the following description with regard to this issue.

> a. Demand, Energy, and Load Variance
>
> Table 1 hereto will be the template for the relationship of the monthly Heavy Load Hour, Light Load Hour, Demand and Load Variance rates for the PF-07 rate schedule. The rates in the PF-07 rate schedule will be as set forth in Table 1, adjusted proportionally (*i.e.*, by an equal percentage applied to each rate) if necessary to recover the revenue requirement in total as determined in the Final Studies of the WP-07 wholesale power rate case when applied to the billing determinants in the final rate case studies.

(Evans, *et al.*, WP-07-E-BPA-31, at A-3.) The template defines the Demand rate for the PF-07 rate schedule; as stated in cross-examination (Cross-Ex., Tr. at 56.), the Demand rate for IP-07, NR-07, and FPS-07 rate schedules will be set equal to this rate.

> b. Application of the CRAC, including the NFB Adjustment
>
> With the exception of the NFB Adjustment, the CRAC surcharges and DDC dividends will be applied proportionately (*i.e.*, by an equal percentage change for each rate) to the LLH and HLH energy and LV rates of the PF-07, IP-07, and NR-07 rate schedules. If a triggering event due to the NFB Adjustment (*see* Wholesale Power Rate Schedules and GRSPs, WP-07-E-BPA-07 at 83-84) increases the total amount of revenue to be collected through the CRAC, BPA will recover the revenues in excess of the amounts recoverable from a CRAC without the NFB through an increase to all demand, energy, and LV rates proportionately (*i.e.,* by an equal percentage) in the PF-07, IP-07, and NR-07 rate schedules.

(*Id*. at A-3.) The resolution of the Demand, Energy, and Load Variance rates between BPA and the rate case parties is a proper and reasonable one. The Preference Customer Group, representing a majority of BPA's preference customers, argued that they prefer a rate design that places more emphasis on stability over time rather than exact precision of price signals. (Carr, *et. al.*, WP-07-E-JP5-01, at page 3, lines 14-15.) Their testimony, WP-07-E-JP5-01, offered a compromise proposal that formed the basis for the modification to the Demand, Energy, and Load Variance rates as proposed in the Partial Resolution of Issues. BPA reviewed the Preference Customer Group's proposal and concluded that BPA's costs would be fully recovered and agreed that stability in rates over time was important, which would help lay the foundation for BPA's Regional Dialogue efforts and new long-term contracts.

Decision

BPA adopts the modification to the Demand, Energy, and Load Variance rates as proposed in the Partial Resolution of Issues.

9.0 RESIDENTIAL EXCHANGE PROGRAM AVERAGE SYSTEM COSTS, AND LOAD FORECASTS

9.1 Calculation of Exchanging Utilities' ASCs

Issue 1

Whether the effect of REP benefits should be removed from reported power costs in calculating utilities' Average System Costs (ASCs).

Parties' Positions

The IOUs argue that BPA's input data for the Cookbook Model should be revised to remove the effect of REP benefits on reported power costs. (Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 9.)

BPA's Position

BPA staff took no position on this issue.

Evaluation of Positions

The IOUs argue that BPA's input data for the Cookbook Model should be revised to remove the effect of REP benefits on reported power costs. (Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 9.) The IOUs note that such removal is appropriate because power costs used in BPA's Cookbook Model as input data should be actual power costs and not power costs reduced by REP benefits. (*Id*.) BPA concurs.

Decision

BPA will remove the effect of REP benefits from reported power costs in calculating utilities' ASCs.

10.0 SECTION 7(b)(2) RATE STEP

10.1 Introduction

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a comparison of the projected amounts 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 rate step can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

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

To understand the context of the development of BPA's rates and the implementation of the 7(b)(2) rate step, it is helpful to review the genesis of the REP and Section 7(b)(2).
BPA was established by the Project Act of 1937 (Project Act). 16 U.S.C. § 832 *et seq*. After enactment of this Act, BPA marketed the low-cost hydropower generated by Federal dams in the PNW. Although 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 IOUs and 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. H.R. Rep. No. 96-976, Part II, 96th Cong., 2nd Sess. 28 (1980). In the 1970s, forecasts showed that preference customers soon would require all of BPA's power. *Id*. 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 and 1991, the contracts were not likely to be renewed. *Id*. at 29. 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. *Id*. at 30.

The high cost of alternative sources of power caused BPA's non-preference customers to attempt to regain access to cheap Federal power. *Id*. at 30. 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. *Id*. The uncertainty inherent in the situation greatly complicated the efforts by all BPA customers to plan for their future power needs. *Id*. at 31. In order to avoid the prospect of unproductive and endless litigation regarding access to the Federal power marketed by BPA, Congress enacted the 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 IOU or DSI customers. 16 U.S.C. § 839g(c). The Northwest Power Act also established the REP. 16 U.S.C. § 839c(c). When BPA had insufficient Federal power to meet the needs of IOUs in the 1970s, such utilities developed their own resources, which generally were more costly than Federal hydropower. The REP provides PNW utilities a form of access to low-cost Federal power. Under the program, PNW utilities may sell power to BPA at a rate based on the utility's ASC of its resources. *Id*. BPA is required to purchase that power and sell, in exchange, an equivalent amount of power to the utility at BPA's PF rate. *Id*. This is the same rate that applies to BPA's sales of power to its preference customers, although the Northwest Power Act provides that the PF rate for the REP may be higher than the PF rate for preference customers due to the 7(b)(2) rate step 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 REP benefits. 16 U.S.C. § 839c(c). These benefits are thus available only to utilities' residential and small farm loads and are passed through directly to such consumers through lower retail rates. *Id*.

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 Northwest Power 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:

- the public body and cooperative customers' general requirements had included during such 5-year period the DSI loads which are: (1) served by the Administrator; and (2) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

- public body, cooperative, and Federal agency customers were served, during such 5-year period, with FBS resources not obligated to other entities under contracts existing as of the effective date of this Northwest Power Act (during the remaining term of such contracts) excluding obligations to DSI loads included in this paragraph;

- no purchases or sales by the Administrator as provided in Section 5(c) were made during such 5-year period;

- all resources that would have been required, during such 5-year period, to meet remaining general requirements of the public body, cooperative, and Federal agency customers (other than requirements met by the available FBS resources determined under this paragraph) were: (1) purchased from such customers by the Administrator pursuant to Section 6; or (2) 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

- the quantifiable monetary savings, during such 5-year period, to public body, cooperative and Federal agency customers resulting from: (1) reduced public body and cooperative financing costs as applied to the total amount of resources, other than FBS resources, identified under this paragraph; and (2) reserve benefits as a result of the Administrator's actions under this Northwest Power Act were not achieved.

16 U.S.C. § 839e(b)(2). There may, however, be additional adjustments to reflect the natural consequences of the five assumptions. (*See, e.g., Implementation ROD* at 19-23.) BPA's studies contain a discussion of the development of the Program Case and 7(b)(2) Case rates. (*See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, and Documentation, WP-07-E-BPA-06A.)

Pursuant to Section 7(b)(2), BPA was required to implement the rate step 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 PNW Electric Power Planning and Conservation Act*" (*Legal Interpretation*), 49 Fed. Reg. 2911 (1984). The *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 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 including BPA's WP-07 rate case.

Because of the importance and complexity of the 7(b)(2) rate step, and in order to provide customers certainty as to how Section 7(b)(2) would be applied, BPA conducted a special evidentiary hearing which lasted from February 29, 1984, to August 17, 1984, to establish a *Section 7(b)(2) Implementation Methodology* (*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, IOUs, 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 were 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 ROD including a final 7(b)(2) Methodology on August 17, 1984. (*See Implementation Methodology*, b-2-84-F-02.) The Methodology prescribes in detail how the 7(b)(2) step is to be conducted.

The ROD and the Methodology address the major issues involving the implementation of Section 7(b)(2), including reserve benefits, financing benefits, natural consequences, and the rate step trigger. The *Implementation Methodology* has been used by BPA in every rate case since 1985, when the 7(b)(2) rate step was first run, and was used in the development of BPA's WP-07 rate case.

Section 7(b)(3) of the Northwest Power Act governs the allocation of costs in the event the 7(b)(2) rate step triggers. Section 7(b)(3) provides that "[a]ny 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 step triggers, the resulting costs must be allocated to other power sales, including sales to utilities participating in the REP. These costs increase the PF Exchange rate, which is the rate at which BPA sells power to utilities participating in the REP. When the PF Exchange rate increases, the difference between that rate and the utility's ASC rate decreases, resulting in a reduction of REP benefits paid to the utility. Because each exchanging utility's ASC rate and residential load are different from those of other utilities, exchange benefits differ by utility. A utility receives no benefits when its ASC goes below BPA's PF Exchange rate.

Because the average Program Case rate was higher than the average 7(b)(2) Case rate in the WP-07 proceeding, the rate step triggered, and an adjustment to the preference customers' Priority Firm Power (PF-07) rate was required. During the WP-07 rate proceeding, however, the litigants developed a Partial Resolution of Issues. (Evans, *et al.*, WP-07-E-BPA-31, Attachment A.) This agreement provides in part:

> **1. 7(b)(2)**
>
> BPA will not, in any other proceeding, cite any action taken or not taken in this WP-07 proceeding as evidence of the propriety of (or precedent for) the resolution of any issue with respect to the treatment, under Section 7(b)(2), of the Mid-Columbia resources, conservation, uncontrollable events or secondary revenues counted as reserves. To the extent that BPA has addressed and resolved in this WP-07 proceeding any such issues, such BPA actions shall not be considered by BPA to be precedential or binding on BPA in any other proceeding. No action taken or not taken in this WP-07 proceeding with respect to any such issues shall be considered by BPA to either create an adverse inference with respect to any such issues in, or preclude any party from arguing the treatment of any such issues in, any other proceeding (whether before BPA, FERC or a court and whether or not on remand) or in any remand of a rate developed in WP-07 by FERC or a court. BPA recognizes that, in reliance on this BPA approach, the prefiled testimony labeled WP-07-E-JP6-01, WP-07-E-JP6-03, and WP-07-E-JP6-04 were not proffered into evidence in this proceeding when they would otherwise have been proffered.

(*Id.*) Due to the foregoing, BPA has not fully litigated all issues regarding Section 7(b)(2) in the WP-07 rate proceeding. For example, BPA has not litigated all legal issues regarding the inclusion of the Mid-Columbia resources in the 7(b)(2) Case resource stack. If BPA had reviewed all such issues it is possible that BPA would have changed its position from its WP-07 Initial Proposal. Such a change would have had a dramatic effect on the Section 7(b)(2) rate step by significantly reducing the reallocation amount, and thereby reducing the PF Exchange rate and making greater REP benefits available to exchanging utilities. Instead, BPA is proposing to adopt the implementation of the Section 7(b)(2) rate step as contained in BPA's WP-07 Initial Proposal. All issues regarding Section 7(b)(2), however, may be revisited in BPA's rate proceeding to establish rates for FY 2010-2011 and used in the development of such rates, and may influence subsequent BPA rates.

In summary, BPA followed the provisions of Section 7(b)(2) of the Northwest Power Act, BPA's *Legal Interpretation,* and the *Implementation Methodology* in developing its proposed rates and agreed with parties that BPA's 7(b)(2) decisions in this rate proceeding are not precedential and may be revisited in the next BPA rate proceeding. Issues regarding the implementation of the 7(b)(2) rate step are addressed below.

10.2 Absence of an Absolute PF Preference Rate Ceiling

Issue 1

Whether Section 7(b)(2) of the Northwest Power Act establishes an absolute rate ceiling for the PF Preference rate.

Parties' Positions

The Preference Customer Group[1] (PCG) argues that Section 7(b)(2) sets an upper limit on what BPA can charge its preference customers for power. (JP1 Br., WP-07-M-62 at 2.)

The IOUs argue that Section 7(b)(2) does not establish a rate ceiling for the PF Preference rate, which would conflict with BPA's statutory obligations to recover its total costs through rates and create an unacceptable TPP. (JP6 Br., WP-07-M-67 at 5-13.)

BPA's Position

BPA notes that, since 1984, BPA has interpreted the Northwest Power Act in a manner that recognized that Section 7(b)(2) does not establish an absolute cap or rate ceiling on the PF Preference rate. (Keep, *et al.*, WP-07-E-BPA-37 at 2-4.)

[1] Preference Customer Group is comprised of Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities and Pacific Northwest Generating Cooperative. However, JP1, the joint party that submitted the underlying testimony, did not include Pacific Northwest Generating Cooperative.

Evaluation of Positions

A. Section 7(b)(2) Is an Interim Rate Step, Not a "Rate Ceiling" That Creates an Absolute Limit on the PF Preference Rate

BPA first determined that Section 7(b)(2) of the Northwest Power Act does not constitute a "rate ceiling" in 1984 in both BPA's *Legal Interpretation* and *Implementation Methodology.* BPA's position has remained unchanged for the 20 years since that time. BPA's analysis was and is informed, in the first instance, by BPA's organic statutes, including the Northwest Power Act. After reviewing the relevant statutory ratemaking provisions below, BPA will review the parties' arguments on this issue.

1. Section 7(a) of the Northwest Power Act Requires BPA to Establish Rates That Recover Its Costs

Section 7(a)(1) of the Northwest Power Act provides that BPA's rates "shall be established and, as appropriate, revised 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 . . . and the other costs and expenses incurred by the Administrator." 16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Northwest Power Act states that FERC cannot approve BPA's rates unless the rates are (1) "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," 16 U.S.C. § 839e(a)(2)(A), and (2) "are based upon the Administrator's total system costs . . . ." 16 U.S.C. § 839e(a)(2)(B). Simply put, the cardinal statutory rule of BPA ratemaking is that BPA's rates *must* recover BPA's costs. If BPA's proposed rates do not recover BPA's total costs, they cannot be approved and implemented, and BPA cannot meet its obligations to the Treasury.

2. The 7(b)(2) Rate Step Requires BPA to Project Costs Based on Hypothetical Assumptions

The Section 7(b)(2) rate step is an interim step in BPA's determination of power rates. (*See, e.g.,* Keep, *et al.,* WP-07-E-BPA-37 at 2 "For over 20 years, BPA has noted that the Section 7(b)(2) rate step is not the final step in BPA ratemaking.") This step is a complex procedure that is conducted for the rate period plus an additional four years following the rate period. 16 U.S.C. § 839e(b)(2). As noted previously, Section 7(b)(2) directs BPA to conduct, after July 1, 1985, a comparison of the projected amounts to be charged its preference and Federal agency customers for their general requirements with the hypothetical costs of power to those customers if five assumptions are made. These five assumptions are summarized as follows:

> preference customers' general requirements included BPA's DSI loads located within or adjacent to the geographic service boundaries of such preference customers;

preference customers were served, during such 5-year period, with certain FBS resources;

no REP purchases or sales were made by BPA during such 5-year period;
all resources other than FBS resources that would have been required to meet remaining general requirements of the preference customers would be purchased from such customers by BPA and were the least expensive resources owned or purchased by such customers; and

certain savings resulting from the Northwest Power Act were not achieved.

16 U.S.C. § 839e(b)(2).

The 7(b)(2) rate step thus involves the projection and comparison of two sets of wholesale power costs for the general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) customers): (1) a set for the rate period and ensuing four years assuming that Section 7(b)(2) is not in effect (Program Case costs); and (2) a set for the same period taking into account the five hypothetical assumptions listed in Section 7(b)(2) (7(b)(2) Case costs). Certain specified costs allocated pursuant to Section 7(g) of the Northwest Power Act are subtracted from the Program Case costs. If the discounted Program Case costs exceed the average 7(b)(2) Case costs, the 7(b)(2) test is said to "trigger," and the amount to be reallocated in the rate period (reallocation amount) is calculated.

Section 7(b)(2) is based on hypothetical assumptions and projected amounts that extend beyond the rate period. Therefore, it does not reflect the overriding statutory directive that BPA's rates recover its costs:

> [Section 7(b)(2)] does not set the final rates to be charged to such customers. The 7(b)(2) rate step is not the most important element of BPA's ratemaking. The most important element of BPA's ratemaking is to establish rates that will recover BPA's total costs.

(Keep, *et al.*, WP-07-E-BPA-37 at 2.) Accordingly, as an interim rate step that is followed by subsequent steps, Section 7(b)(2) cannot be read in isolation; rather, any interpretation of it must reflect the fact that BPA's rates must recover its costs. (*See, e.g., id.*)

3. Section 7(b)(3) Provides for the Allocation of Certain Amounts to BPA's Non-Preference Power Rates

Section 7(b)(3) of the Northwest Power Act addresses the allocation of costs in the event the 7(b)(2) rate step triggers. 16 U.S.C. § 839e(b)(3). Section 7(b)(3) provides that "[a]ny 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." *Id*. In other words, if the 7(b)(2) rate step triggers (*i.e.*, there is a reallocation amount), the next step is to credit the reallocation amount from the 7(b)(2) rate step to the 7(b)(2) customers' rates and, if possible, reallocate such amounts to the rates for non-preference power sales, including the PF Exchange rate for sales to utilities participating in the REP, and the IP rate for sales to DSI customers.

4. Section 7(g) Requires BPA to Equitably Allocate Costs Not Otherwise Allocated to Ensure Recovery of Its Total Costs

Section 7(g) of the Northwest Power Act serves two functions. It lists certain costs, such as conservation costs and costs of uncontrollable events, that are excluded from the Program Case in the 7(b)(2) test. 16 U.S.C. § 839e(g). More importantly here, it provides BPA with the authority to allocate costs that are not otherwise allocated, such as the costs of settlements, to any and all rates, including preference rates, in a manner that BPA deems equitable. Section 7(g) states, in pertinent part, as follows:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, 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 section, all costs and benefits not otherwise allocated under this section . . .

(*Id.*). Under Section 7(b)(1) of the Northwest Power Act, BPA is to allocate to rates for BPA's preference customer loads the costs of the various resources needed to supply such loads. 16 U.S.C. § 839e(b)(1). Similarly, under Section 7(f) of the Act, BPA is to allocate to rates for certain other firm power sales the cost of resources "which, in the determination of the Administrator, are applicable to such sales." 16 U.S.C. § 839e(f). In general, BPA allocates in the first instance the cost of resources pursuant to Section 7(b)(1) and other specific sections of the Northwest Power Act and allocates other costs pursuant to Section 7(g).

The Report of the Senate Committee on Energy and Natural Resources explains the allocation of Section 7(g) costs:

> The costs or benefits under this Section 7(g) are intended to be applied in an equitable manner and as appropriate to any or all of the rates for power sales of the Administrator in order to assure that he can meet the requirements of section 7(a) to collect sufficient revenues to recover all of his costs including repayment of the Federal investment in the Federal Columbia River Power System. . . .

S. Rep. No. 96-272, 96th Cong., 1st Sess. 32 (1979).

Thus, Section 7(g) of the Northwest Power Act provides for the allocation of costs and benefits not otherwise governed by statute in an equitable manner and as appropriate to any or all of the rates for power sales of the Administrator in order to ensure that BPA can meet the requirements of Section 7(a) to collect sufficient revenues to recover all of BPA's costs and repay the Federal Treasury. Section 7(g) was drafted to be totally inclusive, precisely because of the overriding imperative that the Federal Treasury be repaid in full. Section 7(g) thus provides BPA a mechanism to ensure that power rates meet the requirements of Section 7(a) to recover BPA's total costs.

5. BPA's *Legal Interpretation* and *Implementation Methodology* Describe How These Sections Are Harmonized

For over 20 years, BPA has noted that the Section 7(b)(2) rate step is not the final step in BPA ratemaking. (Keep, *et al*., WP-07-E-BPA-37 at 2.) Before BPA had occasion to develop any power rates applying the 7(b)(2) test, BPA established the *Legal Interpretation* to provide guidance on how BPA would harmonize Section 7(b) with Section 7(a). The *Legal Interpretation* provides that "implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a)." (*Legal Interpretation* at 10.) As noted previously, Section 7(a)(1) of the Northwest Power Act establishes BPA's paramount rate directive, which provides that BPA's rates "shall be established and, as appropriate, revised 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 . . . and the other costs and expenses incurred by the Administrator." 16 U.S.C. § 839e(a)(1).

BPA's *Legal Interpretation* recognized that absent establishing rates in accordance with Section 7(a), BPA's rates could not be confirmed and approved by FERC and therefore could not be placed into effect. 16 U.S.C. § 839e(a)(2). BPA concluded:

> The legislative history of the Northwest Power Act supports application of Section 7(b) in a manner consistent with BPA's primary statutory obligation that its rates recover costs. The House Interior Committee report declares that:
>
> > Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject 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, BPA is required by the legislation to establish the following rates: [report continues by setting out rate structure of the Act]. H. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980).
>
> Section 7(a)(2) illustrates the importance of BPA's statutory obligation to set rates at levels sufficient to collect its costs. Section 7(a)(2) states that FERC cannot approve BPA's rates unless 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," 16 U.S.C. §839e(a)(2)(A), and are based upon the Administrator's total system costs . . . . 16 U.S.C. § 839e(a)(2)(B).

. . .

> BPA is neither predetermining the results of the rate test nor suggesting a disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a), 7(b)(2), and 7(b)(3). BPA is merely attempting through this notice to alert its customers and the public to one possible problem which may present itself in the future. By raising the matter at this early date, BPA hopes that full discussion and consideration of such issues will enhance resolution of the problem when, and if, it arises in the context of the relevant rate case.
>
> (d) Decision:
>
> *BPA will interpret section 7(b)(2) so that implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).*

(Emphasis added.)

The PCG argues that the *Legal Interpretation* does not provide that sections 7(b)(2) and 7(b)(3) must be subordinated to section 7(a) because the *Legal Interpretation* states that "BPA is neither predetermining the results of the rate test nor suggesting disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a), 7(b)(2), and 7(b)(3)." (JP1 Br. Ex., WP-07-M-79 at 6, citing *Legal Interpretation* at 10.) This argument misconstrues the *Legal Interpretation*. The cited excerpt is consistent with BPA's conclusion in 1984, as previously established, that section 7(a) controls over section 7(b)(2) in the event of a conflict. The cited excerpt merely notes that, because the *Legal Interpretation* was being developed outside of and prior to a BPA rate case, the *Legal Interpretation* could not address the actual existence of the problem within a rate case or the way the problem would be resolved in that rate case. (*Legal Interpretation* at 10.) This does not alter the fact that the *Legal Interpretation* specifically establishes the principle that section 7(a) will govern BPA's resolution of a conflict between section 7(a) and 7(b)(2): "*BPA will interpret section 7(b)(2) so that implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).*" (*Id.*)

The PCG argues that Section 7(b)(2) requires BPA to set the rates for preference sales so that they will collect no more than an amount as limited by Section 7(b)(2), and pejoratively argues that BPA believes Congress did not mean what it said. (JP1 Br. Ex., WP-07-M-79 at 4.) To the contrary, however, BPA believes Congress meant exactly what it said, but which the PCG's superficial analysis fails to mention. Congress recognized that there could be circumstances where BPA's statutory obligation to recover its total costs under section 7(a) of the Northwest Power Act could conflict with section 7(b)(2), and therefore did not make the rate step language absolute. Congress did <u>not</u> say in section 7(b)(2) that "the amounts to be charged . . . <u>*shall*</u> not exceed in total" a calculated amount. Instead, Congress said that "the amounts to be charged . . . <u>*may*</u> not exceed in total" a calculated amount. 16 U.S.C. § 839e(b)(2) (emphasis added). Indeed, the legislative history of the Northwest Power Act confirms this intent. A floor statement by Representative Swift states:

> Throughout legislative consideration of this bill, however, there was also repeated discussion and concern about the difference between mandatory provisions and discretionary provisions. Therefore, the simplest point to make for the record is that where the bill uses the word "shall", it means "shall", not "may".

Congressman Swift, Congressional Record, Extensions of Remarks, (Dec. 1, 1980), page E 5092.

Congress thus recognized that section 7(b)(2) is not absolute and there are circumstances where section 7(a) must take precedence over section 7(b)(2). Indeed, Congress affirmed this principle in the legislative history of the Northwest Power Act:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject 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, BPA is required by the legislation to establish the following rates:
>
> A. The lowest rates [PF rates] will be reserved for the normal loads ("general requirements") of preference utilities and for the power sold to utilities under the section 5(c) exchange provisions for service to their residential and small farm loads (section 7(b)(1)).
>
> * * *
>
> 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.

H.R. Rep. No. 96-976, Part II, 96th Cong., 2d Sess. 36 (1980) (emphasis added). The foregoing language provides that the establishment of the PF rate for preference customers, which includes the section 7(b)(2) rate step used in developing that rate, is "[s]ubject to the general requirement (contained in section 7(a))" that BPA's rates be set to recover BPA's total costs. *Id*.

Also contrary to the PCG's assertions, Section 7(b)(2) describes using amounts projected under hypothetical assumptions to calculate a credit to 7(b)(2) customers as part of BPA's rate design, *not* the setting of final rates to be charged to such customers. *Compare* Section 7(b)(2) with Sections 7(b)(1), 7(c)(1) and 7(f) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(2), 839e(b)(1), 839e(c)(1), 839e(f).

Also, as BPA's *Implementation Methodology* concluded, such crediting will not necessarily be the last rate step, given BPA's need to assure recovery of all of its costs. BPA's *Implementation*

Methodology (which was adopted in 1984 when BPA was preparing to first implement the 7(b)(2) test) states:

> The section 7(b)(2) rate test, up to and including the point at which the test year amount is determined, is conducted outside the mainstream of BPA's rate development process. While the rate test reflects the assumptions used in the rate proposal, the rate test has no impact on BPA's rates until the test year amount is included in BPA's rate design. At this point, any adjustment made to reflect the rate test results in BPA rates must be done within the overall framework of the rate development process and of BPA's ratemaking objectives and statutory requirements. Therefore, the section 7(b)(2) rate test will be conducted and a test year determined as outlined in section 7(b)(2). *The test year amount will then be included as a step in BPA's rate design process, consistent with other statutory provisions and BPA's ratemaking objectives*.

(*Implementation Methodology* at 9-10; emphasis added.)

The PCG argues that BPA's reliance on the *Implementation Methodology* for the proposition that the 7(b)(2) rate step is not the last step in BPA's ratemaking is misplaced. (JP1 Br. Ex., WP-07-M-79 at 6.) The PCG argues that the language BPA quotes simply notes that one interim step in the process of developing rates, calculating the aggregate cost that is reallocated to non-preference rates, does not complete the rates process. (*Id*. at 6-7.) The cited language, however, states that the "test year amount will then be included as a step in BPA's rate design process, consistent with other statutory provisions and BPA's ratemaking objectives." (*Implementation Methodology* at 9-10.) This refers to the allocation of the test year amount, or 7(b)(3) reallocation amount, which allocates costs after the 7(b)(2) rate step to other loads, if such loads exist. The Section 7(b)(2) rate step and 7(b)(3) reallocation are "outside the mainstream of BPA's rate development process" and are conducted within the framework of (i) BPA's rate development process, (ii) BPA's ratemaking objectives, and (iii) BPA's statutory requirements, such as Section 7(a). The Section 7(b)(2) rate step thus is not BPA's only rate directive, it is not BPA's controlling or ultimate rate directive, and it is not a "rate ceiling" that creates an absolute limit on the PF Preference rate. Sections 7(b)(2) and 7(b)(3) must be consistent with "other statutory provisions," such as section 7(a) of the Northwest Power Act.

The PCG also argues that BPA cannot allow "the amounts to be charged" to preference customers to exceed what the Northwest Power Act says they may not exceed based solely on the order in which BPA chooses to do the arithmetic. (JP1 Br. Ex., WP-07-M-79 at 7.) The PCG has mischaracterized the issue and BPA's position. BPA does not claim that it can use "an order of arithmetic" to improperly conduct the 7(b)(2) rate step. Instead, BPA has conducted the 7(b)(2) rate step in its entirety and has allocated the full trigger amount, consistent with section 7(b)(3), to non-preference rates. BPA, however, must still recover its total costs, including the REP settlement costs. These are costs that are not otherwise allocated under section 7 of the Act and therefore are allocated to rates as provided in section 7(g). This is not simply a matter of the "order of arithmetic."

Despite the foregoing statutory language and legislative history, the PCG argues that Section 7(b)(2) sets an absolute upper limit on what BPA can charge its preference customers for power. (JP1 Br., WP-07-M-62 at 2.) The PCG cites BPA's *Implementation Methodology* as requiring that the PF Preference rate may not exceed, in total, the amount calculated under Section 7(b)(2):

> Section 7(b)(2) of the Regional Act (16 U.S.C. 839e(b)(2)) requires that after July 1, 1985, the rates charged by BPA for firm power sold to public body, cooperative and federal agency customers ("7(b)(2) customers") may not exceed, in total, as determined by the BPA Administrator, such customers' power costs for their general requirements, under five specified assumptions. In other words, the Administrator, before establishing rates to be charged the 7(b)(2) customers for wholesale firm power sold them after July 1, 1985, must compare two numbers: the average amount BPA would charge them over a five-year period pursuant to the general ratemaking guidelines found elsewhere in the Regional Act ("the program case amount") and the average cost of power to them over the same five-year period pursuant to those guidelines and, in addition, pursuant to the five assumptions listed in section 7(b)(2) ("the 7(b)(2) case amount"). If, upon comparison of the two numbers, the 7(b)(2) case amount is smaller than the net program case amount, then the 7(b)(2) customers will be charged the sum representing the total program case amount less the difference between the net program case amount and the 7(b)(2) case amount. The purpose of section 7(b)(2), then, is to afford BPA's preference customers rate protection in the event that other provisions of the Regional Act (in particular, the power exchange program with the investor owned utilities) would otherwise increase the price of power sold them.

(*Implementation Methodology* at 3.) The foregoing excerpt from the *Implementation Methodology ROD* affirms that Congress noted that "the amounts to be charged . . . <u>*may*</u> not exceed in total" a calculated amount, not "*shall* not exceed in total" a calculated amount. 16 U.S.C. § 839e(b)(2). In addition, the language describes the general manner in which the 7(b)(2) rate step normally occurs, that is, in a circumstance where there is no conflict between the rate step and BPA's statutory obligation to recover its costs under Section 7(a) of the Northwest Power Act. As noted above, however, the *Legal Interpretation* and *Implementation Methodology* also recognize that Section 7(b)(2) does not establish an absolute rate ceiling because such circumstances can occur. Furthermore, as noted below, BPA's preference customers have admitted that the Section 7(b)(2) rate step does not establish an absolute "rate ceiling."

In BPA's original rebuttal testimony (Keep, *et al*., WP-07-E-BPA-37), BPA noted the preference customers' admission that there is no absolute rate ceiling, citing the WPAG reply brief in challenges to BPA's 2002 power rates in *Golden Northwest Aluminum v. Bonneville Power Administration,* Nos. 03-73426, *et al*. (*Golden Northwest*). The Hearing Officer granted a motion to strike BPA's reference to WPAG's reply brief. (Order, WP-07-O-27.) The Hearing Officer noted, however, that "such argument, which can be made by asking for official notice of a previously submitted document, is properly in the realm of the briefing process." (*Id*. at 2.) BPA therefore, consistent with the Hearing Officer's order, takes official notice, in this briefing and ROD development process, of WPAG's reply brief in challenges to BPA's 2002 power rates in *Golden Northwest*. WPAG's brief states:

> There is only one conceivable way that a conflict could arise between the revenue sufficiency requirement of section 7(a) and the rate test and cost reallocation directives of sections 7(b)(2) and (3). Such a conflict *could* arise if the costs that must be excluded from the preference customer rate, and allocated to the rates for "all other power sold by the Administrator" pursuant to sections 7(b)(2) and (3) would raise such rates to a level that the non-preference customers could not or would not purchase enough power to recover all of the reallocated costs. In such a limited case, the ability of BPA to collect from non-preference customers the full costs reallocated to their rates under sections 7(b)(2) and (3) could jeopardize BPA's ability to collect sufficient revenues to cover its total costs. *Such a situation would violate the revenue sufficiency test set out in section 7(a), and would require BPA to take action to reconcile these two directives.*

(WPAG Reply Brief at 5.) (second emphasis added). The situation WPAG describes existed in BPA's Initial Proposal in the current rate case, where there were no loads subject to reallocation. There were no DSI loads. (Keep, *et al*., WP-07-E-BPA-27 at 23.) There were no IOU requirements loads or other NR loads. (Load Resource Study, WP-07-E-BPA-01 at 8.) Also, the 7(b)(3) reallocation amount made the PF Exchange rate so high that there were no REP loads. (Keep, *et al*., WP-07-E-BPA-27 at 11.) In such circumstances, BPA must recover any remaining 7(b)(3) reallocation amount from BPA's preference customers. 16 U.S.C. § 839e(a)(1).

In its brief on exceptions, the PCG then argues that BPA incorrectly cited WPAG's reply brief in *Golden Northwest Aluminum, Inc., et al. v. Bonneville Power Administration*, Nos. 03-73426, *et al*., as acknowledging that section 7(a) must prevail over section 7(b)(2) in such circumstances. (*Id.*) The PCG, however, has misstated BPA's citation. BPA instead stated that WPAG "admitted that Section 7(b)(2) does not establish an absolute 'rate ceiling.'" (Draft ROD at 10-11.) The PCG also argues that WPAG's brief says that an agency is obligated to give effect to all of a statute's provisions. (*Id*. at 5.) The cited section of the WPAG brief, however, does not make this statement. WPAG's reply brief acknowledges that there is a "way that a conflict could arise between the revenue sufficiency requirement of section 7(a) and the rate test and reallocation directives of sections 7(b)(2) and (3)." (WPAG Reply Br. at 5.) WPAG acknowledges that "the ability of BPA to collect from non-preference customers the full costs reallocated to their rates under sections 7(b)(2) and 7(b)(3) could jeopardize BPA's ability to collect sufficient revenues to cover its total costs." (*Id.*) WPAG admits that "[s]uch a situation would violate the revenue sufficiency test set out in section 7(a), and would require BPA to take action to reconcile these directives." (*Id.*)

Conflicts between section 7(a) and section 7(b)(2) can be either reconcilable in some manner or irreconcilable. In the latter event, BPA's ability to recover its total costs must take precedence over section 7(b)(2). As explained previously, BPA must comply with section 7(a) in developing its rates. Otherwise, BPA cannot receive FERC approval of its rates. 16 U.S.C. § 839e(a)(2). Without FERC approval, BPA would not have valid rate schedules and could not collect any revenues from its customers. Without revenues, BPA would cease to function. This is why section 7(a) is BPA's paramount rate directive. Because BPA must comply with section 7(a), the resolution of an irreconcilable conflict between section 7(a) and section 7(b)(2) is for section 7(a) to prevail over section 7(b)(2) in the event of such a conflict. In this case the conflict is irreconcilable. It is not appropriate, as the PCG contends, for BPA to act contrary to law in another area of section 7(b)(2) in order to correct a conflict between section 7(a) and 7(b)(2).

The PCG also argues that WPAG's reply brief does not state that BPA should fail to implement section 7(b)(2) and 7(b)(3). (JP1 Br. Ex., WP-07-M-79 at 5.) BPA agrees that it should not fail to implement these provisions. Despite the conflict between section 7(a) and 7(b)(2), BPA has still conducted the 7(b)(2) rate step in its entirety and has allocated the full trigger amount, consistent with section 7(b)(3), to non-preference rates. BPA, however, must still recover its total costs, including the REP settlement costs. These are costs that are not otherwise allocated under section 7 of the Act and therefore are allocated to rates as provided in section 7(g).

The PCG notes that in BPA's Initial Proposal, the rate step triggered and $40 million was to be allocated to non-preference rates, but because there were no non-preference loads, the $40 million had to be allocated to BPA's preference customers. (JP1 Br. Ex., WP-07-M-79 at 11-12.) The PCG claims this indicates BPA did not plan to give full effect to section 7(b)(2). (*Id.*) This is incorrect. The PCG ignores the fact, previously admitted by preference customers, that there can be a conflict between BPA's requirement under section 7(a) to recover its total costs through rates and the section 7(b)(2) rate step. In the Rate Design Step, as the PCG admits, the rate step triggered and "there were no other customers to whom this $40 million could be reallocated." (JP1 Br. Ex., WP-07-M-79 at 11.) If there are no other customers from whom a reallocation amount can be recovered, BPA must recover such costs from BPA's remaining customers (preference customers) in order that BPA can recover its total costs through rates as required by law. Contrary to the PCG's claims, this does not show that BPA did not plan to give full effect to section 7(b)(2). Instead, it shows that BPA gave full effect to section 7(b)(2), but when a trigger amount occurred, BPA was precluded from allocating that amount to non-preference customers because such customers did not exist, yet BPA had to recover such costs to comply with section 7(a) of the Northwest Power Act.

6. Treating Section 7(b)(2) of the Northwest Power Act as an Absolute "Rate Ceiling" Would Produce Inadequate BPA Revenues and Thus Fail to Comply with Section 7(a) of the Act

The IOUs argue that the PCG erroneously characterizes Section 7(b)(2) as an absolute "rate ceiling." (JP6 Br., WP-07-M-67 at 10.) The IOUs note the PCG's assertion that BPA (i) used flawed cost assumptions in performing the Section 7(b)(2) rate step and (ii) proposed a PF Preference rate that disregards the results of the Section 7(b)(2) "rate ceiling." (*Id.* citing Saleba, *et al.*, WP-07-E-JP1-01 at 9.) The PCG states it "modified" BPA's "flawed assumptions" and performed the Section 7(b)(2) rate step using its "modified" assumptions. (*Id.*) The PCG treats the results of its performance of the Section 7(b)(2) rate step as an absolute "rate ceiling":

> The revenues that BPA could collect from its preference customers at a rate no higher than the section 7(b)(2) rate ceiling calculated by BPA and by us are

> $4,889 million for the rate period. The amount BPA projects to collect from the preference customers under the PF rate it develop[s] by deviating from the requirements of its own Legal Interpretation and *Implementation Methodology* is $5,791 million. Thus, BPA proposes to charge the preference customers $902 million more than the proper implementation of the section 7(b)(2) rate ceiling allows. This translates into an average PF Preference rate that is $5.02/MWhr. above the section 7(b)(2) rate ceiling.

(Saleba, *et al*., WP-07-E-JP1-01 at 13.)

First, as discussed above, BPA did not calculate a "rate ceiling" of $4,889 million. Second, the PCG's calculation is based only on the preliminary 7(b)(2) step. The 7(b)(2) rate step used a forecast of the REP in the Program Case. BPA, however, will likely incur greater costs from the REP settlements. This is why BPA used two steps, the Rate Design Step and the Subscription Step, in developing BPA's rates. Because the REP settlement costs have not been considered in the PCG's calculation of the PF Preference rate, it grossly understates BPA's costs (which must be recovered under Section 7(a)(1) of the Northwest Power Act) and grossly understates the level of the PF Preference rate.

In addition, the PCG asserts that, as a result of the "rate ceiling," BPA is required to reduce its proposed average PF Preference rate by $5.02/MWh. (JP6 Br., WP-07-M-67 at 11.) The IOUs' rebuttal testimony analyzed the effects on BPA's projected revenues of reducing the proposed average PF Preference rate by $5.02/MWh. (*Id*. citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 18.) The IOUs' rebuttal testimony made a cash adjustment of negative $902 million in the ToolKit model supplied with BPA's Initial Proposal, which is equivalent to a $5.02/MWh reduction of the proposed average PF Preference rate. (*Id.*) This adjustment resulted in a TPP of 59.8 percent and left intact BPA's assumption that the CRACs reflected in BPA's ToolKit model are available and timely implemented. (*Id.*)

The $902 million is taken from the testimony of the PCG discussed above, which asserted that BPA was proposing a PF Preference rate that would overcollect $902 million under that rate. (*Id.*) Accordingly, the IOUs' rebuttal testimony analyzed the effect of removing $902 million of BPA revenues. (*Id.*) It should be noted that BPA's ToolKit model treated IOU REP settlement benefits as a variable factor and generated thousands of "games" or scenarios, in which the IOU REP settlement benefits for FY 2008 and FY 2009 varied from $123 million to $323 million annually. (*Id.*) The ToolKit model simply did not assume that IOU REP Settlement benefits would equal $902 million over the 3-year rate period. (*Id.*) The distribution of the level of IOU REP settlement benefits generated by the thousands of scenarios is shown at pages 150, 154, 158, and 162 of the Documentation for the Risk Analysis Study, WP-07-E-BPA-04A. (*Id.*) This distribution reflects, for example, IOU REP settlement benefits of less than $202 million for a substantial portion of the scenarios for FY 2008 and less than $214 million for a substantial portion of the scenarios for FY 2009. (*Id. citing* Documentation for Risk Analysis Study, WP-07-E-BPA-04A, at 150, 154, 158, and 162.)

BPA has established a TPP standard of 92.6 percent for the WP-07 rate case. (Leathley, *et al*., WP-07-E-BPA-08 at 8.) A 59.8 percent TPP is far below BPA's minimum TPP standard of

92.6 percent for the rate period. (*Id.; see* "2007 Wholesale Power Rate Adjustment Proceeding," 70 Fed. Reg. 67,685, 67,692 (Nov. 8, 2005)). A TPP level of at least 92.6 percent is a BPA "key policy directive for rate-setting." (Leathley, *et al*., WP-07-E-BPA-08 at 8.) BPA power rates that result in a 59.8 percent TPP are therefore not acceptable to BPA (and most likely would not be acceptable to FERC) and, even if adopted and approved, would result in a BPA revenue shortfall. (JP6 Br., WP-07-M-67 at 12.) Because of such revenue shortfall, BPA would have no option but to restore the PF Preference rate to the rate it has initially proposed in order to achieve an acceptable TPP. (*Id*.) Making the "modification" of the Section 7(b)(2) cost assumptions asserted by the PCG would, in light of BPA's need for rates to recover all of its costs, result in no change in the PF Preference rate that BPA ultimately adopts. (*Id*. citing Brattebo, *et al*, WP-07-E-AC-GE-IP-PL-PS -07 at 18.)

The Section 7(b)(2) rate step cannot be treated as an absolute "rate ceiling" that results in BPA setting rates that fail to fully recover its costs. (JP6 Br., WP-07-M-67 at 12.) Treating the Section 7(b)(2) rate step as an absolute "rate ceiling" would be particularly problematic because, as acknowledged by the JP1 Parties, the Section 7(b)(2) rate step relies on an "alternative set of costs and rates using . . . hypothetical assumptions." (*Id*. citing Saleba, *et al*., WP-07-E-JP1-01 at 3.)

The PCG argues that the IOUs note that if the PF Preference rate were set no higher than after the 7(b)(2) rate step, and BPA met its contractual obligations to the IOUs, then BPA would have only a 59 percent probability of making its next Treasury payment. (JP1 Br., WP-07-M-62 at 15.) Therefore, the IOUs note than Section 7(b)(2) is not a rate ceiling. (*Id*.) The PCG argues that the REP Settlement Agreements are beyond BPA's authority because current facts do not support the payment of REP benefits. (*Id*.) PCG's argument, however, is misplaced. The WP-07 rate case is establishing BPA's power rates only for the FY 2007-2009 rate period. This proceeding is not establishing or determining the validity of BPA's 2000 REP Settlement Agreements with the IOUs. These Agreements were previously established, are the current basis for providing REP settlement benefits to residential and small farm consumers of the IOUs, and are currently in litigation.

Furthermore, the PCG is incorrect in arguing that the 2000 REP Settlement Agreements are beyond BPA's authority because they allegedly are not supported by "current facts." When BPA developed the 2000 REP Settlement Agreements, BPA settled numerous disputes with the IOUs regarding implementation of the REP. BPA, taking official notice of its "Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision" (REP Settlement Agreement ROD), notes that there are two primary issue areas that must be resolved when settling REP disputes: (1) challenges to BPA's implementation of the REP using the 1984 Average System Cost Methodology (ASC Methodology) (*e.g.*, issues regarding the exclusion of return on equity and income taxes from ASCs), and (2) challenges to BPA's implementation of Section 7(b)(2) (*e.g.*, issues regarding uncontrollable events and including Mid-Columbia resources in the 7(b)(2) Case resource stack). (REP Settlement Agreement ROD at 49-52.) The IOUs' claims and disputes regarding the REP for the FY 2002-FY 2006 period were substantial:

- a return from the 1984 ASC Methodology to the 1981 ASC Methodology, as advocated by the IOUs, would "dramatically" increase REP benefits for the FY 2002-FY 2006 period to approximately $1.615 billion (*id.* at 50);

- if the IOUs succeeded in their claims with respect to BPA's PF Exchange rate, benefits for the residential and small farm consumers served by IOUs would be $1.4 billion for the FY 2002-FY 2006 period and substantially greater than benefits under the 2000 REP Settlement Agreements (*id.* at 52); and

- the REP Settlement ROD recognized that the REP claims of the IOUs could "dwarf" the difference between BPA's rate case forecasts of REP benefits and REP settlement benefits (*id.*).

BPA offered REP Settlement Agreements that it forecast to cost $140 million per year to settle claims substantially in excess of $300 million per year. (*Id*. at 49-52, 78.)

The PCG fails to recognize that the 2000 REP monetary settlements resolved REP disputes for 10 years without changing the underlying sources that created the disputes. This is typical of settlements. For example, reaching a monetary settlement of issues regarding the application of BPA's 1984 ASC Methodology does not change the ASC Methodology itself. Thus, a rate case forecast of REP benefits might be based on the 1984 ASC Methodology, although REP settlement payments could properly exceed this forecast amount because they are based on the settlement of all disputes arising under the 1984 ASC Methodology and Section 7(b)(2), which would have exposed BPA to REP costs far greater than forecast in the rate case. If, as the PCG implies, BPA can only settle REP disputes for the amount of REP benefits forecast in BPA's rate case, BPA could never settle such disputes. This is because the rate case reflects BPA's litigation positions, which are subject to being reversed on appeal. Under the PCG's position, a settlement could occur only if BPA were to insist that the settlement should be based on the assumption that BPA would win every issue. Obviously, it would be nearly impossible for parties to reach a settlement where one party insists the settlement would reflect only its litigation positions and would reject the other party's positions entirely. The PCG basically argues that it should receive the benefits of BPA's REP settlements, which allow BPA and its preference customers to avoid the substantial risk of high REP payments if the IOUs were to prevail on their claims, but preference customers should not pay any cost associated with obtaining such benefits. This makes little sense.

The PCG argues that BPA ignored approximately $900 million of REP settlement costs that it expects to incur during the rate period. (JP1 Br., WP-07-M-62 at 4.) To the contrary, BPA has not ignored the REP settlement costs. As explained elsewhere in this ROD, BPA allocates such costs under Section 7(g) of the Northwest Power Act because such costs are costs not otherwise allocated under Section 7 of the Act. 16 U.S.C. § 839e(g). PCG also states that because REP settlement costs would be ignored in the 7(b)(2) Case in any event, this did not affect the $4,899 million that BPA calculated the PF Preference rate may not exceed in total. (JP1 Br., WP-07-M-62 at 4.) In addition to erroneously claiming that $4,899 million is a cap on the PF Preference rate, this argument lacks merit because it focuses on only one part of the 7(b)(2) rate step; that is, the 7(b)(2) Case. The 7(b)(2) rate step has *two* parts: the Program Case and the 7(b)(2) Case. By ignoring the Program Case, the PCG distorts the true level of the PF Preference rate. The PCG's argument also ignores BPA's statutory obligation to recover its total costs through rates. Development of the Program Case using the REP was necessary for the proper development of BPA's rates. Regardless of whether the Program Case was developed using the REP or REP settlement costs, however, makes little difference. In either event there is a significant rate step trigger. Consequently, there is a need to allocate the reallocation amount to other loads. If there are no non-preference loads, the reallocation amount must be allocated to the PF Preference rate.

The PCG acknowledges that this rate case is not the place to review the propriety of BPA's REP Settlement Agreements with the IOUs, which BPA has always contended are lawful. (JP1 Br. Ex., WP-07-M-79 at 11.) The PCG argues that BPA's REP settlements do not supersede the law. (*Id.*) BPA agrees. The REP settlements are consistent with the law, including section 7(b)(2), as explained at length in BPA's REP Settlement Agreement ROD and before the court in pending litigation. Also, contrary to the PCG's argument, the REP Settlement Agreements do not make section 7(b)(2) impossible to reconcile with section 7(a). BPA's rate proposals, including the section 7(b)(2) rate step and other statutory ratemaking directives, contain many facts and requirements. An irreconcilable conflict between section 7(a) and 7(b)(2) does not arise from a single fact or requirement, but from the interaction among all such elements. Each BPA rate case, and the establishment of BPA's rates, must be reviewed based on its unique circumstances.

Decision

Section 7(b)(2) of the Northwest Power Act does not establish an absolute rate ceiling for the PF Preference rate.

10.3 REP Forecasts In BPA's Program Case

Issue 1

Whether BPA's Program Case properly includes a forecast REP.

Parties' Positions

The PCG argues that the Program Case must reflect all costs, sales, revenue, and other assumptions and all methodologies used by BPA to develop the PF Preference rate in the relevant rate proceeding except for the effects of Section 7(b)(2) itself. (JP1 Br., WP-07-M-62 at 7.) The PCG argues the Program Case should reflect the REP settlement and not the REP. (*Id.*)

BPA's Position

Because Section 7(b)(2), BPA's *Legal Interpretation* and BPA's *Implementation Methodology* are based on reflecting the REP in the Program Case, and because it was not possible to reflect a monetary settlement of REP disputes in the Program Case without rejecting a fundamental assumption of the rate step and creating absurd results, BPA properly reflected a forecast REP in the Program Case, later adjusting to reflect BPA's REP settlement costs. (Keep, *et al*., WP-07-E-BPA-27 at 8-9; Keep, *et al*., WP-07-E-BPA-37 at 5-7.) The inclusion of REP settlement costs in the Program Case also would have resulted in the same level of the PF Preference rate determined by BPA. (Keep, *et al*., WP-07-E-BPA-37 at 12-13.)

Evaluation of Positions

BPA developed its WP-07 power rates using a computer model called RAM2007. (Keep, *et al*., WP-07-E-BPA-27 at 5.) RAM2007 has three main steps: a Rate Design Step, a Subscription Step, and a Slice Separation Step. (*Id*. at 7.) This stepped ratemaking is similar to that used in RAM2002 for BPA's WP-02 rate case. (*Id*.) RAM2002 developed rates in a two-step process. (*Id*.) In 2002, Program Case rates for the 7(b)(2) Rate Test were calculated in the Rate Design Step using all costs including a forecast of gross exchange costs for the IOUs. (*Id*.) BPA then conducted a Subscription Step to calculate rates assuming the IOUs had signed their Subscription REP Settlement Agreements. (*Id*.)

The RAM2007 Rate Design Step follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Exchange resources, and new resources) used to serve sales load and then allocating those costs to the rate pools (PF, IP, and NR). (*Id*.) After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in Sections 7(b) and Section 7(c) and, if necessary, Section 7(a) of the Act. (*Id*.) RAM2007 performs these rate adjustments, including the 7(b)(2) rate test, in its Rate Design Step. (*Id*. at 8.) The Rate Design Step of RAM2007 concludes with the calculation of the Rate Design Step rates. (*Id*.) At this point in the modeling, all posted rates are still preliminary except for the PF Exchange rate, which is set and is then used to calculate the net cost of any public utility participation in the REP or IOU participation in the absence of the REP Settlement Agreements. (*Id*.)

RAM2007 includes a Subscription Step to calculate power rates, which includes the costs of the IOUs' Subscription REP Settlement Agreements. (*Id*.) The Subscription Step takes the results of the Rate Design Step and adjusts them by first subtracting any net cost of the traditional REP for the IOUs that has been included in the Rate Design Step rates, and then adding the costs of the IOU REP Settlement Agreements. (*Id*.)

In BPA's WP-02 rate case, BPA did not know whether the IOUs would elect to continue participation in the REP or instead choose to participate in REP settlements. In the WP-07 rate case, BPA knows that the IOUs have chosen to sign the REP Settlement Agreements. (*Id*.) BPA, however, must continue to forecast IOU ASCs and exchangeable load in the 7(b)(2) rate test for a number of reasons. (*Id*.) The Section 7(b)(2) rate test compares Program Case rates with 7(b)(2) Case rates. (*Id*.) Section 7(b)(2) of the Northwest Power Act provides that the REP does not exist in the 7(b)(2) Case. (*Id*.) Historically, BPA has always conducted the 7(b)(2) rate test with the REP reflected in the Program Case and the REP absent from the 7(b)(2) Case. (*Id*.) BPA has continued this comparison in conducting the 7(b)(2) rate test by forecasting the IOUs' participation in the REP in the Program Case. (*Id*.)

Also, the PF Exchange rate is used to determine exchanging utilities' benefits under the REP. (*Id*. at 9.) Historically, the size of the REP has been a large factor in determining whether the 7(b)(2) rate test will trigger. (*Id*.) Also, the costs to be reallocated due to the 7(b)(2) rate test trigger have been largely allocated to the PF Exchange rate. (*Id*.) This relationship between the size of the REP and the magnitude of the costs represented by the 7(b)(2) reallocation amount that are reflected in the PF Exchange rate is preserved by forecasting IOU participation in the REP in the Rate Design Step. (*Id*.) In the Rate Design Step BPA conducts the 7(b)(2) rate test, which determines the PF Exchange rate. (*Id*.)

In the WP-02 rate case, the Subscription Step assumed that regional IOUs executed proposed settlements of the REP instead of electing to participate in the REP. (*Id*.) BPA then allocated the costs of such settlements to rates in the Subscription Step. (*Id*.) The IOU REP settlements have now occurred and BPA now knows the costs of the Amended Settlement Agreements that provide a floor and a cap to settlement benefits. (*Id*.) BPA is continuing the methodology developed in the WP-02 rate case of allocating settlement costs in the Subscription Step. (*Id*.) In the WP-07 rate case, however, BPA is allocating the actual FY 2007 and the forecast FY 2008-2009 costs of these settlements instead of allocating assumed settlement costs. (*Id*.)

The PCG argues that the Program Case must reflect all costs, sales, revenue, and other assumptions and all methodologies used by BPA to develop the PF Preference rate in the relevant rate proceeding except for the effects of Section 7(b)(2) itself. (JP1 Br., WP-07-M-62 at 7.) The PCG quotes the *Implementation Methodology* and *Legal Interpretation* as defining the "Program Case" as:

> The entire process of projecting rates to be charged in the future under the provisions of the Northwest Power Act other than section 7(b)(2), including specific data, assumptions and results.

(*Id*. at 5 citing *Implementation Methodology* at 38; *Legal Interpretation* at 5.)

The *Legal Interpretation* also states that "Section 7(b)(2) requires BPA to assume the section 7(b)(2) Case is identical to the Program Case except for those differences required by the five assumptions set out in section 7(b)(2)(A)-(E)." (*Legal Interpretation* at 9.)

The *Implementation Methodology* provides:

> The program case is the five-year projection of power costs for serving the general requirements of the 7(b)(2) customers conforming with all the provisions of the Northwest Power Act, but without considering the effects of section 7(b)(2). 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 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. Input data for the ensuing four years will be consistent with or extrapolated from test year data. Ratemaking methodologies,

> such as those based on the "post-85" rate directives in the Northwest Power Act and those used to allocate costs and revenue adjustments to BPA customer classes, will be unchanged over the five-year rate test period.
>
> * * *
>
> In summary, the program case will be BPA's best projection of its rates without considering the effects of section 7(b)(2). The exact methodology for the rate calculation in the program case cannot be determined until BPA has prepared its rate proposal. However, the rate test model will reflect the proposed methodology as completely as possible in producing the program case when the [7(b)(2)] rate test is conducted for that rate proposal.

(*Implementation Methodology* at 39-40).

The *Implementation Methodology* defines the "7(b)(2) Case" as follows:

> The entire process of projecting rates for the relevant [test] period under the provision of section 7(b)(2) of the Northwest Power Act, including specific data, assumptions and results.

(*Implementation Methodology* at 38.) Also, the *Implementation 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." (*Id*. at 41.) Similarly, the *Implementation Methodology* provides:

> The PF rate in the program case will be developed in the same manner as it is in BPA's rate proposal. The 7(b)(2) rate in the 7(b)(2) case will include the costs of resources required to serve the 7(b)(2) customers, along with all other costs and revenue adjustments not excluded by the assumptions in Section 7(b)(2). These costs and revenue adjustments include BPA administrative and general costs, fixed rate contract revenue deficiencies, and surplus firm power revenue deficiencies.

(*Implementation Methodology* at 44.) The PCG argues that the foregoing provisions require that the identical costs, revenues, and assumptions and methodologies upon which BPA bases its rates in the rate case be used for both the Program Case and the 7(b)(2) Case with only two exceptions: the Program Case excludes only the effects of Section 7(b)(2); and the 7(b)(2) Case is modified only to reflect the assumption in 7(b)(2). (JP1 Br., WP-07-M-62 at 7; JP1 Br. Ex., WP-07-M-79 at 8.) The PCG argues that BPA should have included the cost of the REP settlements in the Program Case instead of including a forecast REP and adjustment to reflect actual settlement costs. (*Id*..)

In response to the PCG's arguments, it should first be noted that this issue concerns the development of the Program Case. As the *Implementation Methodology* notes, the Program Case is 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 proposal methodology and data. (*Implementation Methodology* at 39-40.) The *Implementation Methodology,* however, which was established after BPA's *Legal Interpretation*, recognizes that the Program Case may not be able to mirror all of the assumptions in BPA's rate proposal. The Methodology provides that "[a]ll 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*." (*Implementation Methodology* at 39-40) (emphasis added). The *Methodology* also notes that "the rate test model will reflect the proposed methodology *as completely as possible* in producing the program case when the [7(b)(2)] rate test is conducted for that rate proposal." (*Id*.) The *Methodology* therefore recognizes the possibility that the Program Case might not be able to be identical to the rate proposal. The instant case involves circumstances where reflecting only REP settlement costs in the Program Case would create an absurd result. BPA therefore properly reflected a forecast REP in developing the Program Case.

Also, in the instant case, BPA has REP settlement agreements with the IOUs that extend through 2011. BPA's preference customers, however, have challenged the validity of those Agreements in court. (Keep, *et al*., WP-07-E-BPA-37 at 8-9.) *See Portland General Electric Co., et al. v. Bonneville Power Administration*, Nos. 01-70003, *et al*. The parties are currently waiting for the court to issue an opinion regarding the validity of the 2000 REP Settlement Agreements. (*Id*.) If the preference customers prevail in their challenge, the REP Settlement Agreements may be eliminated and the IOUs could participate in the REP through RPSAs, *even during the WP-07 rate period*. (*Id*.) Absent the REP settlements, both IOUs and public agencies can participate in the REP. (Keep, *et al*., WP-07-E-BPA-37 at 8-9.) Because there is the possibility that utilities will be participating in the REP during the rate period, it is reasonable to reflect such participation in the Program Case. This is particularly true in light of the statutory relationship of the REP and Section 7(b)(2), as discussed below.

The PCG argues that nothing in Section 7(b)(2) or Section 7(g) or any other provision excludes BPA settlement payments from the limitation in Section 7(b)(2) of the amount that can be charged to preference customers. (JP1 Br., WP-07-M-62 at 12.) The first error in this argument is that, as noted previously, there is no absolute limit to the amount to be charged preference customers. Second, contrary to the PCG's argument, Section 7(b)(2) of the Northwest Power Act reflects implementation of the 7(b)(2) rate step with the traditional REP. Section 5(c) of the Northwest Power Act established the REP. BPA has a statutory obligation to participate in the REP with each regional utility upon the utility's request. 16 U.S.C. § 839c(c)(1). In every BPA rate case since 1985, which marked the first implementation of Section 7(b)(2), BPA has always forecast the resources, loads, and costs of the REP when developing rates. As a matter of contrasting the Program Case with the 7(b)(2) Case, Section 7(b)(2) has reflected the REP in the Program Case and its absence in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2). In contrast, Section 7(b)(2) does not reference settlement costs, which are costs not otherwise allocated under Section 7, and therefore are equitably allocated by the Administrator pursuant to Section 7(g). 16 U.S.C. § 839e(g). Thus, the Section 7(b)(2) rate step is conducted by comparing the costs of the Program Case, which has always included resource costs and loads of the REP, with the 7(b)(2) Case, which excludes the costs and loads of the REP and the other four assumptions of Section 7(b)(2). (Keep, *et al*., WP-07-E-BPA-37 at 5-6.) The inclusion of the REP in the Program Case allows Section 7(b)(2) to function properly.

The existence of REP resources and loads directly affects the 7(b)(2) rate step. (*Id*. at 6.) However, including only REP settlement costs in the Program Case, as advocated by the PCG, would create an anomalous and absurd result. (*Id*.) By removing the REP resources and loads from the Program Case, which historically has included such resources and loads, the Program Case would contain $900 million of settlement costs (in addition to other Program Case costs) and no loads. (*Id*.) This would dramatically increase the costs in the Program Case while reducing the loads in the Program Case, thereby creating an artificially and extraordinarily high-cost Program Case rate that would be compared to the 7(b)(2) Case rate, which is unaffected because no REP costs are included in the 7(b)(2) Case. (*Id*. at 6-7.) This would cause an artificially and extraordinarily high trigger and ensuing artificially and extraordinarily high 7(b)(3) reallocation amount. (*Id*. at 7.) This would radically increase the PF Exchange rate, or create an infinite PF exchange rate, and eliminate the possibility of any utility participating in the REP.

Furthermore, there is no indication that Section 7(b)(2), the *Legal Interpretation* or the *Implementation Methodology* considered the possibility of settlements of REP disputes, which create REP settlement costs, but not REP resource costs or loads. (Keep, *et al*., WP-07-E-BPA-37 at 6.) BPA had to implement the Section 7(b)(2) rate step reflecting these unanticipated circumstances. (*Id*.) BPA recognized that the REP settlement benefits are simply monetary payments paid to settling utilities to resolve disputes regarding the manner in which BPA implements the REP. (*Id*.) REP benefits, in contrast, are the benefits provided to exchanging utilities' residential and small farm consumers under implementation of the REP. (*Id*.) The REP is comprised of (1) a power sale from an exchanging utility to BPA at the utility's average system cost in the amount of its residential and small farm loads, and (2) a power sale from BPA to the exchanging utility's residential and small farm loads at the PF Exchange rate in the amount of such loads. (*Id*.) The REP therefore contains both resources and loads. In addition, traditional REP costs and REP settlement benefit costs are allocated differently. (*Id*.) REP costs enter the ratemaking process as the costs associated with REP resources and are allocated to preference and REP loads, if needed, and then to other loads. (*Id*.) REP settlement benefit costs, in contrast, are equitably allocated to power rates. (*Id*.)

The PCG argues that the fact that the REP settlement benefits are simply monetary payments does not justify ignoring them or distinguish them from traditional REP payments because the traditional REP was monetary and the REP settlements provide that they are "in full and complete satisfaction of [BPA's] obligations . . . under or arising out of Section 5(c) of the Northwest Power Act . . .", citing REP Settlement Agreement Section 3(a). (JP1 Br., WP-07-M-62 at 11.) To the contrary, as noted above, the REP settlement benefits are simply monetary payments to settle REP *disputes*. Unlike the REP, the REP settlement benefits involve no power sales, resources, or loads. Also contrary to PCG's argument, the REP was established in the Northwest Power Act as a power purchase and sale transaction. 16 U.S.C. § 839c(c)(1). Even though BPA and other parties did not require the physical purchase and sale of power to implement the REP for practical purposes, BPA has always reflected the REP as a physical purchase and sale in BPA's ratemaking under the Northwest Power Act. In addition, even when monetary payments were made to implement the REP, the Northwest Power Act and Residential Purchase and Sale Agreements implementing the REP continued to provide for actual physical power purchases and sales in specified circumstances. This occurs under Section 5(c)(5) of the Northwest Power Act for "in lieu" transactions. 16 U.S.C. § 839c(c)(5). Section 5(c)(5) of the Northwest Power Act provides that the Administrator, in lieu of purchasing power from an exchanging utility under the REP, can acquire an equivalent amount of power from other sources to replace the power sold to the utility as part of an exchange if the cost of the acquisition is less than the cost of purchasing power from the utility. *Id*. The REP is therefore not simply a monetary payment program.

Similarly, the PCG's citation to provisions of the REP settlements as being "in full and complete satisfaction of [BPA's] obligations . . . under or arising out of Section 5(c) of the Northwest Power Act . . ." has been taken out of context. The REP settlements settled all *disputes* arising under the REP between BPA and the IOUs. BPA logically did not want to enter into a settlement of all REP disputes with the IOUs for the 10-year settlement term only to have the IOUs apply for participation in the REP and receive REP benefits in addition to REP settlement benefits. In order to avoid this double payment problem, BPA and the IOUs agreed that by receiving monetary payments to resolve all REP disputes, the IOUs would agree that the settlement payments would eliminate any obligation BPA had to make REP payments to the IOUs during the 10-year settlement term. This does not make monetary payments to settle disputes regarding the implementation of the REP the same as payments under the REP itself. During more than 20 years of implementing the 7(b)(2) rate step, BPA has always established the PF Exchange rate based, in part, on the forecast resources and loads of the REP. (*Id*.) REP resources and loads have always been part of the Program Case and, when the 7(b)(2) rate step has triggered, the 7(b)(3) reallocation amount has largely been reallocated to the PF Exchange rate. (*Id*.)

The PCG argues that BPA used the forecast REP to develop the PF Preference, NR, IP, and PF Exchange rates, but no sales are forecast under the NR, IP and PF Exchange rates. (JP1 Br., WP-07-M-62 at 9.) BPA notes, however, that absent settlement, the IOUs can participate in the REP. (Keep, *et al*., WP-07-E-BPA-37 at 8-9.) Public agencies also may participate. (*Id*.) BPA also recognizes that changing conditions can increase utilities' ASCs during the rate period and make utilities eligible to receive REP benefits. (*Id*.) BPA has a statutory obligation to participate in the REP with a regional utility upon the utility's request. 16 U.S.C. § 839c(c)(1). In the event a utility makes such a request (whether through invalidity of an REP settlement or an increased ASC), BPA must have an established PF Exchange rate in order to implement the REP. If BPA did not establish a PF Exchange rate, BPA could not implement the REP as required by law. 16 U.S.C. § 839c(c)(1). For this reason, BPA established the PF Exchange rate. Similarly, BPA has the authority, but not the affirmative obligation, to sell power to the DSIs. 16 U.S.C. § 839c(d). In the event BPA exercised this authority during the rate period, BPA had to establish an IP rate. Also, public agencies may acquire new large single loads during the rate period. 16 U.S.C. §§ 839a(13); 839c(a)(1); 839e(f). In order to be able to sell such power, BPA had to establish an NR rate.

Because it was not anticipated that BPA would enter into settlement agreements to resolve disputes arising under the REP when Section 7(b)(2), the *Legal Interpretation* and the *Implementation Methodology* were established, no guidance is provided on how to treat REP settlements in performing the rate step, except that the REP itself is a central assumption in the rate step. (Keep, *et al*., WP-07-E-BPA-37 at 8-9.) BPA's WP-02 rate case addressed this issue by starting with a Program Case reflecting the traditional REP, running the Rate Design Step, calculating the rate step trigger, calculating the reallocation amount, allocating the 7(b)(3) reallocation amount to non-preference rates, then crediting BPA's rates for REP costs avoided by the possible REP settlements, and equitably allocating REP settlement costs to BPA's rates. (*Id.*) This method allowed BPA to recover its costs and to equitably allocate the REP settlement costs, which are costs not otherwise allocated under Section 7 of the Northwest Power Act. (*Id.*) BPA is conducting the 7(b)(2) rate step and 7(b)(3) reallocation in a similar manner in this proceeding. (*Id.*) Because BPA's *Implementation Methodology* does not address the treatment of REP settlements in implementing the 7(b)(2) rate step, BPA's proposal is consistent with the manner in which BPA has previously implemented the *Methodology*, and with BPA's WP-02 rate proceeding. (*Id.*)

Furthermore, the *Legal Interpretation* and *Implementation Methodology* contemplated and recognized that "issues of fact and policy" and "methodologies and data from the rate proposal" not specifically addressed by those documents would be addressed in proceedings such as the current WP-07 proceeding under section 7(i) of the Northwest Power Act. The *Legal Interpretation* states:

> BPA maintains that the issues resolved by this legal interpretation provide the legal determinations necessary in order to develop the 7(b)(2) implementation methodology. BPA does not deny that other issues of fact and policy remain for resolution. These issues, however, are appropriately addressed through other forums which will eventually result in testimony presented in a section 7(i) proceeding under the Northwest Power Act.

(*Legal Interpretation* at 18.) Similarly, the *Implementation Methodology* states:

> The methodology and data from the rate proposal cannot be described in detail in this document. They are properly rate case determinations that are outside the scope of the methodology for implementing section 7(b)(2). The section 7(b)(2) methodology must be flexible enough to incorporate the methodologies and data from the rate proposal for which the 7(b)(2) rate test is being conducted. These methodologies and data, as part of a BPA rate filing are, in turn, subject to review and comment pursuant to section 7(i) of the Northwest Power Act. . . .

Thus, BPA has properly reflected the REP and REP settlements in implementing sections 7(b)(2) and 7(b)(3) of the Northwest Power Act and in developing BPA's WP-07 rates.

The PCG argues that BPA notes at the time the Northwest Power Act was enacted, "it was not anticipated that BPA would enter into Settlement Agreements to resolve disputes under the REP." (JP1 Br, WP-07-M-62 at 11 citing Keep, *et al*., WP-07-E-BPA-37 at 7.) The PCG argues that such settlements were anticipated because Section 9(a) of the Northwest Power Act reaffirms BPA's general contract and settlement authority, which is subject to the provisions of the Northwest Power Act. (*Id.*) This argument is not persuasive. Section 9(a) of the Northwest Power Act reaffirms Section 2(f) of the Project Act. 16 U.S.C. §§ 839f(a), 832a(f). Section 9(a) provides that "[s]ubject to the provisions of this section, the Administrator is authorized to contract in accordance with Section 2(a) of the Project Act of 1937 (16 U.S.C. § 832a(f))." 16 U.S.C. § 839f(a). Section 2(f) of the Project Act, which was enacted before the existence of the REP, provides:

> Subject only to the provisions of this section, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancellation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.

16 U.S.C. § 832a(f). A general grant of contracting and settlement authority does not show a congressional expectation that BPA would resolve all disputes under the REP. Indeed, neither Section 2(f) nor Section 9(a) nor their legislative history even mentions the REP. Similarly, nothing in Section 7 of the Northwest Power Act mentions REP settlements or addresses the allocation of settlement costs. Because such costs are not otherwise allocated under Section 7, they are equitably allocated to power rates under Section 7(g). A general grant of contracting and settlement authority does not support a conclusion that specific disputes would be resolved. The PCG has failed to point to any statutory provision in the Northwest Power Act, or any other act, that assumes an REP settlement would occur.

In its brief on exceptions, the PCG reiterates its erroneous argument that Congress anticipated REP settlements. (JP1 Br. Ex., WP-07-M-79 at 9.) The PCG then argues that because the "amounts to be charged" preference customers in the Program Case "may not exceed in total" the amounts calculated in the 7(b)(2) Case, it is irrelevant whether Congress anticipated whether BPA might settle REP disputes or whether the payments are allocated under section 7(g). (*Id.* at 10.) This argument fails, however, because it ignores that, as established previously, the 7(b)(2) rate step is not the final step in establishing BPA's rates. Furthermore, it ignores that there can be an irreconcilable conflict between section 7(a) and section 7(b)(2), in which case BPA's statutory obligation to recover its costs must take precedence.

Also, BPA's approach produces a reasonable result. (Keep, *et al.*, WP-07-E-BPA-37 at 7-8.) In BPA's WP-02 rate case, the IOUs raised numerous arguments challenging BPA's implementation of the 7(b)(2) rate step and the implementation of the REP under the 1984 ASC Methodology. (*Id.*) The REP Settlement Agreements resolved these disputes. (*Id.* at 8.) In the absence of the REP Settlement Agreements, if BPA had adopted the IOUs' positions on Section 7(b)(2) in the WP-02 proceeding, the rate step would not have triggered. (*Id.*) If this had occurred, the PF Exchange rate in the WP-02 proceeding would have equaled the PF Preference rate at 27.48 mills per kWh. (*Id.*) In this circumstance the IOUs would have received over $329 million in REP benefits each year. (*Id.*) (Also, if the IOUs had prevailed on their challenges to BPA's implementation of the REP, this alone would have produced $323 million in REP benefits each year.) (*Id.*) Similarly, if there were no REP settlement and no trigger in the instant case due to BPA adopting the IOUs' previous positions on 7(b)(2) issues, the PF Preference rate would be higher than the PF Preference rate now proposed by BPA. (*Id.*)

In contrast, the PCG advocates fixing the PF Preference rate after the preliminary 7(b)(2) rate step. (Saleba, *et al*., WP-07-E-JP1-01 at 10.) By doing so, it posits an average PF Preference rate of 27.2 mills per kWh for FY 2007-2009. (*Id*.) This rate is flawed because it does not reflect BPA's recovery of REP settlement costs. (Keep, *et al*., WP-07-E-BPA-37 at 8.) BPA's WP-07 Initial Proposal contains a PF Preference rate of 31.11 mills per kWh. (*Id*.) This is a reasonable result. (*Id*.) The PF Preference rate is not the low rate advocated by the PCG, nor the high rate that would occur in the absence of a trigger. (*Id*.) Instead, as one would expect for a rate that reflected a settlement of REP disputes, the PF Preference rate proposed by BPA is between these two extremes. (*Id*.)

The PCG notes BPA's argument that BPA's approach produces a reasonable result because arguments advanced by the IOUs in the WP-02 case, if adopted by BPA there or in this case, would have prevented Section 7(b)(2) from triggering at all. (JP1 Br., WP-07-M-62 at 12.) The PCG notes that BPA did not adopt those IOU arguments and the IOUs did not advance those arguments in this case. (*Id*.) Actually, the IOUs did advance such arguments in this case, but agreed to withdraw the testimony supporting such arguments in the Partial Resolution of Issues. BPA therefore is not relying on the arguments withdrawn by the IOUs in this case. Although such arguments have been withdrawn in this case, it does not mean that the corresponding issues completely cease to exist. For example, even absent the IOUs' arguments, there is a legal issue regarding the inclusion of Mid-Columbia resource costs in the 7(b)(2) resource stack that would be dispositive of the issue and would have a significant impact on the results of the 7(b)(2) rate step. If BPA finds a legal error in its Section 7(b)(2) implementation, BPA can correct such error in its ROD without requiring a party to raise the issue. BPA is not proposing to change its position on the Mid-Columbia resources in this case, although such would be permitted by the Partial Resolution of Issues. As discussed elsewhere, because the Partial Resolution of Issues provides that BPA will not claim that its treatment of 7(b)(2) issues will be precedential in any future rate case, it is unnecessary for BPA to resolve the legal issues regarding the Mid-Columbia resources or similar issues in this proceeding.

Furthermore, the IOUs did raise such issues in BPA's 2002 rate case. This was the rate case where BPA established power rates for the FY 2002-2006 period. In BPA's 2002 rate case, BPA addressed the potential for settlement by first calculating a PF Preference rate of 20.79 mills/kWh, after full application of the 7(b)(2) test. This rate was the preliminary post-7(b)(2) PF Preference rate, using BPA's calculation (contested by the IOUs) of net residential and small farm consumer benefits if there were an REP. Then, because of an expectation that IOUs might accept the settlement and not enter REP contracts, BPA properly made two adjustments to the post-7(b)(2) 20.79 mill/kWh PF Preference rate: (a) BPA allocated to the PF Preference rate and the Residential Load (RL) rate "the cost, a cost not otherwise allocated under Section 7 of the Northwest Power Act, of the cash payment associated with the 800 or 900 aMW portion of the proposed settlement"; and (b) BPA "allocate[d] the net cost of the REP credit, a benefit not otherwise allocated under Section 7 of the Northwest Power Act, to the PF Preference class, the IP-02 class, and the RL-02 class." (WP-02 ROD, WP-02-A-02 at 12-4, 12-2 to 12-5.) The result was an after-settlement PF Preference rate of 22.33 mills/kWh – a number that, not surprising in the case of a settlement, was higher than produced by application of BPA's contested calculation of REP benefits but lower than produced by application of the IOUs' contested calculation of REP benefits.

The PCG argues that BPA has not settled how Section 7(b)(2) should be implemented in this case. (JP1 Br., WP-07-M-62 at 12.) Although BPA has not reached a comprehensive WP-07 rate case settlement of all 7(b)(2) issues, the PCG ignores the 2000 REP Settlement Agreements. When BPA entered into the REP Settlement Agreements, it resolved two sets of disputes regarding implementation of the REP: (1) disputes regarding implementation of the 1984 ASC Methodology (*e.g.*, return on equity, income taxes, etc.); and (2) disputes regarding BPA's implementation of the 7(b)(2) rate step (*e.g.*, uncontrollable events, Mid-Columbia resources, *etc.*) BPA concluded that the REP settlement provided the IOUs an appropriate level of benefits to resolve all of the REP disputes. The REP settlements protected BPA from the risk of paying extremely high REP benefits during the 10-year settlement period. BPA's preference customers benefit from this protection.

The PCG argues that BPA incorrectly stated that the REP Settlement Agreements settled disputes over BPA's implementation of the section 7(b)(2) rate step, citing a statement in BPA's REP Settlement Agreement ROD. (JP1 Br. Ex., WP-07-M-79 at 11, n.5.) The cited statement, however, does not support the PCG's claim. First, the context for the cited BPA statement was an argument by Puget Sound Energy that BPA's rate pledge to preference customers in BPA's 2002 rate case would provide preference customers $150 million more benefits than they received under BPA's 1996 rates while at the same time decreasing REP benefits for IOUs. (REP Settlement Agreement ROD at 79.) BPA noted in response that:

> The foregoing issues raised by PSE are based on [future] development of BPA's rates for power sales to BPA's public agency customers and BPA's IOU customers. Issues regarding the development of BPA's rates can only be addressed in a section 7(i) hearing to establish such rates. *See, e.g.,* 16 U.S.C. § 839e(i)(1994 & Supp. III 1997). One of the Subscription Strategy's goals is to provide rate stability and to avoid rate increases in the PF Preference rate. This goal has become generally known as the imprecisely worded "rate pledge." The Subscription ROD, however, specifically stated that rates would be decided in BPA's rate case: "The Subscription Strategy does not establish rates or rate designs. The establishment of rates and the use of rate design can be determined only in a formal hearing under section 7(i) of the Northwest Power Act."

(*Id.*) The PCG has confused the development of BPA's rates, which can occur only in a section 7(i) hearing, with the settlement of disputes regarding the implementation of the REP, which was developed through negotiations and reviewed in a public administrative process. This distinction is clarified through a review of the settlement of REP disputes.

When BPA settles disputes regarding the implementation of the REP, as it has done with BPA's preference customers and IOUs for over 20 years, BPA must consider the disputed elements that comprise the determination of REP benefits. These include the establishment of a utility's ASC pursuant to an ASC Methodology, and the PF Exchange rate. The PF Exchange rate is determined in part by BPA's implementation of the 7(b)(2) rate step. BPA's REP Settlement Agreements considered the IOUs' claims that BPA had improperly calculated their ASCs under a flawed methodology and the IOUs' claims that BPA had improperly conducted the 7(b)(2) rate step. BPA reviewed its litigation exposure under these respective claims and settled the claims for a specified amount of consideration. BPA therefore settled its disputes with the IOUs regarding BPA's implementation of section 7(b)(2) through the REP Settlement Agreements. Thus, contrary to the PCG's claim, the REP Settlement Agreements resolved, for their duration, the amounts to be paid to the IOUs in settlement of their claims under the REP (which include ASC, ASC Methodology, 7(b)(2) rate step, and other PF Exchange rate claims). The REP settlements, however, did not establish any rates, which would require a section 7(i) hearing.

The PCG argues that BPA's witnesses testified that their Section 7(b)(2) calculation produced reasonable results and there is no reason to change those results now. (JP1 Br., WP-07-M-62 at 12.) More specifically, however, BPA's witness said that "the calculation [they] did of the 7(b)(2) rate step was reasonable" and he had no corrections to make to it. (Tr. 65-66.) This testimony, however, does not address any changes BPA might make based on changes in legal conclusions. For example, if BPA's legal analysis regarding inclusion of the Mid-Columbia resources were to change, this would have a dramatic effect on the results of the 7(b)(2) rate step. The cited testimony also does not address any changes the witnesses might make in the event that all of the issues in the rate case had been fully litigated instead of being withdrawn for purposes of a Partial Resolution of Issues. Also, this testimony supports BPA's position regarding rate development. BPA's witness confirmed, contrary to PCG's arguments, that BPA correctly reflected the REP in the Program Case of the 7(b)(2) rate step. BPA's witnesses also support the allocation of REP settlement costs under Section 7(g) of the Northwest Power Act after the 7(b)(2) rate step. BPA's witnesses did not address whether there were alternative approaches to assumptions used in the 7(b)(2) rate step. BPA knows from past rate cases that this is so. (*See, e.g.*, WP-02 ROD at 13-9 to 13-63.) As noted previously, BPA settled all disputes regarding the implementation of the REP in the 2000 REP Settlement Agreements. These disputes included the calculation of ASCs under the 1984 ASC Methodology, and disputes regarding assumptions used in implementing Section 7(b)(2) in BPA's rate cases (*e.g.*, uncontrollable events, Mid-Columbia resources, etc.).

As noted previously, the *Legal Interpretation* and *Implementation Methodology* recognize that it may not be possible to have the model reflect the rate proposal exactly. This is particularly true where using REP settlement costs in place of the REP (which is a fundamental assumption in section 7(b)(2) and has been used in every Section 7(b)(2) rate step since enactment of the Northwest Power Act), would produce artificial and extraordinarily anomalous results.

Decision

BPA properly reflects a forecast of an REP in the Program Case.

10.4 BPA's RAM and Conservation

Issue 1

Whether BPA's RAM contains a modeling error and whether BPA properly models conservation costs.

Parties' Positions

The PCG argues that Section 7(b)(2) should not trigger when BPA is forecasting no REP transactions and therefore there must be some error in the manner in which BPA modeled conservation costs. (JP1 Br., WP-07-M-62 at 16-17.) The PCG implies that this alleged error results from implementing the 7(b)(2) rate step in a manner that results in unnecessary conflicts in statutory provisions.

BPA's Position

BPA's RAM does not contain modeling errors and BPA properly modeled conservation costs in conducting the 7(b)(2) rate step. (Keep, *et al*., WP-07-E-BPA-27 at 6-7; Section 7(b)(2) Rate Test Study and Documentation, WP-07-E-BPA-06 and -06A.) BPA's modeling properly applies BPA's *Legal Interpretation* and *Implementation Methodology*.

Evaluation of Positions

A. The Partial Resolution of Issues

The PCG's initial brief raised a procedural issue concerning whether the PCG had violated the Partial Resolution of Issues in this proceeding. In its direct testimony, the PCG argued that there was a modeling error in RAM2007 used to conduct the Section 7(b)(2) rate step. (Saleba, *et al*., WP-07-E-JP1-01 at 13.) Although the PCG was unable to identify a modeling error, it said a modeling error was suggested because the rate test triggered by $42 million after all residential exchange costs and non-preference loads were removed. (*Id*.) The PCG's direct testimony then concluded that BPA should change the way it models conservation in conducting the 7(b)(2) rate step. (*Id*. at 14.) BPA staff was eager to address these arguments in BPA's rebuttal testimony because they were easily refuted, and BPA staff drafted such rebuttal testimony. Prior to BPA filing its rebuttal testimony, however, rate case litigants conducted settlement discussions and reached the Partial Resolution of Issues. In particular, members of the PCG strongly encouraged BPA to agree to the following language as a way to avoid having to address the modeling error and conservation issue:

> BPA staff has reviewed the testimony of the Preference Customer Group in WP-07-E-JP1-01 and WP-07-E-JP1-01(E1) section 5 regarding the $42 million §7(b)(2) trigger due to what they describe as a modeling error. The Preference Customer Group contends that on the issue presented in section 5 of that testimony, the mathematical end result produced for the amount recoverable from preference customers absent BPA's Subscription Step by the BPA approach and that advocated in the Preference Customer Group testimony is identical. Assuming this contention to be true, BPA concludes that it is not necessary to decide in this case whether the alleged modeling error in fact exists.

(Evans, *et al*., WP-07-E-BPA-31, Attachment A at A-1.) BPA agreed to adopt the language in the Partial Resolution of Issues.

BPA's rebuttal testimony summarized the Partial Resolution of Issues:

> *Q. What issues have BPA and the parties agreed to resolve?*
>
> A. BPA and the parties agreed on a resolution of some conditions to the FPS rate schedule, design of the Low Density Discount, treatment of revenue credits from Operating Reserves, PF rate design and a few Slice issues involving the treatment of particular costs. *In addition, BPA and the parties reached agreement regarding the non-precedential nature of the treatment under section 7(b)(2) of the Mid-Columbia resources, conservation, uncontrollable events and secondary revenues counted as reserves*. Attachment A describes in detail the resolution that BPA and the parties have reached regarding these issues. We, as members of BPA's negotiating team, support the resolution of the issues as set forth in Attachment A as a reasonable compromise to the different points of view presented in the discussions and we recommend that the Administrator adopt this resolution in the Record of Decision for this rate proceeding.
>
> *Q. Were other conditions established between BPA and the parties that are associated with the resolution of issues that are not set forth in Attachment A?*
>
> A. Yes. As part of this agreement BPA and the parties agreed that the WP-07-E-JP6-01 testimony and related exhibits filed by the investor-owned utilities would not be submitted into evidence. *In addition, with regard to the issues included in the partial resolution, the parties agreed to five conditions. They agreed not to file rebuttal testimony, not to cross-examine witnesses, and not to raise these topics in briefs in this rate proceeding. In addition, they would not raise these issues with the Federal Energy Regulatory Commission or in any appeal to the Ninth Circuit Court of the rates established in this proceeding established consistent with this resolution.*

(*Id.* at 2-3) (emphasis added). In reliance on the PCG's representations, BPA staff did not file rebuttal testimony regarding the alleged modeling error and conservation issues the PCG raised in its direct testimony.

Despite the foregoing agreement, the PCG raised the alleged modeling error and conservation as issues in its initial brief. (JP1 Br., WP-07-M-62 at 16-17.) In fact, the title of Section IV of the PCG brief is "BPA's RAM Model Appears to Contain Errors." (*Id*. at 16.) The PCG brief reiterated the alleged modeling error and conservation conclusions contained in the PCG's direct testimony. (*Id*. at 16-17.) Because BPA must address every argument raised by parties in their briefs, BPA is forced to address the PCG's arguments regarding an alleged modeling error and conservation as reflected in BPA's implementation of the Section 7(b)(2) rate step.

The PCG claims it did not violate the Partial Resolution of Issues by raising the modeling error and conservation issue in its initial brief because the PCG refused to compromise its position on the apparent conflict or on any other 7(b)(2) issue. (JP1 Br. Ex., WP-07-M-79 at 12.) Although

BPA disagrees with the PCG's argument, there is little benefit to debating this issue. BPA will view this incident as a misunderstanding between the litigants. The most important issues concern the merits and, as discussed below, the PCG has failed to establish any modeling error in BPA's implementation of section 7(b)(2). Furthermore, as explained below, the PCG's position on conservation is plainly at odds with the *Implementation Methodology*, which reflects BPA's interpretation of section 7(b)(2). Also as explained below, the PCG's testimony and initial brief did not argue that the *Implementation Methodology* should be changed with regard to the treatment of conservation, and the PCG believes that any attempts to change the *Methodology* based on a brief on exceptions would be improper. (JP1 Br. Ex., WP-07-M-79 at 9.)

B. There Is No Modeling Error In RAM2007

The PCG argues that Section 7(b)(2) should not trigger when BPA is forecasting no REP transactions and therefore there must be some error in the manner in which BPA modeled conservation costs. (JP1 Br., WP-07-M-62 at 16.) The PCG's premise is incorrect: Section 7(b)(2) of the Northwest Power Act provides that the rate step can trigger in the absence of REP transactions. As noted previously, Section 7(b)(2) directs BPA to conduct, after July 1, 1985, a comparison of the projected amounts to be charged its preference and Federal agency customers for their general requirements with the hypothetical costs of power to those customers if five assumptions are made. These five assumptions are summarized as follows:

> preference customers' general requirements included BPA's DSI loads located within or adjacent to the geographic service boundaries of such preference customers;
>
> preference customers were served, during such five-year period, with certain FBS resources;
>
> no REP purchases or sales were made by BPA during such five-year period;
>
> all resources other than FBS resources that would have been required to meet remaining general requirements of the preference customers would be purchased from such customers by BPA and were the least expensive resources owned or purchased by such customers; and
>
> certain savings resulting from the Northwest Power Act were not achieved.

16 U.S.C. § 839e(b)(2).

The 7(b)(2) rate step thus involves the projection and comparison of two sets of wholesale power costs for the general requirements of BPA's "7(b)(2) customers": (1) a set for the rate period and ensuing four years assuming that Section 7(b)(2) is not in effect ("Program Case costs"); and (2) a set for the same period taking into account the five hypothetical assumptions listed in Section 7(b)(2) ("7(b)(2) Case costs"). Certain specified costs allocated pursuant to Section 7(g) of the Northwest Power Act are subtracted from the Program Case costs. If the average Program

Case costs exceed the average 7(b)(2) Case costs, the 7(b)(2) test is said to "trigger," and the amount to be reallocated in the rate period ("reallocation amount") is calculated.

The elimination of the REP in the 7(b)(2) Case is only one of the five assumptions in Section 7(b)(2). (*Id*.) The 7(b)(2) trigger and resultant 7(b)(3) reallocation amount, however, is a function of all five different, required assumptions, only one of which involves the REP. Thus, the 7(b)(2) rate test can trigger in the absence of REP costs, as it did in the WP-07 Initial Proposal (Keep, *et al*., WP-07-E-BPA-37 at 11; Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06 at 14), and not trigger with substantial REP costs as it has done in the past (*e.g*., WP-85 ROD at 72-73, 159.)

Furthermore, the PCG did not specify where an alleged error occurred. Instead, because the rate step triggered, it argues this "suggests" that there is a flaw in the RAM model. Although the PCG cannot identify any specific modeling error, it attributes a trigger of $42 million to BPA's modeling of conservation costs in the Program Case and/or the 7(b)(2) Case. (JP1 Br., WP-07-M-62 at 16.) BPA has modeled conservation in the 7(b)(2) rate step in the same manner for over 20 years. The PCG therefore argues that BPA should change its treatment of conservation now, seemingly for the sole reason that there are no loads to which to allocate the 7(b)(3) reallocation amount. BPA, however, has properly modeled conservation savings and conservation costs consistent with the *Legal Interpretation* and *Implementation Methodology*.

The *Implementation Methodology* provides that "[t]he initial loads that will be used in the 7(b)(2) case will be the same as those used in the program case, except that they will not include estimates of programmatic conservation savings." (*Implementation Methodology* at 41.) In WP-07, BPA used the same initial loads in the 7(b)(2) Case as those used in the Program Case, except that they do not include estimates of programmatic conservation savings. (Keep, *et al*., WP-07-E-BPA-27 at 6-7.) Furthermore, the amount of programmatic conservation savings has always been quantified as the amount of conservation contained in the 7(b)(2) resource stack. The cumulative amount of conservation investments in the resource stack is 795.6 MW. (Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, Appendix D at D-24.) The conservation resources, when added to billing credit resources of 17.5MW, increase the 7(b)(2) Case loads by 813.1 MW when compared to Program Case loads. (Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, Appendix B at B-5.)

Also, when conservation resources are brought on from the 7(b)(2) resource stack, there is an impact on the 7(b)(2) Case PF rate. If a conservation resource is brought on, the load forecast is reduced by the power savings amount purchased through the conservation resource in the year it is brought on and in each subsequent year of the rate study. (Keep, *et al*., WP-07-E-BPA-27 at 14.) The revenues to be recovered from 7(b)(2) Case rates are increased by the historical cost of the conservation resources adjusted for inflation. (*Id*. at 21.)

BPA has properly excluded Program Case conservation costs from the 7(b)(2) Case cost of service analysis (COSA) and the debt service repayment studies that determine the mix of BPA's interest and amortization payments for each year of the test period. Because conservation costs can only be brought on from the stack, they should not be included in the 7(b)(2) Case debt service repayment studies and COSA. There is no allegation or documentation in the WP-07 rate case record that the amount of conservation resources and their costs were incorrect with the exception of the issue of the 7(b)(2) debt service repayment studies, which is addressed below.

Rather than conservation, an explanation for the $42 million rate protection amount is that the 7(b)(2) Case rate is reduced because of the access to a large amount of inexpensive non-dedicated Mid-Columbia resources costing approximately $17.5/MWh within the resource stack that provide power at less than the 7(b)(2) Case average cost of power. (Keep, *et al.*, WP-07-E-BPA-27 at 17.) In the 7(b)(2) Case, the marginal resource cost is below average, whereas in the Program Case, the marginal resource cost consisting of market purchases is above average. In addition, the first two types of resources are brought on in whole resource increment amounts and not in discrete portions to meet the exact amount of forecast loads. (*Implementation Methodology* at 42.) The Mid-Columbia resources create higher amounts of secondary revenues that are credited against 7(b)(2) Case expenses to lower the amount of revenues that need to be collected from 7(b)(2) Case rates.

The PCG argues that BPA's Draft ROD identified the source of an apparent conflict between section 7(a) and section 7(b)(2), that is, the *Implementation Methodology's* requirement to change the loads in the 7(b)(2) Case so that they do not include the actual savings from programmatic conservation and billing credits. (JP1 Br. Ex., WP-07-M-79 at 13.) The PCG has misstated the conclusion in BPA's Draft ROD. Although BPA correctly adjusted the 7(b)(2) Case loads to reflect the fact that conservation savings had not occurred and correctly conducted the financing studies as if conservation had not occurred, it was the availability of inexpensive resources in the 7(b)(2) Case, as explained in the preceding paragraph, that BPA believed was the chief cause of the non-zero trigger amount in the Initial Proposal.

The PCG argues that neither Section 7(b)(2) nor the *Implementation Methodology* specifies the details of how conservation costs should be modeled in determining compliance with Section 7(b)(2). (JP1 Br., WP-07-M-62 at 17.) The PCG argues that BPA must exercise its discretion to model conservation in a manner consistent with the congressional purpose of Section 7(b)(2). (*Id.*) Contrary to the PCG's argument, the Northwest Power Act, *Implementation Methodology*, and *Legal Interpretation* provide direct guidance in modeling conservation. Furthermore, all of these sources are consistent concerning how conservation should be treated. The Act and the *Methodology* provide that the resource stack used to meet the 7(b)(2) Case loads after FBS resources have been exhausted consists of Type 1 Resources, the resources actually acquired by BPA from the 7(b)(2) customers; Type 2 Resources, the resources owned or purchased by 7(b)(2) customers that are not dedicated to their own regional loads; and Type 3 Resources, generic resources of whatever size that are required after Type 1 and 2 Resources have been exhausted from non-7(b)(2) customers. 16 U.S.C. § 839e(b)(2)(D); (*Implementation Methodology* at 42; *Legal Interpretation* at 16-17.) Type 1 resources include any conservation programs undertaken or acquired by BPA. The first two resource types must be the least expensive resources owned or purchased by public bodies or cooperatives. (*Id.*) To give effect to the statute, the resource stack is arranged in order of least cost, with the least cost resources used first to meet 7(b)(2) loads. (*Id.*) In order to perform this ranking, the resources are stated at their historical costs adjusted for inflation to a common "base year nominal dollar amount." (Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, Appendix B at B-5, -6.) The model restates the resource costs in 1980 nominal dollars along with their projected operating costs during the rate study period. (*Id.*; Keep, *et al.*, WP-07-E-BPA-27 at 17.) This common basis of comparing costs of generating resources and conservation resources based on their unit cost per unit of output is critical to arranging the resources by least cost. Once a resource is chosen from the resource stack, its costs are then escalated for inflation up to the year when it is chosen (placed in service) to meet the loads in the 7(b)(2) case. (*Id.*) This approach to modeling conservation costs has been followed consistently in all rate cases since 1985, which was the inception of implementing Section 7(b)(2) in BPA's ratemaking. There is no argument in the record that the amount of conservation resources or their costs were incorrectly modeled with the exception of a point concerning the 7(b)(2) Case debt-service repayment study discussed below.

Indeed, the level of documentation presented in the WP-07 rate case concerning conservation resources and costs was more extensive than any prior rate case. (*See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06, Appendix D.) BPA responded to over twenty different data requests concerning how the amount of conservation resources and their costs were determined. No arguments were presented in the PCG's direct testimony concerning the amount of conservation resources or the costs of those resources contained in the resource stack. (Saleba, *et al.*, WP-07-E-JP1-01.) Similarly, no arguments were raised concerning the fact that 7(b)(2) Case loads were greater than Program Case loads by 795.6 MW due to conservation resources being in the resource stack. (*Id.*) The PCG's direct testimony's arguments surrounding conservation were limited to the amount of conservation costs that were subtracted out of the Program Case and the repayment study that was prepared to produce the 7(b)(2) Case revenue requirements. (*Id.* at 13-15). Thus, there is no evidence in the rate case record that the amount of conservation resources and their costs were incorrectly modeled with the exception of the following allegation.

The PCG's direct testimony argued that there was no need to do a separate debt service repayment study. (Saleba, *et al.*, WP-07-E-JP1-01 at 14.) The PCG argues that the difference in costs between the Program Case and the 7(b)(2) Case should be limited to subtracting the conservation costs from the Program Case revenue requirement yearly amounts. (*Id.*) The PCG argues that if these changes were made that the "trigger amount would be eliminated." (*Id.*) The PCG, however, fails to grasp the purpose of performing a separate repayment study for the 7(b)(2) Case. The repayment study establishes a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service necessary to repay all Federal obligations within the required repayment period. (Revenue Requirement Study, WP-07-E-BPA-02 at 19.) This methodology for determining the lowest levelized debt service stream of payments applies to both the Program Case, with conservation present, and the 7(b)(2) Case, where conservation payments are not present unless they are selected from the resource stack. (Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06 at 12.) In order to treat the costs in the two cases in a comparable manner, it is necessary to perform separate repayment studies, because there is no fixed schedule of annual repayment. (Revenue Requirement Study, WP-07-E-BPA-02 at 42.) The resulting interest and amortization included in revenue requirements, then, will be unique based on the repayment requirements included in a given study. (*Id.* at 18-19.) This is consistent with the *Legal Interpretation*, which provides that "[e]xcept for the assumptions specified in Section 7(b)(2), all underlying premises will remain constant between the program case and the 7(b)(2) case. . . . This general approach will allow the 7(b)(2) case to be modeled under the same accepted ratemaking techniques used in the program case." (*Legal Interpretation* at 7.) Because the treatment of conservation costs does not involve any inconsistencies with fundamental assumptions in section 7(b)(2) and does not produce absurd results, this language provides that the same ratemaking technique (determining the lowest levelized repayment stream) should be applied to both cases.

In addition to subtracting out conservation costs in the 7(b)(2) Case, the costs associated with resources purchased from preference customers were also subtracted from the Program Case revenue requirement in determining costs that should be borne by 7(b)(2) customers in the 7(b)(2) Case. (Doubleday, *et al*., WP-07-E-BPA-15 at 3.) This same treatment of cost segregation and removal from the 7(b)(2) revenue requirement along with conducting separate repayment studies has been consistently performed in all prior rate cases since the inception of implementing the Section 7(b)(2) rate step. (*Id*.)

The PCG argues that BPA must model conservation so that BPA can hold the PF Preference rate to a level that does not exceed the Section 7(b)(2) amount and retain its ability to recover its costs in rates under Section 7(a) of the Northwest Power Act. (JP1 Br., WP-07-M-62 at 17.) The PCG argues that BPA cannot make discretionary modeling choices to create an apparent conflict between its obligation to provide preference customers rate protection under Section 7(b)(2) and its obligation to recover costs under Section 7(a), in order to allow itself to choose compliance with one mandatory provision over another. (*Id*.) The PCG also argues that BPA must exercise its discretion to model conservation in a manner consistent with the Congressional purpose of Section 7(b)(2), with the inference that it was modeled incorrectly because there was a reallocation amount when no REP loads were present. First, BPA disagrees with the PCG's proposal to first establish the level of BPA's rates and then use assumptions contrary to BPA's *Implementation Methodology* to rationalize such rates after the fact. The PCG's other arguments suffer from a fatal flaw. As previously explained, the PCG's premise that a modeling error exists is incorrect. The 7(b)(2) trigger and resultant 7(b)(3) reallocation amount is a function of all five 7(b)(2) assumptions, only one of which involves the REP. 16 U.S.C. § 839e(b)(2). The 7(b)(2) rate step can trigger in the absence of REP costs, as it did in this case, and not trigger with substantial REP costs, as has occurred in previous rate cases. BPA also previously explained that conservation was not the primary reason for the $42 million reallocation amount. Furthermore, BPA modeled conservation consistent with BPA's existing *Implementation Methodology*, which is not a discretionary modeling choice absent revision of the *Methodology*.

The PCG claims that nothing in section 7(b)(2) directs BPA to increase the loads in the 7(b)(2) rate step to create hypothetical loads as if savings from programmatic conservation had not been achieved. (JP1 Br. Ex., WP-07-M-79 at 14.) The PCG argues that the only specific requirement regarding loads concerns adjusting DSI loads, and absent DSI loads there was no required adjustment to PF loads at all. (*Id*.) Contrary to the PCG's argument, however, the *Implementation Methodology* directs BPA to include all conservation programs "undertaken or acquired" by BPA in the 7b2 Case resource stack. (*Implementation Methodology* at 42.) Logically, if this conservation is an available resource in the 7b2 Case world, it could not have also lowered the starting loads in that world. If, during the calculation of rates, the model picks an individual conservation resource from the stack, the loads are then decremented in the amount of the chosen conservation resource. In addition, the 7b2 Case is defined by the five 7(b)(2) assumptions and their natural consequences. The specified additional resource stack is one of the five assumptions, and the lack of initial conservation savings is clearly a natural consequence.

The PCG argues that the PF loads in the Program Case are less than the FBS resources available to serve load in the 7(b)(2) Case; the 7(b)(2) resource stack requires BPA to assume that 7(b)(2) loads are served with FBS resources, if possible; and therefore no Mid-C resources are needed to serve the 7(b)(2) loads except due to BPA's discretionary choice to increase the loads in the 7(b)(2) Case. (JP1 Br. Ex., WP-07-M-79 at 14.) As noted previously, however, BPA does not believe that it has discretion on whether or not to follow the *Implementation Methodology*.

The PCG argues that merely because section 7(b)(2) does not protect preference customers from the costs of conservation or billing credits does not require BPA to assume, contrary to the facts, that the conservation or billing credits and their resulting savings did not occur. (JP1 Br. Ex., WP-07-M-79 at 14.) The PCG argues that section 7(b)(2) is structured so that preference customers pay a share of BPA's conservation and billing credit costs; that the costs of these items are expressly excluded from the costs to which the "may not exceed in total" language applies; and therefore such costs are to be paid by preference customers irrespective of section 7(b)(2), so eliminating the savings in the 7(b)(2) Case is not warranted. (*Id.* at 14-15.) The fact that preference customers may pay the cost of conservation irrespective of section 7(b)(2) is irrelevant to the question of whether or not to adjust the loads in the 7(b)(2) Case for conservation savings that do not occur in that case. The *Implementation Methodology*, however, is not irrelevant to the question and it clearly directs BPA to adjust such loads in a manner that was done in BPA's rate modeling.

The PCG argues that BPA's discretionary decision on how it treats conservation costs and load savings in RAM caused an apparent conflict between section 7(a) and 7(b)(2), and it was BPA's duty to avoid such conflicts, if possible, and BPA chose to ignore the conflict rather than address it, because BPA did not consider itself bound by section 7(b)(2). (JP1 Br. Ex., WP-07-M-79 at 15.) Contrary to the PCG's argument, BPA considers itself bound by section 7(b)(2) of the Northwest Power Act, the *Implementation Methodology*, and the *Legal Interpretation*. As stated above, these authorities directed BPA's treatment of conservation costs and load savings. The fact that the PCG does not like the outcome, or that an apparent conflict between sections 7(b)(3) and 7(a) may occur, is no reason to ignore the ratemaking rules.

Also, there is no provision in the *Legal Interpretation* or *Implementation Methodology* that requires BPA to model conservation in the manner suggested by the PCG. The PCG would like BPA to initially model costs in the 7(b)(2) Case as if there were programmatic conservation being done in each year and then, after the fact, BPA should remove those costs associated with conservation from the 7(b)(2) Case because annual programmatic conservation is not done in the 7(b)(2) Case. This methodology would skew the results of the 7(b)(2) Case repayment study because it would include costs of programmatic conservation that do not exist in the 7(b)(2) Case. BPA should model conservation as provided in the Northwest Power Act, as interpreted by the *Legal Interpretation* and *Implementation Methodology*. This is what BPA has done. If modeling conservation, or any other element of Section 7(b)(2), in accordance with the law produces a reallocation amount, and there are no non-preference loads to which to allocate the reallocation amount, BPA must allocate such amount to the PF Preference rate in order that BPA can comply with Section 7(a) of the Northwest Power Act and recover its total costs through rates. 16 U.S.C. § 839e(a)(1). BPA cannot model conservation, or any other element of Section 7(b)(2), contrary to law in order to avoid a trigger. Because BPA's treatment of conservation is consistent with the *Legal Interpretation* and the *Implementation Methodology*, BPA believes it is consistent with the law. If the PCG believes otherwise, it should not have couched the issue as a modeling error.

The PCG members had the opportunity to challenge the *Implementation Methodology* in challenges to BPA's 1985 power rates. The *Methodology,* however, has not changed. BPA has been implementing the *Methodology* for over 20 years using the same treatment of conservation. The PCG cannot now challenge the *Implementation Methodology* as unlawful. But it is only now, over 20 years after adoption of the *Methodology*, that the PCG claims in its brief on exceptions that the *Methodology* is wrong. Although BPA can revise the *Methodology* in a section 7(i) hearing, BPA did not propose to amend the *Methodology* in its WP-07 Initial Proposal. Similarly, no party's testimony in the administrative record advocated amending the *Methodology*. Indeed, the PCG's direct testimony did not argue that a *Methodology* change was needed, but rather that its suggestion for modeling conservation was not "inconsistent with BPA's *Implementation Methodology*" because "[t]he *Implementation Methodology* does not specify exactly how to remove the conservation costs from the Program Case or 7(b)(2) Case." (Saleba, *et al*., WP-07-E-JP1-01 at 14.) (This argument is refuted elsewhere.)

In its brief on exceptions, however, the PCG argues that '[i]t may have seemed logical to BPA in 1984 [in the *Implementation Methodology*] to treat conservation as it did, but the NPA did not so require." (JP1 Br. Ex. at 14.) The PCG thus argues that BPA's *Implementation Methodology* is either contrary to section 7(b)(2) or is a discretionary choice that creates a conflict between section 7(a) and section 7(b)(2) ("BPA demonstrated in its Draft ROD that it knows precisely the source of the apparent conflict between sections 7(a) and 7(b)(2)—that is, the decision in the *Implementation Methodology* to change the loads in the section 7(b)(2) Case so that they do not include the actual savings from programmatic conservation and billing credits." (JP1 Br. Ex. at 13.)). The PCG argues that it is BPA's duty to avoid such conflicts if at all possible, but rather than address the conflict and reconcile sections 7(a) and 7(b)(2), BPA chose to ignore the conflict. (*Id*. at 15.) The PCG, however, has refuted its own argument. First, the *Implementation Methodology* is consistent with section 7(b)(2) because no court found any error in the *Methodology's* treatment of conservation when the *Methodology* was established in 1984. The *Methodology* therefore governs BPA's implementation of the section 7(b)(2) rate step. Second, if there were an inconsistency between BPA's conservation treatment and section 7(b)(2), the PCG could have advocated amendment of the *Methodology* in its direct case in this proceeding. It did not do so. Third, the PCG has argued that it is too late to amend the *Methodology* in the WP-07 rate proceeding. The PCG argues that any such amendment would be an impermissible retroactive amendment; that no party would have had any notice of a proposed amendment, thereby violating due process under the APA and section 7(i) of the Northwest Power Act; and that the *Methodology* was incorporated into BPA's case in chief. (JP1 Br. Ex. at 9.)

Furthermore, although the PCG argues that BPA should not make discretionary modeling choices to create a conflict between Section 7(b)(2) and Section 7(a) of the Northwest Power

Act, BPA has not done so. The prior and projected amounts of conservation resources that will be available to meet the loads in the 7(b)(2) Case have been stated as objectively as possible with no known bias. The costs of prior conservation investments are based on the actual historical costs for the years in question, and the projected future amounts of conservation and their costs have been estimated as accurately as possible and subject to customer review during the PFR process.

The PCG states that although it accepts BPA's apparent decision not to ferret out and correct the imagined modeling error in light of the PCG's testimony that the PF Preference rate is an acceptable Section 7(b)(2) amount, it does not accept that BPA has discretion to choose not to comply with Section 7(b)(2). (JP1 Br., WP-07-M-62 at 17-18.) BPA agrees that it must comply with Section 7(b)(2), and BPA has done so in this case. As outlined in the arguments above, there was no error in how BPA modeled conservation in performing the 7(b)(2) rate step. BPA modeled the amount of conservation and the cost of conservation investments as it done for over 20 years. BPA complied with Section 7(b)(2), the *Legal Interpretation* and the *Implementation Methodology*. In addition to complying with Section 7(b)(2), however, BPA must also comply with Section 7(a) of the Northwest Power Act and recover its total costs through rates. This includes recovering a reallocation amount from the PF Preference rate in the absence of non-preference loads.

Decision

BPA's RAM does not contain a modeling error and BPA properly models conservation costs in conducting the 7(b)(2) rate step consistent with the Legal Interpretation and the Implementation Methodology.

10.5 Subscription Step

Issue 1

Whether BPA should have conducted a Subscription Step in BPA's ratemaking.

Parties' Positions

The PCG argues that BPA's allocation of REP settlement costs under Section 7(g) of the Northwest Power Act in the Subscription Step is contrary to BPA's *Legal Interpretation* and *Implementation Methodology*. (JP1 Br., WP-07-M-62 at 8-10.)

BPA's Position

BPA properly included a Subscription Step in BPA's ratemaking because BPA is statutorily obligated to recover its total costs through rates, 16 U.S.C. § 839e(a)(1), and REP settlement costs, which are costs not otherwise allocated under Section 7 of the Northwest Power Act, must be allocated through Section 7(g) of the Act, 16 U.S.C. § 839e(g). Also, the *Legal Interpretation* and *Implementation Methodology* concern the implementation of the 7(b)(2) rate step and do not govern the allocation of costs after the rate step occurs.

Evaluation of Positions

The PCG argues that preference customers should be charged only a limited amount of costs but BPA improperly allocated the full cost of the REP settlements to preference customers. (JP1 Br., WP-07-M-62 at 8.) First, as noted previously, Section 7(b)(2) does not establish a "rate ceiling" or amount of costs that cannot be exceeded. Second, BPA's *Legal Interpretation* and *Implementation Methodology* are silent on how to treat settlements of REP disputes. BPA, however, addressed this issue in BPA's WP-02 rate case. (Keep, *et al*., WP-07-E-BPA-37 at 9.) After calculating the 7(b)(2) rate step in the Rate Design Step, BPA had additional, unallocated costs and benefits associated with its settlement of REP disputes with the IOUs. (*Id*.) BPA equitably allocates any costs and benefits that are otherwise unallocated under Section 7 of the Northwest Power Act, which include the unallocated costs and benefits of REP settlements, to all power rates. (*Id*.) Therefore, in order to recover BPA's total costs, BPA equitably assigned the unallocated REP settlement costs and benefits to both preference and non-preference rates (the Subscription Step). (*Id*.)

The *Implementation Methodology*, which BPA has used for over 20 years, states that the 7(b)(2) rate step is "conducted outside the mainstream of BPA's rate development process." (*Id*. citing *Implementation Methodology* at 45.) It has "no impact on rates" until it is included in BPA's rate design. (*Id*.) If an adjustment is made, it "must be done within the overall framework of the rate development process and of BPA's ratemaking objectives and statutory requirements." (*Id*.) The Section 7(b)(2) rate step is a step in BPA's rate design process, which must be included in a manner that is "consistent with other statutory provisions and BPA's ratemaking objectives." (*Id*.) By first implementing Sections 7(b)(2) and 7(b)(3), and then allocating otherwise unallocated REP settlement costs equitably to both preference and non-preference rates, BPA properly implemented the 7(b)(2) rate step. (*Id*.)

The PCG argues that although BPA claims that its REP exercise provided preference customers protection from costs, in fact, BPA used the Subscription Step to subvert the 7(b)(2) protection. (JP1 Br., WP-07-M-62 at 9.) To the contrary, preference customers received rate protection from the Section 7(b)(2) rate step in BPA's WP-07 Initial Proposal. (Keep, *et al*., WP-07 E-BPA-37 at 11.) BPA started the current ratemaking process with the assumption that there were as many as twelve potential exchanging utilities. (*Id*.) The initial 7(b)(2) rate step had a Program Case with over 5,900 aMW of PF Exchange load and $2.1 billion in gross REP costs. (*Id*.) The resultant Section 7(b)(2) rate step trigger was 8.1 mills per kWh. (*Id*.) Through an iterative rate modeling process, the Section 7(b)(3) reallocation amount raised the PF Exchange rate, which in turn eliminated some potential exchangers from receiving REP benefits, which then lowered the Program Case costs, which then changed the Section 7(b)(2) rate step trigger, which then changed the Section 7(b)(3) reallocation amount, and so on. (*Id*.) The iterations ended when all potential exchanging utilities were eliminated and the gross cost of the REP became zero. (*Id*.) In short, BPA reallocated the 7(b)(3) reallocation amount to non-preference customers until there were no more non-preference loads, and only then was BPA required to allocate a portion of the 7(b)(3) reallocation amount to the PF Preference rate. (*Id*.) BPA's preference customers received protection from all of the reallocation amount except that portion necessarily allocated to the PF Preference rate to ensure that BPA could recover its costs. (*Id.*)

The 7(b)(2) rate step, however, is not the final step in BPA's ratemaking. BPA still had to recover its total costs, including REP settlement costs, which had not yet been reflected in BPA's ratemaking. These costs are costs that are not otherwise allocated under Section 7 of the Northwest Power Act, and therefore are equitably allocated pursuant to Section 7(g) of the Act. 16 U.S.C. § 839e(g). BPA therefore subtracted any net cost of the traditional REP for the IOUs that had been included in the Rate Design Step rates, and then allocated the costs of the IOU REP settlement. (Keep, *et al*., WP-07-E-BPA-27 at 8.) This same result would have occurred if BPA had included the REP settlement costs in the Program Case and not conducted the Subscription Step. In that event, the reallocation amount would have been even higher and, in the absence of any loads to allocate the reallocation amount to (because no REP would be implemented), BPA would have been forced to allocate such costs to the PF Preference rate.

Furthermore, the REP Settlement Agreements resolved the IOUs' disputes with BPA regarding implementation of the REP. (Keep, *et al*., WP-07-E-BPA-37 at 11.) These disputes exposed BPA and its preference customers to over $300 million per year in REP costs during the settlement period. (*Id.*) The REP Settlement Agreements resolved these claims for $140 million per year during the first 5 years of the settlements, or less than 50 cents on the dollar. (*Id.*)

BPA's preference customers have received extensive cost protection from BPA's limited exposure to high REP costs through the REP Settlement Agreements. (*Id.*)

<u>Decision</u>

BPA properly conducts a Subscription Step in its ratemaking and properly allocates REP settlement costs pursuant to Section 7(g) of the Northwest Power Act.

<u>Issue 2</u>

Whether the PCG properly calculated the PF Preference rate.

<u>Parties' Positions</u>

The PCG argues that its witnesses calculated the PF Preference rate by including the cost of the REP settlements in the Program Case and removed REP costs and REP settlement costs from the 7(b)(2) Case. (JP1 Br., WP-07-M-62 at 13; JP1 Br. Ex., WP-07-M-79 at15.)

<u>BPA's Position</u>

BPA notes that the PCG analysis *purports* to include the cost associated with the IOU REP Settlement Agreements in the Program Case rather than the traditional IOU REP, but does not do so. (Keep, *et al*., WP-07-E-BPA-37 at 12-13.) Further, if the PCG had actually retained the calculated costs of the IOU REP Settlement Agreements in the Program Case, the PCG's

Program Case rates would have been similar, if not equal, to BPA's Subscription Step rates. (*Id.*)

Evaluation of Positions

In its initial brief, the PCG argued that its witnesses calculated the PF Preference rate by including the cost of the REP settlements in the Program Case and removed REP costs and REP settlement costs from the 7(b)(2) Case. (JP1 Br., WP-07-M-62 at 13.) The PCG argued that it did not assume those costs would disappear from the Program Case. (*Id.*) The PCG argued its approach produced the same PF Preference rate that BPA's analysis produced before the Subscription Step. (*Id.*) The PCG argued that this shows that there was no need for BPA to model the REP in the Program Case, and that creation of the REP in the Program Case did not help to protect the PF Preference rate from the potential of public REP costs, which were eliminated by Section 7(b)(3) using accurate assumptions. (*Id.*)

In the Draft ROD, BPA stated that the PCG analysis *purported* to include the cost associated with the IOU REP Settlement Agreements in the Program Case rather than the traditional IOU REP. (Keep, *et al.*, WP-07-E-BPA-37 at 12-13.) The costs of the IOU REP Settlement Agreements are calculated by multiplying the difference between the lowest cost PF rate and a market forecast rate by 2,200 aMWs and are approximately $300 million per year. (*Id.*) Because the difference between the lowest cost PF rate and the market forecast rate is forecast to be greater than zero for the rate period, the PCG (under its approach) should have included the $300 million per year of IOU REP settlement benefits in the Program Case. (*Id.*) Instead, contrary to the PCG's claims, the PCG arbitrarily assumed that the $300 million would simply disappear ("[i]n our analysis, we have directly removed the REP Settlement Agreement costs . . .", Saleba, *et al.*, WP-07-E-JP1-01 at 11.) (*Id.*)

The Draft ROD also noted that if the PCG had actually retained the calculated costs of the IOU REP Settlement Agreements in the Program Case, approximately $300 million per year, and had not arbitrarily removed those costs from the calculation of their Program Case PF rates, the 7(b)(2) rate step trigger would have been much higher. (*Id.*) This would have caused an extraordinarily high 7(b)(3) reallocation amount, which in the absence of non-preference loads would have been reallocated to the PF Preference rate in order for BPA to recover its total system costs. (*Id.*) In fact, because the PCG's Program Case rates, after the arbitrary removal of $300 million per year, were similar to the Program Case rates BPA produced after BPA's iterative process removed all potential exchanging utilities, the PCG's Program Case rates would have been similar, if not equal, to BPA's Subscription Step rates if PCG had not removed the $300 million per year. (*Id.*)

The Draft ROD further noted that the Program Case rates calculated by PCG would have been similar, if not identical to, BPA's Subscription Step rates if PCG had not removed the $300 million per year from its Program Case. (JP1 Br., WP-07-M-62 at 14.) The PCG claims it did not do so. (*Id.*) In its direct testimony, the PCG describes how BPA used Sections 7(b)(2) and 7(b)(3) to exclude all REP load through an iterative process. (Saleba, *et al.*, WP-07-E-JP1-01 at 11.) Then, as noted above, the PCG states that it "directly removed the REP Settlement Agreement costs, which has the same effect for IOU exchangers as the many iterations that remove the hypothetical exchange loads in BPA's analysis." (*Id*.) The REP, however, is not the same as the REP Settlement Agreements. BPA used the provisions of the Northwest Power Act to reduce the REP load to zero, that is, BPA allocated trigger costs to the PF Exchange rate under Section 7(b)(3) until it was higher than the ASCs of all the potential exchanging utilities. The PCG, in contrast, simply deemed the REP settlement amount to be zero. The PCG did not follow any provisions of the Northwest Power Act in doing so. The REP settlement formula to determine settlement benefits subtracts the PF Preference rate from a higher market price and multiplies that number by 2,200 aMW times 0.00876 to get millions of dollars. If the PCG had actually used this formula, it would not have produced a zero result.

The Draft ROD noted PCG's claims that it constructed the Program Case in a way that rendered the Subscription Step unnecessary. (Saleba, *et al*., WP-07-E-JP1-01 at 12.) At this point, contrary to its previous removal of the REP settlement costs, the PCG includes the $900 million of settlement costs and develops the same PF Preference rate as BPA's Subscription Step. Apparently, for purposes of the 7(b)(2) rate step, the PCG deems the REP settlement cost to be zero, even though it is not, and it then reconstructs the Program Case using the REP settlement costs to get the same PF Preference rate as BPA's Subscription Step.

The Draft ROD also noted PCG's argument that BPA need not use a two-step process to produce its PF Preference rate, and that the Subscription step was unnecessary. However, the PCG itself produced its PF Preference rate using a two-step process. In its first step, it removed the REP settlement costs from the Program Case and produced an unbifurcated PF rate similar to BPA's. In its second step, the PCG added in the REP settlement cost and produced PF Preference rates similar to those produced by BPA in the Subscription Step. Therefore, both BPA and the PCG used one ratemaking step to conduct the 7(b)(2) rate test and a second step to recognize the costs of the REP settlement. The major difference between the two approaches is that BPA used the ratemaking sections of the Northwest Power Act to arrive at a Program Case in the 7(b)(2) rate step that had no REP costs, while the PCG arbitrarily deemed the REP settlement costs to be zero.

In its brief on exceptions, the PCG argues that BPA incorrectly concluded that the PCG witnesses removed REP settlement costs from the Program Case, even though the PCG admits in its brief on exceptions that "the [PCG] witnesses remove[d] the REP Settlement Agreement costs from their analysis." (JP1 Br. Ex. at 15.) This apparent contradiction is explained by reviewing BPA's and the PCG's development of estimated rates after the section 7(b)(2) rate step and the section 7(b)(3) reallocation. BPA used sections 7(b)(2) and 7(b)(3) in an iterative process when allocating the section 7(b)(3) reallocation amount to non-preference rates. In particular, BPA allocated the reallocation amount to REP loads. This reallocation raised the PF Exchange rate in a step-wise iterative manner, with such step increases gradually exceeding all of the forecasted ASCs of exchanging utilities. At the end of the iterative process, the PF Exchange rate eliminated all REP loads. BPA therefore properly implemented section 7(b)(2) and 7(b)(3) in the same iterative process it has consistently used in ratemaking. Although the PCG included REP settlement costs in the Program Case for the calculation of the unbifurcated PF rate, when it calculated the PF Preference rate it arbitrarily removed the costs of the REP settlements. The PCG has provided no statutory support for the direct removal of costs that BPA is contractually obligated to pay from its PF Preference rate calculation, namely, the costs associated with the signed IOU REP Settlement Agreements.

In its direct testimony, the PCG attached a table showing BPA's Program Case unbifurcated PF rates for each year of the rate period, BPA's PF Preference rates after sections 7(b)(2) and 7(b)(3), and BPA's PF Preference rates after allocation of IOU REP settlement costs. The PCG's table also includes its unbifurcated PF rates and what it calls the PF Preference rates after 7(b)(2) and 7(b)(3). This table is instructive, but perhaps not in the way the PCG intended. First, BPA's unbifurcated PF rates for FY 2007-2009 as shown in the table average $34.83 per MWh, while the PCG calculation results in an average unbifurcated PF rate of $32.23 per MWh for the same time period. It is instructive to remember that BPA's IOU REP Settlement Agreements settled disputes BPA had with the IOUs that could have resulted in a section 7(b)(2) rate step that would likely never trigger to give preference customers rate protection. Using the PCG's own table, it is clear that without the IOU REP Settlement Agreements and if the resolution of the disputes had favored the IOUs, yielding a zero trigger, BPA's preference customers would be subject to the $34.83 average rate rather than the $32.23 average rate.

Second, BPA used its own 7(b)(2) rate step assumptions, with which the IOUs strongly disagreed, to move from a $34.83 unbifurcated PF rate to an average Rate Design Step PF Preference rate (after all potential exchangers dropped out due to the application of sections 7(b)(2) and 7(b)(3)) of $27.2 per MWh. The PCG's table indicates that the PCG calculated an essentially identical average PF Preference rate from their unbifurcated PF rate of $32.23, not by the application of sections 7(b)(2) and 7(b)(3), as BPA did, but by simply removing a legitimate cost item with which they disagreed. If the PCG had retained the REP settlement costs when it calculated BPA's proposed PF Preference rates, it would have resulted in rates nearly equivalent to BPA's proposed PF Preference rate as calculated in BPA's Subscription Step.

Decision

The PCG has not properly calculated the PF Preference rate.

11.0 INVESTOR-OWNED UTILITY BENEFITS AND SETTLEMENT

Issue 1

Whether the IOUs' benefits under the REP Settlement Agreements are consistent with historical REP benefit levels and reasonable in relation to public agency benefits from the FCRPS.

Parties' Positions

WPAG and NRU argue that the portion of the FCRPS benefits allocated to the residential and small farm customers of the IOUs is disproportionately large, and an increase over historical levels. (Saleba, *et al*., WP-07-E-WA-01 at 7; Saven, *et al*., WP-07-E-NR-01 at 14.) WPAG argues there is a substantial disparity between the residential retail rates of the IOUs and those of BPA's preference customers. (Saleba, *et al*., WP-07-E-WA-01(E3).) WPAG suggests that the level of benefits received by residential and small farm customers of the IOUs is the cause of the purported retail rate disparity. (Saleba, *et al*., WP-07-E-WA-01 at 7.)

The IOUs note that the proportion of FCRPS benefits received by their residential and small farm customers is not commensurate with the proportion of the region's residential customers served by the IOUs. (JP6 Br., WP-07-M-67 at 15.) The IOUs note that the average residential retail rate of the BPA preference customers does not substantially exceed the average residential retail rate of the IOUs. (*Id*. at 18.) The IOUs conclude that REP benefits received by residential and small farm customers of the IOUs are not the primary cause of WPAG's asserted substantial disparity in average residential retail rates. (*Id*.)

BPA's Position

BPA questioned the relevancy of WPAG's arguments. (Normandeau, *et al.,* WP-07-E-BPA-33 at 28.) Many factors contribute to rate disparity between the two groups of utilities. (*Id*.) BPA also noted that the methodology used by WPAG was noticeably flawed. (*Id*. at 29.)

Evaluation of Positions

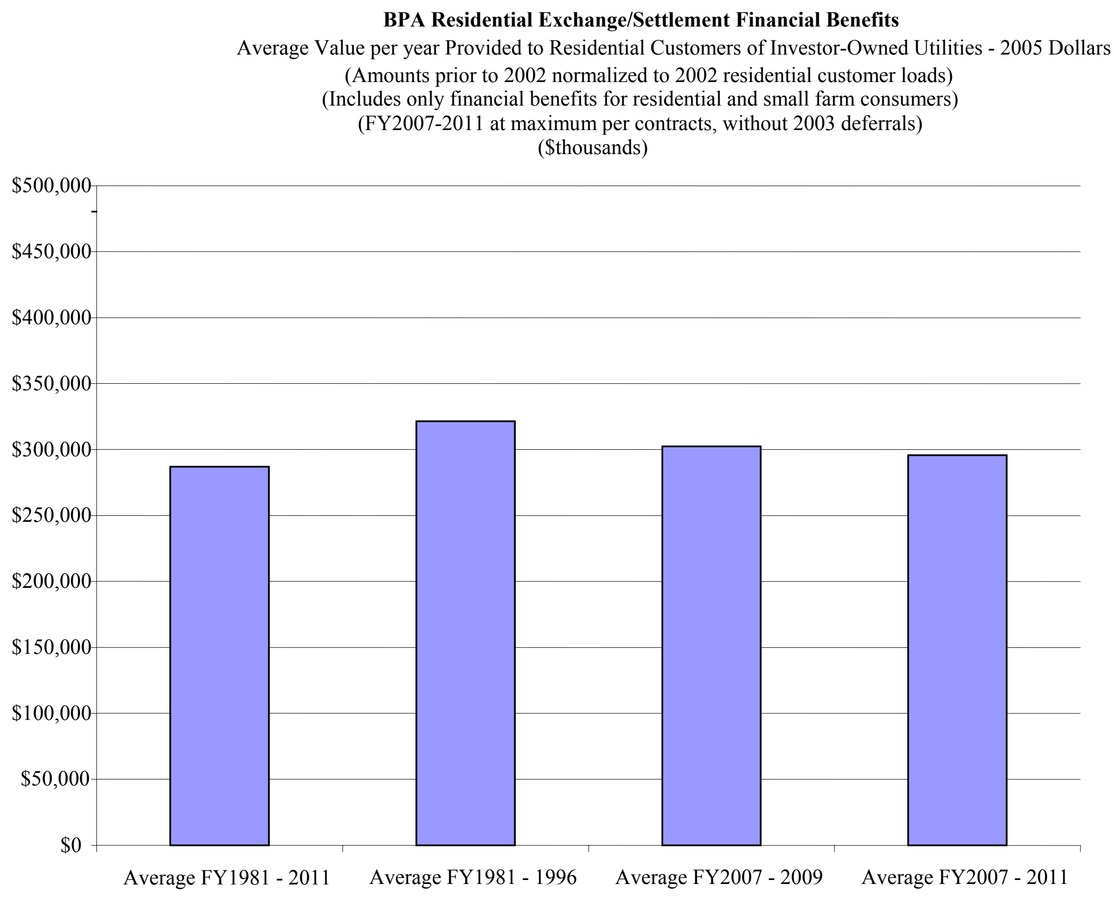
A. The IOUs' Residential and Small Farm Customers' REP Settlement Benefits Are Not Disproportionately or Inequitably Large

The IOUs' argument that WPAG's characterization of the benefits received by residential and small farm customers of the IOUs as inequitably or disproportionately large is incorrect. (JP6 Br., WP-07-M-67 at 15-18.) The IOU REP Settlement Agreements resolved, for their durations, REP-related claims substantially in excess of the amounts payable under such Agreements. (*Id*. at 15.) The IOUs note that FCRPS benefits provided under such Agreements are not inequitably or disproportionately large for a number of reasons. (*Id*.) The IOUs state that WPAG fails to demonstrate that the values of the IOU REP Settlement benefits for the FY 2007-2009 rate period are greater than those historically provided. (*Id*.) Also, WPAG makes a conclusory assertion based on payments in nominal dollars but does not demonstrate that the value of the

IOU REP Settlement benefits for the FY 2007-2009 rate period is an increase over those historically provided. (*Id*., citing Saleba, *et al*., WP-07-E-WA-01 at 7.) Similarly, the NRU comparison of IOU REP Settlement benefits in a single, selected historical year (1999) with projected benefits in a single, selected future year (2007) fails to demonstrate that the level of IOU REP benefits is inconsistent with average historical levels. (JP6 Br., WP-07-M-67 at 15, citing Saven, *et al*., WP-07-E-NR-01 at 14.)

The IOUs note that the projected IOU REP Settlement benefits for the FY 2007-2009 rate period are not an increase over those historically provided when the effects of inflation and load growth are taken into account. (JP6 Br., WP-07-M-67 at 15.) To assess the fairness of the distribution of FCRPS benefits over time, comparisons of the REP benefits for the FY 2007-2009 rate period with those historically provided should take into account the effects of inflation and load growth. (*Id*.) Figure 1, which was provided in the IOU rebuttal testimony, compares average REP benefits over various periods adjusting for inflation and load growth.

Figure 1



(*Id*., citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 5.)

The IOUs note that, contrary to WPAG's suggestion, Figure 1 demonstrates that, when adjusted for the effects of inflation and load growth, the IOU REP benefits during the FY 2007-2009 rate period are generally consistent with the average payments that the residential and small farm customers of the IOUs have historically received under the REP. (JP6 Br., WP-07-M-67 at 16.)

WPAG implies that IOU REP benefits provided under REP settlements since 1996 are disproportionate compared to REP benefits provided before 1996. (Saleba, *et al.*, WP-07-E-WA-01, at 7.) The IOUs state this implication is wrong. (JP6 Br., WP-07-M-67 at 17.) Figure 1 shows that BPA provides less in IOU REP benefits for the FY 2007-2009 rate period under the REP settlements, when adjusted for the effects of inflation and load growth, than BPA provided during the 1981-1996 period. (*Id.*) In addition, however, BPA notes that the IOUs received a lower level of REP benefits from 1996-2001. In determining historical benefits under the REP and/or REP settlements, it may be more accurate to review all individual years through time and true them up for inflation rather than viewing snapshots of specific periods.

The IOUs also note that in determining the fairness of REP settlement benefits for the FY 2007-2009 rate period, BPA should consider that six out of every 10 residential customers in the PNW are served by an IOU. (*Id.*, citing Brattebo, *et al.*, WP-07-E-AC-GE-IP-PL-PS-07 at 6.)

B. WPAG's Comparison of Purported Average Residential Retail Rates Is Based on Incorrect Data, and, in Any Event, the More Relevant Comparison of Relative Benefit Levels Is Based on a Comparison of BPA's PF Preference Rate with the Average System Costs of the IOUs

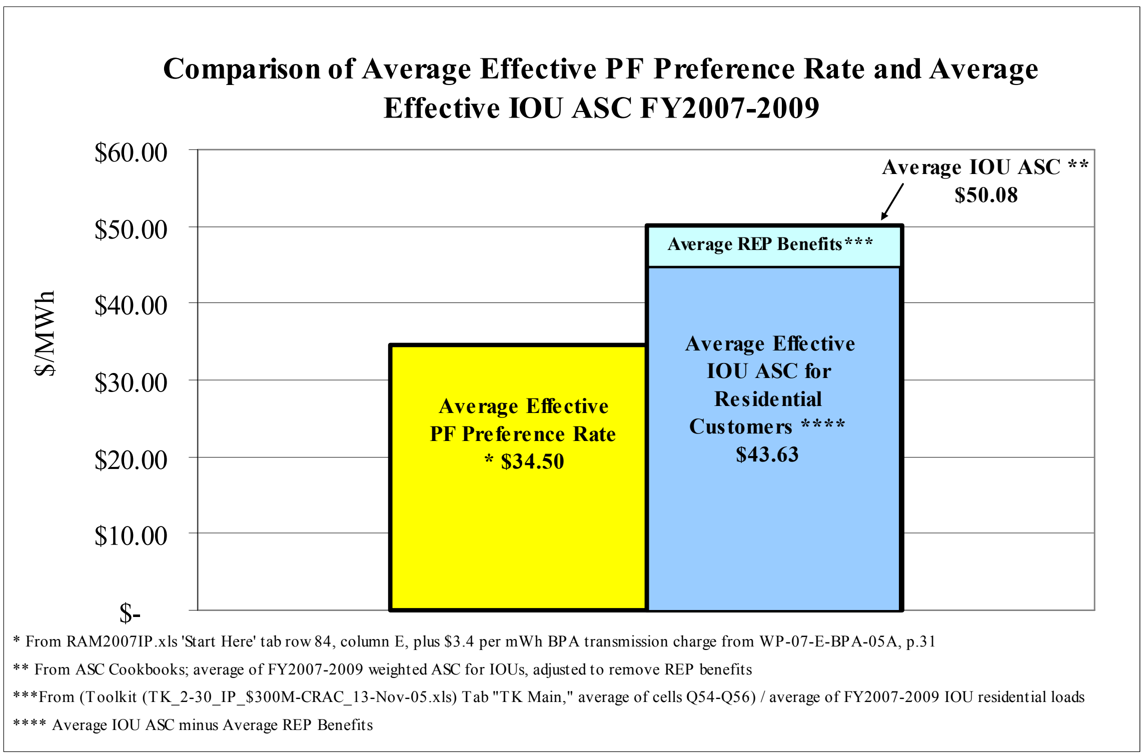
WPAG's exhibit, Saleba, *et al.*, WP-07-E-WA-01(E3) purports to compare the 2004 retail rates of the residential customers of the IOUs with the 2004 retail rates of the residential customers of BPA preference utilities. (JP6 Br., WP-07-M-67 at 18.) The IOUs state that WPAG's claims lack evidentiary support because the data used for such comparison are flawed. (*Id.*) More fundamentally, a comparison of residential retail rates is not an appropriate method for assessing the allocation of FCRPS benefits because a comparison of residential retail rates does not provide a meaningful basis for assessing the allocation of FCRPS benefits. (*Id.*) Retail rates reflect not only the costs and benefits of the FCRPS, but also other power costs, as well as transmission, distribution and customer service costs, all of which vary from utility to utility. (*Id.* at 18-19.)

Further, the residential retail rates depicted in the WPAG exhibit are determined by the individual decisions of each utility regarding how it should best allocate these costs among its various customer classes. (*Id.* at 19.) Because residential retail rates reflect allocated costs from all of these cost categories, residential retail rates do not provide a useful basis for assessing the allocation of FCRPS benefits among BPA's utility customers. (*Id.*, s*ee also* Normandeau*, et al.,* WP-07-E-BPA-33 at 28-29.)

The allocation of FCRPS benefits among BPA's utility customers is, however, reflected in (i) the PF Preference Rate for sales to BPA's preference customers and (ii) the REP benefits received by BPA's customers. (JP6 Br., WP-07-M-67 at 19.) The PF Preference Rate and the REP benefits received by BPA's customers can, as discussed below, be used to assess the allocation of FCRPS benefits among BPA's utility customers. (*Id.*)

The IOUs' rebuttal testimony shows that the allocation of FCRPS benefits among BPA's utility customers for the FY 2007-2009 rate period can be assessed by comparing (i) the effective PF Preference Rate to (ii) the effective ASCs for power delivered to residential customers of utilities receiving REP benefits (*i.e.,* average ASC less average REP benefits). (For the FY 2007-2009 rate period, BPA projects that there will be an insubstantial level of REP benefits for preference agencies.) (*Id.*, citing Brattebo, *et al.*, WP-07-E-AC-GE-IP-PL-PS-07 at 8.) Figure 2 shows (i) BPA's average effective PF Preference Rate proposed in the WP-07 Initial Proposal, $34.50/MWh ($31.10/MWh for the PF Preference Rate plus $3.40/MWh for BPA transmission), for the FY 2007-2009 rate period; (ii) BPA's projected average IOU ASC (adjusted as described below), $50.08/MWh, for the same period; and (iii) the average effective IOU ASC, $43.63/MWh, for power delivered to residential customers (*i.e.,* average IOU ASC less average IOU REP benefits). (*Id.* at 8-9.) Figure 2 thus shows that the effective PF Preference Rate proposed in the WP-07 Initial Proposal is substantially lower than the average IOU ASC, even when the average IOU ASC is reduced by average IOU REP benefits.

Figure 2



(JP6 Br., WP-07-M-67 at 20, citing Brattebo, *et al.*, WP-07-E-AC-GE-IP-PL-PS-07 at 9.) The Average Effective PF Preference Rate shown in Figure 2 is based on the average PF Preference Rate proposed by BPA in its WP-07 Initial Proposal. (JP6 Br., WP-07-M-67 at 20.)

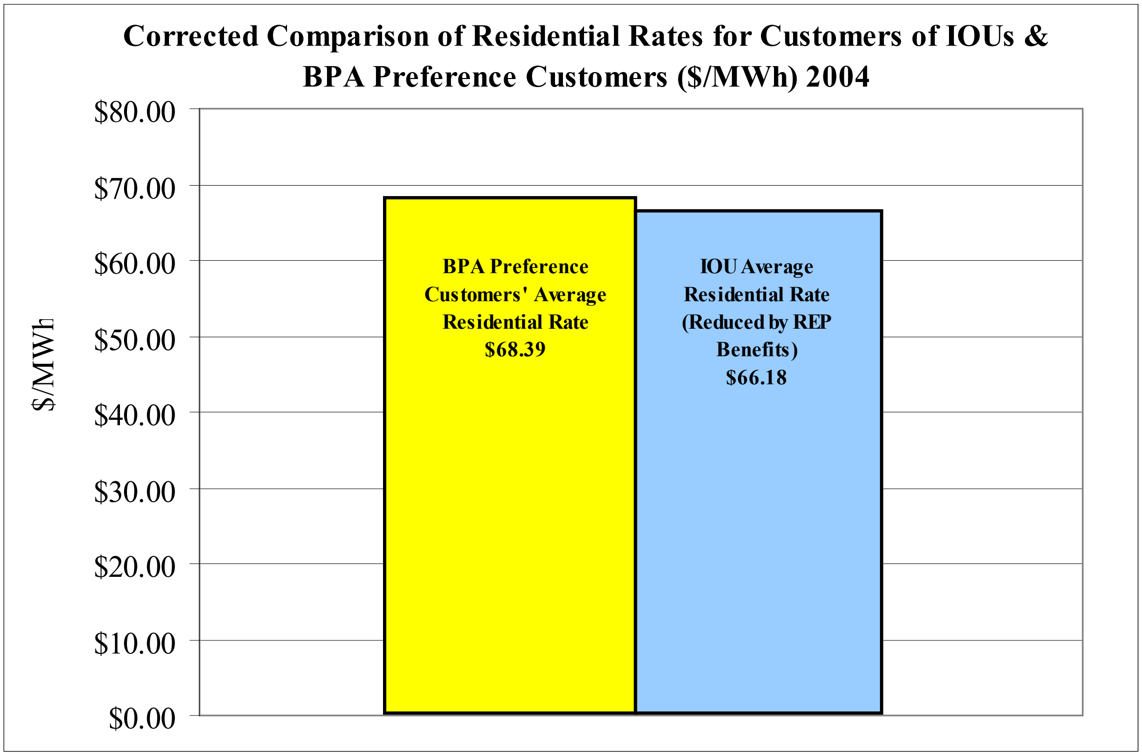
In preparing Figure 2, the IOUs' rebuttal testimony used the output from BPA's Cookbook models that BPA used to estimate ASCs of the IOUs in this proceeding and have, with one exception, used BPA's data from that model. (*Id*. at 20-21.) (That exception was to remove the effect of REP benefits on reported power costs. This removal is appropriate because power costs used in BPA's Cookbook model as input data should be actual power costs, not power costs reduced by REP benefits.) (*Id.,* citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 9.)

Putting aside the issue of whether a comparison of residential retail rates is an appropriate method for assessing the allocation of FCRPS benefits, WPAG's exhibit is not an accurate comparison of residential retail rates among BPA's customers. This chart purports to be a comparison of residential retail rates. However, the chart is inaccurate because it uses incomplete data for BPA's municipal or cooperatively owned customers and because it double-counts the effect of REP settlement benefits on the IOUs' residential retail rates. (JP6 Br., WP-07-M-67 at 21.) WPAG uses residential retail rate data for BPA's municipal and cooperatively-owned customers and the IOUs from the Energy Information Administration annual electric power industry report for calendar year 2004 (EIA 2004). (*Id*., citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 10.) The WPAG calculation of the average residential retail rate for BPA preference customers in its chart is incomplete because it excludes EIA 2004 data for at least 10 BPA municipal or cooperatively owned utilities, including the City of Eugene, Oregon (Eugene Water and Electric Board). (*Id*.)

More significantly, WPAG double-counted the effect of REP settlement benefits on the IOUs' residential retail rates in Saleba, *et al*., WP-07-E-WA-01(E3). (JP6 Br., WP-07-M-67 at 21.) The EIA 2004 data used by WPAG for the IOUs already reflects the reduction in their residential retail rates due to IOU REP benefits. (*Id*.) However, WPAG subtracted IOU REP benefits from the EIA 2004 retail rate data for the IOUs, thus mistakenly accounting for those benefits twice. (*Id*., citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 10.)

The IOU rebuttal testimony corrected the errors described above in the retail rate data shown in WPAG's chart. (*Id*. at 11.) Figure 3 reflects corrections to (i) include EIA 2004 data for 10 municipal or cooperatively owned customers excluded from WPAG's exhibit, and (ii) correct the double-counting found in that chart of the effect of IOU REP benefits on the IOUs' residential retail rates.

Figure 3



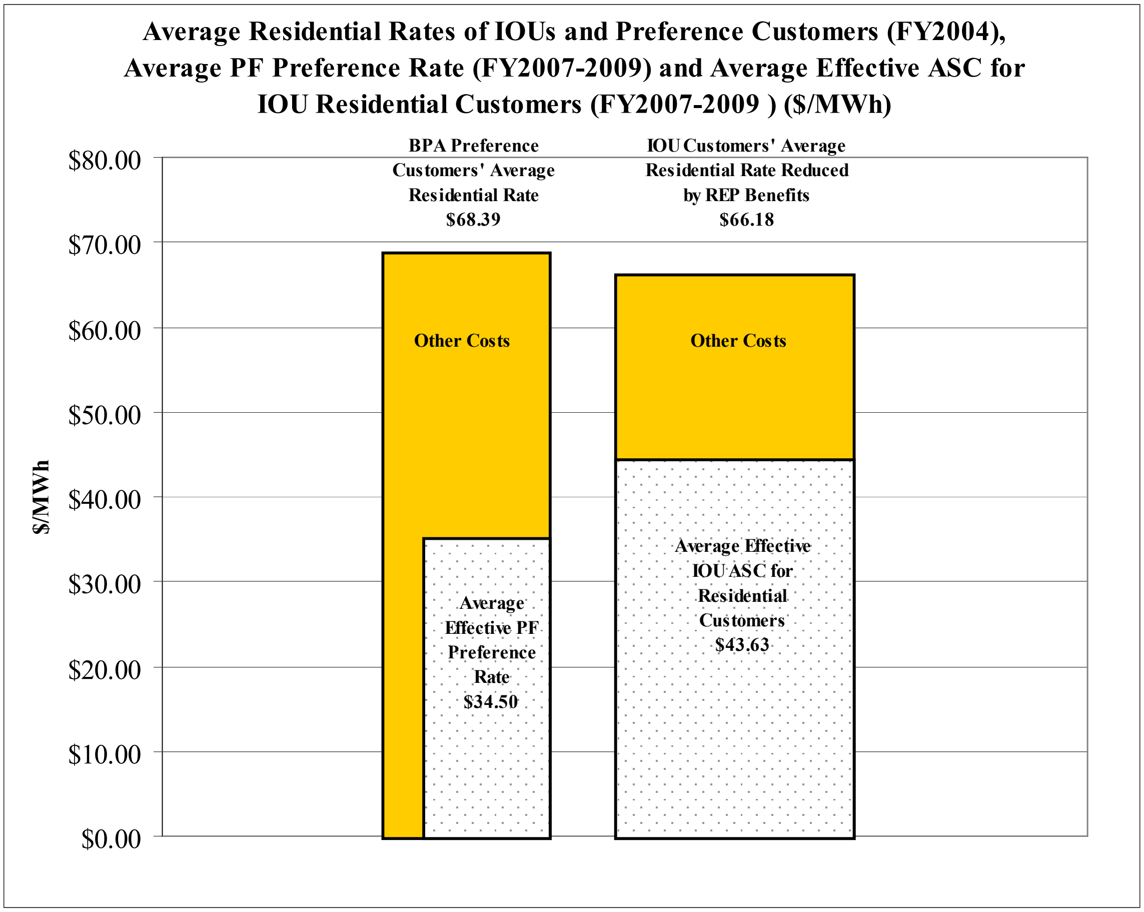
(JP6 Br., WP-07-M-67 at 22, citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 11.)

Figure 3 demonstrates that in 2004, the average rates of residential customers in the region were roughly equal (6.84 cents/kWh versus 6.62 cents/kWh), regardless of whether those customers were served by preference utilities or IOUs. (*Id.* at 11.) Thus, even assuming, for the purpose of argument, that a comparison of residential retail rates could be used to assess the allocation of FCRPS benefits, such a comparison, if properly performed, shows no significant difference between the residential retail rates of BPA's preference customers and those of the IOUs. (JP6 Br., WP-07-M-67 at 22-23.) Therefore, such a comparison does not demonstrate that the IOU REP benefits are an inequitably or disproportionately large share of the FCRPS benefits. (*Id*. at 23.)

The effect of these corrections is significant. (*Id*.) The WPAG chart erroneously indicates that in 2004, the average retail rate paid by residential customers of BPA's municipal and cooperatively owned customers was $11.53/MWh (1.15 cents/kWh) greater than the average retail rate paid by residential customers of the IOUs. (*Id*.) The IOUs' corrections reduced that differential from $11.53/MWh (1.15 cents/kWh) to $2.21/MWh (0.22 cents/kWh). (*Id*. at 12.) In short, the average rates in 2004 of residential customers in the region were roughly equal, regardless of whether such customers were served by BPA preference utilities or IOUs. (JP6 Br., WP-07-M-67 at 23.)

Figure 4 summarizes the data presented in Figures 2 and 3 and depicts the corrected average residential retail rate data from Figure 3, together with the average PF Preference Rate and the effective ASC for IOU residential and small farm customers from Figure 2. (*Id*.)

Figure 4



(*Id*. at 24, citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 13.)

Figure 4 again demonstrates that the average residential rates of the IOUs and BPA preference customers were roughly equal, even though the proposed PF Preference Rate is substantially lower than the projected average effective IOU ASC. (JP6 Br., WP-07-M-67 at 24.) By the widths of the bars, Figure 4 also roughly represents the relative sizes of (i) the residential loads of the IOUs (57 percent) and BPA preference customers (43 percent) and (ii) the relative sizes of residential loads of BPA preference customers served by purchases at the PF Preference Rate (75 percent) and served by other resources (25 percent). (JP6 Br., WP-07-M-67 at 25, citing Brattebo, *et al*., WP-07-E-AC-GE-IP-PL-PS-07 at 14.) As noted above, the projected average effective IOU ASC and proposed average effective PF Preference Rate are for FY 2007-2009, and the retail residential rate data is from EIA 2004. (*Id.*) Accordingly, the residential retail rate data used in WPAG's exhibit, and the corrected retail rate data presented above, do not reflect (i) the impact of retail rate changes since 2004, or (ii) the impact of the changes in the PF Preference Rate (including CRACs) on the average residential retail rate of BPA preference customers since 2004. (*Id.*)

In addition, WPAG erroneously asserts that its exhibit "shows graphically the fact that due in part to the Subscription contracts and the ensuing events, most preference customer residential rates exceed the residential rates charged by IOUs." (Saleba, *et al*., WP-07-E-WA-01 at 7.) The chart does not explain or show how, or the extent to which, any of these items affects retail rates. (JP6 Br., WP-07-M-67 at 25.) The chart purports to show only a relative relationship between average residential retail rates of BPA preference customers and those of IOUs, without showing the causes of any differences between those rates. (*Id*.) As discussed above, the average retail rates paid by residential customers of BPA's preference utilities and by IOUs in 2004 were roughly equal. (*Id*.) This is true notwithstanding the Subscription contracts and the ensuing events. (*Id*.)

Decision

The IOUs' benefits under the REP Settlement Agreements are not inequitably large or a disproportionately large share of FCRPS benefits. The average residential retail rate of BPA's preference customers does not substantially exceed the average residential retail rate of the IOUs and this issue is not a matter for this rate case.

12.0 SLICE REVENUE REQUIREMENT AND RATE

12.1 Introduction

As part of the Partial Resolution of Issues, BPA staff and rate case parties supported, or did not oppose, modifications to BPA's Initial Proposal. In part, those modifications include the treatment of the revenues and expenses associated with renewable resource facilitation and research and development, the treatment of bad debt expenses, and changes to the format of the Slice Costing and True-Up Table. The specifics of the proposed changes are set forth in WP-07-E-BPA-31, specifically Attachment A thereto (Partial Resolution of Issues). For a detailed discussion of the Partial Resolution of Issues, refer to Section 2 and Attachment 1 of this ROD.

BPA is engaged in litigation before the Ninth Circuit concerning the appropriate interpretation and implementation of the Slice rate and Slice Rate Methodology. *Northwest Requirements Utilities v. Bonneville Power Administration*, Nos. 03-73849, 03-74170 and 04-71311. In that litigation, the Slice customers contend that BPA's Slice True-Up Adjustment Charges for Contract Years 2002 and 2003 are inconsistent with the terms of the Slice contracts, which incorporate language of the Slice rate and Slice Rate Methodology. BPA proposed to clarify the rate treatment of certain Slice rate and Slice Rate Methodology matters at play in the litigation, consistent with BPA's prior interpretations and treatment of them. (*See* Lee, *et al*., WP-07-E-BPA-23.) It is possible that a settlement could be reached in the litigation that would obviate the need for some or all of the clarifications proposed in BPA's Initial Proposal, *i.e.*, BPA, the Slice customers, and NRU would resolve their differences over which interpretation is reasonable and should be applied. Therefore, BPA wishes to clarify that each of its proposed clarifications here will apply unless a final, executed settlement agreement is reached in the litigation regarding the particular issue, and unless BPA and the parties to the settlement have specifically agreed that the interpretation underlying the settlement of an issue should continue to apply in the future.

12.2 Treatment of Renewable Resource Facilitation and Research and Development Expenses

Issue 1

Whether BPA should remove the expenses associated with renewable resource facilitation and research and development from the Slice Revenue Requirement and Actual Slice Revenue Requirement.

Parties' Position

The IOUs, PNGC, NRU, WPAG, PPC, and SUB either support, or do not oppose, the Partial Resolution of Issues negotiated between BPA and the rate case parties. (IOU Br., WP-07-M-67 at 3; PNGC Br., WP-07-M-70 at 9; NRU Br., WP-07-M-61 at 2; WPAG Br., WP-07-M-68 at 7; SUB Br., WP-07-M-66 at 2.) The Partial Resolution of Issues includes a provision that removes the expenses associated with the renewable resource facilitation and research and development from the Slice Revenue Requirement and Actual Slice Revenue Requirement.

BPA's Position

BPA supports the decision to remove the expenses associated with the renewable resource facilitation and research and development from the Slice Revenue Requirement and Actual Slice Revenue Requirement. When the Slice Revenue Requirement was developed for the Initial Proposal, BPA included the expenses associated with renewable resource facilitation and research and development, but did not include the corresponding revenues that were assumed to be used for this reinvestment in these activities. In the Partial Resolution of Issues, BPA agreed to remove the expense element from the Slice Revenue Requirement and Actual Slice Revenue Requirement. (*See* Evans, *et al.,* WP-07-E-BPA-31, Attachment A at 4; Evans, *et al.,* WP-07-E-BPA-31(E1).)

Evaluation of Positions

The Partial Resolution of Issues contains the following paragraph with regard to this issue.

> In BPA's Initial Proposal the Slice Revenue Requirement contained an expense associated with the reinvestment in BPA's renewable resource facilitation and research and development of what was referred to collectively as "Green Tag revenues." These revenues comes [sic] from three sources: 1) Green Energy Premium revenues resulting from sales of Renewable Energy Certificates (RECs), 2) Green Tag revenues resulting from sales of Environmentally Preferred Power (EPP), and 3) revenues from sales of Alternative Renewable Energy (ARE) to Pre-Subscription power purchasers. The Slice Revenue Requirement did not include a credit for these revenues. BPA will remove the expense associated with such revenues from Slice Revenue Requirement in BPA's Final Proposal. In addition, BPA will not include such reinvestment expenses in the Actual Slice Revenue Requirement in the Slice True-Up process. BPA will continue its current proposal and will not include credits in the Slice Revenue Requirement for any revenues from the three sources listed above.

(WP-07-E-BPA-31, Attachment A at A-4.)

The resolution of this issue negotiated between BPA and the rate case parties is a proper and reasonable one. Given that BPA's intent was reinvestment of "Green Tag revenues" in renewable resource facilitation and research and development, such that there was a net zero financial impact for BPA's customers (*see* Ingram, *et al.,* WP-07-E-BPA-25 at 4.), it is appropriate that the Slice product is not credited with "Green Tag revenues" and that the Slice product should not bear the expense associated with the reinvestment of such revenues. In addition, the fact that the resolution of this issue enjoyed support from, or was not opposed by, parties beyond BPA and the Slice customers provides further evidence of the reasonableness of the resolution of this issue.

Decision

BPA will remove from the Slice Revenue Requirement and the Actual Slice Revenue Requirement the expense associated with renewable resource facilitation and research and development.

12.3 Bad Debt Expense

Issue 1

Whether BPA should exclude from the Slice Revenue Requirement bad debt expenses associated with sale of energy for customers that purchase exclusively under the FPS-07 rate schedule.

Parties' Position

The IOUs, PNGC, NRU, WPAG, PPC, and SUB either support, or do not oppose, the Partial Resolution of Issues negotiated between BPA and the rate case parties. (IOU Br., WP-07-M-67 at 3; PNGC Br., WP-07-M-70 at 9; NRU Br., WP-07-M-61 at 2; WPAG Br., WP-07-M-68 at 7; SUB Br., WP-07-M-66 at 2.) The Partial Resolution of Issues includes a provision that excludes from the Slice Revenue Requirement and Actual Slice Revenue Requirement bad debt expenses associated with sales of energy to any customer that purchases exclusively under the FPS-07 rate schedule.

BPA's Position

BPA supports the resolution of this issue in the manner described in the Partial Resolution of Issues. In the Initial Proposal, BPA proposed to include all power-related bad debt expenses in the Actual Slice Revenue Requirement for the Slice True-Up process. In the Partial Resolution of Issues, BPA agreed to exclude any bad debt expense associated with the sale of energy to any customer that purchases exclusively under the FPS-07 rate schedule from the Actual Slice Revenue Requirement for True-Up purposes. (*See* Lee, *et al.,* WP-07-E-BPA-23 at 16-17.)

Evaluation of Positions

The Partial Resolution of Issues contains the following paragraphs with regard to this issue.

> BPA's Initial Proposal contained testimony (including data responses) that described how Slice purchasers would pay for bad debt expense through the Actual Slice Revenue Requirement and Slice True-Up process. Under the Initial Proposal, all Power-related bad debt expense would be included in the Slice True-Up.
>
> Bad debt expense is recognized on the income statement in the current accounting period when the determination is made that all or a portion of outstanding accounts receivable are in question. A reserve account is created for the amount BPA estimates will not be collectible, with the receivables remaining in the accounting records. BPA will identify accounts receivable associated with non-Preference customers that were estimated to be uncollectible, and result in bad debt expense. The Actual Slice Revenue Requirement

> will not include any bad debt expense associated with the sale of energy to any customer that exclusively purchases under the FPS-07 rate schedule. However, any bad debt expense associated with the sale of energy under both the PF-07 and FPS-07 or just the PF-07 rate schedules will be included in the Actual Slice Revenue Requirement for Slice True-Up purposes.

(Evans, *et al.*, WP-07-E-BPA-31, Attachment A at A-4.)

The resolution of this issue negotiated between BPA and the rate case parties is reasonable. Slice customers receive a share of surplus power directly through their purchase of the Slice product and do not share in the expenses or revenues associated with BPA's surplus power sales. (*See* Lee, *et al.,* WP-07-E-BPA-23 at 3.) Given that the Slice product assumes the secondary sales risk directly, it is reasonable to exclude the bad debt expense associated with the sales of secondary energy to customers purchasing exclusively under the FPS-07 rate schedule from the Actual Slice Revenue Requirement. These transactions represent the type of sales for which no revenue credit is included in either the Slice Revenue Requirement or Actual Slice Revenue Requirement.

<u>Decision</u>

BPA will exclude from the Slice Revenue Requirement and Actual Slice Revenue Requirement any bad debt expense associated with the sale of energy to customers purchasing exclusively under the FPS-07 rate schedule.

13.0 POLICY ON DSI SOLUTIONS

Issue 1

Whether the Administrator should consider arguments regarding DSI Service in this rate proceeding.

Parties' Positions

In spite of the fact that the FRN explicitly excluded DSI service issues (namely, whether service benefits should be provided, and if so, in what amount and through what delivery mechanism) from the scope of this rate proceeding, two parties, Alcoa and PNGC, submitted briefs that attempt to make various arguments regarding DSI service. (Alcoa Br., WP-07-M-60; PNGC Br., WP-07-M-70 at 10-11; s*ee also* WPAG, WP-07-M-68 at 6.) These submittals raise the issue of whether the Administrator should address the arguments made or, consistent with the FRN, exclude such arguments from consideration in this proceeding.

PNGC argues that "BPA has no obligation or discretion to incur costs for DSI 'service benefits,' and inclusion of such costs in the rates of its preference and priority customers is unlawful." (PNGC Br., WP-07-M-70 at 11.) PNGC also notes that the legal arguments supporting its point of view have previously been made in the context of two separate cases being argued before the Ninth Circuit Court of Appeals. (*Id.* at 10.) In particular, PNGC notes that, in one of the cases, PNGC is directly challenging the current proposal to provide up to $59 million in monetary benefits to the DSIs. (*Id.* at 10-11.) PNGC notes finally that its purpose in submitting DSI testimony in this proceeding "is to preserve the issue and reserve all available arguments for possible review by the Ninth Circuit pursuant to Section 9(e) of the Northwest Power Act." (*Id.* at 11-12.)

Alcoa notes that practically all testimony related to DSI service was stricken, but the hearing record "left in place certain testimony that referred to the BPA's proposed provision of a Monetary Benefit to the DSIs as a 'subsidy,' 'inequitable,' and 'unlawful'." (Alcoa Br., WP-07-AL-M-60 at 2.) Alcoa seeks "to point out why the Monetary Benefits that BPA proposes are not a subsidy or inequitable." (*Id.* at 3.) In this connection, Alcoa argues that the DSIs have made substantial contributions to the BPA system historically, so that the current proposal cannot be deemed a subsidy, particularly in light of the rates that DSIs can be expected to pay. (*Id.* at 3-5.) Alcoa also argues that the DSIs are entitled to greater benefits than offered under the current DSI proposal, concluding that this lesser benefit could not be considered a subsidy. (*Id.* at 6-8.)

In its brief on exceptions, Alcoa states that to the extent BPA considers in this rate proceeding any testimony concerning the merits of providing service benefits to the DSIs, it takes exception both to the order striking portions of Alcoa's testimony on that issue, and to BPA's draft decision in the Draft ROD not to address arguments made by Alcoa on that issue. (Alcoa Br. Ex., WP-07-AL-M-86.) PNGC in its brief on exceptions reiterated the statement from its initial brief reserving "all available arguments" for possible review in the Ninth Circuit regarding BPA's decision to provide service benefits to the DSIs. (PNGC Br. Ex., WP-07-M-82.)

BPA's Position

The Administrator need not address the issues raised by PNGC and Alcoa. The FRN explicitly excluded consideration of the DSI service benefits from this proceeding because the issues were under consideration in other processes. Therefore, the arguments have been, or should have been, raised and considered elsewhere. Addressing those issues here would be redundant and unfair to parties that relied on BPA's statement that it would not address DSI service benefit issues in this rate proceeding.

Evaluation of Positions

BPA has proposed, in separate proceedings, to provide the DSIs with a monetary benefit instead of electric power service. Accordingly, BPA's FRN in this proceeding stated:

> The DSI Service decision finalized and established the manner and method by which BPA would provide service and benefits to its DSI customers. The decisions in that ROD resolved the method and level of service to be provided DSIs in the FY 2007-2011 Period. Pursuant to § 1010.3(f) of BPA Hearing Procedures, the Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit the appropriateness or reasonableness of BPA's decisions made in the DSI ROD.

70 Fed. Reg. 67,685, 67,689 (2005). Alcoa notes that practically all testimony on the DSI service plan was stricken, but that a small portion "slipped through the cracks" and remained on the record. This inadvertent error, however, does not provide a basis for introducing the matter pertaining to DSI service benefits into this proceeding. The FRN makes it clear that the Administrator decided to determine the method and manner for providing DSI service in other processes. There has been ample opportunity for comment on DSI service issues in these other processes. It would be extraordinarily redundant, administratively inefficient, and unfair to other parties to reverse course at this point and provide yet another forum for rehashing issues that have already been addressed elsewhere.

As to the substance of the arguments made by PNGC and Alcoa, there is little to say. PNGC candidly admits that its arguments are already before the Ninth Circuit in separate litigation. That being the case, it is not clear what useful purpose would be served by addressing the same issues in this forum. The Ninth Circuit will ultimately render an opinion that will be binding on BPA.

Alcoa expresses its concern that there are statements in the testimony of this proceeding to the effect that the DSI service proposal creates an inequity, constitutes a subsidy, or should be deemed unlawful. It goes without saying that the Administrator would not approve a plan that he believed to be unlawful.

Decision

The Administrator will not consider the arguments made by PNGC and Alcoa in this proceeding. DSI service benefits were established in separate proceedings, and their testimony adds nothing new or relevant to the subject.

14.0 LOW DENSITY DISCOUNT

Issue 1

Whether BPA should adopt the Partial Resolution of Issues regarding the Low Density Discount (LDD).

Parties' Positions

The Pacific Northwest Generating Cooperative (PNGC) supports the Partial Resolution of Issues regarding the LDD. (PNGC Br., WP-07-M-70 at 7; NRU Br., WP-07-M-61 at 2-3, *citing* Evans, *et al*., WP-07-E-BPA-31, Attachment A at A-2.) Other parties support or do not oppose it.

BPA's Position

BPA supports the Partial Resolution of Issues, including provisions regarding the LDD. (Evans, *et al*., WP-07-E-BPA-31, Attachment A.)

Evaluation of Positions

A Partial Resolution of Issues was negotiated between BPA and rate case parties. (*See* Evans, *et al*., WP-07-E-BPA-31, Attachment A (E2).) With regard to the LDD, the Partial Resolution of Issues contains the following provisions:

> **Low Density Discount (LDD)**
>
> For the FY 2007-2009 rate period, BPA's General Rate Schedule Provisions (GRSPs) for the Low Density Discount (LDD) shall remain unchanged from BPA's 2002 GRSPs except for the following:
>
>> Section II.L.2.c of the LDD Eligibility Criteria will be replaced with the following language:
>>
>>> the Purchaser's average retail rate for the reporting year must exceed BPA's average Priority Firm power rate for the most closely corresponding fiscal year by at least 25 percent.
>>
>> Section II.L.4 shall be amended to include the following language:
>>
>>> For Purchasers with Pre-Subscription power sales contracts who are converting to Subscription power sales contracts on October 1, 2006, the "existing discount" shall be calculated by BPA using BPA's 2002 GRSPs and calendar year 2004 data. This "existing discount" will only be used for determining the Purchaser's Phase-In Phase-Out Adjustment for the first year of the rate period. The

> Purchaser shall provide BPA with such calendar year 2004 data by October 1, 2006.

(*See* WP-02 Rate Schedule and GRSPs, Revised May 2004.)

> BPA shall propose, in its Initial Proposal in its next wholesale power rate case for the FY 2010-2011 rate period, GRSPs for the LDD that are not materially different from Sections 1 and 2 of BPA's FY 2007-2009 GRSPs. Customers' current methods of calculating "consumers" prior to or during the FY 2007-2009 and FY 2010-2011 rate period shall remain unchanged, unless both the customer and BPA agree otherwise. BPA shall continue to review LDD data submittals for accuracy.
>
> BPA shall schedule meetings with the Pacific Northwest Generating Cooperative and other interested BPA customers to discuss and attempt to achieve mutual agreement on the proper application of the LDD to the Slice Product. These discussions shall be based on the principle that Slice customers will not be advantaged or disadvantaged in the implementation of the LDD compared to BPA's non-Slice customers receiving the LDD. These meetings shall be scheduled well before the preparation of BPA's Initial Proposal for its FY 2010-2011 wholesale power rate case. Any successful agreement on the resolution of the Slice LDD issue shall be included in BPA's Initial Proposal for its FY 2010-2011 wholesale power rate case.

(*Id.*)

PNGC was one of the main parties interested in LDD issues. Because of PNGC's support for the LDD provisions of the Partial Resolution of Issues, and the lack of any opposition to those provisions, they will be adopted.

Decision

BPA adopts the provisions of the Partial Resolution of Issues regarding the LDD noted above.

15.0 FIRM POWER PRODUCTS AND SERVICES (FPS) RATE SCHEDULE

15.1 Introduction

As part of the Partial Resolution of Issues, BPA staff and the rate case parties negotiated proposed modifications to BPA's Initial Proposal. Those modifications involve two changes to BPA's Initial Proposal. The specifics of the changes are set forth in Evans, *et al.*, WP-07-E-BPA-31, and in Attachment 1 of this ROD.

15.2 Posting of Quarterly Reports on BPA External Website

Issue 1

Whether BPA should post reports on its external website that contain the same information as contained in the Electric Quarterly Reports (EQRs) that are filed by utilities with FERC.

Parties' Position

The direct testimony of the Surplus Marketing Coalition (Cowlitz County PUD, Eugene Water and Electric Board, Grant County PUD, Pend Oreille County PUD, Pacific Northwest Generating Cooperative, Seattle City Light, and City of Tacoma) suggests that BPA post on its website information that is "directly analogous to that contained in EQR reports required by FERC of 'public utilities' with [Market Based Rate] authority . . . ." (Peters, WP-07-E-JP4-01, at 8-10.) The Partial Resolution of Issues includes a provision in which BPA agreed to post, 30 days after the end of each calendar quarter, on its external website, reports that contain the same information as contained in the EQRs filed by utilities with FERC. The IOUs, PNGC, NRU, WPAG, PPC, and SUB all support, or do not oppose, the Partial Resolution of Issues negotiated between BPA and the rate case parties. (IOU Br., WP-07-M-67 at 3; PNGC Br., WP-07-M-70 at 9; NRU Br., WP-07-M-61 at 2; WPAG Br., WP-07-M-68 at 7; SUB Br., WP-07-M-66 at 2.)

BPA's Position

Although BPA is not under FERC's jurisdiction in this regard, BPA supports the proposal to post reports that contain the same information as contained in the EQRs filed by utilities that are under FERC's jurisdiction of market-based rate authorization. When the FPS rate schedule was developed for the Initial Proposal, BPA had not considered the idea of posting reports equivalent to the EQRs. In the Partial Resolution of Issues, BPA responded to the testimony of the Surplus Marketing Coalition by agreeing to post such reports.

Evaluation of Positions

The Partial Resolution of Issues contains the following paragraph with regard to this issue.

> BPA will agree to post, 30 days after the end of each calendar quarter, on its external web site, reports that contain the same information as contained in the Electric Quarterly

> Reports filed by utilities with the Federal Energy Regulatory Commission. BPA will begin filing these reports once the software platform has been developed and tested by BPA. BPA does not believe the software will be ready until FY 2008. BPA will make best efforts to have the software ready for posting by that time. BPA will advise parties about the schedule of the software development quarterly.

(Evans, *et al.*, WP-07-E-BPA-31 at A-1.) The resolution of this issue negotiated between BPA and the rate case parties is a reasonable one. For comparative purposes, and in furtherance of BPA's overall goal of agency transparency, it is reasonable for BPA's FPS-07 rate schedule to comply with this requirement because it is similar to requirements in place for FERC-jurisdictional utilities with market-based rate authorization. In addition, the fact that the resolution of this issue enjoyed support from, or was not opposed by, parties, including members of the Surplus Marketing Coalition provides further evidence of the reasonableness of the resolution of this issue.

Decision

BPA will post, 30 days after the end of each calendar quarter, on its external website, reports that contain the same information as contained in the Electric Quarterly Reports filed by utilities with FERC consistent with the Partial Resolution of Issues. BPA will begin posting these reports as soon as the software is developed.

15.3 Price Cap

Issue 1

Whether BPA should voluntarily agree to limit the price of any sales under the FPS-07 rate schedule to the applicable west-wide price cap, if any, established by FERC.

Parties' Position

The direct testimony of the Surplus Marketing Coalition suggested that "[e]ither the FPS rate schedule or the GRSPs should refer explicitly to the price cap as currently established and potentially revised by FERC during the FY07-09 rate period." (Peters, WP-07-E-JP4-01 at 7.) The Partial Resolution of Issues includes a provision setting forth language that BPA will include in Section II of the GRSPs regarding a price cap for sales under the FPS-07 rate schedule. The IOUs, PNGC, NRU, WPAG, PPC, and SUB all support or did not oppose the Partial Resolution of Issues negotiated between BPA and the rate case parties. (IOU Br., WP-07-M-67 at 3; PNGC Br., WP-07-M-70 at 9; NRU Br., WP-07-M-61 at 2; WPAG Br., WP-07-M-68 at 7; SUB Br., WP-07-M-66 at 2.)

BPA's Position

BPA agrees with the rate case parties and supports the resolution of this issue in the manner described in the Partial Resolution of Issues. In the Initial Proposal, BPA proposed to "adhere to a regime of price caps that is equivalent to the FERC west-wide cap." (FPS-Market Power

Study, Rate Schedule Design, WP-07-E-BPA-26 at 9.) In the Partial Resolution of Issues, BPA agreed to specifically include language in the GRSPs regarding a price cap for sales under the FPS-07 rate schedule.

Evaluation of Positions

The Partial Resolution of Issues contains the following paragraph with regard to this issue.

Section II of the General Rate Schedule Provisions will be modified to include following:

> **West-wide Price Cap of FPS Sales**
> BPA will voluntarily agree to limit the price of any sales under the FPS rate schedule to the applicable west-wide price cap, if any, established by the Federal Energy Regulatory Commission.

(Evans, *et al.*, WP-07-E-BPA-31 at A-2.)

The resolution of this issue negotiated between BPA and the rate case parties is reasonable. As noted in BPA's Direct Testimony, the intent of this cap is to demonstrate BPA's commitment to participating in the market on a level playing field with other market participants. (*See* Mainzer, *et al.*, WP-07-E-BPA-26 at 9.) The Surplus Marketing Coalition suggested that BPA memorialize that commitment by including language regarding the price cap in the GRSPs. The Partial Resolution of Issues contains language that would do so, thus it is advisable to incorporate this language into the GRSPs. In addition, the fact that the resolution of this issue enjoyed support from parties beyond BPA and members of the Surplus Marketing Coalition provides further evidence of the reasonableness of the resolution of this issue.

Decision

BPA will include language in Section II of the GRSPs setting forth BPA's voluntary commitment to limit the price of any sales under the FPS-07 rate schedule to the applicable FERC west-wide price cap.

16.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

16.1 Introduction

BPA has assessed the potential for environmental effects from the WP-07 Wholesale Power Rate Adjustment Proceeding, consistent with the National Environmental Policy Act (NEPA). 42 U.S.C. § 4321, *et seq*. The NEPA analysis is conducted separately from the formal rate process.

BPA has previously evaluated the environmental impacts of a range of business structure alternatives that included, among other things, various rate designs for BPA's power products and services. (Business Plan Final Environmental Impact Statement, DOE/EIS-0183, June 1995 (Business Plan EIS).) In August 1995, the BPA Administrator issued a Record of Decision (Business Plan ROD) that adopted the Market-Driven alternative from the Business Plan EIS. As discussed in more detail below, the WP-07 Wholesale Power Rate Adjustment Proceeding falls within the scope of the Market-Driven alternative and is not expected to result in significantly different environmental impacts that are significantly different from those examined in the Business Plan EIS. The decision to implement this rate proposal thus is tiered to the Business Plan ROD.[1]

16.2 Business Plan EIS and ROD

The Business Plan EIS was prepared in response to a need for an adaptive business policy that would allow BPA to be more responsive to the evolving and increasingly competitive wholesale electricity market, while still meeting both its business and public service missions. Accordingly, BPA designed the Business Plan EIS to support a wide array of business decisions, including decisions to establish rates for products and services in rate cases in 1995 and thereafter. (Business Plan EIS, Section 1.4.) BPA identified several purposes for consideration, including: achieving strategic business objectives; competitively marketing BPA's products and services; providing for equitable treatment of Columbia River fish and wildlife; achieving BPA's share of the NWPPC conservation goal; establishing rates that are easy to understand and administer, stable, and fair; recovering costs through rates; meeting legal mandates and contractual obligations; avoiding adverse environmental impacts; and establishing productive government-to-government relationships with Indian Tribes. (*Id.* Section 1.2; Business Plan ROD, Sections 5 and 6.)

---

[1] Although BPA is electing to tier its decision to the Business Plan ROD, BPA notes that this rate proposal is the type of action typically excluded from NEPA pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this rate proposal falls within Categorical Exclusion B4.3, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA documentation of "[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits." Nonetheless, BPA has laid out a strategy in the Business Plan EIS and ROD for NEPA compliance concerning future business-related decisions, and believes that a ROD tiered to the Business Plan ROD is an appropriate means for ensuring NEPA consideration of this rate proposal.

BPA’s Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. (Business Plan EIS, Section 2.4.) Four policy options, or modules, were also developed in the EIS to allow variations of the alternatives in key areas, including rate design. The alternatives and modules are designed to cover the range of options for the important issues affecting BPA’s business activities, as well as the impacts of those options, and variations can be assembled by matching issues and substituting modules among the six alternatives. (*Id.* Section 2.1.2.) All of the alternatives and modules are examined under two widely different hydrosystem operations strategies that served as “bookends” for reasonably possible operations of the FCRPS. These alternatives thus represent a range of reasonable alternatives for BPA’s business activities and BPA’s ability to balance costs and revenues.

The Business Plan EIS focuses on BPA's business relationships to the market. BPA’s business decisions, such as setting or revising rates, do not have a direct effect on the environment. Previous environmental studies for key BPA actions have shown that actual environmental impacts are determined by the market responses to BPA's marketing and business decisions, rather than by the actions themselves. (*Id.* Sections 2.1.5 and 4.1.2.) Four types of market responses are identified: resource development; resource operations; transmission development and operation; and consumer behavior. These market responses determine the environmental impacts, which include impacts to natural resources such as air, land, and water, as well as socioeconomic impacts. (*Id.* Figures 2.1-1 and 2.6-9.) For wholesale power ratemaking, the Business Plan EIS describes how BPA rates can affect the environment through market responses. (*Id.* Section 2.4.2.1 and figure 2.4-1.)

Thus, the Business Plan EIS is based on a “relationship analysis” – that is, BPA has quantitatively and qualitatively evaluated relationships among variables in the short run, and assumed that these relationships will hold true in the long term. While the Business Plan EIS does provide a numerical example based on assumptions about rates, loads, resources, and other factors, this discussion was provided as an illustrative example only, and was not intended to be relied on for quantitative comparisons in the future. (*Id.* Sections 4.4.1.1 and 4.4.3.)

To determine the potential environmental consequences of the various alternatives, the Business Plan EIS identifies general market responses to key policy issues. (*Id.* Table 4.2-1.) The market responses for products and services are discussed for each of the alternative business directions, and the market responses for rates also are discussed. (*Id.* Sections 4.2.1 and 4.2.2.) The market responses and the environmental consequences are discussed both in general terms and in terms specific to each alternative. (*Id.* Section 4.3.) Table 4.3-1 details the typical environmental impacts from power generation and transmission. Section 4.4 presents the market responses and environmental impacts by alternative, under two "bookend" hydro operation scenarios. Table 4.4-19 summarizes the key environmental impacts by alternative. (*Id.* Section 4.4.3.8.) In addition, Appendix B to the Business Plan EIS includes an extensive evaluation of rate design, including market response and environmental impacts. (*Id.* Appendix B.)

Each of the alternative business directions examined in the Business Plan EIS was also evaluated against the purposes for the action to determine how well each of the alternatives meets the need. (*Id.* Section 2.6.5.) Based on the evaluation of potential environmental impacts and the comparison of each alternative to the identified purposes, the Administrator adopted the Market-Driven alternative as the Agency's overall business policy in the August 1995 Business Plan ROD. (Business Plan ROD, Section 6.) The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also assists BPA in maintaining the financial strength necessary to continue a relatively high level of support for public service benefits, such as energy conservation and fish and wildlife mitigation activities, while keeping BPA rates and the costs of other BPA products and services as low as possible.

Recognizing that the Administrator could select a variety of actions, BPA included many mitigation response strategies in the Business Plan EIS and ROD to address changed conditions and allow the Agency to balance costs and revenues. These response strategies include measures that BPA could implement to increase revenues (including rates), decrease spending, and/or transfer costs if its costs and revenues do not balance. (Business Plan EIS, Section 2.5; Business Plan ROD, Section 7.) These strategies enable BPA to best meet its financial, public service, and environmental obligations, while remaining competitive. In the Business Plan ROD, the BPA Administrator decided to implement as many response strategies, or equivalents, as necessary to balance costs and revenues. (Business Plan ROD, Section 7.)

The Business Plan EIS and ROD also document a decision strategy for tiering subsequent business decisions to the Business Plan ROD. (Business Plan EIS, Section 1.4; Business Plan ROD, Section 8.) For each such decision, as appropriate, the BPA Administrator reviews the Business Plan EIS and ROD to determine whether the proposed subsequent decision falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the proposed decision is found to be within the scope of this alternative, the Administrator may tier his decision under NEPA to the Business Plan ROD. (Business Plan ROD, Section 8.) Tiering a ROD to the Business Plan ROD helps BPA delineate its business decisions clearly and provides a logical framework for connecting broad policy decisions to more specific actions. (Business Plan EIS, Section 1.4.)

16.3 Relevant RODs Tiered to the Business Plan ROD

Since 1995, over 40 RODs for various BPA business decisions have been tiered to the Business Plan ROD. Several of these RODs are directly applicable to the WP-07 Wholesale Power Rate Adjustment Proceeding.

16.3.1 Power Subscription Strategy

In December 1998, BPA issued an Administrator's ROD for its Power Subscription Strategy, which is a strategy for distributing to BPA customers the electric power generated by the FCRPS, within the framework of existing law. The Power Subscription Strategy addressed the availability of power, described power products and contracts, and provided strategies for pricing, including risk management and cost recovery strategies to ensure that BPA's costs and public responsibilities are met. The Power Subscription Strategy also further refined rate design approaches to be used to establish rates during subsequent power and transmission rate cases.

As part of its consideration of Power Subscription Strategy, BPA conducted a NEPA evaluation of the Strategy. This NEPA evaluation is described in the December 1998 NEPA ROD that was prepared and issued separately from the Administrator's Power Subscription Strategy ROD. Consistent with the approach laid out in the Business Plan EIS and ROD for tiering subsequent business decisions, the Administrator reviewed the Business Plan EIS and ROD to determine if the Power Subscription Strategy was within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. In the NEPA ROD, the Administrator noted that the Power Subscription Strategy is a direct application of BPA's Market-Driven approach adopted in the Business Plan ROD, and that the potential environmental impacts of the Power Subscription Strategy were adequately covered in the Business Plan EIS. (NEPA ROD, at 1, 16, and 22.) The Administrator also noted that the risk management strategies in the Power Subscription Strategy are consistent with the mitigation response strategies in the Business Plan EIS and ROD. (*Id.* at 10.) The Administrator thus determined that the Power Subscription Strategy is clearly within the scope and consistent with the Business Plan EIS and the Market-Driven alternative adopted in the Business Plan ROD. (*Id.* at 1-2.) BPA thus tiered its NEPA ROD for Power Subscription Strategy to the Business Plan ROD.

16.3.2 2002 Power Rate Case

In May 2000, BPA issued an Administrator's ROD for the 2002 Final Power Rate Proposal that addressed BPA's 2002 Wholesale Power Rates Proceeding for the FY 2002-2006 rates (WP-02 Rate Case). The Administrator's ROD included a NEPA analysis of the 2002 rate proposal. (WP-02-A-02, at page 18, lines 50 to 53.) This analysis addressed the various elements of the WP-02 proposal, including the possible use of a CRAC to allow BPA to address potential revenue shortfalls. (*Id.*; *see also* WP-02-A-02, Sections 7.1 and 7.3.) The Administrator noted that the WP-02 proposal includes many features that would help BPA achieve the goals of BPA's Power Subscription Strategy and found the WP-02 proposal to be consistent with the Power Subscription Strategy and its associated ROD. (WP-02-A-02, at page 18, line 51.) In addition, the Administrator determined that the WP-02 proposal fell within the scope of the Business Plan EIS based on a review of the Business Plan EIS and its evaluation of environmental impacts related to various rate design issues for BPA's power products and services. (*Id.*) The Administrator therefore found that the WP-02 proposal was consistent with the Business Plan as well as the Business Plan EIS and ROD. (*Id.*) Thus, BPA tiered its NEPA decision for the WP-02 Rate Case to the Business Plan ROD. (*Id.*)

In December 2000, BPA announced proposed amendments to the WP-02 proposal. *Proposed Amendments to 2002 Wholesale Power Rate Adjustment Proposal*, 65 Fed. Reg. 75,272 (2000). After BPA released these proposed amendments, changes in reserve forecasts and market prices led to settlement discussions between BPA and rate case parties. After a Partial Settlement Agreement was reached with many of these parties, BPA prepared a June 2001 Administrator's ROD for the 2002 Supplemental Power Rate Proposal. (WP-02-A-09.) This Supplemental Proposal reflected the three separate CRACs – the Load-Based CRAC, the Financial-Based CRAC, and Safety Net CRAC – that were negotiated with the parties as part of the terms of the

Partial Settlement Agreement. (*See* WP-02-A-09, Section 4.1.) Like the May 2000 Administrator's ROD, the Administrator's ROD for the Supplemental Proposal included a NEPA analysis. (*Id.* at 9-28 to 29.) This analysis was intended to supplement the NEPA analysis prepared for the 2002 Final Power Rate Proposal in order to reflect the changes contained in the Supplemental Proposal. In this analysis, the Administrator noted that the Supplemental Proposal was a continuation of the WP-02 rate proposal and that BPA had again reviewed the Business Plan EIS to determine if the Supplemental Proposal was within the scope of the Business Plan EIS and the Market-Driven alternative adopted in the Business Plan ROD. (*Id.* at 9-28.) The Administrator concluded that the proposed modifications were consistent with the Market-Driven alternative. (*Id.* at 9-29.) Thus, the NEPA ROD prepared for the WP-02 rate proposal reflected the 2002 Final Power Rate Proposal, as well as changes embodied in the Supplemental Proposal.

16.3.3 Safety Net Cost Recovery Adjustment Clause (SN CRAC) Adjustment to 2002 Wholesale Power Rates

In June 2003, BPA issued an Administrator's ROD on BPA's decision to implement the SN CRAC Adjustment to 2002 Wholesale Power Rates. This rate adjustment allows BPA to address potential revenue shortfalls and recover its costs through rates. The SN CRAC rate adjustment represents implementation of one of BPA's risk management tools that were conceptually identified and evaluated in the Business Plan EIS and ROD, and more specifically identified and evaluated under NEPA as part of BPA's Power Subscription Strategy and WP-02 rates. The Administrator reviewed the previous NEPA documentation, and found that the SN CRAC rate adjustment was adequately covered within its scope and that the rate adjustment would not result in significantly different environmental effects. Therefore, the decision to implement the SN CRAC rate adjustment was tiered to the Business Plan ROD.

16.3.4 Policy for Power Supply Role for FY 2007-2011

In February 2005, BPA adopted a policy on the Agency's power supply role for FY 2007-2011, which is also referred to as BPA's Near-Term Regional Dialogue policy.[2] This policy is intended to provide BPA's customers with greater clarity about their Federal power supply so they can effectively plan for the future and make capital investments in long-term electricity infrastructure if they choose. It is also intended to provide guidance on certain rate matters BPA expects to be addressed in the FY 2007-2009 rate period, while assisting the Agency in aligning its long-term strategic goals and its long-term responsibilities to the region.

As part of its consideration of the proposed Near-Term Policy, BPA conducted a NEPA analysis that reviewed each of the individual issues considered in the policy, as well as the potential implications of these issues taken together. For some issues, there were no environmental effects resulting from implementation and NEPA thus was not implicated. For other issues, the proposed approach was merely a continuation of the status quo, and NEPA was not triggered. For the remaining issues, the potential environmental effects have been addressed in the Business

[2] In addition to the completed Near-Term Regional Dialogue policy process, BPA is currently conducting a Long-Term Regional Dialogue policy process. BPA's consideration of the long-term policy will include an appropriate evaluation under NEPA.

Plan EIS and are within the scope of the Market-Driven alternative adopted in the Business Plan ROD. Furthermore, the policy as a whole is consistent with the Market-Driven alternative. Accordingly, since the 2007-2011 Near-Term Policy falls within the scope of the Market-Driven alternative and would not result in significantly different environmental impacts from those examined in the Business Plan EIS, BPA tiered its NEPA decision for this policy to the Business Plan ROD.

16.3.5 BPA's Service to Direct Service Industrial (DSI) Customers for FY 2007-2011

In June 2005, BPA issued the DSI ROD that identified how BPA would provide power benefits to the region's DSI customers in FY 2007-2011. In this ROD, the Administrator decided to provide up to 560 aMW of benefits to three DSI aluminum companies at a $59 million capped cost, and 17 aMW to a DSI paper mill at a rate approximately equivalent to, but in no case lower than, the PF rate. While some service benefits are to be provided, the decision reflects a trend of BPA ramping down service to DSIs.

The DSI ROD also included the NEPA analysis for this decision. This analysis noted that BPA had already decided through the Near-Term Regional Dialogue policy process to provide eligible Pacific Northwest DSIs with some level of Federal power service benefits, at a known but limited quantity and capped cost, in the FY 2007-2011 period, with specific details to be worked out in a supplemental regional public process. The NEPA analysis also describes how the Business Plan EIS contains policy options, or modules, with one of these modules expressly designed to allow variations of the alternatives in providing service to DSIs. (Business Plan EIS, Section 2.1.2.) The DSI modules in the Business Plan EIS include Renew Existing Firm Contracts, Firm Service in Spring Only, Declining Firm Service, and No New Firm Power Sales Contracts. The EIS thus contains analyses of policy modules that consider service to the DSIs ranging from no new contracts to 100-percent firm service. (Business Plan EIS, Sections 2.3.1.3 and 2.6.3.3.) While all of these modules are applicable to the Market-Driven alternative, the Declining Firm Service module is intrinsic to this alternative. (Business Plan EIS, Section 2.2.3 and Table 2.3-2.) Accordingly, the Administrator found that BPA's proposed service to DSIs for FY 2007-2011 falls within the scope of the Market-Driven alternative and is not expected to result in significantly different environmental impacts from those examined in the EIS. Therefore, the decision to provide service to BPA's DSI customers for FY 2007-2011 was tiered to the Business Plan ROD.

16.4 Environmental Analysis for 2007 Wholesale Power Rate Case

The Business Plan EIS and ROD were reviewed to determine whether the WP-07 Wholesale Power Rate Adjustment Proceeding is adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. The key policy issues analyzed in the Business Plan EIS included several rate-related decisions, such as unbundling or rebundling of BPA's power products and services and pricing. The modules included a range of rate level and design options, including tiered rates, stream-flow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts.

As can be seen from the environmental analysis presented in the Business Plan EIS, the potential environmental impacts of all business direction alternatives fall 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 among alternatives (*Id.* Table 4.4-20.) Thus, the differences among alternatives in total environmental impacts are relatively small.

The Business Plan EIS identified general market responses to BPA actions such as rate cases, and these market responses in turn are the source of environmental impacts. The market responses and environmental impacts are discussed throughout Chapter 4 of the Business Plan EIS, and are summarized in Table 4.2-1. The environmental impacts addressed in the EIS include those related to the natural environment, such as impacts to air, land, and water, as well as impacts to the socioeconomic environment. Hydrosystem operations will not be affected by the WP-07 Wholesale Power Rate Adjustment Proceeding because BPA serves its contractual obligations and markets power and services with available resources consistent with the operating constraints that apply to the hydrosystem. (Business Plan EIS, Section 1.5.6; Business Plan ROD, page 4.)

The primary environmental impacts of power prices and rate attributes are through the choices customers make for generation resources and conservation. (Business Plan EIS, Section 4.5.2.) For example, increasing rates may cause more customers to seek energy on the market, or may encourage customers to develop their own generation resources. If this were to occur, customers could develop or purchase energy from thermal generation, which in theory would be less expensive. This market response in turn could increase various environmental impacts, such as air pollution from nitrogen, sulfur and carbon emissions, water use, and land use impacts.

Based on the review of the Business Plan EIS and ROD, the WP-07 Wholesale Power Rate Adjustment Proceeding is a direct application of the Market-Driven alternative. This rate proposal continues most of the elements of BPA's existing rate design, with changes and modifications mainly reflecting revisions in the type and methodology for cost adjustments. Even with these revisions, the rate proposal remains consistent with the type of rate designs identified in the Business Plan EIS. In addition, the rate proposal is largely a continuation of BPA's approach to power service and rates developed in the Power Subscription Strategy and provided for in subsequent power rate cases.

This rate proposal thus is consistent with the competitive and unbundled, yet cost-based, characteristics of the Market-Driven alternative. The issues related to this proposal are consistent with the analysis of key policy issues related to power products and services identified for the Market-Driven alternative. (*Id.* Sections 2.2.3 and 2.6.) In addition, this rate proposal does not differ substantially from the types of rate designs considered and evaluated in the Business Plan EIS. (*Id.* Sections 2.4.1.6 and 2.4.2.2, Appendix B.) Therefore, the WP-07 Wholesale Power Rate Adjustment Proceeding falls within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD. Because of these consistencies, implementation of this rate proposal would not be expected to result in environmental impacts that are not significantly different from those examined for the Market-Driven alternative in the Business Plan EIS.

Furthermore, the WP-07 Wholesale Power Rate Adjustment Proceeding will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD. This alternative was selected as BPA's business direction because, among other reasons, it allows BPA to: (1) recover costs through rates; (2) competitively market BPA's products and services; (3) develop rates that meet customer needs for clarity and simplicity; and (4) continue to meet BPA's legal mandates.

The WP-07 Wholesale Power Rate Adjustment Proceeding provides a competitive rate structure that includes various mechanisms to account for potential revenue shortfalls. The rate proposal thus allows BPA to continue to recover its costs though its rates while remaining competitive, and is consistent with the general approach to setting rates and managing and responding to risk that was developed in the Market-Driven alternative and continued through the Power Subscription Strategy and subsequent rate cases. In addition, the rate design included in the rate proposal has been made as clear and simple as possible, given the various types of products and services covered in the proposal. Finally, BPA believes that the rate proposal will allow BPA to meet all of its applicable legal mandates. Accordingly, the WP-07 Wholesale Power Rate Adjustment Proceeding is consistent with these aspects of the Market-Driven Alternative.

Issue 1

Whether BPA adequately considered the environmental impacts of its rate proposal, as well as alternatives to the proposal, in its NEPA analysis.

Parties' Position

The Tribes maintain that Bonneville has not complied with the requirements of NEPA. (JP13 Br., WP-07-M-69, page 66- 67.) The Tribes assert that "[t]he Business Plan EIS and subsequent NEPA compliance documents do not consider the environmental impacts and alternatives associated with the policy choices Bonneville will make in this proceeding." (*Id.* at page 66-67.)

In their brief on exceptions, the Tribes again contend that the Business Plan EIS and subsequent NEPA compliance documents do not consider the environmental impacts and alternatives associated with the policy choices in the proceeding. (JP13 Br. Ex. WP-07-M-77 at 20.) These include the allocation of risk and benefits between BPA's fish and wildlife and the desires of its customers; the risk of failure to repay Treasury on time and in full; the need to increase revenues to meet the agency's statutory mission; and additional policy choices raised by the Tribes in their brief and testimony. (*Id.*) BPA's failure to raise rates to recover its costs and repay Treasury was not among the alternatives contemplated in the Business Plan EIS and subsequent NEPA documents. (*Id.*) BPA can address these shortcomings by adopting the Tribes' recommendations. (*Id.*)

BPA's Position

Bonneville believes that its NEPA analysis and findings comport with statutory requirements and properly account for environmental impacts relevant to the WP-07 Wholesale Power Rate

Adjustment Proceeding. BPA has fully complied with its NEPA obligations because it has prepared documentation showing that this proposal falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD, for the reasons more fully described by BPA previously in this Section 16. The Business Plan EIS remains a viable model for making NEPA determinations and fully accounts for the factors noted by the Tribes. It thus is appropriate to tier the decision to implement this rate proposal to the Business Plan ROD.

Evaluation of Positions

The Tribes contend that the Business Plan EIS and subsequent NEPA compliance documents do not consider the environmental impacts and alternatives associated with the policy choices in the proceeding, and list several policy choices that they believe were not considered. (JP13 Br., WP-07-M-69, page 66- 67; JP13 Br. Ex. WP-07-M-77 at 20) Specifically, the Tribes assert that Bonneville's methodology has not considered "the allocation of risk and benefits between Bonneville's fish-related obligations and the desires of its customer, the risk of failure to repay Treasury on time and in full, [and] the need for increased revenues necessary to support the 's statutory mission." (JP13 Br., WP-07-M-69, at 67.)

It is important to recognize that the Tribes allege in their brief on exceptions that certain policy choices are being made in the rate case. However, these policy choices are not being made in this proceeding. All of these issues were considered in separate processes from this proceeding and they are not being revisited here. The decisions being made in this current rate case reflect these already-made choices.

The Tribes nevertheless maintain that the Business Plan EIS and subsequent NEPA compliance documents are no longer appropriate models for making determinations regarding environmental impacts. (*Id.*) The Tribes are incorrect. The Business Plan EIS and subsequent NEPA documents remain viable models for reviewing the environmental impacts of BPA's business decisions under NEPA. Bonneville's NEPA analysis for this rate case fully describes the Business Plan EIS and demonstrates that it is a highly-flexible model adaptable to the policy decisions made in this rate case. There is no indication that a different model is needed or would be superior to the Business Plan EIS. Moreover, contrary to the Tribes' assertions, the NEPA analysis shows that all factors relevant to potential environmental impacts were identified and considered. Bonneville's NEPA analysis is entirely appropriate and complies with all relevant statutory requirements.

A review of the Business Plan EIS shows that this EIS does indeed include consideration of the issues identified in the Tribes' brief on exceptions, to the extent appropriate for a policy-level EIS. Section 2.4.5 of the Business Plan EIS describes various aspects of BPA's fish and wildlife administration activities, including costs, as they relate to the policy choices made through the Business Plan EIS and ROD, and discusses alternate approaches to carrying out these activities. Section 2.5 of the EIS identifies various alternative response strategies to be implemented to ensure a balance of costs and revenues, including increasing revenues where appropriate. These strategies were adopted in the Business Plan ROD to enable BPA to meet its financial obligations, including Treasury repayments and fish and wildlife costs, while remaining competitive in energy markets and ensuring its rates recover its costs. Business Plan ROD, Section 7. Section 4.4 of the EIS addresses the environmental impacts of the alternative business policies addressed in the EIS, and Section 4.4.4 in particular describes impacts associated with expected increased fish and wildlife costs, including how these costs would be factored into BPA's rate setting and cost/revenue balancing. The NEPA ROD for the WP-07 Wholesale Power Rate Adjustment Proceeding describes how this rate proposal fits within the scope of the Business Plan EIS and ROD by continuing most of the elements of BPA's existing rate design, with changes and modifications mainly reflecting revisions in the type and methodology for cost adjustments to even better allow for sufficient revenue generation to cover costs and ensure full and on-time Treasury repayments.

The Tribes also contend that BPA's failure to raise rates to recover its costs and repay the Treasury was not among the alternatives contemplated in the Business Plan EIS and subsequent NEPA documents. (JP13 Br. Ex. WP-07-M-77 at 20.) That is not necessary to include because BPA has an obligation under the Northwest Power Act to set rates to recover its costs. 16 USC §839e(a)(1). This obligation is at the very core of BPA's mission. As demonstrated by BPA's Revenue Requirement Study and Documentation (WP-07-FS-02 and WP-07-FS-02A and 02B respectively), rates are set sufficient to recover costs and repay Treasury on time and in full, consistent with the standards adopted for this proceeding. The WP-07 Wholesale Power Adjustment Proceeding also includes cost recovery adjustment mechanisms to help ensure that BPA can recover its costs and meet its Treasury repayment obligations. Forms of these mechanisms have been implemented by BPA in the past when needed, and have been shown to be effective. Therefore, an alternative of failing to raise rates to recover costs and repay Treasury is not a reasonable alternative meriting consideration under NEPA.

To the extent that the Tribes are arguing that BPA has underestimated its fish and wildlife program expenses and that future fish and wildlife costs have not been sufficiently mitigated, these issues are not matters properly raised in this rate setting forum. The program level expenses used in the rate proceeding were established through the PFR and were determined by the Administrator to be a matter outside the scope of this proceeding. *See,* section 17 for further discussion.

Decision

BPA's NEPA documentation adequately addresses the policy choices before it in this rate case. BPA complied with its NEPA obligations in making decisions in the WP-07 Wholesale Power Rate Adjustment Proceeding.

16.5 NEPA Decision

Based on a review of the Business Plan EIS and ROD, BPA has determined that BPA's WP-07 Wholesale Power Rate Adjustment Proceeding falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. This rate proposal is a direct application of the Market-Driven alternative, is not expected to result in significantly different environmental impacts that are significantly different from those examined in the Business Plan EIS, and will assist BPA in accomplishing the goals *related to the Market-Driven alternative that are identified in the Business Plan ROD. Therefore, the decision to implement this rate proposal is tiered to the Business Plan ROD.*

17.0 PROCEDURAL ISSUES

17.1 Tribal Issues

Issue 1

Whether the Administrator should reverse the Hearing Officer's decision to strike portions of the joint testimony of CRITFC, the Nez Perce Tribe and Yakama Nation (collectively referred to as the Tribes) regarding the assumptions for future fish and wildlife funding.

Parties' Positions

The Tribes ask the Administrator to reinstate the testimony of Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at page 18, line 4 through page 48, line 23. The Tribes contend that the testimony "directly rebuts BPA's testimony that the comments to PFR were used to inform the FY 2007-2009 spending levels as asserted by BPA's testimony at Revenue Requirement Study, WP-07-FS-BPA-02 at page 12, line 5." (JP13 Br., WP-07-M-69 at 13.) The Tribes contend that the stricken testimony would have, among other things, "provided evidence regarding the likely costs of implementing the subbasin plans," along with "the costs of implementing the FCRPS Biological Opinion and NOAA Fisheries recovery plans." (*Id.* at 14.) The Tribes contend that the stricken "testimony did not suggest that Bonneville must make decisions in this rate proceeding on its actual spending levels for fish and wildlife during the rate period. Rather, the Tribes' testimony documented detailed alternative fish and wildlife cost assumptions in the context of BPA's Revenue Requirement Study and notes that BPA's cost assumptions that resulted from the PFR were not based on the best available information." (*Id.*)

In their brief on exceptions, the Tribes contend that BPA violated the Administrative Procedures Act, the Northwest Power Act, its treaty and trust responsibilities and the Tribes due process rights by not reinstating their stricken testimony. (JP13 Br. Ex., WP-07-M-77 at 21.)

BPA's Position

The Hearing Officer did not err in his decision to strike the referenced testimony. The Revenue Requirement Study (WP-07-FS-BPA-02) relied upon results of the PFR to inform the study on assumptions related to budget levels for the rate case. (Homenick, *et al*., WP-07-E-BPA-10 at 3.) PFR focused on nine major program cost areas, which included fish and wildlife program expenses and capital investments. (*Id.*) BPA also conducted workshops on fish and wildlife program expenses that were separate but concurrent with the PFR. (Revenue Requirement Study, WP-07-FS-BPA-02 at 13.) The Tribes participated in these workshops and provided comments to BPA on the appropriate assumptions for the rate case. The Tribes' comments on the assumptions for fish and wildlife program level expenses were addressed in a letter from BPA's Environment, Fish and Wildlife Vice-President, Greg Delwiche.[1] The testimony in question merely restates the positions taken by the Tribes during PFR.

[1] June 20, 2005 letter from Greg Delwiche to Jerry Meninick, Yakama Tribal Council and Olney Patt, CRITFC.

The Federal Register Notice states the Hearing Officer should exclude from the record "*any* material attempted to be submitted or arguments attempted to be made in the hearing which seek to *in any way* revisit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's revenue requirements for FY 2007-2009." 70 Fed. Reg. 67,685, at 67,689 (2005) (emphasis added). Given that the issues raised were identical to the ones addressed in PFR, the Hearing Officer properly excluded the testimony.

Evaluation of Positions

The Tribes contend that the stricken testimony[2] directly rebuts the contention that the Tribes' comments in the PFR informed the assumptions for fish and wildlife program expenses and capital investments used for BPA's Initial Proposal. (JP13 Br., WP-07-M-69 at 14.) The Tribes contend that if the testimony were allowed to stand, it would show that BPA's costs are going to be higher than those that resulted from the PFR. They contend the expense assumptions that resulted from the PFR process are not based upon the "best available information." (*Id.*) While the Tribes maintain that they are not arguing to determine the expense levels for these items in the rate case, nevertheless the logical conclusion of the Tribes' argument would be to substitute its assumptions for the results from the PFR.

PFR was a five-month public process to review BPA's spending level assumptions for the FY 2007-2009 rate period. Numerous workshops were held to discuss various topic areas and interested parties were provided the opportunity to provide written comments to BPA prior to the conclusion of the process. As an adjunct to the PFR, BPA conducted workshops specifically addressing BPA's fish and wildlife program expenses. (Revenue Requirement Study, WP-07-FS-BPA-02 at 13.) As with the PFR, interested parties could provide written comments to BPA regarding its assumptions for BPA's fish and wildlife program expenses and capital investments. The Tribes participated in this process and provided written comments to BPA about what it believed were the appropriate program level expense assumptions for the upcoming rate period. (*See* The Yakama Nation Comments on Bonneville Power Administrations' Power Function Review, WP-07-E-CR-01Q.) These forty pages of comments covered many of the same topics that are addressed in the testimony in question. The PFR comments recommended that BPA adopt the Columbia Basin Fish and Wildlife Authority (CBFWA) recommendations which are identical to the assumptions in the stricken testimony.

In crafting the scope of this proceeding, the Administrator limited testimony on matters related to BPA's spending level assumptions that resulted from the PFR. The Federal Register Notice states that the Hearing Officer should exclude from the record "*any* material attempted to be submitted or arguments attempted to be made in the hearing which seek to *in any way* revisit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's revenue requirements for FY 2007-2009." 70 Fed. Reg. 67,685, at 67,689 (2005) (emphasis added). The reasons for limiting the scope of this proceeding in this fashion are twofold. First, BPA has provided parties a public forum to discuss and comment on the budget assumptions

[2] The Tribes brief implies that the testimony in question, Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 18, line 4 through page 48, line 23 was stricken in its entirety. While a great portion of that section of the testimony was stricken, the Hearing Officer's decision left intact some portions of the approximately 30 pages of testimony in question.

used in the rate case during the PFR process. To revisit these very same issues during the rate case is an unnecessary exercise and a waste of administrative resources. BPA gave careful and thoughtful consideration to each of the cost areas during the PFR process. To simply ignore the results of that effort and reopen discussion of these matters in the rate case is a redundant effort and disrespectful to the time and efforts of the PFR process. Second, the fact that BPA committed to a follow-on PFR II process during the rate case to update cost assumptions only reinforces the decision to exclude the testimony. The Tribes' concerns here are an after-the-fact challenge to the expense assumptions that they lobbied for during the PFR, but which were rejected.

In their brief on exceptions, the Tribes contend that striking its testimony violates the Administrative Procedures Act, the NWPA, BPA's treaty and trust responsibilities along with its due process rights. (JP13 Br. Ex., WP-07-M-77 at 21.) While the Tribes make these broad and sweeping allegations, they do not provide any legal or factual support for the position. Without providing even token support for their position, it is impossible to address the concerns in a meaningful way. The Tribes' primary concerns generally revolve around the spending levels for fish and wildlife program. As previously noted, BPA addressed these matters outside of the rate case process. While the Tribes may disagree with the outcome of that process, this fact does not create a procedural right to review the prior decisions in this forum.

Decision

The Hearing Officer did not err when he struck the Tribes' testimony on the assumptions of future fish and wildlife funding. The issues raised in brief, by the Tribes, are therefore outside the scope of this proceeding and shall not be further addressed in this ROD.

Issue 2

Whether the Administrator should reverse the Hearing Officer's decision to strike the Tribes' testimony on assumed river operations for the rate period.

Parties' Positions

The Tribes argue that the Administrator should restore its stricken testimony on the assumed river operations for the hydro system for the rate period. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 11, line 16 through page 15, line 6 ; WP-07-E-CR-01C, D, K, L, M and N.) They contend that the stricken evidence rebuts BPA's testimony on the hydro regulation study performed for the Initial Proposal. (JP13 Br., WP-07-M-69 at 20.)

PPC moved to strike portions of the testimony (page 12, line 16 through page 13, line 10) because they believed the testimony addressed the proposed hydro operations that they contend are outside the scope of the rate proceeding. (PPC Br., WP-07-M-13 at 7.) In addition, PPC moved to strike other portions of the testimony in question (page 13, line 22 through page 14, line 12, and an exhibit, the four-page fish passage letter, WP-07-E-CR-01L), because the testimony and the exhibit address matters beyond the scope of, and irrelevant to, this proceeding. (*Id.*)

In their brief on exceptions, the Tribes contend that WP-07-E-CR/NZ/YA-01, page 14, lines 8-12; page 41, line 14 through page 42, line 8; page 51, lines 17-19 and page 57, lines 1-16, should also be restored because these portions of their direct testimony also address operational issues. (JP13 Br. Ex., WP-07-M-77 at 21.)

<u>BPA's Position</u>

The Tribes seek to reinstate the following testimony they contend was improperly stricken from the record. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 11, line 16 through page 15, line 6.) However, not all of the referenced testimony was actually stricken from the record. Some portions of the referenced testimony were left in the record and to that extent, the Tribes' request is overly broad.

Within the pages of the referenced testimony, BPA moved to strike only page 14, line 8 through page 15, line 6 of Sheets, *et al.,* WP-07-E-CR/NZ/YA-01. PPC separately moved to strike the testimony on page 12, line 16 through page 13, line 10, and page 13, line 22 through page 14, line 12. The order granting the motion to strike granted both BPA's and PPC's motions, with regard to this portion of the testimony, but the order also inadvertently struck the testimony on page 12, lines 7 through 15, which neither BPA nor PPC moved to strike.

The crux of the Tribes' concern revolves around the proper assumptions for hydro operations during the rate period. BPA stated in its rebuttal testimony that it would assume the most current operational assumptions for final studies. (Hirsch, *et al*., WP-07-E-BPA-32 at 2.)

BPA moved to strike a portion of the testimony in question because, contrary to the representations in the Tribes' brief, the testimony did not address the operations, but rather focused upon additional measures beyond changes in operations that the court could order as part of the litigation over the 2004 Biological Opinion. In particular, the disputed testimony provided, "[w]e anticipate the New Biological Opinion will include other measures, in addition to spill and flow, to avoid jeopardizing the continued existence of listed species and to recover salmon and steelhead." (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at 14.)

In addition, BPA moved to strike another portion of the Tribes' testimony because it related to impacts of particular court orders on FY 2006 hydro operations. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 14, line 13 through page 15, line 6.) This testimony related to other litigation, such matters are not relevant to the issues in this rate case. (BPA Br., WP-07-M-14 at 13-14.)

<u>Evaluation of Positions</u>

The subject testimony the Tribes seek to reinstate involves four separate and distinct areas that present different issues. The first matter involves that portion of the stricken testimony that neither BPA nor PPC moved against. Although this matter is not addressed in the Tribes' brief, the order which granted BPA's and PPC's motion to strike included additional testimony that was not included in either of the two aforementioned motions. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 12, lines 7 through 15; Order, WP-07-O-23.) There is little question that this portion of the testimony should be reinstated. There appears to be a typographical error in the order that was never noticed that resulted in striking this portion of the testimony.[3]

The second aspect of the subject testimony involves the testimony related to hydro operations that PPC moved to strike. (Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 12, line 16 through page 13, line 10.) PPC contends, and the Hearing Officer agreed, that hydro operations were outside the scope of this proceeding. (PPC Br., WP-07-M-13 at 7; Order, WP-07-O-23 at 11.) Although the Tribes never directly address the relevancy of hydro operations to the rate case in their reply to PPC's motion to strike, these are relevant rate case matters. The hydro regulation study that is part of the rate case uses hydro plant operating characteristics to determine the energy production given particular operating conditions. (Load Resource Study, WP-07-FS-BPA-01 at 12.) These studies are directly affected by changes in hydro operations due to restrictions that result from court orders and biological opinions. As a result, the assumed operations for the hydro system are very relevant to generation levels and resource availability.

The testimony in question addresses a belief by the Tribes that BPA's forecast of hydro operations in its Initial Proposal is inadequate because they contend that BPA will be required to increase spill and flow in the spring and summer months as a result of pending litigation. (Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 14, line 13 through page 15, line 6.) This testimony relates directly to the assumptions BPA made regarding hydro operations for the upcoming rate period. While parties may disagree with the Tribes conclusions, the matter is a proper subject for testimony and BPA believes that the testimony Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 12, line 16 through page 13, line 10 and page 13, line 22 through 14, line 8, should be reinstated.

The third aspect of the subject testimony involves the matters where the Tribes' testimony strayed beyond operational assumptions. Beginning at Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 14, lines 8 through 12, the Tribes engage in a discussion of unspecified additional measures, beyond spill and flow, that BPA would be required to perform as part of the remand of the Biological Opinion. As previously noted, these program level cost assumptions were part of the PFR and are not properly addressed in the rate case. As a result, BPA does not believe this testimony should be reinstated.

The fourth aspect of the Tribes' testimony involves a discussion of BPA's operational assumption for FY 2006. (Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 14, line 13 through page 15, line 6.) There are two separate issues that are intertwined in the subject testimony. Behind part of the testimony is a response to a data request that sought the following: "Please provide a

[3] The Order (WP-07-O-23 at page 11) struck the subject testimony beginning on page 12, line 6 through page 13, line 10. However, the PPC motion requested only that the testimony beginning on page 12, line 16 through page 13, line 10 be stricken. Since there is no testimony actually on page 12, line 6, it appears the order inadvertently omitted the "1" from the reference to the line.

copy of any information or analysis regarding the impacts on BPA's Initial Proposal if the FY 2005 injunctive relief for river operations is also ordered for FY 2006." (Data Req. CR-BPA-008.) BPA responded by stating that it had not performed any such analysis. BPA moved to strike the material because the operational assumptions for FY 2006 were deemed to be not relevant because the Tribes use this response to argue that BPA will lose approximately $33 million annually in secondary revenues during the rate period. (Sheets, *et al.*, WP-07-E-CR/NZ/YA-01 at 15; WP-07-E-CR-01N.)

The testimony appears to mix and confuse two distinct issues. Contrary to BPA's original assertion, the operational assumptions for FY 2006 are relevant to the issues in the rate case. However, the operational assumptions for FY 2006 primarily impact only the starting reserve levels for the rate period. FY 2006 operations have little or no direct affect on the lost secondary revenues the Tribes forecast for the upcoming rate period. Any forecast of secondary revenues during the rate period relates, in part, to the operational assumptions during that period. While the two issues are not related to each other, they are nevertheless still relevant to the issues in this rate case. As a result, BPA believes that the subject testimony, Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 14, line 13 through page 15, line 6, should be reinstated.

In the Draft ROD BPA invited to Tribes to determine if there were other aspects of their testimony that addressed operational issues. In their brief on Exceptions, the Tribes pointed to four parts of testimony that they argued involved operational issues (page 14, lines 8-12; page 41, line 14 through page 42, line 8; page 51, lines 17-19 and page 57, lines 1-16).

The testimony on page 14 was specifically addressed in the Draft ROD and rejected. It does not deal with river operations but rather addresses anticipated new costs that BPA will incur with the new BiOp. As previously noted, these program level cost assumptions were part of the PFR and are not properly addressed in the rate case.

The testimony on pages 41 and 42 is as follows:

> The remand of the current Biological Opinion will result in significant changes in required fish and wildlife activities, and will likely increase costs or affect revenues. Bonneville estimates that the 2005 operations reduce its revenues by an estimated $75 million above the operations contemplated in the 2004 Biological Opinion and the impact of the FY 2006 operation is expected to by approximately $60 million. We expect that the operations that are most likely to occur in 2007-2009 are those operations that actually occurred in 2005 and 2006—we believe it is unrealistic to assume that the Circuit Court will order less protection for listed species during the rate case period. We also expect that other river operations, habitat, and monitoring and evaluation activities will be identified in the remand process.

The testimony cited above generally addresses the impact of a particular operations and should be reinstated.

The testimony on page 51 is a follows:

> In the testimony above, we have provided evidence that Bonneville has not adequately budgeted for implementation of the Biological Opinions and the Fish and Wildlife Program.

Unlike the testimony on page 41, this testimony relates to the budget assumptions that BPA developed in the PFR and should not be reinstated.

The testimony on page 57 is as follows:

> **Q: ARE BPA'S PROPOSED CRAC AND NFB MECHANISMS ADEQUATE TO ADDRESS THE COSTS OF IMPLEMENTING THE FCRPS BIOLOGICAL OPINION AND THE COLUMBIA RIVER BASIN FISH AND WILDLIFEPROGRAM?**
>
> No. We used the Toolkit model to analyze two cases where Bonneville would implement the Court-ordered river operations under the biological opinion litigation and the Columbia Basin Fish and Wildlife Program. We first analyzed a low case that assumes that the 2006 river operations would be implemented in FY2007 through FY 2009 and that Bonneville would implement the Columbia River Basin Fish and Wildlife Program based on the Tribes' recommended budgets. The low case would add $96 million in FY 2007, $114 million in FY 2008, and $127 million in FY 2009 assuming average water conditions. The low case results in a TPP of 80.7 percent (see attachment WP-07-E-CR-01AAA). In the high case, we assumed that the plaintiffs' 2006 proposed river operations would be implemented in FY 2007 through FY 2009 and that Bonneville would not use its borrowing authority to acquire land and water as it implemented the Program. The high case would add $376 million in FY 2007, $363 million in FY 2008, and $362 million in FY 2009 assuming average water conditions. The high case results in a TPP of 57.7 percent (see attachment WP-07-E-CR-01BBB).

While the testimony notes the analysis involves an underlying assumption about assumed river operations, the testimony primarily focuses on the impact on TPP of incurring additional fish and wildlife costs consistent with the Tribes' spending levels for fish and wildlife. The testimony builds on the impacts of the 2006 river operations (the material reinstated on page 41) by adding the additional impact of the Tribes' fish and wildlife spending levels. Given the structure of the testimony, it is impossible to segregate the testimony regarding operations from that involving program costs. Because the primary purpose of the testimony is to highlight the consequences of different fish and wildlife spending levels, this testimony will not be reinstated.

<u>Decision</u>

BPA will reverse the Hearing Officer's decision to strike the Tribes' testimony on assumed river operations for the rate period and reinstate the testimony on the following sections: Sheets, et al., WP-07-E-CR/NZ/YA-01, page 12, lines 7 through 15; Sheets, et al., WP-07-E-CR/NZ/YA-01, page 12, line 16 through page 13, line 10 and page 13, line 22 through 14, line 8; Sheets, et al., WP-07-E-CR/NZ/YA-01, page 14, line 13 through page 15, line 6; Sheets, et al., *WP-07-E-CR/NZ/YA-01, page 41, line 14 through page 42, line 8;. However, these sections of testimony, Sheets, et al., WP-07-E-CR/NZ/YA-01, page 14, lines 8 through 12; Sheets, et al., WP-07-E-CR/NZ/YA-01, page 51, lines 17-19 and Sheets, et al., WP-07-E-CR/NZ/YA-01, page 57, lines 1-16, will not be reinstated.*

Issue 3

Whether the Administrator should reverse the Hearing Officer's decision to strike the Tribes' testimony regarding the Tribes' contention that there are significant uncertainties surrounding the adequacy of funding for BPA's fish and wildlife obligations.

Parties' Positions

The Tribes argue that the Administrator should reconsider the order striking their testimony which addressed the uncertainties surrounding the adequacy of funding for BPA's fish and wildlife obligation. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 29, line 4 through page 31, line 2; page 61, line 1 through page 62, line 16; WP-07-E-CR-01Y; JP13 Br., WP-07-M-69, pages 24-25.) The Tribes maintain that BPA should adopt its fish and wildlife funding estimates as part of BPA's revenue requirement in order to address this uncertainty. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 48, lines 12-19 and page 62, lines 13 and 14.)

BPA's Position

Although the Tribes couch their argument as one addressing the "uncertainties" surrounding the fish and wildlife program expenses and capital investments, in reality, their argument is nothing more than a thinly veiled attempt to revisit the decisions made during the PFR. As the Tribes' own testimony points out, BPA can address the uncertainties surrounding the fish and wildlife program levels by adopting the funding levels that it espoused during PFR. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 48, lines 12-19 and page 62, lines 13 and 14.)

As noted above in Issue 1, the Tribes' disagreements with BPA over the funding levels were matters that were fully vetted during the PFR, where the same arguments were made and rejected by BPA in the PFR close-out letter.

Evaluation of Positions

The Tribes contend that there are significant "uncertainties" surrounding BPA's future fish and wildlife program costs. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at 29-30.) The Tribes maintain that these uncertainties are the result of BPA's failure to adopt its recommendations for fish and wildlife budgets. (*Id.* at 48.)

The Tribes' testimony on this point does not address the risk uncertainty surrounding these cost items or the methods for evaluating those risks. Instead, the testimony focuses on alternative cost assumptions regarding future fish and wildlife costs that the Tribes believe BPA should adopt. BPA developed its fish and wildlife spending level for use in this proceeding during the PFR. The Tribes participated in that process and provided significant substantive written comments. In the end, for the reasons stated in the close out letters, BPA did not adopt the Tribes' recommendations.

The fact the Tribes view BPA's exposure to future fish and wildlife cuts differently than BPA does not create a risk or uncertainty that BPA must address in it rate case. Risk or uncertainty of fish and wildlife operational and maintenance and capital expenditures are addressed in this rate case through modeling of the risks surrounding the budget assumptions. BPA did this through a robust NORM analysis. The NORM model was developed to quantify non-operational risks. (Wagner, *et al.*, WP-07-E-BPA-12 at 30.) The NORM models 16 different components of the revenue requirement, including fish and wildlife O&M and fish and wildlife Capital Expenditures. (*Id.* at 31.)

While the Tribes have recharacterized its challenge to the fish and wildlife funding assumptions as an "uncertainty" it is in reality nothing more than an attempt to challenge the outcome of the PFR. The Tribes' testimony does not challenge the NORM analysis. Rather, the Tribes merely assert that BPA can address the risk or uncertainty surrounding these costs by adopting the Tribes' fish and wildlife funding levels that it espoused during PFR. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at page 48, lines 12-19 and page 62, lines 13-14.) As previously noted, the budget assumptions were matters that were specifically deemed to be outside the scope of the proceeding and there is no valid reason to address those matters again within the context of this rate case.

Decision

BPA will not reverse the Hearing Officer's decision to strike The Tribes' testimony regarding the uncertainties surrounding the adequacy of funding for BPA's fish and wildlife obligations.

Issue 4

Whether the Administrator should reverse the Hearing Officer's decision to strike the Tribes' testimony regarding the assumptions for capitalization of land and water acquisitions.

Parties' Positions

The Tribes contend that the Hearing Officer erred when he struck some testimony and exhibits on the assumptions regarding the capitalization of land and water acquisitions. Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 page 43, line 14 through page 44, line 3; WP-07-E-CR-01R. The Tribes believe that "BPA's current policy for land and water acquisition would add $70 million per year to the full implementation of the subbasin plans. (JP13 Br., WP-07-M-69 at 27.) The Tribes point out in their brief that they provided detailed information on this issue during the PFR and contend that should "Bonneville address our recommendations in this proceeding, it would allow Bonneville to fund more of its fish and wildlife costs using capital borrowing." (*Id.* at 29.)

BPA's Position

As the Tribes note in their brief, the issue regarding the capitalization of land and water acquisitions was a matter fully vetted in the PFR. The cited material from WP-07-E-CR-01R on pages 27 and 28 from their brief is taken directly from their written comments during the PFR. For the reasons previously explained in response to Issues 1 and 3, there is no purpose in revisiting these matters again in this rate proceeding.

Evaluation of Positions

The capitalization of land and water was discussed during the PFR. While there was no formal decision on this issue in the PFR because this matter involves internal financial management and accounting policy decisions, BPA nevertheless used the PFR process to take input from parties on this topic and addressed it in the close-out letter. For the reasons previously stated in response to Issue 1, there is no reason to allow the assumptions regarding the capitalization of land and water acquisitions to be reviewed again in the rate case. Parties were provided significant opportunities to discuss and debate the various alternatives during the PFR.

Decision

BPA will not reverse the Hearing Officer's decision to strike the Tribes' testimony regarding the assumptions regarding the capitalization of land and water acquisitions.

Issue 5

Whether the Administrator should reverse the Hearing Officer's decision to strike the Tribes' testimony regarding BPA's ability to meet its TPP standard.

Parties' Positions

The Tribes contend that the testimony related to the fish and wildlife expenditures was not designed to advocate a competing budget, but rather, it was designed to test BPA's risk mitigation package. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 53, lines 23 through page 54, line 10, and page 57, lines 1 through 16; Sheets, *et al.,* WP-07-E-JP13-03, page 7, line 10 through page 8, line 4, and page 13, lines 11 through 23; JP13 Br., WP-07-M-69 at 41, 50 and 52.) The Tribes' testimony used their own cost assumptions, as well as hypothetical examples of increased costs to test whether BPA's proposed risk mitigation measures effectively responded to a range of cost increases. (*Id*. at 42.)

The Tribes further contend that the Hearing Officer improperly struck testimony on alternative risk mitigation strategies that BPA could use to improve its ability to repay the Treasury if it experiences additional costs. (JP13 Br., WP-07-M-69 at 53; Sheets, *et al.,* WP-07-E-JP13-03 page 8, lines 14 through page 9, line 9.)

BPA's Position

Contrary to the Tribes' representations, the testimony in question does not address alternative risk mitigation strategies nor does it "test" BPA's risk mitigation strategy. The stricken material on page 53, line 23 through page 54, line 10, and page 57, lines 1-16 is directly related to the draft cost estimates from CBFWA that the Tribes submitted as part of their comments in PFR. (BPA Br., WP-07-M-14.) BPA has explained in other forums its reasoning for not adopting CBFWA's cost estimates or legal interpretations of BPA's fish and wildlife mitigation obligations.[4] The attachments to CRITFC's Exhibit WP-07-E-CR-01DD include links to two letters (totaling 36 pages) in which BPA analyzed and rebutted CBFWA's cost estimates as well as the funding proposals of the Yakama Nation and CRITFC.[5] Generally, BPA found that the draft CBFWA proposal was based on imprecise estimates and extrapolation; it sought funding for a considerable amount of mitigation that is not attributable to the impacts of the Federal hydropower system and correspondingly, is not BPA's responsibility; it did not meaningfully consider the effects of the proposal on BPA's customers and their rates; and it did not account for the limits to BPA's available capital (for borrowing from the U.S. Treasury).[6] It would defeat the Administrator's purpose for conducting the PFR separately if the Tribes could reintroduce the same material that BPA already reviewed.

With regards to the testimony at Sheets, *et al.,* WP-07-E-JP13-03, page 7, line 10 through page 8, line 4, page 8, line 14 through page 9, line 9, and page 13, lines 11-23, the Tribes disregarded the Hearing Officer's prior ruling and attempted to submit alternative budget assumptions under the guise of testing BPA's risk mitigation mechanisms. The Hearing Officer, in his prior ruling on BPA's initial motion to strike, concluded that similar cost estimates were "too remote to have probative value and relevance in this case" and inappropriate because they amounted to "an alternative budget recommendation to the decisions made in the PFR." (Order, WP-07-O-23, at page 7.) Not swayed by this ruling, CRITFC re-engaged in a lengthy discussion of various hypothetical cost assumptions. This attempt to recycle the prior argument provides little probative value. The test of the TPP performed by the Tribes is flawed. Merely adding costs to the model does not demonstrate an inadequacy of the risk package.

Evaluation of Positions

While the Tribes contend that the testimony in question was not designed to advocate a competing budget, but instead was designed to test BPA's risk mitigation package, the evidence indicates that the testimony seeks merely to substitute their cost estimates for those developed

---

[4] *See* WP-07-E-CR-01CC, 01Q, and 01R. Moreover, some CBFWA members objected to these draft estimates and CBFWA never finalized them.

[5] Exhibit WP-07-E-CR-01DD and attached internet links to BPA fish and wildlife program and PFR documents. http://www.efw.bpa.gov/Integrated_Fish_and_Wildlife_Program/YINCRITFCLetterandAttachments.pdf http://www.efw.bpa.gov/Integrated_Fish_and_Wildlife_Program/05CBFWAResponse422.pdf. BPA commends these documents to the Hearings Officer. They show how during the PFR BPA analyzed and refuted every fish and wildlife policy, budget, revenue, and risk point CRITFC raised in its direct testimony—such as Council Program fish recovery goals, subbasin plan implementation, hatchery reform, capitalizing land and water purchases (and whether the CBFWA's draft cost estimates are "the best available information").

[6] WP-07-E-CR-O1DD, link http://www.efw.bpa.gov/Integrated_Fish_and_Wildlife_Program/YINCRITFCLetterandAttachments.pdf, at page 2.

during the PFR. The stricken material on page 53, line 23 through page 54, line 10 and page 57, lines 1-16 is directly related to the cost estimates from CBFWA that the Tribes submitted as part of their comments in the PFR. BPA explained in great detail during the PFR why these cost estimates should be rejected. In discussing the CBFWA estimates, BPA found that

> the draft CBFWA proposal was based on imprecise estimates and extrapolation; it sought funding for a considerable amount of mitigation that is not attributable to the impacts of the federal hydropower system and not BPA's responsibility; it did not meaningfully consider the effects of the proposal in BPA's customers and their rates; and it did not account for the limits to BPA's available capital (for borrowing from the U.S. Treasury).

(*See* BPA Br., WP-07-M-14.)

For these reasons and others, BPA determined during the PFR that the CBFWA proposed cost estimates were not reasonable.

Even assuming the CBFWA estimates were reasonable, using them as a mechanism to test the adequacy of the risk mitigation package does not materially aid the discussion in this rate case. As BPA noted in its rebuttal testimony, simply adding additional fish and wildlife costs to the ToolKit model for the TPP analysis is not a valid test of the relative strength of BPA's risk mitigation tools and the Agency's ability to meet its TPP standard. Merely adding costs as if they were 100 percent probable is not a proper way to model a risk using the ToolKit model. (Lovell and Normandeau, WP-07-E-BPA-34 at 2.) Rather, it is just an argument for alternative cost assumptions.

In their sur-rebuttal testimony, the Tribes again tried to reintroduce the notion that BPA's risk package does not meet the stated TPP standard. Rather than relying upon the CBFWA estimates, the Tribe created what it referred to as "hypothetical" cost increases for fish and wildlife. (WP-07-E-JP13-03, page 7, line 10 through page 8, line 4, page 8, line 14 through page 9, line 9, and page 13, lines 11-23.) By substituting the hypothetical increases for the CBFWA estimates, the Tribes preformed an identical TPP analysis. In the end, this analysis is no more valid than the TPP test the Tribes preformed in conjunction with their direct testimony. Furthermore, the hypothetical cost estimates are relevant only if they are designed to replace the estimates that resulted from the PFR. At the core of the Tribes' proposal is a dispute with BPA over the cost assumptions for fish and wildlife costs that resulted from the PFR. As previously noted, these matters are outside the scope of this proceeding and there is no purpose in revisiting these matters in this proceeding.

<u>Decision</u>

BPA will not reverse the Hearing Officer's decision to strike the Tribes' testimony regarding BPA's ability to meet its TPP standard.

Issue 6

Whether the Administrator should reverse the Hearing Officer's decision to strike the Tribes' testimony regarding the impact of its risk mitigation strategies.

Parties' Positions

The Tribes contend that testimony related to the impacts of BPA's risk mitigation strategies was improperly stricken by the Hearing Officer. (JP13 Br., WP-07-M-69 at 55; Sheets, *et al.,* WP-07-E-CR/NZ/YA-01, page 59, line 9 through page 62, line 16.) The Tribes believe the testimony rebuts BPA's testimony that the chosen risk mitigation package represents a reasonable balance between the competing objectives. (WP-07-E-BPA-08, page 14, lines 13-23.) The Tribes contend the stricken testimony shows how, when forced to make a choice between making its Treasury payment and reducing costs, BPA has routinely decided to reduce fish and wildlife protection. (JP13 Br., WP-07-M-69 at 55.)

BPA's Position

BPA disagrees with the Tribes' characterization of the stricken testimony. (BPA Br., WP-07-M-14.) In particular, this testimony does not address any particular risk mitigation strategy, but rather is a recounting of a number of prior BPA decisions related to the events of the 2001 drought and corresponding West Coast energy crisis. The Yakama Nation and Nez Perce Tribe litigated CRITFC's interpretation of those events, and BPA's legal obligations related to them, in *Confederated Tribes v. BPA*, 342 F.3d 924 (9th Cir. 2003). The court did not agree with the Tribes' arguments in that proceeding and revisiting them in this proceeding is not relevant to the matters at issue.

Evaluation of Positions

The Tribes attempt to rehabilitate the stricken testimony as a matter related to the impact of the risk mitigation strategies. In fact, the testimony bears little resemblance to a discussion of the impact of various risk mitigation strategies and relates solely to the circumstances surrounding the 2001 drought and corresponding West Coast energy crisis. The Tribes' testimony characterizes BPA's actions during this period as ones which sacrificed its fish and wildlife obligations in favor of deferring Treasury payments. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at 59-60.) The testimony goes on to discuss the "uncertainties" that BPA faces because "it is not possible to accurately forecast West Coast electricity market costs. (sic)" and its internal costs were higher than assumed in the WP-02 rate case. (*Id.* at 61-62.) The Tribes conclude by suggesting that BPA should incorporate its recommendations for funding for the fish and wildlife program as part of the revenue requirement to address this uncertainty. (*Id.* at 61.)

There are two distinct aspects to the stricken testimony. Part of it relates to prior actions by BPA that the Tribes view as ones that sacrifice fish over Treasury payments. These matters were previously litigated and resolved by the courts. BPA's actions demonstrate BPA's commitment to its fish and wildlife obligations even when faced with unprecedented circumstances. The market conditions and limited power supply presented in 2001 were extraordinary, as the Tribes acknowledge. Market prices were higher than ever seen before and BPA was experiencing its fourth worst water year on record. This constrained BPA's generation and forced BPA to buy power at unprecedented price levels. As a result, BPA had to take a variety of steps, not related solely to fish and wildlife, in order to avert a financial crisis. The Tribes directly challenged BPA's actions and as the court acknowledged, BPA did not violate its fish and wildlife obligations in doing so. *Confederated Tribes v. BPA*, 342 F.3d 924, 933 (9th Cir. 2003).

The second aspect of the testimony deals with alleged uncertainties related to the forecasts of revenues and expenses in the rate case. The Tribes contend that BPA cannot accurately forecast wholesale market prices and BPA under-forecast internal costs by $222 million in the WP-02 rate case. (Sheets, *et al.,* WP-07-E-CR/NZ/YA-01 at 61.) The Tribes contend BPA can address these risks by adopting its proposed fish and wildlife funding assumptions. (*Id*. at 62.)

There are two problems with the Tribes' argument. First, there is no relationship between adopting higher fish and wildlife budget assumptions and the ability to forecast wholesale market prices. Adopting a different budget assumption for fish and wildlife will not solve any alleged deficiency in BPA's forecast of wholesale market prices. Second, assuming there were such a relationship, the underlying argument, as the Tribes note, is for the adoption of budget levels that are different from those adopted in the PFR. As noted earlier, these matters are outside the scope of this proceeding and there is no reason to revisit the conclusions from the PFR.

<u>Decision</u>

BPA will not reverse the Hearing Officer's decision to strike the Tribes' testimony regarding the impact of BPA's risk mitigation strategies.

<u>Issue 7</u>

Whether the Hearing Officer erred in striking the Tribes' testimony regarding fulfillment of BPA's treaty and trust obligations.

<u>Parties' Positions</u>

The Tribes request that the Administrator reinstate testimony addressing BPA's tribal trust and treaty obligations. (JP13 Br., WP-07-M-69, page 61, line 18 through page 66, line 16.) The testimony was stricken by the Hearing Officer in Order, WP-07-O-23 (Striking Sheets, *et al.*, WP-07-E-CR/NZ/YA-01: page 1, line 16 through page 4, line 2; page 4, line 19 through page 5, line 9; page 5, line 18 through page 6, line 7; page 6, line 19 through page 11, line 14; page 12, line 3 through page 15, line 6; page 18, line 4 through page 48, line 19; page 53, line 23 through page 54, line 10; page 59, line 9 through page 62, line 16.) The Tribes argue that the stricken testimony rebuts Bonneville's rebuttal testimony. (*See* Leathley, *et al.*, WP-07-E-BPA-08, page 14, lines 13 through 23.) The Tribes argue further that having the testimony stricken and failing to address the concerns raised therein, BPA violated its fiduciary duty to the Tribes. (JP13 Br., WP-07-M-69, page 61, line 22, through page 63, line 5.) The Tribes maintain that the stricken testimony "would have provided historical information on how Bonneville's prior actions have adversely affected Tribal interests. . ." (*Id.* at page 63, lines 19-20.)

More specifically, the Tribes want testimony reinstated that supports its contention that "Bonneville's rate proposal does not provide sufficient financial capability for BPA to meet its total system costs, which include its statutory and other legal duties to fund salmon recovery." (JP13 Br., WP-07-M-69 at 2.) The Tribes contend that the alleged flaws in Bonneville's rate proposal will force the agency to "either defer needed fish and wildlife restoration . . . or it will not have sufficient funds to assure timely repayment of" FCRPS debt. (*Id.* at 3.)

BPA's Position

The testimony was properly stricken in that it is outside the scope of this rate proceeding. In essence, the Tribes are trying to interject into this proceeding material related to fish and wildlife funding levels. There was extensive opportunity to comment on programmatic funding levels in the PFR, so the Administrator directed the Hearing Officer to exclude such matters from the record of the rate proceeding. Therefore, it was appropriate for the Hearing Officer to strike the testimony cited above.

Moreover, there has been no failure by Bonneville to meet its trust and treaty obligations. BPA disagrees with the Tribes' contentions regarding whether BPA has a "statutory" or "other legal" duty to "fund salmon recovery" generally. BPA indicated in the PFR that it did not share the Tribes' broad interpretation of BPA's duties "to fund salmon recovery." This rate proceeding is not the right place to attempt to resolve that dispute, which is a legal issue hinging on whether BPA is fulfilling, or will fulfill, a substantive legal responsibility.

Evaluation of Positions

Program level expense estimates, except those decided elsewhere, have already received extensive public review and comment in the PFR process. Pursuant to § 1010.3(f) of BPA Hearing Procedures, the Administrator directed the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which sought to in any way revisit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's revenue requirements for FY 2007-2009. The Hearing Officer did not err in striking the cited testimony.

As to the Tribes' substantive concerns regarding fulfillment of trust and treaty obligations, BPA takes a different view of what it is required to do to fulfill those obligations. "Recovery" is a legal term of art referring to conservation of species listed under the ESA following a recovery plan. Every agency has a duty to aid in the conservation of listed species, so BPA shares in the duty to aid in the recovery of listed salmon and steelhead. There are currently no final recovery plans for anadromous fish in the Columbia Basin and the Tribes' testimony and exhibits do not reference any particular duties BPA must fulfill as part of its recovery obligation. To the extent recovery is part of the jeopardy standard applied in the forthcoming Section 7 ESA biological opinion for the FCRPS, BPA has already made provisions for those costs through its budget for the integrated program (which integrates Northwest Power Act and ESA mitigation funding) and through the NFB Adjustment.

The Tribes' analysis also incorporates several underlying assumptions that are not supported. First, BPA has already explained that there are more than two alternatives if the dilemma the Tribes fear really does materialize. BPA can cut costs in other program areas, raise rates if a CRAC has been triggered, reprioritize funding within existing fish and wildlife budgets (by reducing the amount of discretionary projects and replacing them with "mandatory" or "required" projects), or initiate a new rate case. Second, the Tribes assume more money spent and costs incurred by BPA translate into more fish and wildlife to be harvested by the Tribes' constituents. While BPA's costs have grown significantly in the last decade, the Tribes say "Columbia River salmon stocks have generally continued to decline." The Tribes have not explained how they can say more money is needed yet spending in the last decade has left stocks to generally continue to decline. (JP13 Br., WP-07-M-69 at page 5, fn 3.) Third, the Tribes have not shown what law or treaty requires BPA to "restore" fish and wildlife. BPA is unaware of any law requiring "restoration." Finally, the Yakama Nation has raised this exact issue in current Ninth Circuit litigation and BPA has disagreed with the Tribe's legal argument for the preceding reasons.

With this testimony, the Tribes attempt to interject a new, unsupported legal standard that BPA must fund "fish and wildlife restoration" in this proceeding. In addition, this testimony repeats arguments made in the PFR and several ongoing cases in the Ninth Circuit. Because BPA has no duty to "restore" fish and wildlife, and it addressed these issues as budgetary matters in PFR, and one or more Tribes have raised these issues in at least three ongoing cases in the Ninth Circuit, the cited testimony should not be reinstated.

Decision

The Hearing Officer did not err striking the Tribes' testimony regarding fulfillment of BPA's treaty and trust obligations. Not reinstating the testimony has no implications with regard to BPA's trust and treaty obligations to the Tribes.

Issue 8

Whether BPA has failed to meet its treaty and trust obligations by not adopting the Tribes' recommended spending levels for fish and wildlife.

Parties' Position

The Tribes contend that BPA has not properly addressed its treaty and trust obligations when formulating the spending levels for fish and wildlife. (JP 13 Br. at 61-66, WP-07-M-69). The Tribes generally claim that BPA must adopt a risk adverse approach to setting its rates in order to avoid threatening the funding of fish and wildlife restoration efforts. (JP 13 Br. Ex., WP-07-M-77 at 24.) If BPA's rates are set too low, the Tribes suggest that BPA will defer fish and wildlife measures, which will in turn cause the Tribes' treaty rights to be at risk. (*Id.* at 26.) Accordingly, the Tribes argue that BPA's proposal in the Draft ROD sets rates too low and shifts risks to fish and wildlife funding, which are important tribal trust resources. (*Id.* at 24.) The Tribes conclude that BPA must adopt the Tribes' recommendations for fish and wildlife restoration in order to comply with its treaty and trust obligations under Federal law. (*Id.* at 26.)

BPA's Position

There has been no failure by Bonneville to meet its general trust and treaty obligations. As previously articulated in BPA's SN-03 and WP-02 Rate proceedings, BPA consistently keeps its trust responsibility as a Federal agency in mind when making decisions. (*See generally,* 2002 Final Rate Proposal - Record of Decision at 18.2.2., WP-02-A-02; 2003 Safety-Net Cost Recovery Adjustment Clause Final Proposal -- Administrator's Final Record of Decision at 2.8, SN-03-A-02.) BPA fulfills its share of the trust responsibility by fully complying with the laws governing its activities, such as, but not limited to, the Northwest Power Act (protect and mitigate fish and wildlife and their habitats, provide equitable treatment), NEPA (impacts of proposed actions on tribes and resources), ESA (protection for listed fish, wildlife, and plants), Native American Grave Protection and Repatriation Act (protection of cultural resources), and the Clean Water Act (water quality).

The Tribes have not identified a statute applicable to BPA that broadens BPA's general trust responsibility to include the requirement to take specific fish and wildlife mitigation actions on behalf of the tribes. None of BPA's rate-setting directives calls for the type of analysis sought by the Tribes. Moreover, BPA disagrees with the Tribes' contentions regarding whether BPA has a "statutory" or "other legal" duty to "fund salmon recovery" generally. BPA indicated in the PFR that it did not share the Tribes' broad interpretation of BPA's duties "to fund salmon recovery." Therefore, by setting its rate proposal to meet its obligations under its enabling acts and other pertinent laws, BPA will also have adequate rate levels to support trust and treaty obligations. To the extent the Tribes disagrees with BPA's assessment of its treaty obligations, this rate proceeding is not the forum to attempt to resolve that issue, which is a legal issue hinging on whether BPA is fulfilling, or will fulfill, a substantive legal responsibility.

Evaluation of Positions

BPA agrees that the federal government recognizes the "undisputed existence of a general trust relationship between the United States and the Indian people." *United States v. Mitchell*, 463 U.S. 206, 225 (1983). BPA shares the Government's trust responsibility to Indian tribes. However, Federal agencies and tribes look to Congress and the Executive Branch to delegate specific trust duties to agencies through statutes or executive orders. It is only when a specific trust responsibility is established that an agency must fulfill this responsibility as a "moral obligation of the highest responsibility" to be "judged by the most exacting fiduciary standards." (*Seminole Nation v. United States*, 316 U.S. 286, 297 (1942).)

Neither Congress nor the Executive Branch has delegated to BPA specific trust related duties to manage an Indian resource on behalf of Indian beneficiaries. BPA's power marketing statutes lack any expression of intent by Congress to impose a fiduciary duty on BPA to treat Indian tribes or their resources differently when mitigating for fish and wildlife. BPA's choice to treat Indian tribes or their resources with a higher degree of care is done as a matter of discretion and in tandem with the fulfillment of one or more of its statutory purposes. BPA is not under a specific trust responsibility for purposes of increasing spending levels to benefit Indian tribes.

"[A]lthough the United States does owe a general trust responsibility to Indian tribes, unless there is a specific duty that has been placed on the government with respect to Indians, this responsibility is discharged by the agency's compliance with general regulations and statutes not specifically aimed at protecting Indian tribes."

Morongo Band of Indians v. Federal Aviation Administration, 161 F.3d 569, 574 (9th Cir. 1998); *see also*, *Pawnee v. United States*, 830 F.2d 187, 191 (Fed. Cir. 1987); *Skokomish Indian Tribe v. FERC*, 121 F.3d 1303, 1308 09 (9th Cir. 1997) (FERC exercises its trust responsibility in the context of the Federal Power Act and is not required to afford Indian tribes greater rights than they would otherwise have under that Act.) Therefore, BPA fulfills its trust responsibilities by working with the PNW's tribes in the manner prescribed by the DOE and BPA tribal policies, and by fully complying with the laws governing its activities. (*See, generally, United States v. Mitchel*l, 463 U.S. 206, 225 (1983); *North Slope Burough v. Andrus*, 642 F.2d 589 (D.C. Cir. 1980).)

The Tribes suggest that the general fiduciary standard accorded to all federal agencies requires BPA to consider and implement the Tribes' fish and wildlife recommendations. (JP 13 Br. at 62, WP-07-M-69; JP 13 Br. Ex. at 22, WP-07-M-77.) In its initial brief, the Tribes relies on *Seminole Nation v. United States*, 316 U.S. 286 (1942) and *Navajo Tribe of Indians v. United States*, 364 F.2d 320 (Ct. Cl. 1966) to support its position that all executive departments that may deal with Indian tribes are under an obligation to assert their statutory and contractual authority to the fullest extent possible to fulfill their trust obligations. (JP 13 Br. at 61-62, WP-07-M-69.) The Tribes claim that BPA violated its fiduciary obligations by failing to analyze its proposals in light of this responsibility and by striking material from the record that was supportive of the Tribes recommendations. (*Id.*; JP 13 Br. Ex., WP-07-M-77 at 22.)

BPA does not believe the law cited by the Tribes stands for the proposition that BPA is under a specific trust responsibility to either fund the Tribes' specific project requests or make additional funding available for projects proposed by or supporting tribes. The Tribes have not shown what law or treaty requires BPA to adopt the Tribes' recommendation of "restoring" fish and wildlife. Indeed, BPA is unaware of any law requiring "restoration." The Yakama Nation has raised this exact issue in current Ninth Circuit litigation and BPA has already disagreed with the Tribes' legal argument for the preceding reasons. No amount of briefing or submission of evidence in this rate case will change BPA's trust responsibility, nor is this rate proceeding the appropriate forum for determining BPA's treaty and trust obligations.

Equally unavailing is the Tribes' claim that its testimony and exhibits must be admitted and considered by BPA as part of BPA's general trust responsibilities. Nothing in any Executive Order or cases articulating the government's trust responsibility requires BPA to alter procedural rules for evidentiary hearings to allow tribes to raise issues that are not germane to the agency's rate making process. BPA has provided a number of forums, including the PFR I and PFR II processes, for parties to raise concerns related to the proposed spending levels. The Tribes, as well as all other interested parties, were given an opportunity to submit comments and provide inputs into BPA's assumptions. Indeed, the Tribes actively participated in these other processes. Whether BPA's decision to adopt or not adopt the Tribes recommendations for fish and wildlife funding in some way violates BPA's trust responsibilities is not an issue to be decided in this rate proceeding. The scope of the rate case is clearly identified in the FRN, and no statute or case cited by the Tribes requires BPA to alter its procedural rules for the rate proceeding in favor of the Tribes to allow the submittal of material that is otherwise inappropriate for setting rates. Thus, BPA did not violate its general trust responsibilities by not admitting and considering the Tribes' testimony and exhibits. BPA shares the federal government's general trust responsibility and in fulfilling that duty, it has considered the Tribes' views and recommendations as part of the PFR processes and this rate case.

Decision

BPA has not failed to meet its treaty and trust obligations by not adopting the Tribes' recommended spending levels for fish and wildlife.

Issue 9

Whether the Hearing Officer erred by striking the Tribes' testimony on rate and economic impacts.

Parties' Positions

The Tribes argue that the Hearing Officer's decision striking portions of their testimony on rate and economic impacts should be reversed and the subject testimony reinstated. (JP13 Br., WP-07-M-69, page 67, line 14 through page 71, line 10; *see* Order, WP-07-0-23 (striking Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, page 66, line 12 through page 72, line 2 and page 73, line 10 through page 74, line 15.)) The Tribes assert that the testimony is appropriate rebuttal to Bonneville's testimony and should be admitted to the administrative record. (JP13 Br., WP-07-M-69, page 69, lines 8 through 20.)

PPC believe the Tribes' testimony on rate and economic impacts should be stricken. (PPC Br., WP-07-M-13 at 10.) They argue that the testimony is irrelevant to the matters to be determined in this rate proceeding. (*Id.*) Moreover, PPC argues that the testimony simply seeks to revisit fish and wildlife spending levels by attempting to demonstrate the effect on BPA's rates if the Tribes' views on spending levels and river operations were adopted. (*Id.*)

BPA's Position

Bonneville believes the testimony was properly stricken as outside the scope of matters to be determined in this rate proceeding. The testimony essentially deals with funding levels for fish and wildlife programs. This issue was dealt with in the PFR and the Administrator directed the Hearing Officer to exclude such testimony from the administrative hearing record. Thus, the Hearing Officer acted properly in ordering the testimony stricken.

Evaluation of Positions

The Tribes maintain that the stricken testimony should be reinstated for a number of reasons. First, as noted above, the Tribes argue that the testimony rebuts Bonneville's testimony. The

Tribes also maintain that the testimony offers "relevant information that Bonneville could revise the balance it set in its policy decisions that gave too much weight to the lowest possible rates." (*Id.* at page 69, lines 12-16.) The Tribes then describe the stricken testimony as providing evidence comparing Bonneville's proposed rates and market rates. (*Id.* at page 69, line 17 through page 70, line 9.) Moreover, the Tribes state that the testimony provided relevant evidence "that expanding the implementation of the fish and wildlife program would provide thousands of jobs in the region, primarily in rural and tribal communities." (*Id.* at lines 10-15.)

The Hearing Officer's perspective was far different. He agreed with the Joint Parties' contention that the testimony "contains material that is irrelevant to this proceeding, and which seeks to revisit BPA's spending levels for its fish and wildlife program by addressing how BPA's rates would be affected if CRITFC's proposed spending levels and river operations were adopted." (Order, WP-07-0-23, citing PPC Br., WP-07-M-13 at 11.) The Tribes did not respond to the Joint Parties' assertions. The Hearing Officer concluded:

> The testimony at issue describes the extent to which BPA proposes below-market rates for electricity. . . The remainder of the testimony discusses the impact on rates if CRITFC's fish and wildlife proposals are adopted. . . . [T]he recommendations are, in fact an attempt to reopen discussions of funding levels for fish and wildlife already examined in the PFR and should therefore be excluded from the Record in accordance with the Administrator's directions to the Hearing Officer in the FRN.

(Order, WP-07-0-23 at 13.) Thus, the Hearing Officer carefully examined the nature and substance of the testimony, and found that the testimony was outside the scope of matters to be determined in this rate proceeding. Bonneville understands the Tribes' concerns but believes the PFR provided the appropriate forum and adequate opportunity was provided addressing the issues raised in the Tribes' testimony. Therefore, the testimony should not be reinstated.

Decision

The Hearing Officer did not err when he ordered the Tribes' testimony on rate and economic impacts stricken.

Issue 10

Whether the Hearing Officer erred by striking the Tribes' testimony regarding equitable treatment for fish and wildlife and compliance with the NPCC's plan.

Parties' Positions

The Tribes request that their testimony regarding equitable treatment of fish and wildlife and compliance with the NPCC's plan be reinstated. (JP13 Br., WP-07-M-69, page 71, line 12 through page 75, line 5; *see* Order, WP-07-O-23 (striking Sheets, *et al.*, WP-07-E-CR/NZ/YA, pages 18, line 4 through page 41, line 2.)) The Tribes maintain that the testimony is appropriate rebuttal to Bonneville's testimony and properly addresses Bonneville's statutory obligation to provide equitable treatment to fish and wildlife.

BPA's Position

The testimony was properly stricken. Program level expense estimates, except those decided elsewhere, have already received extensive public review and comment in the PFR process. Pursuant to § 1010.3(f) of BPA Hearing Procedures, the Administrator directed the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which sought to in any way revisit the appropriateness or reasonableness of BPA's decisions on spending levels, as included in BPA's revenue requirements for FY 2007-2009. BPA, however, did commit to revisit many of the program areas where final results were not known at the time the final report was issued and has held discussions separately from the rate case proceeding to share the updated forecasts, define associated policy choices, and solicit feedback from customers and constituents before they are incorporated into the final rates.

Evaluation of Positions

The Tribes argue that testimony to the effect that BPA has not met its obligation to provide equitable treatment to fish and wildlife should be reinstated. The Tribes maintain that BPA has not analyzed its equitable treatment obligation in the rate proposal. The stricken testimony, according to the Tribes, dealt with the issue of whether BPA was fully implementing the NPCC's plan, that is directly relevant to whether BPA is fulfilling its equitable treatment obligation. The Tribes also offered testimony "regarding Bonneville's previous actions that eliminated fish protection river operations and Bonneville's continuing arguments that fish protection river operations may reduce Bonneville's ability to repay the Treasury." This testimony, the Tribes argue, "rebuts Bonneville's rebuttal . . . and is directly relevant to Bonneville's responsibilities under 16 U.S.C. § 839b(h)(11)(A)(i)."

The testimony regarding Bonneville's adherence to the NPCC's plan addresses the adequacy of funding for discretionary policy and budgeting decisions, specifically the adequacy of BPA's funding for fish and wildlife programs. As Bonneville pointed out in its motion to strike this and other testimony offered by the Tribes, the adequacy of BPA's funding levels cannot be resolved in the rate proceeding. (Order, WP-07-O-23 at page 6, citing BPA Motion at page 4.) The Tribes and other parties have had adequate opportunity to provide Bonneville with input on these matters, particularly in the PFR. The Hearing Officer agrees with Bonneville's view, noting that attempts to revisit decisions made in the PFR are to be explicitly excluded from this proceeding (*Id.*)

Decision

The Hearing Officer did not err in excluding the Tribes' testimony regarding equitable treatment of fish and wildlife.

17.2 Regional NPCC Funding Issues

Issue 1

Whether the Hearing Officer properly excluded from the record testimony introduced by WPAG that sought to challenge BPA's funding levels for the NPCC.

Parties' Positions

WPAG seeks reversal of the Hearing Officer's order that excluded certain testimony proffered by WPAG regarding NPCC funding. (WPAG Br., WP-07-M-68 at 28-30 citing Saleba, *et al.*, WP-07-E-WA-01 at 10-11; Order, WP-07-O-17; WPAG Br. Ex., WP-07-M-81 at 18-20.) WPAG contends that the Hearing Officer improperly excluded from the record testimony that described and calculated the funding cap detailed in Section 4(c)(10)(B) of the Northwest Power Act, 16 U.S.C. § 839b(c)(10)(B). (WPAG Br., WP-07-M-68 at 28-30; WPAG Br. Ex., WP-07-M-81 at 18-20.) WPAG argues that rate case parties have a right under Section 7(i) of the Northwest Power Act to rebut any evidence submitted by BPA into the record, and BPA cannot usurp this right by limiting the scope of the rate case through the FRN. (*Id.*) Because BPA introduced into the record material related to the funding levels of the NPCC's budget through its revenue requirement, WPAG states that the parties should be afforded an opportunity to refute this evidence. (*Id.*)

In addition, WPAG argues that the Hearing Officer was wrong in concluding that WPAG's witness was providing a legal opinion on the Northwest Power Act. (*Id.* at 29-30.) WPAG asserts that its witness was only making statements of fact about the application of Section 4(c)(10)(B) to BPA's forecast. (*Id.*) WPAG then contends that BPA witnesses have done similar calculations on the record. (*Id.* at 30.) WPAG states that the witnesses' testimony was, therefore, not a legal opinion and should not have been stricken. (*Id.*)

BPA's Position

The FRN properly limited the scope of the rate proceeding. (BPA Br., WP-07-M-04.) It is wholly consistent with Congressional intent, as well as applicable law, that the Administrator may limit the scope of the rate case by excluding certain matters from the proceeding, particularly BPA's program levels. (*Id.*) BPA's process of budgeting is an exclusive Executive function that can only be reviewed and approved by Congress. BPA's budget levels, therefore, have no place in the rate proceeding, and the Administrator's direction to the Hearing Officer in the FRN to limit the scope was appropriate. (*Id.*)

Because the FRN's limitations were proper, the Hearing Officer was correct in ordering the exclusion of portions of WPAG's testimony. (*Id.*) In the stricken testimony, WPAG's witnesses reviewed the line-item figures in the revenue requirement for NPCC's budget. (Saleba, *et al.*, WP-07-E-WA-01 at 11.) Based on their interpretation of Section 4(c)(10)(B) of Northwest Power Act, WPAG's witnesses then testified that BPA's direct program level for the NPCC needed to be reduced by over $2 million a year. (*Id.*) This testimony, however construed, was an impermissible challenge to the spending levels included in BPA's revenue requirement. The

FRN clearly stated that issues related to BPA's program levels would not be addressed in the rate case. *See* 70 Fed. Reg. 67,685, 67,689 (2005). Thus, the testimony was outside of the scope of the FRN and was appropriately struck.

BPA also concurs with the Hearing Officer's finding that WPAG's witnesses were providing an impermissible legal argument. WPAG's witnesses cited to Section 4(c)(10)(B) of the Northwest Power Act and testified to their "understanding" of the statutory provision. (Saleba, *et al.*, WP-07-E-WA-01 at 10.) They then reviewed BPA's forecasts and concluded as a matter of fact that BPA's proposed funding of the NPCC was in violation of the statutory cap. (*Id.* at 11.) The Hearing Officer's assessment that this line of testimony, which required the witnesses to interpret the Northwest Power Act and apply such interpretation to specific facts, was a legal argument reserved for the parties' brief.

Evaluation of Positions

WPAG argues that Section 7(i) of the Northwest Power Act provides parties a statutory right to offer rebuttal and refutation of evidence submitted in the record by BPA. (WPAG Br. Ex., WP-07-M-81 at 19.) Although this is correct, Section 7(i) does not provide that everything related to the development of BPA's rate proposal constitutes a ratemaking issue. BPA's revenue requirement includes all of BPA's costs, including, for example, the costs of conservation. This does not mean that all of BPA's conservation programs, and the cost of such programs, are developed in a Section 7(i) hearing. Such a requirement, as discussed below, would effectively preclude BPA from functioning as a business as intended by Congress. This is why the FRN contains legitimate limits on the scope of the rate case. Contrary to WPAG's argument, BPA has not placed the FRN above Section 7(i) of the Northwest Power Act. (WPAG Br. Ex., WP-07-M-81 at 19.) BPA has interpreted Section 7(i) in a manner that allows complete public participation in the development of BPA's rates, but limits the litigation of issues to those directly related to ratemaking while respecting Congressional authority and the Administrator's separate public processes and program responsibilities. In addition, WPAG's argument that BPA cannot ban testimony regarding the legality of BPA's proposed rates for the rate case is not well-founded. (WPAG Br. Ex., WP-07-M-81 at 19.) Testimony should not contain legal argument. Legal argument is presented in the parties' briefs. Indeed, in this proceeding the public agency parties filed numerous successful motions to strike the testimony of other parties on the basis that such testimony comprised legal argument. It would be contradictory for the public agencies to benefit from the exclusion of legal issues from testimony on one hand and then to claim an entitlement to do so on the other.

Thus, the exclusion of BPA's program levels from the rate case proceeding is not simply a function of the FRN, but is legally necessary to preserve the Executive responsibility of budgeting. BPA's rate case is not an appropriate forum to establish program levels. BPA's rate cases do not establish BPA's program levels. Indeed, the NPCC did not intervene as a party in BPA's rate case because it has little interest in BPA's rates. Under WPAG's proposal, BPA would decide the funding level for the NPCC in a forum where the NPCC would not have had an opportunity to defend its funding. Ultimately, though, BPA's spending decisions have remained an unreviewable and discretionary function of the Executive Branch. BPA's spending levels are part of the Federal Budget, and are subject to review only by the President and the Congress.

Allowing parties to submit competing spending level proposals in the rate case would, thus, conflict with Presidential and Congressional authority.

WPAG's argument that BPA included the NPCC's funding level in its revenue requirement and therefore raised the funding level as a ratemaking issue is incorrect. BPA's revenue requirement, by definition, contains the costs BPA must recover through its rates. These costs, particularly program costs, are determined in separate BPA proceedings. Under WPAG's argument, the individual cost of each of hundreds of BPA programs would be determined in an adversarial ratemaking proceeding before limited parties instead of in a program level proceeding where all interested parties could have the informal discussions necessary to determine proper funding levels. The Administrator must place limitations on the scope of the rate case in order to prevent parties from introducing material not relevant to the establishment of BPA's rates. Without these limitations, the rate case would become a general forum for resolving policy, budget, non-rate related contract disputes, and other issues, which would render the proceeding unworkable.

This does not mean, though, that the parties are unable to voice their concerns with BPA's spending levels. The Administrator has specifically designed several non-rate case forums, like the PFR, for the parties to raise their concerns with BPA's program costs. Indeed, as noted in the FRN, the Administrator established this separate collaborative process to inform BPA's customers as to the proposed spending levels, and to receive input on those proposed levels. WPAG participated in the PFR, which included the examination of the costs assumed for the NPCC budget. It would frustrate the Administrator's purpose of holding these separate dialogues and blur the uniform purpose of the rate proceeding to establish rates if parties were able to challenge program levels in the rate case.

WPAG claims that alternative BPA processes are insufficient to satisfy a party's procedural rights. (WPAG Br. Ex., WP-07-M-81 at 19.) WPAG argues that such alternative processes are informal, do not include a record on which decisions are made, and do not conclude with a ROD that explains the decision. (*Id.*) WPAG's argument is refuted by BPA's current separate administrative process, which directly addresses the substantive issue raised by WPAG, that is, Council funding. BPA previously released a public notice regarding BPA's "*Proposed Interpretation of Section 4(c)(10)(B) of the Northwest Power Act*," available at http://www.bpa.gov/corporate/public_affairs/comment.cfm. Contrary to WPAG's arguments, the Administrator's legal determination of the limits of Council funding does not occur in the first instance in, and does not need to be established in, a rate case. Also, the foregoing notice solicits public comments with the same formality as other notice and comment rulemaking proceedings; the notice begins the administrative process, which will establish a record upon which the Administrator will make his decision; and the Administrator will issue a ROD at the conclusion of the public process. (*Id.*) In summary, BPA will properly establish its interpretation of Section 4(c)(10)(B) in the ongoing administrative proceeding, and not in the current rate case.

The Hearing Officer also did not err when he concluded in his order that WPAG's witnesses were providing legal arguments in their testimony. (*See* WPAG Br. Ex., WP-07-M-81 at 20.) The Special Rules of Practice governing the rate proceeding prohibit witnesses from providing legal opinions or arguments as part of their testimony. (*See* Order, WP-07-O-01 at 6.) The

Hearing Officer's order requires that legal arguments of this nature remain within the purview of the parties' brief. (*Id.*) WPAG's witnesses were providing a combination of factual and legal arguments in their testimony.

In a certain respect, the witnesses do provide evidence related to BPA's WP-07 Initial Proposal. The witnesses restate the projected amounts in BPA's revenue requirement for the NPCC's budget, BPA's projected firm loads in the loads and resource study, and then provide certain calculations relating to these two figures. The import of this factual information, however, is included only to support the witnesses' proposition that BPA's WP-07 Initial Proposal has violated the statutory cap of Section 4(c)(10)(B). To reach this conclusion, the witnesses had to testify as to their interpretation of Section 4(c)(10)(B), which they did by providing their "understanding" of the statutory cap. (Saleba, *et al*., WP-07-E-WA-01 at 10.) This testimony was therefore properly stricken as a legal argument. Furthermore, WPAG has not been harmed by the Hearing Officer's ruling. WPAG had the opportunity to raise this same *legal* argument regarding the statutory cap as part of its initial brief in conformance with the Hearing Officer's Special Rules of Practice. (Order, WP-07-O-01 at 6.)

Decision

The Hearing Officer properly excluded from the record testimony introduced by WPAG that sought to challenge BPA's proposed funding levels for the NPCC.

Issue 2

Whether BPA's projected funding of the NPCC is consistent with the statutory cap contained in Section 4(c)(10)(B) of the Northwest Power Act.

Parties' Positions

WPAG implies that BPA's proposed funding for the NPCC as represented in the rate proceeding exceeds the statutory cap provided in Section 4(c)(10)(B) of the Northwest Power Act. 16 U.S.C. § 839b(c)(10)(B). (WPAG Br., WP-07-M-68 at 28-30; WPAG Br. Ex., WP-07-M-81 at 18-20.)

BPA's Position

BPA does not determine program levels, including NPCC funding, in BPA's rate proceedings. (BPA Br., WP-07-M-04.)

Evaluation of Positions

BPA has previously concluded that NPCC funding levels, like program levels, should not be addressed in BPA's rate proceedings. This same logic applies to the issue of whether BPA's proposed funding for the NPCC exceeds the statutory cap. Nevertheless, WPAG's counsel expressed frustration at oral argument that this issue was outside the scope of BPA's rate proceedings, and even though it is being addressed in BPA's separate PFR, the findings of that process do not constitute final actions subject to judicial review. BPA notes, however, that it has released a proposed interpretation regarding Section 4(c)(10)(B) of the Northwest Power Act. 16 U.S.C. § 839b(c)(10)(B). BPA will be taking comments on the proposed interpretation and issuing a final interpretive rule at the end of that public process. BPA believes this addresses WPAG's counsel's concerns.

Decision

Whether BPA's projected funding of the NPPC is consistent with the statutory cap contained in Section 4(c)(10)(B) of the Northwest Power Act and is an issue outside the scope of this rate case.

17.3 WPAG and ICNU Legal Issues:

Issue 1

Whether the NFB Surcharge is a valid rate under the Northwest Power Act.

Parties Position

WPAG and ICNU contend that the NFB Surcharge is not a rate. (WPAG Br., WP-07-M-68 at 18; ICNU Br., WP-07-M-72 at 4.) According to WPAG, the Ninth Circuit clearly articulated the definition of a rate in the context of BPA Rules of Procedure as a "price stated or fixed for some commodity or service… measured by a specific unit or standard." Citing *Association of Public Agency Customers v. BPA*, 126 F.3d 1158, 1177 (9^{th} Cir. 1997). The NFB Surcharge is not a rate because it is does not have a price stated or fixed for service measured by a unit or standard. Rather it is a mechanism to cover estimates of ESA compliance obligations. (WPAG Br., WP-07-M-68 at 19; ICNU Br., WP-07-M-72 at 4.)

In addition, the NFB Surcharge neither defines a formula for computing charges for power sold nor does it give BPA authority to increase or decrease established charges for energy. (*Id.* at 20.)

In WPAG's brief on exceptions, it renewed its argument that NFB Surcharge does not meet the 9^{th} Circuit definition of a rate. (WPAG Br. Ex., WP-07-M-81 at 13.) WPAG contends the NFB Surcharge lacks a formula or methodology from which customers can understand how BPA will calculate how much customers will be asked to pay. (*Id.* at 14.) Instead, the NFB Surcharge is a mechanism that allows BPA to determine without any meaningful limitation how much money it wants to collect from customers to cover what it estimates that ESA compliance will cost. (*Id.*)

BPA's Position

This matter was never discussed during the extensive settlement discussion related to the NFB Surcharge. Had WPAG stated these concerns, BPA would have engaged parties in a discussion that might have resulted in a resolution. Nevertheless, contrary to WPAG's assertion, a rate is not so narrowly defined as to exclude a surcharge like the one proposed. BPA has recognized a surcharge as a means of charging costs to customers taking service from BPA. Under the

Procedures Governing Bonneville Power Administration Rate Hearings, § 1010.2(j), a rate is defined as follows:

> 'Rate' means the monetary charge, discount, credit, surcharge, pricing formula, or pricing algorithm for any electric power or transmission service provided by BPA, including charges for capacity and energy.

(Emphasis added.) The proposed NFB Surcharge clearly fits within the definition noted above.

Evaluation of Positions

WPAG's and ICNU's basic argument is that a rate must either be a per unit stated, or fixed, charge or alternatively a formula from which one can calculate the charge. (WPAG Br., WP-07-M-68 at 18 and 20; ICNU Br., WP-07-M-72 at 4.) [7] Absent fitting within either of these narrow definitions, WPAG argues, the NFB Surcharge exceeds BPA's authority under the Northwest Power Act. (*Id.* at 20.)

As proposed, if triggered, the NFB Surcharge will calculate the estimated ESA related costs and assess each eligible public customer a proportionate share of those costs based upon the prior year's bills. (Lovell and Normandeau, WP-07-E-BPA-34 at A-6). Apparently WPAG believes a surcharge that assesses a flat charge for these ESA related costs to customers rather than converting the assessment to a per unit charge is fatal to its design. (WPAG Br., WP-07-M-68 at 18.) This argument is inconsistent with the definition of a rate under BPA's Procedures. Under the *Procedures Governing Bonneville Power Administration Rate Hearings*, §1010.2(j), a rate is defined as follows:

> 'Rate' means the monetary charge, discount, credit, surcharge, pricing formula, or pricing algorithm for any electric power or transmission service provided by BPA, including charges for capacity and energy.

(Emphasis added.) Clearly the rules contemplated a broader definition of a rate than that advocated by WPAG. Furthermore, the case law does not support WPAG's limited definition of a rate. In *City of Seattle v. Johnson*, 813 F.2d 1364 (9th Cir. 1987) the court looked at BPA's availability charge to recover specific costs. The court rejected the utilities' contention that the charge was a penalty and not a rate, reasoning that rates "may be structured in many ways besides a single unchanging amount for each kilowatt-hour of supplied energy." *Id.* at 1367.

In addition, the costs recovered under the NFB Surcharge are costs which BPA must recover and for which WPAG members must pay their proportionate share. BPA could have elected to forecast these fish and wildlife costs and incorporate the results into the calculation of base rates. However, given the difficulty in forecasting the outcome of pending litigation, the result would have produced speculative results that may have produced unnecessarily high rates. Instead, BPA chose to avoid these problems and elected to collect the costs after the outcome of the pending litigation was understood. This comports with BPA's statutory responsibility to

---

[7] A related, but separate, issue involves whether there is sufficient particularity in the GRSPs in order avoid holding a hearing pursuant to Section 7(i). That issue is addressed in Section 6.

establish rates at the lowest possible level consistent with sound business principles. 16 U.S.C. § 838g.

Since these are costs that customers would otherwise pay as part of base rates the fact that BPA chose to forecast them after a trigger event as opposed to incorporating them into base rates does not remove the "salient characteristics" of a rate. As noted, the Procedural Rules and the court decisions do not support a narrow definition of a rate. Assessing these costs in the manner proscribed by the GRSPs does not deprive it of the earmarkings of a rate.

Additionally, contrary to WPAG's belief, the NFB Surcharge does contain a formula for calculating the Surcharge Amount. BPA provided the following formula for assessing the Surcharge Amount:

> **3. Formula for Calculating the Financial Effects and the Surcharge Amount**
>
> The calculation of the Financial Effects will be determined as follows making use of the best information available at the time:
>
> Financial Effects =
>
> Expected Value Modified Net Revenue without Trigger Event
>
> Minus
>
> Expected Value Modified Net Revenue with Trigger Event
>
> Where:
>
> (1) The Expected Value Modified Net Revenue without Trigger Event is BPA's projection of what the Modified Net Revenues would be at the end of the fiscal year assuming the Financial Effects of the Trigger Event did not take place. Such projection will be based on actual generation function revenues and expenses to the extent available and forecasted results for the remainder of the fiscal year, and will include revenues and expenses that are associated with the production, acquisition, marketing, and conservation of electric power, including BPA's best estimate of 4(h)(10)(C) credits.
>
> (2) The Expected Value Net Revenue with Trigger Event is the identical projection as made in (1) above except that BPA will assume the Financial Effects of the Trigger Event did take place.
>
> The calculation of the Surcharge Amount will be determined as follows making use of the best information available at the time:

The Surcharge Amount =

Financial Effects

Minus

Expense Changes Borne by Slice Customers

Where:

(1) The Expense Changes Borne by Slice Customers are the estimated costs subject to the Annual True-up Adjustment for Actual Costs, including changes in IOU and/or DSI benefits due to the Surcharge. The portion of the Surcharge Amount allocated to the IOU and DSI customers in determining the Adjusted Surcharge Amount is set forth in subsection E.4 below. The Adjusted Surcharge Amount to be collected from firm power purchasers subject to the Surcharge, excluding the IOU and DSI customers, is set forth in subsection E.5 below.

The above referenced section from the GRSPs is sufficiently detailed to provide customers an understanding of how the surcharge will be calculated. BPA's rebuttal testimony and accompanying GRSPs described in detail the methodology used to develop the forecasts used in the rate case. Thus, there was a thorough proposal available for parties' analysis and comments. However, as noted in Section 6, BPA will initiate a public process to describe the Agency Within-year TPP methodology within 120 days of submitting this record to FERC.

Decision

The NFB Surcharge is a valid rate under the Northwest Power Act.

Issue 2

Whether the NFB Surcharge constitutes retroactive ratemaking.

Parties' Position

WPAG argues that by using the prior year's revenues as the mechanism for determining the share of the NFB Surcharge applicable to each customer, BPA is engaging in retroactive ratemaking. (WPAG Br., WP-07-M-68 at 21.) WPAG contends that the NFB Surcharge does not change the rate for service in effect therefore it can be only viewed as a recalculation of the rate paid by customers in the prior fiscal year. (*Id.*)

In its brief on exceptions, WPAG argues that the NFB Surcharge is retroactive ratemaking. WPAG contends that the Draft ROD authorizes BPA to impose surcharges that recalculate the payment due for services for which customers have already made payment. (WPAG Br. Ex., WP-07-M-81 at 15.) They further contend that the *Central Elec. Coop v. SEPA* cited in the Draft ROD is factually distinguishable from the current situation because it was collecting for a prior revenue shortfall. (*Id*. at 16.) They contend that once a bill has been paid in accordance with its terms, there is accord and satisfaction and the obligation to make further payment is extinguished. (*Id*.)

<u>BPA's Position</u>

This issue was raised for the first time on brief. BPA believes the methodology employed by BPA for determining a utility's share of the charges based upon the prior years revenues does not constitute retroactive ratemaking.

<u>Evaluation of Positions</u>

WPAG argues that BPA is engaging in retroactive ratemaking. (WPAG Br., WP-07-M-68 at 21.) However, the principles of retroactive ratemaking are not applicable to BPA. In *Central Electric Power Coop. Inc. v. SEPA*, 338 F.3d 333, 337 (4th Cir. 2003), the court addresses the applicability of the principle of retroactive ratemaking to Federal power marketing administrations. Southeastern Power Administration (SEPA) operates under the Flood Control Act of 1994. Section 7(a)(i) of the Northwest Power Act requires, among other things, that BPA rates be established in accordance with Section 5 of the Flood Control Act. 16 U.S.C. § 839e(a)(1).

Under the Flood Control Act, SEPA is required to set rates for the sale of hydroelectric power in accordance with two criteria. 16 U.S.C. §825s. SEPA must devise rate schedules that encourage "the most widespread use [of hydroelectric power] at the lowest possible rates to consumers consistent with sound business principles..." *Central Electric Power Coop.* at 337. Secondly, SEPA, must devise rate schedules with "regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years." *Id*) The court concluded that SEPA is "required by the plain language of [the Flood Control Act] to protect the public by ensuring that Federal hydro-electric programs recover their own costs and do not require subsidies from the federal treasury." *Id*. When a drought in the southeastern United States limited hydroelectric production in the area and caused SEPA's costs to rise beyond what SEPA would recover under the 1985 rate schedule, the court found SEPA was required by statute to address the revenue shortfall. *Id.* As a result, the court determined SEPA must sometimes set rates specifically aimed at recovering revenue shortages sustained during prior rate periods. *Id.* The court noted that "although provisions in the Natural Gas Act, 15 U.S.C. §§ 717c and 717d (2000), and the Federal Power Act, 16 U.S.C. §§ 824d and 824e (2000), prohibit retroactive ratemaking, the Flood Control Act contains no similar provisions. It further found that SEPA would be unable to meet the requirements of the Flood Control Act if they were prohibited from devising rates aimed at addressing unexpected revenue shortfalls.

Although retroactive ratemaking is a ratemaking principle for utilities subject to FERC jurisdiction under the Federal Power Act, the principle is not found in either the Flood Control Act or the Northwest Power Act. BPA, like SEPA, is required by law to collect its costs and is provided substantial discretion in the design of rates to accomplish that purpose. 16 U.S.C § 839e(a)(1); 16 U.S.C. § 839e(e).

WPAG argues in its brief on exceptions that the *Central Electric Power Coop.* case is factually distinguishable from the NFB Surcharge. WPAG's debate over whether the cases are factually similar misses the primary point of using this case to support BPA's position. As noted below, BPA does not believe the current proposal constitutes retroactive ratemaking, the point of the *Central Electric Power Coop.* case is to establish that the legal principle does not apply to BPA. The court was clear that SEPA's organic statutes did not prohibit it from engaging in retroactive ratemaking. Because the relevant statutory provisions that govern BPA are virtually identical to those governing SEPA, BPA can engage in retroactive ratemaking.

Secondly, even if there were a prohibition against retroactive ratemaking, it would not apply to this circumstance. BPA is not collecting a prior cost under the NFB Surcharge. Under the prohibition against retroactive ratemaking, utilities are barred from collecting an under-recovery for a prior period. Rather than collecting costs for a prior period, the NFB Surcharge is an assessment for a current cost that are allocated to customers based upon a prior year's revenues. The prior year's revenues serve only as a metric to allocate the current cost and the rates for that prior period are not being adjusted.

Using the prior year's revenues is a reasonable method to allocate the costs among customers. Because the NFB Surcharge will likely be assessed only for a portion of the fiscal year (*i.e.*, summer months), assessing the NFB Surcharge based upon forecasted deliveries for the balance of that fiscal year may result in an inequitable allocation of the NFB Surcharge among customers. Customers who have, for example, summer peak load could experience a disproportionate share of the costs if the NFB Surcharge was based upon a forecast of deliveries for the balance of the fiscal year. As a result, BPA elected to assess the NFB Surcharge on the most recently completed year, avoided the inequity that may result from customers who have highly variable loads over the year.

<u>Decision</u>

The principle of retroactive ratemaking does not apply to BPA and even if the principle applied, the NFB Surcharge does not constitute retroactive ratemaking.

<u>Issue 3</u>

Whether the NFB Surcharge conflicts with BPA's power sales contracts.

<u>Parties' Position</u>

WPAG argues that even if one assumes the NFB Surcharge is a rate, the operation of the NFB Surcharge conflicts with provisions of BPA's power sales contracts. (WPAG Br., WP-07-M-68 at 22.) According to WPAG, BPA power sales contracts contain the following language:

Billing

> PBL shall bill Customer monthly, consistent with applicable BPA rates, including GRSPs and the provisions of this Agreement for Amounts Taken, payments pursuant to Section 5, and other services provided to Customer in the preceding month or months under this Agreement.

(*Id*.) Because the NFB Surcharge is not a charge for services provided, WPAG believes it is inconsistent with this contract provision. (*Id.*) Rather than being a charge for services provided, or to the unit charges assessed, it is a bill for the payment of a sum related to ESA costs. (*Id*.)

In its brief on exceptions, WPAG argues the Draft ROD misses the point of their argument. (WPAG Br. Ex., WP-07-M-81 at 16-17.) Even assuming the NFB Surcharge is a valid rate, the charges imposed on a customer under the applicable GRSPs must be for services rendered in the preceding month. (*Id*. at 17.) The NFB Surcharge does not currently impose a charge for services in the preceding month and is therefore inconsistent with the PSC. (*Id.*)

BPA's Position

This issue was raised for the first time on brief. WPAG's argument is a *non sequitur.* WPAG's assumes that the NFB Surcharge is a rate, and then attempts to argue the NFB Surcharge is inconsistent with BPA's power sales contracts. However, the billing provisions referred by WPAG specifically provides that a customer will be billed "consistent with applicable BPA rates, including GRSPs." Given WPAG's underlying assumption that the NFB Surcharge is a valid and applicable BPA rate, it is unreasonable to argue the NFB Surcharge is somehow inconsistent with the contract.

Evaluation of Positions

WPAG's argument is not well founded. As BPA notes, if you assume the NFB Surcharge is a valid rate, then it cannot be inconsistent with the billing provisions in the power sales contracts. The payment provisions specifically provide for monthly billing "consistent with applicable BPA rates." The NFB Surcharge therefore is consistent with these provisions of the PSCs.

WPAG contends that BPA can assess the NFB Surcharge only if it relates to "service provided to a customer in the preceding month or months…" WPAG believes BPA's use of an allocation methodology that uses the prior year's deliveries as the metric for assessing the NFB Surcharge means the charge does not relate to the service in the preceding month. WPAG's argument attempts to blur the distinction between the allocation methodology and charge for these particular costs. As explained above, the allocation methodology is merely the metric for spreading the cost among customers. It is not a revision of the rate for the prior year as alleged by WPAG. Instead, the expenses and revenue reduction associated with the NFB Surcharge are current costs that relate to the services provided in the proceeding months.

Part of the costs associated with the delivery of energy involves the costs associated with BPA's fish and wildlife obligations. Those costs include both the program expenses as well as the economic loss associated with restrictions in operations. BPA is obligated to recover or account these expenses or revenue reductions in rates. 16 U.S.C. § 839e(a)(1).

Traditionally, BPA forecasts its fish and wildlife costs and net secondary revenues and associated uncertainties and embeds those forecasts into base rates. However, BPA determined that it was virtually impossible to forecast changes to both fish and wildlife programs and hydro operations that may result from the pending BiOp litigation. As explained in the testimony of Normandeau, *et al*., WP-07-E-BPA-14 at 12-13, the difficulty predicting the outcome of pending litigation moved BPA to develop the NFB Adjustment and Surcharge. These risk mitigation tools allow BPA to demonstrate cost recovery without having to embed a forecast of these costs and related uncertainties into base rates. A consequence of addressing the costs through the NFB Surcharge means BPA can provide customers a base rate that is lower than would otherwise be the case. However, BPA's customers, purchasing power under the applicable rate schedules, are on notice that those base rates may be subject to an NFB surcharge.

Therefore, contrary to WPAG's argument, the NFB Surcharge is a charge that reflects the fish and wildlife costs associated with power deliveries in the "preceding month or months." When BPA triggers an NFB Surcharge, it is recovering those costs that BPA would traditionally embed in the rates for the power deliveries in those preceding months. The only distinction is that BPA collects these costs through the NFB Surcharge on an as needed basis rather than as part of base rates.

Decision

The NFB Surcharge does not conflict with BPA's power sales contracts.

17.4 DSI Service Issues

Issue

Whether it was an abuse of the Administrator's discretion to exclude evidence related to the cost of DSI service from the rate case.

Parties' Position

PNGC contends that it is an abuse of the Administrator's discretion to exclude from the rate case issues related to the inclusion of costs of DSI service benefits. (PNGC Br. Ex., WP-07-M-82 at 4.) PNGC argues that excluding these issues from the rate case deprives PNGC and others the opportunity to review evidence justifying the inclusion of those costs in rates and offer rebuttal evidence and legal argument. (*Id*.) PNGC believes that the Administrator is not authorized to "incorporate by reference" the decision in the DSI ROD, because that decision process did not include the procedural safeguards of the 7(i) process.

BPA's Position

BPA made the threshold decision to provide a capped amount of benefits ($59 million annually) to the DSIs in a public process outside of this rate case. (*See* Sections 2.5 and 13 for further discussion.) In the FRN, the Administrator excluded from this proceeding any evidence or argument that sought to revisit that decision. However, the Administrator did not exclude all issues regarding the level of DSI service from discussion in the rate case. The amount of DSI benefits provided could be less than the capped amount because the plants must operate in order to receive the benefit. (*See* Wagner, *et al*., WP-07-E-BPA-12 at 2-3.) Parties could provide evidence regarding the forecast level of benefits.

Evaluation of Positions

BPA made the threshold decision regarding the provision of benefits and the capped amount in a series of RODs. The decisions related to the provision of DSI benefits are explained in detail in Section 2.5 of this ROD. The Administrator excluded from consideration in this proceeding any evidence that sought to revisit the decisions made in those RODs. This was explained in BPA's FRN for this proceeding. The FRN stated:

> The DSI Service decision finalized and established the manner and method by which BPA would provide service and benefits to its DSI customers. The decisions in that ROD resolved the method and level of service to be provided DSIs in the FY 2007-2011 Period. Pursuant to § 1010.3(f) of BPA Hearing Procedures, the Administrator directs the Hearing Officer to exclude from the record any material attempted to be submitted or arguments attempted to be made in the hearing which seek to in any way revisit the appropriateness or reasonableness of BPA's decisions made in the DSI ROD.

70 Fed. Reg. 67,685, 67,689 (2005).

The Administrator did not exclude from the rate case issues related to the forecast amount of DSI service benefits. These involved the annual forecasted amount of benefits provided to the DSIs. Because the receipt of the benefits was contingent upon the DSI being operational, BPA made some assumptions regarding plant operations. (*See* Risk Analysis Study, WP-07-E-BPA-04 at 19.) These operational assumptions and the resulting benefit forecast were issues in the rate case and parties were free to provide evidence either rebutting or supporting the assumptions made.

PNGC appears to argue that it was an abuse of discretion to exclude from the rate case evidence related to the threshold issues decided in the series of RODs on this topic. (PNGC Br. Ex., WP-07-M-82 at 4.) PNGC argues that the Administrator cannot incorporate into the rate case the decision in the DSI RODs because the RODs did not contain the same procedural requirements of a Section 7(i) hearing. As a result, excluding the topic from the rate case violates Section 7(i)(2) because excluding this topic deprived them of the opportunity to review evidence justifying the inclusion of these costs in rates. (*Id.*)

PNGC's arguments have no merit. BPA has historically incorporated the decisions from public processes and the accompanying RODs into the rate case and expressly not revisited these decisions in a Section 7(i) hearing. In the 2002 rate case, for example, BPA expressly excluded from discussion the decision made in the Subscription Strategy ROD. The Subscription Strategy ROD provided important background and context for the rate proceeding because it determined the nature of the terms and contracts offered. Although BPA made decisions in the Subscription Strategy ROD "outside of the rate case" those were not rate decisions and did not require the protections of a Section 7(i) hearing. (*See* Section 18.2.1 of *2002 Final Power Rate Proposal Administrator's Record of Decision.)*

PNGC has not cited any statute or case that requires BPA to alter its procedural rules for the rate proceeding in favor of PNGC to allow the submittal of material that is otherwise inappropriate for setting rates.

Similarly, in the series of RODs on DSI service, BPA made decisions in the DSI RODs that were not rate decisions and therefore a Section 7(i) process was neither necessary nor appropriate. PNGC has a remedy if they believe the threshold decision to provide the DSIs benefits violates the Northwest Power Act. PNGC has already availed itself of this forum, by filing a challenge in the 9th Circuit on this matter. It would be a waste of administrative resources to revisit these issues in the rate case while there is a pending 9th Circuit challenge.

<u>Decision</u>

It is not an abuse of the Administrator's discretion to exclude evidence related to the propriety of DSI service from the rate case. The decision related to DSI service was made in a series of RODs outside of the rate case and it is a waste of administrative resources to revisit the issue in this proceeding, particularly given the pending challenge in the 9th Circuit.

18.0 PARTICIPANT COMMENTS

18.1 Introduction

This section summarizes and evaluates the comments of participants in BPA's 2007 rate proceeding. Participants are persons and organizations who comment on BPA's rate proposal by means of attendance at field hearings, correspondence, or phone calls but do not take part in the formal rate case hearings. Comments of participants are part of the official record of the rate proceeding and are considered when the Administrator makes his decisions set forth in this ROD.

Two comment periods are reviewed herein: the 2007 Wholesale Power Rate Case (WP-07) and the 2007 Power Rate Case Supplemental Proposal (WP-07 Supplemental).

The WP-07 comment period commenced after publication of the FRN on November 8, 2005 (70 Fed. Reg. 67685 (2005). The FRN announced the beginning of the 7(i) proceeding and summarized BPA's Initial Proposal. The FRN can be viewed at the BPA website:

www.bpa.gov/power/pfr/rates/ratecases/wp07/wp-07-fr-01.pdf

This written comment period ended on February 13, 2006. The participants' portion of the Official Record also consists of transcripts of six field hearings held in November and December of 2005 throughout the region where participants verbally presented comments. A total of nine letters and or comments were received, including two letters signed by a total of 19 members of the Northwest Congressional delegation, and another letter signed by three commissioners on the Clark Public Utilities Board, acting in their individual capacities and not as representatives of Clark Public Utilities. Comments can be viewed at the BPA website:

www.bpa.gov/corporate/public_affairs/Comment_Listings/wp-07_rate_case

The comment period for the WP-07 Supplemental commenced February 13, 2006, and closed March 6, 2006. Three comments were received. The WP-07 Supplemental modified BPA's Initial Proposal by addressing revenue issues resulting from a recent FERC decision on inside-the-band generation-supplied reactive power. Comments can be viewed at the BPA website:

www.bpa.gov/corporate/public_affairs/Comment_Listings/wp-07_rate_case_supplemental_proposal

BPA reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this section of the ROD. A tally and summary of the testimony provided at the field hearings and the letters and telephone calls that BPA received during both comment periods, along with discussions of those concerns, is provided below. While some letters have multiple signatories, each issue is tallied only once.

18.2 Evaluation of Participant Comments

The following three summaries indicate the total responses for each issue; many letters contained more than one comment. Overall, 23 comments were made in the letters and 26 comments were raised at the field hearings.

18.2.1 Table 1: General Rates Issues

General Rates Issues	Field Hearings Comments	Letters Comments
a. Oppose rate increase.	3	5
b. Cut costs.	2	3
c. Specific rate targets such as $27 per megawatt hour		2
d. Specific rate targets such as PF below $30 per megawatt hour	2	
e. We need high-paying family wage jobs; keep power costs low. Don't put people out of work.	2	2
f. Keep rates as low as possible consistent with multiple statutory obligations, including Treasury Payment.		2
g. Rates should not be lowered when money is needed for fish and renewables, especially when they are part of BPA's statutory obligations under laws such as the Endangered Species Act.	3	
h. Promote transparency. One request was for reports like line item budget information on agency program costs and various rate scenarios on these were requested.		2
i. Power should not be sold outside the Northwest when there are regional customers, such as the DSIs, that are willing to purchase at wholesale rates.		1
j. Do not shift costs from one customer to another because of highly variable loads. The demand rate design that favors utilities with flat loads isn't supportable.		1
k. Negative effects of the 2001 Western Energy Crisis		2

Discussion of Comments on General Rate Issues

Most participants commented on the level of BPA rates, stating they wanted rates kept low and expenses reduced. (*See* Table 1.) There was a call to lower rates from the current levels (which include CRACs) to $27/MWh. This figure was drawn from an earlier call by the Northwest Coalition for Affordable Power to its members to request the $27/MWh rate. There were other comments on transparency and more review of expenses. Much of this has been answered through the Power Function Review I and II processes that, while not part of the rate case, provided background information used in the revenue requirement. (*See* ROD, Section 4.) In addition, Section 2 contains a discussion on overall rate levels. For further information, see BPA web site: www.bpa.gov/power/pl/review/.

In setting the 2007 power rates, BPA has continued with its Subscription Strategy and developed risk management strategies using CRACs and liquidity tools to ensure an adequate proabability of paying BPA's obligations to the U.S. Treasury. BPA has complied with Federal requirements regarding fish and wildlife restoration (such as the 2004 FCRPS Biological Opinion) and conservation and renewable resource development. BPA believes this ROD has successfully balanced the requirements and concerns within the many and varied constraints that affect BPA. (*See* ROD, Section 2.)

How BPA does business is determined largely by its governing statutes, including the Regional Preference Act, P.L. 88-552, and the Northwest Power Act. For example, how BPA markets power to customer groups (utilities, DSIs, and others) is defined in Section 5 of the Northwest Power Act. How BPA sets its rates is defined in Section 7 of the Northwest Power Act. BPA also does business consistent with policies it sets itself, such as the Power Subscription Strategy. Such policies are developed with the help of extensive public involvement processes that allow BPA's customers, constituents, and others to state their opinions and present alternative analyses if they choose. The BPA Administrator makes decisions to establish policies and set rates only after considering all the comments in the official record of the proceeding.

Commenters also stated concerns with the health of the economy. BPA realizes the importance of keeping jobs in the region and using the relatively inexpensive output of the FCRPS to benefit the regional economy. BPA also is aware that the cost of electricity can be a large component of business expenses. There is discussion under way to assist the DSIs with power purchases during the FY 2007-2009 rate period, in particular, the request by them to have a PF-equivalent rate under $30/MWh, but these negotiations are not part of this rate case. (*See* ROD, Section 13.)

Some commenters stated that BPA should assure that FCRPS power is used to benefit the PNW region before selling the power outside the region. BPA does this as a matter of course to comply with the Regional Preference Act, P.L. 88-552, and the Subscription Strategy. The Subscription Strategy ROD states: "Sales to extra-regional entities are a possibility only if BPA does not subscribe all of its Federal power to PNW customers. Such sales are not the focus of the Subscription process, but BPA intends that any power remaining after all requests from regional loads are met will be offered to extra-regional public customers consistent with public preference and other customers under the applicable provisions of Northwest preference statutes." (Subscription Strategy ROD at 71.)

Several comments indicated their favor of a rate increase, in particular to increase spending for fish and wildlife mitigation, resource conservation, and renewable resources. As mentioned above, setting BPA's rates is a fine balancing act. BPA believes its final 2007 power rate proposal has successfully balanced the requirements and concerns within the many and varied constraints. Refer to Sections 2, 5, and 6 of this ROD for discussion of financial issues.

One customer stated that the Partial Resolution of Issues shifted costs to them because of the rate design change for the demand rate. Customers with load following, or highly variable loads, are more severely affected now than those with flat load. (*See* ROD, Section 8.) There were comments on the 2001 Western Energy crisis, but BPA sells wholesale power, pays its expenses as directed by its statutory authorities, and is not able to comment upon other businesses.

18.2.2 Table 2: Fish and Wildlife Issue

Fish and Wildlife	Field Hearings Comments	Letters Comments
a. We can have affordable electricity and fish	2	
b. Don't take money from fish and renewable programs to cave in to pressure to lower rates	3	
c. Fund scientifically supported actions that will actually recover healthy runs.	2	
d. People in the Northwest support spending more money to meet fish and wildlife costs.	2	
e. Many fish runs are not recovering.	1	
f. Protect and restore healthy fisheries.	1	
g. Cost of court-ordered spill is not significant when looking at total costs; set aside the foregone revenue argument	1	
h. Cutting funds violates federal laws like the Endangered Species Act.	1	
i. Fish recovery will provide jobs and income and secondary benefits to communities.	1	

Discussion of Comments to Fish and Wildlife Issues

Some commenters have expressed a request that BPA raise rates so it can spend more to support fish and wildlife programs and not lower rates whereby these programs are negatively affected. (*See* Table 2.) BPA is the region's leading funding entity for fish and wildlife mitigation and recovery programs and is aware of its statutory obligations under laws such as the Northwest Power Act and the Endangered Species Act. The cost of these programs are included in BPA's rates was addressed in the PFR, and the conclusions from these processes have been incorporated into this rate proposal. Furthermore, the issue of spending levels for these programs has been addressed in the PFRs and is outside the scope of the rate case. In addition, the proposed NFB Adjustment and NFB Surcharge are designed to recover the costs of additional fish and wildlife measures decided upon through litigation on the 2004 FCRPS Biological Opinion or its remand process after the close of the rate case. BPA's NORM modeling also included a range of risk around the proposed funding levels for fish and wildlife cost to address potential cost increases in addition to those addressed by the NFB Adjustment. BPA will manage fish and wildlife cost increases not covered by triggering the CRAC and the NFB Adjustment in the same manner as it will manage cost increases in other program areas—that is, by cutting costs in some or all of its programs, triggering a CRAC, or initiating new 7 (i) rate-setting process.

Commenters said that the fish program, and the science behind it, need to be analyzed to determine if there are alternatives. BPA's fish and wildlife programs do incorporate analysis of alternatives, monitoring, and efficacy, but these analyses and BPA's accountability are not at issue in this rate case. One commenter stated that fish recovery will provide jobs, income, and secondary benefits to communities.

18.2.3 Table 3: Supplemental Proposal

Supplemental Proposal on Generation Supplied Reactive Power (GSR) (Inside the Band)	Field Hearings Comments	Letters Comments
a. Protests BPA's proposal to deprive independent power producers (IPP) of compensation for GSR		1
b. BPA as a whole will not lose money as this is a simple cost shift between its two business lines, PBL and TBL.		1
c. Do not discourage IPPs as they play a major role in Northwest power development.		1

Discussion of Supplemental Proposal Comments

One commenter protested BPA's Supplemental Proposal (*see* Table 3) on the grounds that it is bad policy to try to deprive non-affiliate generators of compensation for GSR. The commenter also claimed that BPA is merely shifting GSR costs from transmission to power rates and that BPA has misinterpreted FERC decisions regarding compensation for GSR.

In this rate case, BPA is not depriving non-affiliate generators of compensation, it is forecasting revenues for GSR inputs from TBL. For FY 2008-2009, BPA is forecasting no revenues for inside-the-band GSR and this would allow TBL to file at FERC to extinguish the rates of certain non-affiliate generators. BPA's analysis shows that this would be the best outcome for regional rate payers. FERC has stated that generators do not need to be compensated for inside-the-band operations, as these operations can be a requirement of all generators in order to be interconnected to the grid reliably, and non-affiliate generators are only entitled to compensation for inside-the-band GSR if the transmission provider is compensating its own generators for this service. BPA's Supplemental Proposal is not a cost shift of GSR costs because these costs are generation costs and, under FERC precedent, it is left to the transmission provider's discretion whether to allocate some of these generation costs to inside the band GSR. (*See* ROD, Section 7.2.)

19.0 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 marketing of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and all other power-related 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, and to satisfy BPA's other ratemaking obligations. The Hearing Officer has assured me that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must evaluate its 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 rates 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 WP-07 final power rate proposal. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the attached Wholesale Power Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R. §300.10(g), the Administrator hereby certifies that the Wholesale Power 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 17th day of July 2006.

/s/ Stephen J. Wright
Administrator

ATTACHMENT 1

Partial Resolution of Issues
WP-07-E-BPA-31
WP-07-E-BPA-31(E1)

This page intentionally left blank.

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

Introduction of a Partial Resolution of Issues with Parties

March 2006

WP-07-E-BPA-31

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY OF

ELIZABETH EVANS, DIANE CHERRY, AND VALERIE LEFLER

Witnesses for Bonneville Power Administration

SUBJECT: INTRODUCTION OF A PARTIAL RESOLUTION OF ISSUES WITH PARTIES

Page

This page intentionally left blank.

REBUTTAL TESTIMONY OF

ELIZABETH EVANS, DIANE CHERRY, AND VALERIE LEFLER

Witnesses for Bonneville Power Administration

SUBJECT: INTRODUCTION OF A PARTIAL RESOLUTION OF ISSUES WITH PARTIES

Section 1. Introduction and Purpose of Testimony

Q. Would you state your names?

A. My name is Elizabeth Evans. My qualifications are contained in WP-07-Q-BPA-57.

A. My name is Diane Cherry. My qualifications are contained in WP-07-Q-BPA-56.

A. My name is Valerie Lefler. My qualifications are contained in WP-07-Q-BPA-29.

Q. Have you previously submitted testimony in this proceeding?

A. No, we have not previously submitted testimony in this proceeding as a panel.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to describe and document the results of several settlement discussions with rate case parties during the month of February that have resulted in a joint resolution of certain issues presented in BPA's Initial Proposal and the parties' direct cases. This testimony also has the purpose of recommending that the Administrator adopt the resolution of issues as presented in Appendix A.

Section 2. Description of Partial Resolution of Issues with Parties

Q. How many discussions has BPA held with the parties regarding settlement?

A. At the request of parties in the WP-07 rate proceeding, BPA and the parties held four publicly noticed settlement discussions. These discussions occurred on February 3, February 8, February 14, and February 22, 2006. The intention was to determine if all parties could come to agreement on a set of issues, thereby limiting the contested issues in this rate proceeding, as well as limiting the workload associated with the rest of the rate proceeding.

Q. What was the outcome of these discussions?

A. BPA and the parties were able to resolve a number of issues. Those resolutions are presented in Attachment A.

Q. Does Attachment A reflect the resolution of all the issues in this rate proceeding?

A. No. There are a number of other issues that remain unresolved that BPA and the parties will continue to litigate in this rate proceeding.

Q. What issues have BPA and the parties agreed to resolve?

A. BPA and the parties agreed on a resolution of some conditions to the FPS rate schedule, design of the Low Density Discount, treatment of revenue credits from Operating Reserves, PF rate design and a few Slice issues involving the treatment of particular costs. In addition, BPA and the parties reached agreement regarding the non-precedential nature of the treatment under section 7(b)(2) of the Mid-Columbia resources, conservation, uncontrollable events and secondary revenues counted as reserves. Attachment A describes in detail the resolution that BPA and the parties have reached regarding these issues. We, as members of BPA's negotiating team, support the resolution of the issues as set forth in Attachment A as a reasonable compromise to the different points of view presented in the discussions and we recommend that the Administrator adopt this resolution in the Record of Decision for this rate proceeding.

Q. Were other conditions established between BPA and the parties that are associated with the resolution of issues that are not set forth in Attachment A?

A. Yes. As part of this agreement BPA and the parties agreed that the WP-07-E-JP6-01 testimony and related exhibits filed by the investor-owned utilities would not be submitted into evidence. In addition, with regard to the issues included in the joint resolution, the parties agreed to five conditions. They agreed not to file rebuttal testimony, not to cross-examine witnesses, and not to raise these topics in briefs in this rate proceeding. In addition, they would not raise these issues with the Federal Energy Regulatory Commission or in any appeal to the Ninth Circuit Court of the rates established in this proceeding established consistent with this resolution.

BPA also explained during the settlement discussions that it intended to propose some changes to the NFB Adjustment in light of issues raised in some parties' direct cases. As part of the resolution of the issues in this proceeding, BPA and the parties agreed to allow the parties to offer sur-rebuttal testimony on any proposed changes to the NFB Adjustment. *See*, Lovell *et al.*, WP-07-E-BPA-34 for a description of the proposed changes to the NFB Adjustment.

Q.	*Does this conclude your testimony?*

A.	Yes.

This page intentionally left blank.

Attachment A
Partial Resolutions of Issues with Parties

The following represents the agreed upon terms which the BPA and the parties agreed not to file rebuttal testimony on, cross examine witness on, or address in their respective briefs:

1. 7(b)(2)

BPA will not, in any other proceeding, cite any action taken or not taken in this WP-07 proceeding as evidence of the propriety of (or precedent for) the resolution of any issue with respect to the treatment, under section 7(b)(2), of the Mid-Columbia resources, conservation, uncontrollable events or secondary revenues counted as reserves. To the extent that BPA has addressed and resolved in this WP-07 proceeding any such issues, such BPA actions shall not be considered by BPA to be precedential or binding on BPA in any other proceeding. No action taken or not taken in this WP-07 proceeding with respect to any such issues shall be considered by BPA to either create an adverse inference with respect to any such issues in, or preclude any party from arguing the treatment of any such issues in, any other proceeding (whether before BPA, FERC or a court and whether or not on remand) or in any remand of a rate developed in WP-07 by FERC or a court. BPA recognizes that, in reliance on this BPA approach, the prefiled testimony labeled WP-07-E-JP6-01, WP-07-E-JP6-03, and WP-07-E-JP6-04 were not proffered into evidence in this proceeding when they would otherwise have been proffered.

BPA staff has reviewed the testimony of the Preference Customer Group in WP-07-E-JP1-01 and WP-07-E-JP1-01(E1) section 5 regarding the $42 million §7(b)(2) trigger due to what they describe as a modeling error. The Preference Customer Group contends that on the issue presented in section 5 of that testimony, the mathematical end result produced for the amount recoverable from preference customers absent BPA's Subscription Step by the BPA approach and that advocated in the Preference Customer Group testimony is identical. Assuming this contention to be true, BPA concludes that it is not necessary to decide in this case whether the alleged modeling error in fact exists.

2. FPS Rate Schedule

BPA will agree to post, 30 days after the end of each calendar quarter, on its external web site, reports that contain the same information as contained in the Electric Quarterly Reports filed by utilities with the Federal Energy Regulatory Commission. BPA will begin filing these reports once the software platform has been developed and tested by BPA. BPA does not believe the software will be ready until FY 2008. BPA will make best efforts to have the software ready for posting by that time. BPA will advise parties about the schedule of the software development quarterly.

Section II of the General Rate Schedule Provisions will be modified to include following:

> **West-wide Price Cap of FPS Sales**
> BPA will voluntarily agree to limit the price of any sales under the FPS rate schedule to the applicable west-wide price cap, if any, established by the Federal Energy Regulatory Commission.

3. Low Density Discount (LDD)

For the FY 2007-2009 rate period BPA's General Rate Schedule Provisions (GRSPs) for the Low Density Discount (LDD) shall remain unchanged from BPA's 2002 GRSPs except for the following:

> Section II.L.2.c of the LDD Eligibility Criteria will be replaced with the following language:
>
> > the Purchaser's average retail rate for the reporting year must exceed BPA's average Priority Firm power rate for the most closely corresponding fiscal year by at least 25 percent.
>
> Section II.L. shall be amended to include the following language:
>
> > For Purchasers with Pre-Subscription power sales contracts who are converting to Subscription power sales contracts on October 1, 2006, the "existing discount" shall be calculated by BPA using BPA's 2002 GRSPs and calendar year 2004 data. This "existing discount" will only be used for determining the Purchaser's Phase-In Phase-Out Adjustment for the first year of the rate period. The Purchaser shall provide BPA with such calendar year 2004 data by October 1, 2006.

BPA shall propose, in its Initial Proposal in its next wholesale power rate case for the FY 2010-2011 rate period, GRSPs for the LDD that are not materially different from Sections 1 and 2 of BPA's FY 2007-2009 GRSPs. Customers' current methods of calculating "consumers" prior to or during the FY 2007-2009 and FY 2010-2011 rate period shall remain unchanged, unless both the customer and BPA agree otherwise. BPA shall continue to review LDD data submittals for accuracy.

BPA shall schedule meetings with the Pacific Northwest Generating Cooperative and other interested BPA customers to discuss and attempt to achieve mutual agreement on the proper application of the LDD to the Slice Product. These discussions shall be based on the principle that Slice customers will not be advantaged or disadvantaged in the implementation of the LDD compared to BPA's non-Slice customers receiving the LDD. These meetings shall be scheduled well before the preparation of BPA's initial proposal for its FY 2010-2011 wholesale power rate case. Any successful agreement on the resolution of the Slice LDD issue shall be included in BPA's Initial Proposal for its FY 2010-2011 wholesale power rate case.

4. Operating Reserves Credit

BPA's initial proposal contained an Operating Reserves Credit (ORC), which would have forecast zero revenues from operating reserves in the base rates as a revenue credit and provided a line item billing credit to firm power requirements customers that elected to purchase operating reserves from TBL rather than self or third party supply. BPA will establish a per unit cost for operating reserves provided to TBL of $5.63/KW-month, as opposed to the $6.96 /KW-month per unit cost in the initial proposal. For the final study BPA will apply the $5.63 /KW-month charge to the adjusted forecast of PBL's share of the control area reserves obligation provided by TBL. BPA will allocate the resulting revenues evenly across all firm power requirements rates. This revenue credit will not be dependent on the transmission customer's choice to buy operating reserves from TBL, self-supply, or third party supply.

5. Rate Design

a. Demand, Energy, and Load Variance

Table 1 hereto will be the template for the relationship of the monthly Heavy Load Hour, Light Load Hour, Demand and Load Variance rates for the PF-07 rate schedule. The rates in the PF-07 rate schedule will be as set forth in Table 1, adjusted proportionally (i.e., by an equal percentage applied to each rate) if necessary to recover the revenue requirement in total as determined in the final studies of the WP-07 wholesale power rate case when applied to the billing determinants in the final rate case studies.

b. Application of the CRAC, including the NFB Adjustment

With the exception of the NFB Adjustment, the CRAC surcharges and DDC dividends will be applied proportionately (i.e., by an equal percentage change for each rate) to the LLH and HLH energy and LV rates of the PF-07, IP-07, and NR-07 rate schedules. If a triggering event due to the NFB Adjustment (see WP-07-E-BPA-07 at 83-84) increases the total amount of revenue to be collected through the CRAC, BPA will recover the revenues in excess of the amounts recoverable from a CRAC without the NFB through an increase to all demand, energy, and LV rates proportionately (i.e., by an equal percentage) in the PF-07, IP-07, and NR-07 rate schedules.

6. Slice

a. Slice and revenues for reinvestment in BPA’s renewable resource facilitation and research and development

In BPA's initial proposal the Slice Revenue Requirement contained an expense associated with the reinvestment in BPA's renewable resource facilitation and research and development of what was referred to collectively as "Green Tag revenues." These revenues comes from three sources: 1) Green Energy Premium revenues resulting from sales of Renewable Energy Certificates (RECs), 2) Green Tag revenues resulting from sales of Environmentally Preferred Power (EPP), and 3) revenues from sales of Alternative Renewable Energy (ARE) to Pre-Subscription power purchasers. The Slice Revenue Requirement did not include a credit for these revenues. BPA will remove the expense associated with such revenues from Slice Revenue Requirement in BPA's final proposal. In addition, BPA will not include such reinvestment expenses in the Actual Slice Revenue Requirement in the Slice True-Up process. BPA will continue its current proposal and will not include credits in the Slice Revenue Requirement for any revenues from the three sources listed above.

b. Slice/Bad Debt

BPA's initial proposal contained testimony (including data responses) that described how Slice purchasers would pay for bad debt expense through the Actual Slice Revenue Requirement and Slice True-Up process. Under the initial proposal, all Power-related bad debt expense would be included in the Slice True-Up.

Bad debt expense is recognized on the income statement in the current accounting period when the determination is made that all or a portion of outstanding accounts receivable are in question. A reserve account is created for the amount BPA estimates will not be collectible, with the receivables remaining in the accounting records. BPA will identify accounts receivable associated with non-Preference customers that were estimated to be uncollectible, and result in bad debt expense. The Actual Slice Revenue Requirement will not include any bad debt expense associated with the sale of energy to any customer that exclusively purchases under the FPS-07 rate schedule. However, any bad debt expense associated with the sale of energy under both the PF-07 and FPS-07 or just the PF-07 rate schedules will be included in the Actual Slice Revenue Requirement for Slice True-Up purposes.

c. Slice Product Costing and True-Up Table

The Slice Product Costing and True-Up Table will be reformatted to be consistent with the table entitled, "Power Business Line Program Spending Levels" (*see,* Table 3A in WP-07-E-BPA-02A, at 44-46). Table 2 contains a prototype of a reformatted Slice Product Costing and True-Up Table. This table will be included in BPA's rebuttal testimony, as well as BPA's final proposal. The reformatted Slice Product Costing and True-Up Table will contain the following differences from the Power Business Line Program Spending Level table:

i. The Slice Product Costing and True-Up Table will include a Revenue Credits section that contains estimates of revenue credits that are applicable to the Slice Revenue Requirement;

ii. The Slice Product Costing and True-Up Table will include estimates of costs associated with programs (such as the Irrigation Rate Mitigation Program and the Low Density Discount program) whose costs are paid for in the base rates of Slice and non-Slice customers;

iii. The Slice Product Costing and True-Up Table will contain an "Augmentation Cost" box, in which the Net Cost of Augmentation is calculated. These costs will not be subject to the Slice True-Up process, but relevant updates, if any, will be made for BPA's final proposal;

iv. The Slice Product Costing and True-Up Table will contain a Minimum Required Net Revenue (MRNR) calculation so that the individual components within the calculation of MRNR can be trued-up in the annual Slice True-Up process;

v. The Slice Product Costing and True-Up Table will include values for Depreciation, Amortization, and Net Interest Expense;

vi. The Slice Product Costing and True-Up Table may have lower or no values in some expense line items, if those expense line items have been excluded from the Slice Revenue Requirement as per the Slice Rate Methodology (such exclusions include but are not limited to Hedging/Mitigation expenses but for those associated with augmentation, other power purchases, augmentation purchases, expenses associated with reinvested "Green Tag revenues" referenced above, bad debt expense associated with FPS sales to non-preference customers, etc.);

vii. The Slice Product Costing and True-Up Table will include estimates of Canadian Entitlement Agreement Transmission expenses and PNCA & NTS Transmission and System Obligation Expenses, even though PBL-Transmission & Ancillary Services expenses in general are excluded as per the Slice Rate Methodology. The Canadian Entitlement Agreement Transmission expenses and PNCA & NTS Transmission and System Obligation Expenses are included in the Slice Revenue Requirement because they are associated with BPA's system obligations and Slice customers must pay their share of these expenses as per the Slice Rate Methodology.

BPA will include estimates of expenses and revenue credits in the Slice Product Costing and True-Up Table that are exactly equal to values in the Cost of Service Analysis (COSA) tables used as the basis for calculating the PF rate, the Power Business Line Spending Level table, and the Generation Revenue Requirement table for those expenses and revenue credits that should be the same for Slice and non-Slice customers. However, there will be differences for those expenses and revenue credits that are treated differently for the Slice Revenue Requirement. Treatment of the expenses and revenue credits for the Slice Revenue Requirement is contained in the Slice Rate Methodology; the WP-07 initial proposal, and rebuttal testimony, and associated documents; and any settlement agreements that pertain to the Slice product.

If, during the FY 2007-2009 rate period, PBL alters the format of the financial information provided on a regular basis to the Public Power Council, as captured currently in Table 3A in WP-07-E-BPA-02A at 44-46, PBL will meet with Slice customers to develop a crosswalk of such reformatted financial information with the Slice Product Costing and True-Up Table.

Table 1

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Averages
Calculation of PF Preference Rate Components													
Test Period October 2006 - September 2009													
Initial Proposal Demand Charges	$ 1.17	$ 1.25	$ 1.31	$ 1.11	$ 1.13	$ 1.05	$ 0.99	$ 0.82	$ 0.75	$ 0.92	$ 1.08	$ 1.11	1.06
Demand at $2 average													
Shaped per Initial Proposal	$ 2.21	$ 2.36	$ 2.48	$ 2.10	$ 2.14	$ 1.99	$ 1.87	$ 1.55	$ 1.42	$ 1.74	$ 2.04	$ 2.10	2.00
Incr. Demand Revenues ('000)	$ 19,443	$ 22,664	$ 25,639	$ 22,691	$ 22,456	$ 18,839	$ 15,923	$ 11,969	$ 10,557	$ 13,528	$ 15,814	$ 16,164	
Total Demand Revenues	$ 41,258	$ 48,093	$ 54,406	$ 48,151	$ 47,652	$ 39,976	$ 33,788	$ 25,398	$ 22,403	$ 28,708	$ 33,558	$ 34,300	
PF billing determinants (GWHs)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	
HLH	6,625	7,074	8,129	8,322	7,428	7,469	6,647	5,966	5,497	5,663	5,939	6,149	
LLH	4,327	5,088	5,851	5,841	5,081	5,093	4,399	4,257	3,695	3,907	3,919	4,274	
Demand	18,646	20,343	21,960	22,937	22,297	20,131	18,046	16,377	15,794	16,499	16,430	16,339	
Proposed PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	
HLH	$ 33.77	$ 36.02	$ 37.59	$ 31.91	$ 32.59	$ 30.23	$ 28.37	$ 23.70	$ 21.45	$ 26.42	$ 30.94	$ 31.94	
LLH	$ 29.23	$ 30.72	$ 31.96	$ 26.97	$ 27.73	$ 25.86	$ 24.01	$ 19.19	$ 14.25	$ 22.80	$ 26.99	$ 29.41	
Demand	$ 1.17	$ 1.25	$ 1.31	$ 1.11	$ 1.13	$ 1.05	$ 0.99	$ 0.82	$ 0.75	$ 0.92	$ 1.08	$ 1.11	
Load Variance	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	$ 0.53	
Revenues at Proposed Rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 223,720	$ 254,794	$ 305,573	$ 265,558	$ 242,086	$ 225,781	$ 188,573	$ 141,404	$ 117,905	$ 149,626	$ 183,742	$ 196,410	$ 2,495,172
LLH	$ 126,464	$ 156,310	$ 187,009	$ 157,519	$ 140,900	$ 131,708	$ 105,623	$ 81,685	$ 52,648	$ 89,079	$ 105,770	$ 125,709	$ 1,460,422
Demand	$ 21,815	$ 25,429	$ 28,767	$ 25,460	$ 25,196	$ 21,137	$ 17,866	$ 13,429	$ 11,846	$ 15,179	$ 17,744	$ 18,136	$ 242,004
												LV Revenue	$ 52,592
													$ 4,250,191
Revised LLH Revenues	$ 107,021	$ 133,646	$ 161,370	$ 134,828	$ 118,444	$ 112,869	$ 89,700	$ 69,716	$ 42,091	$ 75,550	$ 89,955	$ 109,545	
Revised LLH Charges	24.74	26.27	27.58	23.08	23.31	22.16	20.39	16.38	11.39	19.34	22.95	25.63	
Compromise Charges	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	
HLH	**33.77**	**36.02**	**37.59**	**31.91**	**32.59**	**30.23**	**28.37**	**23.70**	**21.45**	**26.42**	**30.94**	**31.94**	
LLH	**24.74**	**26.27**	**27.58**	**23.08**	**23.31**	**22.16**	**20.39**	**16.38**	**11.39**	**19.34**	**22.95**	**25.63**	
Demand	**2.21**	**2.36**	**2.48**	**2.10**	**2.14**	**1.99**	**1.87**	**1.55**	**1.42**	**1.74**	**2.04**	**2.10**	
Load Variance	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	**0.53**	
Revenue Check													Totals
HLH	$ 223,720	$ 254,794	$ 305,573	$ 265,558	$ 242,086	$ 225,781	$ 188,573	$ 141,404	$ 117,905	$ 149,626	$ 183,742	$ 196,410	$ 2,495,172
LLH	$ 107,021	$ 133,646	$ 161,370	$ 134,828	$ 118,444	$ 112,869	$ 89,700	$ 69,716	$ 42,091	$ 75,550	$ 89,955	$ 109,545	$ 1,244,736
Demand	$ 41,258	$ 48,093	$ 54,406	$ 48,151	$ 47,652	$ 39,976	$ 33,788	$ 25,398	$ 22,403	$ 28,708	$ 33,558	$ 34,300	$ 457,691
												LV Revenue	$ 52,592
													$ 4,250,191

Table 2

	SLICE PRODUCT COSTING AND TRUE-UP TABLE ($000s)	Audited Actual Data	FY 2007 forecast		FY 2008 forecast		FY 2009 forecast
1	**Operating Expenses**						
2	**Power System Generation Resources**						
3	**Operating Generation**						
4	COLUMBIA GENERATING STATION (WNP-2)						
5	BUREAU OF RECLAMATION						
6	CORPS OF ENGINEERS						
7	LONG-TERM CONTRACT GENERATING PROJECTS						
8	**Sub-Total**						
9	**Operating Generation Settlement Payment**						
10	COLVILLE GENERATION SETTLEMENT						
11	SPOKANE GENERATION SETTLEMENT						
12	**Sub-Total**						
13	**Non-Operating Generation**						
14	TROJAN DECOMISSIONING						
15	WNP-1&3 DECOMISSIONING						
16	**Sub-Total**						
17	**Contracted Power Purchases**						
18	PNCA HEADWATER BENEFIT						
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)						
20	OTHER POWER PURCHASES (short term - omit)						
21	**Sub-Total**						
22	**Augmentation Power Purchases**						
23	AUGMENTATION POWER PURCHASES (omit - calculated below)						
24	CONSERVATION AUGMENTATION (omit)						
25	**Residential Exchange/IOU Settlement Benefits**						
26	**Renewable Generation**						
27	**Generation Conservation**						
28	LOW INCOME WEATHERIZATION & TRIBAL						
29	ENERGY EFFICIENCY DEVELOPMENT						
30	ENERGY WEB						
31	**LEGACY (Until 11/1/03 this was included with line 72)**						
32	MARKET TRANSFORMATION						
33	TECHNOLOGY LEADERSHIP						
34	INFRASTRUCTURE SUPPORT AND EVALUATION						
35	BI-LATERAL CONTRACT ACTIVITY						
36	**Sub-Total**						
37	CONSERVATION RATE CREDIT						
38	**Power System Generation Sub-Total**						
39							
40	**PBL Transmission Acquisition and Ancillary Services**						
41	**PBL Transmission Acquisition and Ancillary Services**						
42	PBL - TRANSMISSION & ANCILLARY SERVICES						
42a	Canadian Entitlement Agreement Transmission Expenses						
42b	PNCA & NTS Transmission and System Obligaton Expenses						
43	3RD PARTY GTA WHEELING						
44	PBL - 3RD PARTY TRANS & ANCILLARY SVCS						
45	RESERVE & OTHER SERVICES						
46	TELEMETERING/EQUIP REPLACEMT						
47	**PBL Trans Acquisition and Ancillary Services Sub-Total**						
48							
49	**Power Non-Generation Operations**						
50	**PBL System Operations**						
51	EFFICIENCIES PROGRAM (omit TMS expenses)						
52	INFORMATION TECHNOLOGY						
53	GENERATION PROJECT COORDINATION						
54	SLICE IMPLEMENTATION (omit - calculated separately)						
55	**Sub-Total**						
56	**PBL Scheduling**						
57	OPERATIONS SCHEDULING						
58	OPERATIONS PLANNING						
59	**Sub-Total**						
60	**PBL Marketing and Business Support**						
61	SALES & SUPPORT						
61a	Contractual exclusion						
62	PUBLIC COMMUNICATION & TRIBAL LIAISON						
63	STRATEGY, FINANCE & RISK MGMT						
64	EXECUTIVE AND ADMINISTRATIVE SERVICES						
65	CONSERVATION SUPPORT (EE staff costs)						
66	**Sub-Total**						
67	**Power Non-Generation Operations Sub-Total**						
68							
69	**Fish and Wildlife/USF&W/Planning Council**						
70	**BPA Fish and Wildlife (includes F&W Shared Services)**						
71	FISH & WILDLIFE						
72	F&W HIGH PRIORITY ACTION PROJECTS						
73	**Sub-Total**						
74	**PBL-USF&W Lower Snake Hatcheries**						

Table 2

82	**General and Administrative/Shared Services**	
83	**CSRS**	
84	CIVIL SERVICE RETIREMENT SYSTEM	
85	**Corporate Support - G&A (excludes direct project support)**	
86	CORPORATE G&A	
87	**Corporate Support - Shared Services (excluded direct project support)**	
88	SHARED SERVICES	
89	**Sub-Total Corporate Support Services**	
90	**TBL Supply Chain - Shared Services**	
91	**General and Administrative/Shared Services Sub-Total**	
92		
93	**Bad Debt Expense**	
94	**Other Income, Expenses, Adjustments**	
95	**Non-Federal Debt Service**	
96	**Energy Northwest Debt Service**	
97	COLUMBIA GENERATING STATION DEBT SVC	
98	WNP-1 DEBT SVC	
99	WNP-3 DEBT SVC	
100	EN RETIRED DEBT	
101	EN LIBOR INTEREST RATE SWAP	
102	**Sub-Total**	
103	**Non-Energy Northwest Debt Service**	
104	TROJAN DEBT SVC	
105	CONSERVATION DEBT SVC	
106	COWLITZ FALLS DEBT SVC	
107	WASCO DEBT SVC	
108	**Sub-Total**	
109	**Non-Federal Debt Service Sub-Total**	
110		
111		
112	**Total Operating Expenses**	
113		
114	**Other Expenses**	
115	Depreciation (excl. TMS)	
116	Amortization (excl. ConAug amortiz.)	
117	Net Interest Expense	
118	LDD	
119	Irrigation Rate Mitigation Costs	
120	**Sub-Total**	
121	**Total Expenses**	
122		
123	**Revenue Credits**	
124	Ancillary and Reserve Service Revs. Total	
125	COE & USBR Project Revenues	
126	4(h)(10)(c)	
127	Colville Credit	
128	FCCF	
129	Sup/Ent Cap; Irr. Pump	
130	Energy Efficiency Revenues	
131	Property Trnfrs & Misc.	
132	**Total Revenue Credits**	
133		
134	**Augmentation Costs**	
135	**IOU Reduction of Risk Discount (includes interest)**	
136	**Costs in this box are not subject to True-Up**	
137	**Forecasted Gross Augmentation Costs**	
138	(Gross power purchase cost)	
139	Minus revenues	
140	**Net Cost of Augmentation**	
141		
142		
143	**Minimum Required Net Revenue calculation**	
144	Principal Payment of Fed Debt for Power	
145	Irrigation assistance	
146	Depreciation	
147	Amortization	
148	Capitalization Adjustment	
149	Bond Premium Amortization	
150	Principal Payment of Fed Debt exceeds non cash expenses	
151	Minimum Required Net Revenues	
152		
153	SLICE TRUE-UP ADJUSTMENT CALCULATION	**3-Year Total Slice Rev. Reqt.**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**$ -**
155	TRUE UP AMOUNT (Diff. between actuals and forecast)	
156	AMOUNT BILLED (22.6278 percent)	
157	Slice Implementation Expenses (not incl. in base rate)	
158	TRUE UP ADJUSTMENT	
159		
160		
161	**SLICE RATE CALCULATION ($)**	
162	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**	**$ -**
163	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**	**$ -**
164		
165	**ANNUAL BASE SLICE REVENUES**	**$ -**
166	**Annual Slice Implementation Expenses**	**$**
167	**TOTAL ANNUAL SLICE REVENUES**	**$**

Errata No. 1 to
2007 Initial Power Rate Proposal
Rebuttal Testimony,
Introduction of a Partial Resolution of Issues with Parties
WP-07-E-BPA-31 (E1)

Page 2, Lines 10 through 20 should be deleted in entirety and the following should be inserted in its place:

A. BPA and the parties agreed to support, or not to oppose, the resolution of some conditions to the FPS rate schedule, design of the Low Density Discount, treatment of revenue credits from Operating Reserves, PF rate design and a few Slice issues involving the treatment of particular costs. In addition, BPA and the parties have agreed to support, or not to appose, the non-precedential nature of the treatment under section 7(b)(2) of the Mid-Columbia resources, conservation, uncontrollable events and secondary revenues counted as reserves. Attachment A describes in detail the resolution regarding these issues. We, as members of BPA's negotiating team, support the resolution of the issues as set forth in Attachment A as a reasonable compromise to the different points of view presented in the discussions and we recommend that the Administrator adopt this resolution in the Record of Decision for this rate proceeding.

This page intentionally left blank.