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 Supplemental Wholesale Power Rate Case

ADMINISTRATOR'S FINAL RECORD OF DECISION

September 2008

WP-07-A-05

BONNEVILLE
POWER ADMINISTRATION

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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
ASCM	Average System Cost Methodology
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
COU	Consumer Owned Utility
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

IPUC	Idaho Public Utility Commission
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,

[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.

	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
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
LRA	Load Reduction Agreement
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
MMBtu	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
NWEC	Northwest Energy Coalition
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
PS	Power Services (formerly Power Business Line)
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
RD	Regional Dialogue
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
TS	Transmission Services (formerly Transmission Business Line)
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

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STATEMENT OF THE ADMINISTRATOR

Of the three BPA power rate cases I have had the responsibility for deciding, all have been contentious, but this has been by far the most difficult. This case involves the usual array of complex issues associated with projected revenues, rate design, and rate levels one would expect to see in a rate case. But this case also includes the unprecedented challenge of responding to a remand from the Ninth Circuit Court of Appeals. Particularly vexing and of substantial economic importance are the issues associated with the Residential Exchange Program (REP). These issues, in turn, have magnified the intensity of regional parties' focus and debate on section 7(b)(2) of the Northwest Power Act, a Byzantine sentence that nearly fills a page and that is, in my view, the most complicated section in the Act. As a result, BPA has had to address a plethora of issues, some of which have had a long history yet needed to be revisited because of the Court's decisions, and others that are entirely new.

Shortly after the issuance of the Court's decisions in May 2007, it was clear there would be a contentious discussion regarding the REP, which involves literally billions of dollars. This discussion would address, in part, issues with which we have become familiar and, in part, issues that would delve into a realm we have not witnessed before. From the beginning, we have taken this mission extremely seriously, devoting talented staff on a more than full-time basis and substantial management attention to ensure all of the issues raised are treated respectfully and thoughtfully.

We have come a long way since the Ninth Circuit released its decisions a little more than a year ago. We have had many discussions, both formal and informal, regarding how to properly respond to those decisions and respect the will of the Court. We have participated in public meetings, provided opportunities for public comment, and conducted this formal evidentiary rate case. Throughout these discussions, I and other BPA representatives stated that the agency's decisions must be based on the law. At the same time, I have stated that where the law offers me choices, my choices will be strongly influenced by the will of the region because, at its core, this is about allocating the value of the Federal system among regional consumers. We feel particularly strongly about following the law in this proceeding because it is important that the agency's decision be affirmed. The current exercise has seriously strained the resources of both BPA and the parties since the Court's decisions were issued and is diverting important human resources from other pressing challenges. In short, we would not want BPA, customers, and constituents to go through this divisive and time-consuming effort again.

Recognizing the challenges associated with conducting and deciding this case, we have actively encouraged the stakeholders to settle all or parts of the case. We encouraged settlement before this case and, consistent with *ex parte* rules, during this case. In fact, there was an extraordinary effort by regional parties to accomplish just this end. Last year a group of investor- and consumer-owned utility representatives, representing the vast majority of regional utilities, engaged in an intensive effort to find common ground. BPA facilitated some of these discussions in the hope that finding common ground would reduce the number and complexity of the issues that would need to be addressed in this case. Ultimately, the parties to that discussion, although not representing all the parties to this case, were able to reach agreement on a set of recommendations for a financial "landing zone" they believed would be equitable as a long-term solution addressing both the remand remedy and prospective REP benefits. The parties were Seattle City Light, PNGC Power, Public Power Council, Benton PUD, Lane Electric Cooperative, Northwest Requirements Utilities, Western Montana G&T, Idaho Power Company, Tacoma Public Utilities, Puget Sound Energy, Eugene Water and Electric Board, Northwestern Energy, Snohomish County PUD, Portland General Electric, Western Public Agencies Group, Avista Utilities, and Pacific Power. The parties reached these recommendations at a point where little time remained for initiation of this rate case and, therefore, little time remained for the parties to explore how the recommendations might be implemented consistent with law.

Although we were extremely pleased the parties could reach agreement on conceptual recommendations, the recommendations did not readily translate into BPA's rate development. Due to our position that our decisions must comport with the law, the very point of the Court's decisions, certain key elements of the recommendations from the investor- and consumer-owned utility representatives created challenges that BPA Staff and the parties have not been able to resolve. Key among these was defining a legal basis to provide long-term certainty regarding the level of REP payments.

I have explained our approach to this case repeatedly, including in a publicly noticed meeting as part of this proceeding that was designed to encourage the parties to make further movement toward settlement. In that meeting I said:

> When considering the issues raised in this proceeding, I will start from what the law requires. The Ninth Circuit decisions have created a period of great upheaval, uncertainty for all regional electric utilities, and a source of at least some regional discord. I do not want our legacy to be that BPA made decisions that led the Court to remand this case for a second time and put the region through this again. I am committed to developing a solution that is based on the statutes and the guidance provided by the Court, while keeping our Treasury payment probability high.
>
> But as all of you know, these issues are extremely complex, the statute can be vague on matters of substantial financial consequence, and there are many issues the Court has not addressed. As a result, there are a number of areas where I have discretion how to resolve issues. Some issues can swing the level of benefits by hundreds of millions and possibly billions of dollars. In making my decisions, I must consider the entire rate case record. When I consider the issues raised in this proceeding, I will, when the discretion afforded me allows it, give greater weight to proposals that reflect agreement in the region when it exists.[2]

BPA's General Counsel provided guidance to me and BPA Staff on this issue prior to the initiation of the rate case. He emphasized that the law comes first but, where discretion allows, we will seek to work with regional parties' compromise positions:

[2] May 14, 2008, Administrator's Statement, offered in aid of settlement.

First, while we have urged the public utility and investor-owned utility negotiators to reach agreement on what is to them an acceptable level of residential exchange benefits, we have been clear that (a) BPA is not and cannot be a party to their deal, (b) if and once they bring us their deal (and it is "their" deal), their agreement will be an important consideration to us, but there are no guarantees, and the deal will need to be tested and reconciled with decisions that we must make, and (c) the issues are extremely complex and we must hear from other stakeholders that have not participated in the discussions that led to the conceptual agreement.

Second, let me be clearer as to the meaning of "their agreement will be an important consideration to us, but there are no guarantees, and the deal will need to be tested and reconciled with decisions that we must make." The fact of the matter is that there are a number of issues associated with developing the ASC Methodology and implementing section 7(b)(2) where the Administrator has choices. We are still exploring what those choices are. The Administrator has choices because the law affords them to him, either by not being prescriptive, by being general, or by being ambiguous. Rarely is the Administrator's discretion unbounded, so "choice" is a matter of what the reasonable alternatives are. And, yes, sometimes some choices are or may seem better than others, but they are still choices. What that means is that the Administrator has a range of choices – of discretion – afforded by the law, and that his choice of alternatives will be upheld by the court, assuming the court views the range of choices the same way we do as being within the law.

Having choices does not mean that the Administrator can abdicate his decision-making authority to customers. Under law, the decisions are his, not theirs. [The Administrator] knows that and has been unequivocal that the decisions are his to make. But, the Administrator does have a responsibility to implement the Northwest Power Act in a sound and businesslike manner, and to actively encourage and solicit public comment on many issues, such as those involved here. Clearly, in any business setting, what customers think is or should be important to the Administrator. So, here, when the customers who are either receiving the benefits or footing the bill say that they agree upon something, that should be and is an important consideration to the Administrator. But, the customers are not Congress, so the questions ultimately remain whether existing law affords the Administrator a range of discretion sufficient to accommodate what the customers want and, if so, if that is the direction he chooses after hearing from all sides.[3]

[3] General Counsel's guidance to BPA Staff for this proceeding.

On May 14, 2008, I went on to say that:

> Ideally, the decision in this case will result in a fair distribution of the benefits of the FCRPS, based on the law, and where discretion exists, in consideration of the parties' joint recommendations, because the parties are well positioned to identify where that equity lies. As stated repeatedly, BPA is prepared to respect compromises that can be generated across customer and other groups where such compromises are consistent with the law.[4]

We would have preferred that the parties had more time and were more successful at determining how to implement their recommendations and advance a settlement that could have then been reflected in the record. Lacking that, I asked at oral argument if the parties that endorsed the November recommendations continued to believe they are a fair foundation for settlement, and I heard there continued to be broad support among the signatories for that approach, although not all signatories were in the room when I asked the question. The November recommendations are in the rate case record. Consequently, as I have evaluated the issues and the choices afforded me by the law, I have kept in mind the recommendations of the IOU and COU representatives as to the amount of payments they believed to be fair, tempered by the realization that there are key elements of those recommendations, including the provision of long-term certainty, that are not applicable to the time horizon of this case and therefore would impact the parties' views as to fairness. The recommendations have helped provide a rudimentary compass that I recognize is both vague and not dispositive and that can only be referenced when there are issues that leave discretion to the Administrator.

Due possibly to the lack of time and to BPA Counsel and Staff's conclusion that BPA could not translate the customer recommendations as a whole into Staff's initial proposal, many of the same parties to that negotiation arrived at this rate case in the traditional mode of presenting arguments that would maximize benefits for their consumers. This rate proceeding is replete with "definitive" conclusions from various parties about the compelling nature of their arguments, but even more so, how compelling the Court will find them. I have paid great attention to the parties' briefs and arguments, and after reading, listening, and thinking through these points, it becomes clear that many of these issues rest on a debate between a literalist view and an interpretative view of the language contained in the Northwest Power Act. The literalist view speaks to the plain meaning of language, or at least what the party portrays as the plain meaning. Yet, as noted in this Record of Decision, there are times where the literalist view leads to illogical or absurd conclusions either with respect to the world as it existed at the time of enactment of the Northwest Power Act and/or in the world as it exists today. The interpretative view speaks to the intent of the language, which at some points goes beyond what appears from the literal statutory language.

[4] May 14, 2008, Administrator's Statement.

The briefs in this case do not, in general, adhere strictly to one or the other of these philosophies. My own impression, as someone not trained in the law, is that it is extremely difficult in good conscience to adopt either one or the other of these philosophies in total and render fair decisions. In fact, we have spent countless hours reviewing statutes, underlying legislative history, and the briefs, discussing the meaning of specific words and the intent of Congress. I have struggled to be sure that the choices presented to me truly were choices available under the law. Often this discussion has concluded with hypothesizing about the reaction of the Ninth Circuit to the decisions we are contemplating. More often than not we have struggled with uncertainty resulting from the fact that many of these decisions represent very close calls where a reasonable case can be made for various points of view based on the law.

In fact, at some points in our discussion we concluded that the Court, in reviewing a particular decision that has multiple (sometimes more than two) lawful options, could or should sustain any of the options. If there are more than two lawful options, this translates into a less than 50 percent probability that BPA would choose the same option as any other knowledgeable, objective observer. The alternative proposed treatments for conservation resources in the section 7(b)(2) rate test are a good example.

There are vexing issues that result from the remand; in particular, attempting to put the parties in the position they would have been in had the agency's error not been made. We have spent thousands of staff hours wrestling with these issues. For example, we have concluded, despite the reservations of some parties to this case, that because the Court found the original REP Settlement Agreements invalid, it is necessary for us to construct a case that describes what would have happened in the absence of the Agreements, knowing only what we knew at that time. We base this conclusion on our knowledge that, in fact, the existence of the Settlement Agreements altered the agency's (and in particular my) thoughts and behavior in terms of thoroughly considering non-settlement alternatives in the 2001 rate case that I was responsible for deciding. Recreating 2001 without the settlements involves a multitude of judgments as to what actions the agency would have taken in a world that was in the midst of radical upheaval as a result of the West Coast energy crisis, drought, and the associated direct and indirect effects of these prevailing conditions. I have found this to be a particularly difficult exercise as it requires substantial judgments about a hypothetical world, with the consequences of the decisions being that huge sums of money are, when all is said and done, transferred between consumers – residential, commercial, and industrial – of utilities throughout the Northwest. This is not about profits or losses; it is about how the region's consumers share the benefits of the Federal hydrosystem.

There are some decisions in this ROD that amend previous policies. These policies, including the Section 7(b)(2) Methodology and Legal Interpretation, have not undergone such a thorough internal or external review at any point since their initial implementation in the early 1980s, and probably ever. Ironically, this is in large part because rate case and REP settlements, including those with almost all exchanging preference customers, have allowed these issues to be deferred. Given the financial magnitude of what is at stake in this case, and particularly because some of these decisions impact financial benefit levels stretching across an eight-year period (whereas in other cases the benefits being addressed were focused on the shorter term of the rate period), many of the individual decisions embedded in this case represent extraordinarily large sums of money. Therefore, we attempted to assure ourselves we had made every effort to explore every aspect of these issues, which includes reviewing the underlying foundation of the original policies adopted by the agency to test for consistency with the law, reasonableness, and to ensure that all concerns identified by parties were given fair consideration. We have revisited existing BPA policies both as a result of performing our own due diligence and in response to the exhortations of the parties. There are some issues in this proceeding where decisions have reconsidered and amended longstanding BPA policy to correct legal errors, such as the treatment of mid-Columbia resources in the section 7(b)(2) rate test, and, surprisingly, others that require new policy based on issues presented for the first time, such as the appropriate implementation of the cost allocation under section 7(b)(3). These changes occurred only after lengthy discussion of the statutory construct and consideration of the value of maintaining existing precedent. We concluded in these instances that a strict reading of the law leads us to make the changes. A good example of the complexity of attempting to define what the law requires is provided by a decision regarding section 7(b)(3). We describe in this ROD the inherent conflict between the specific words of the Northwest Power Act, past BPA practice by default, and parties' arguments over language from the *PGE*, *Golden NW*, and *Snohomish* decisions.

I would also note that the provisions of the Northwest Power Act are intertwined in ways that are frequently difficult to reconcile. Throughout our deliberations for this proceeding, we would review proposals from the parties only to find that there were interconnections to other issues that produced outcomes we suspect the proposing parties did not realize. I would caution all observers of this Record of Decision to be aware that alternative solutions they propose have a good chance of leading to unintended consequences.

Because this case has been such a struggle, we recognize that reasonable minds can differ on the best way to resolve many of the issues in this case. We do not intend to suggest there is only one correct way to resolve these issues. At the same time we must make decisions, explain them, and be prepared to defend them. Consequently, we have chosen in this Record of Decision to clearly and thoroughly lay out competing arguments, identify the strengths and weaknesses of these arguments, and lead open-minded readers to understand and hopefully appreciate the close and difficult nature of the decisions. In doing so we hope the readers will come to understand that although they may disagree with particular decisions, none were reached without significant contemplation and a sincere attempt to understand and apply what the law requires, and to exercise administrative discretion only where it could and should be applied.

During oral argument, many of the presenters went out of their way to acknowledge the extraordinary dedication of the BPA Staff as displayed by their responsiveness to questions and willingness to ensure the parties had the information necessary to make well-informed decisions. I want to add my compliments as well for more than a year of superb and dedicated public service despite extremely long hours that have been mentally taxing, highly stressful, and have taken a toll on people's personal lives.

This has been a very difficult undertaking, fraught with complexity and with large financial stakes. I believe we have done the best we could do to find a legally sustainable and politically equitable solution (in that order) to the challenge provided by the Ninth Circuit. Nevertheless, I would suggest there remains considerable uncertainty for the parties as to how REP issues may evolve in the future. For that reason I continue to urge the parties to work towards a lawful settlement that will provide greater long-term certainty and, because it will be defined by the parties, greater political equity than what any single Administrator, acting within the confines of the law, can provide.

Stephen J. Wright
Administrator

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1.0 INTRODUCTION

Section 6 of the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. §832e, requires that the Administrator prepare schedules of rates and charges for electric energy sold to purchasers. Under the Project Act, rate schedules become effective upon confirmation and approval by the Federal Power Commission, succeeded by the Federal Energy Regulatory Commission (FERC or Commission). Section 6 of the Project Act directs the Administrator to establish rates with a view to encouraging the widest possible diversified use of electric energy. Section 7 provides that rate schedules are to be established having regard to the recovery of the cost of producing and transmitting electric energy, including amortization of the capital investment over a reasonable period of years. 16 U.S.C. §832f.

This Final Record of Decision (ROD) contains the decisions of the Bonneville Power Administration (BPA), based on the rate proceeding record, with respect to the adoption of revised power rates for October 1, 2008 through September 30, 2009 (FY 2009), the last year of the three-year rate period that commenced October 1, 2006. The "2007 Supplemental Wholesale Power Rate Adjustment Proceeding" revises existing rate schedules and General Rate Schedule Provisions (GRSPs), all of which will expire September 30, 2009. Recent rulings from the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit), BPA's Power Subscription Strategy and Record of Decision (Subscription Strategy), as well as other BPA decisions, provide much of the direction and policy context for this rate case as described in Chapter 2.

The Federal Energy Regulatory Commission (FERC or Commission) granted interim approval of BPA's WP-07 rates in September 2006. Subsequently, BPA requested a stay of FERC's continuing review to allow BPA to correct a minor calculation error. Prior to the resolution of that issue, the Ninth Circuit issued two opinions related to BPA's rates (*see* Section 2.3), whereupon BPA asked FERC to extend the stay of its review while BPA determined how to respond to the Court's rulings. This 2007 Supplemental Rate Proceeding addresses how to determine overpayments made to BPA's investor-owned utility (IOU) customers under Residential Exchange Program (REP) Settlement Agreements and how to return the overpayments to BPA's preference customers. This Supplemental proceeding also establishes new BPA power rates for FY 2009 and permits FERC to review a single supplemented record supporting BPA's proposed rates for FYs 2007, 2008, and 2009.

This Final ROD follows a full evidentiary hearing, including direct and rebuttal testimony, discovery, cross-examination, briefing, and oral argument before the BPA Administrator. Chapters 2 though 21, including any appendices or attachments, present the issues raised by parties in this proceeding, the parties' positions, BPA Staff's positions on the issues, BPA's evaluations of the positions, and the Administrator's decisions.

1.1 Procedural History of this Rate Proceeding

1.1.1 Issue Workshops

Prior to the release of the initial Supplemental Proposal, BPA Staff sponsored workshops on issues related to the Average System Cost (ASC) Methodology, the Section 7(b)(2)

Implementation Methodology, the Section 7(b)(2) Legal Interpretation, and BPA's historical operation of the section 7(b)(2) rate test. These workshops were held so Staff and interested parties could develop a common understanding of the issues, generate ideas, and propose alternative solutions to issues when possible. Conducting these issue workshops prior to the development of the initial Supplemental Proposal enabled Staff to freely exchange ideas and comments with parties on rate case issues without the constraints of the prohibition on *ex parte* communications, which goes into effect with the onset of the formal rate proceeding. The *ex parte* prohibition went into effect on February 8, 2008, with the publication of BPA's 2007 Supplemental Wholesale Power Rate Proposal in the Federal Register, and ends with the issuance of this Final ROD. The initial Supplemental Proposal incorporated many of the ideas and solutions arising from the workshops, and this Final 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. 7,611 (1986) (hereinafter Procedures). The Procedures implement the section 7(i) requirements.

On February 8, 2008, BPA published a Notice of Proposed Wholesale Power Rate Adjustment in the Federal Register (FRN), 73 Fed. Reg. 7,539 (2008). BPA's 2007 Supplemental Rate Proceeding began with a prehearing conference on February 19, 2008. At the prehearing conference, the Hearing Officer issued an order establishing the schedule for the rate proceeding and an order adopting electronic discovery procedures. That same day, the Hearing Officer also issued orders granting petitions to intervene and adopting a service list for the Supplemental Proceeding. The Hearing Officer subsequently granted additional petitions to intervene and/or amended the service list on several occasions.

Staff filed its initial Supplemental Rate Proposal on February 19, 2008, which was supported by prefiled written testimony and studies sponsored by 69 witnesses. Clarification of Staff's initial Supplemental Proposal occurred from February 27-29, 2008. Direct testimony was filed by the parties on March 31, 2008. Clarification on the parties' direct testimony occurred on April 7-9, 2008. The parties filed legal memoranda to accompany their testimony on April 3, 2008 and again on May 9, 2008.

On May 5, 2008, litigants to the proceeding filed testimony in rebuttal to the parties' direct cases. Clarification of the litigants' rebuttal testimony occurred on May 12-14, 2008. Written discovery of Staff's and the parties' direct and rebuttal cases occurred in accordance with the Hearing Officer's procedural schedule. Staff responded to over 300 data requests concerning its initial Supplemental Proposal and rebuttal testimony. Cross-examination took place from May 27-30, 2008, and parties submitted Initial Briefs on June 11, 2008. Oral argument before the Administrator was held on June 19 and 20, 2008. Briefs on Exceptions in response to the Draft ROD were due September 3, 2008.

For interested persons who did not wish to become parties to the formal evidentiary hearings, BPA's Procedures provided opportunities to participate in the ratemaking process by submitting oral and written comments. *See s*ection 1010.5 of BPA's Procedures. BPA received oral and written comments at transcribed field hearings conducted in Spokane, Washington on March 18, 2008 and Portland, Oregon on March 20, 2008. BPA received and considered all comments submitted during the participant comment period, which officially ended on May 5, 2006. The transcribed field hearings and the comments from rate case participants are part of the record upon which the Administrator bases his decisions. All WP-07 rate case exhibits (including testimony, studies, and documentation), witness qualifications, motions, and orders can be viewed at https://secure.bpa.gov/ratecase/.

This Final ROD is based on the Administrator's consideration of the entire rate case record, including oral and written comments discussed in Chapter 21. This ROD was published on September 22, 2008.

On occasion, certain rate case parties consolidated as a single group for the purposes of filing testimony or briefs on issues where such parties shared the same position. 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 convenience, BPA has identified all of the entities that comprise each of the joint parties in the list of Commonly Used Acronyms, which is included in this ROD.

1.1.3 Waiver of Issues by Failure to Raise in Briefs

Although 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 *any* matter at issue. A party needs to specifically raise issues in either its Initial Brief or Brief on Exceptions in order to preserve the issue. A party does not need to repeat an issue in its Brief on Exceptions if it raised the issue in its Initial Brief. Furthermore, the procedural schedule allows a party to adopt other parties' arguments if identified by September 19, 2008.

1.2 Legal Guidelines Governing Establishment of Rates

1.2.1 Statutory Guidelines

The Flood Control Act of 1944 (Flood Control Act) directs that BPA's 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 using 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 Ratemaking Discretion Vested in the Administrator

The Administrator has certain 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. Cir. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (widest possible use standard is so broad as to permit the exercise of the widest administrative discretion); *ElectriCities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985). The United States Court of Appeals for the Ninth Circuit has also recognized the Administrator's ratemaking discretion. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1120-1129 (9th Cir. 1984) (because 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.*, 442 F.3d 1204 (9th Cir. 2006).

1.3 FERC Confirmation and Approval of Rates

BPA's rates become effective upon confirmation and approval by the Federal Energy Regulatory Commission (FERC). 16 U.S.C. §§ 839e(a)(2); 839e(k). FERC's review is appellate in nature and based on the record developed by the Administrator. *United States Department of Energy – Bonneville Power Admin.*, 13 FERC ¶¶ 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 FERC ¶¶ 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 rates, FERC reviews BPA power rates under the Northwest Power Act 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; and (2) rates are based on BPA's total system costs. With respect to transmission rates, FERC's review includes an additional requirement to ensure that transmission 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 FERC ¶ ¶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 is 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 updating its forecasts of certain inter-business line costs and unit costs that are used as inputs for the transmission and ancillary services rates BPA developed in its separate transmission rate proceeding. BPA's current transmission rates were approved by FERC through FY 2009 and contain formula rates for some ancillary services.

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2.0 OVERALL POLICY CONTEXT

2.1 Introduction

In the FRN announcing this Supplemental Rate Proceeding, BPA explained that it is conducting this proceeding in order to respond to the Ninth Circuit's decisions in *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) regarding the 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements) and *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) regarding BPA's allocation of REP Settlement Agreement costs in BPA's WP-02 power rates, and to adjust BPA's FY 2009 power rates consistent with those decisions. As was the case for BPA's initial WP-07 rate proposal, BPA undertook five major public consultation and review processes in the past five years that provide a policy foundation for this rate proceeding. 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); the Post-2006 Conservation Program Structure Proposal; the 2007 Transmission Rate Case; and the Integrated Program Review (IPR). 73 Fed. Reg. 7,542-7,543 (Feb. 8, 2008). 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 67,689-67,690. 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. The two DSI RODs further clarify BPA's decisions regarding service to BPA's DSI customers. In addition, due to the need to establish a functioning REP in response to the Court's rulings, BPA undertook a separate consultation proceeding to revise its 1984 Average System Cost Methodology (ASCM). The FRN explained that the rate case would respond to the Court's rulings as well as remain consistent with the policy decisions reached in each of these processes, where appropriate.

FERC granted interim approval of BPA's WP-07 rates in September 2006. Subsequently, BPA requested a stay of FERC's ongoing review due to the need to resolve a minor technical error. Prior to the resolution of that issue, the Ninth Circuit issued two opinions related to BPA's rates (*see* Section 2.3), whereupon BPA asked FERC to extend the stay of its review while BPA determined how to respond to the Court's rulings. This 2007 Supplemental Proceeding reopens the WP-07 proceeding to respond to the Court's rulings by correcting the WP-02 and WP-07 rates as described in greater detail in this ROD. This approach will permit FERC to review a single supplemented record supporting BPA's proposed rates for FYs 2007, 2008, and 2009.

2.2 History of BPA's WP-02 and WP-07 Rates

BPA's WP-02 rates had their roots in the regional Comprehensive Review of the Northwest Energy System and the associated Cost Review process. The Comprehensive Review led to the Federal Power Subscription Work Group process and the resulting Subscription Strategy ROD and contracts. The Subscription Strategy proposed that BPA would offer Residential Purchase and Sale Agreements (RPSAs) to regional utilities, including the IOUs, to implement the REP for FY 2002-2011. The Strategy also proposed that BPA would offer the IOUs settlement agreements to resolve disputes arising under BPA's implementation of the REP. All of the region's six IOUs elected to execute the REP Settlement Agreements. Bliven, *et al.*, WP-07-E-BPA-52, at 4-5.

In the first phase of BPA's WP-02 Wholesale Power Rate Proceeding, concluding with the WP-02 Final Proposal in May 2000, BPA established rates consistent with the Subscription Strategy. Subsequently, BPA's financial position began to deteriorate as a result of the West Coast energy crisis, coupled with the return of more COU loads than expected. These developments undermined the basis for the rates determined in the WP-02 Final Proposal and threatened BPA's ability to recover its costs through rates and make its Treasury payment. BPA responded in the second phase of the WP-02 rate proceeding by implementing a set of Cost Recovery Adjustment Clauses (CRACs) and a Dividend Distribution Clause (DDC) to compensate for cost and revenue variations. *Id*. at 5.

In the WP-02 Final Proposal, BPA performed the section 7(b)(2) rate test assuming that a traditional REP existed. However, BPA then removed the traditional REP costs and allocated the costs of the REP Settlement Agreements to all customers, including COUs. It is this second step that the Court found contrary to law in *Golden NW*. In the WP-07 Final Proposal, BPA continued this allocation methodology.

2.3 The Rulings from the Ninth Circuit

In developing BPA's WP-02 power rates, BPA's revenue requirement included anticipated costs of REP Settlement Agreements with six regional IOUs. BPA allocated the majority of these settlement costs to the Priority Firm Power (PF) Preference rate. Following final approval of BPA's WP-02 rates by FERC, a number of parties challenged the WP-02 power rates in the Ninth Circuit. In *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Court held BPA had improperly allocated REP Settlement Agreement costs to BPA's rate for preference customers. During the litigation of *Golden NW*, but prior to the Court's decision, BPA conducted a subsequent hearing (WP-07) to establish power rates for FY 2007-2009. In establishing these rates, as noted above, BPA allocated REP settlement costs in the same manner as in BPA's WP-02 rates. Because the Court held in *Golden NW* that BPA's allocation of REP settlement costs in its WP-02 rates was improper, BPA's allocation of such costs in the WP-07 rates is similarly flawed.

In addition, the Court held that BPA's WP-02 fish and wildlife cost estimates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. The Court indicated BPA relied on outdated assumptions and had not appropriately considered information presented regarding its fish and wildlife costs. BPA's subsequent approach to forecasting fish and wildlife costs in the development of its WP-07 rates differed from the approach BPA used in developing its WP-02 rates. Nonetheless, as described in more detail in Chapter 13, BPA is taking steps to ensure that its final WP-07 Supplemental rates for FY 2009 are based on the most recent projections of fish and wildlife costs available at the time of rate development. In a procedural forum separate from the WP-07 Supplemental Proceeding, BPA provided opportunities for fish and wildlife managers and others to provide input to BPA regarding fish and wildlife program costs for FY 2009. Decisions made based on the information gained from this separate program cost review forum have been be used in the development of BPA's final WP-07 Supplemental rates.

As noted above, in a companion case to *Golden NW*, the Court held that BPA's REP Settlement Agreements with the IOUs were contrary to the Northwest Power Act. *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*). Also, subsequent to the *Golden NW* and *PGE* decisions, the Court reviewed three petitions for review challenging Load Reduction Agreements (LRAs) BPA executed with two IOUs during the energy crisis of 2000-2001. The Court dismissed two of the petitions for lack of jurisdiction and one petition as moot. The Court also reviewed challenges to amendments to the REP Settlement Agreements signed in 2004. In *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*), the Court remanded the amendments and a contract provision establishing a Reduction of Risk Discount to BPA. BPA must respond to the foregoing decisions. Because the ratemaking and REP issues are interrelated, BPA proposed to address its response to the Court's decisions in this WP-07 Supplemental Proceeding.

2.4 Overview of BPA's Response to the Court's Rulings

BPA's response to the Court's rulings focuses on FY 2002-2008. It is comprised of four steps. First, BPA calculates the REP settlement benefits that the IOUs received, or would have received, in each year for FY 2002-2008. These amounts are collectively referred to in this proceeding as "REP settlement benefits." Second, BPA calculates the amount of REP benefits that each IOU would have received under the REP in the absence of the REP Settlement Agreements, referred to as "reconstructed REP benefits." Third, BPA calculates the appropriate differences between the first two components for each year for each IOU, after certain additional considerations. These considerations include the treatment of related issues, such as deemer balances, interest, and treatment of LRA payments. The resulting amount is called the annual Lookback Amount. The aggregate overpayment to the IOUs represents the amount that should not have been included in the PF Preference rate paid by COUs, constituting an overcharge to the COUs by BPA. Then, in the final step, BPA implements a method of returning these overcharges to the COUs. *See* Marks, *et al.*, WP-07-E-BPA-62, for explanations of the calculations included in Section 15 of the Lookback Study, WP-07-E-BPA-44. BPA is also revising the Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology.

The main focus of BPA's response for FY 2002-2006 is to calculate the effect of the REP settlements on rates to COUs through a return to the period of December 2000 to June 2001, when BPA decided to respond to the West Coast energy crisis and unanticipated load increases through a series of CRACs. With an active REP in place instead of the REP settlements, BPA would have chosen to reset its base rates instead of adopting CRACs in order to properly calculate the PF Exchange rate. The PF Exchange rate is a major factor in the determination of the REP costs that would have been charged to COUs instead of REP settlement costs. Burns, *et al.*, WP-07-E-BPA-53, at 7. Backcasts of ASCs and exchange loads also were used to calculate the reconstructed REP benefits the IOUs would have received in the absence of the REP settlements. These calculations are key to the determination of the overcharges to the COUs and the Lookback obligations of the IOUs.

This ROD contains two main Parts. Part 1 addresses BPA's response to the Court's rulings. Part 2 describes the changes to BPA's power rates for FY 2009.

2.5 Policies and Objectives that Guide the WP-07 Supplemental Proposal

2.5.1 Subscription Strategy

On December 21, 1998, BPA issued a 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.
73 Fed. Reg. 7,542 (2008).

The Subscription Strategy provided a marketing framework for BPA's WP-02 and WP-07 power rate cases. The WP-02 and WP-07 power rate cases developed the rate schedules necessary for the products and contracts that were developed through Subscription. The Subscription contracts, except for the REP Settlement Agreements, continue to be the basis for the contractual relationship between BPA and nearly all of its firm power customers. BPA is assuming for purposes of this WP-07 Supplemental Proceeding that the IOUs, except Idaho Power Company (Idaho Power) and PacifiCorp, would have signed Residential Purchase and Sale Agreements (RPSAs) in the fall of 2000 instead of the 2000 REP Settlement Agreements. *Id*. BPA assumes PacifiCorp would have delayed signing an RPSA a few years until its ASC exceeded the PF Exchange rate. Forman, *et al.*, WP-07-E-BPA-76, at 81.

2.5.2 Firm Power Products and Services Rate Schedule

BPA is adopting a few changes to the WP-07 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.

The changes to the FPS rate schedule include the removal of certain obsolete rate components and a provision to allow BPA's Power Services to remarket its excess transmission capacity to other entities. Fisher, *et al.*, WP-07-E-BPA-69, at 3-4.

2.5.3 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 Pacific Northwest 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 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 expired in September 2006. The issues in the second phase were addressed in BPA's Long-Term Regional Dialogue Final Policy and Record of Decision, which was published on July 19, 2007. The Long-Term Regional Dialogue Final Policy is expected to be implemented through new power sales contracts and a future rate case conducted before such contracts go into effect in FY 2012. The Long-Term Regional Dialogue Final Policy does not affect this WP-07 Supplemental Proceeding. *Id*.

2.5.4 Service to Direct Service Industries (DSIs)

The Near-Term Policy established parameters for service to the DSIs that were further addressed in the DSI ROD and the Supplemental DSI ROD (together the "DSI RODs"). *Id*.

In the DSI RODs, BPA determined to offer DSI aluminum companies power sales contracts for an aggregate 560 aMW of benefits at a capped cost of $59 million. In addition, BPA offered a 17 aMW surplus firm power sales contract for Port Townsend Paper Company through the local public utility under the FPS rate (or the Industrial Firm Power (IP) rate, if viable) at a price approximately equivalent to, but in no case less than, the utility's lowest-cost PF rate. *Id*.

BPA decided to allocate a share of the 560 aMW of service benefits to each DSI aluminum company for purposes of making an initial offer of service. Because of the financial risks inherent in providing actual power and in order to meet the known and capped cost prerequisite, BPA determined that the delivery mechanism would be to monetize the value of the below-market power sales to provide service benefits through cash payments. *Id*.

2.5.5 Power Function Review (PFR) and the Integrated Program Review (IPR)

In January 2005, BPA initiated an extensive process, known as the PFR, to examine Power Services' (formerly known as Power Business Line or PBL) intended program spending levels for FY 2007-2009. The PFR process consisted of two phases designed to give interested parties an opportunity to provide input on the cost projections that would form the basis for BPA's initial WP-07 Power Rate Proposal. The first phase concluded in June 2005 when BPA issued the PFR Final Report. At that time, BPA committed to re-examine program levels prior to establishing power rates in BPA's final proposal. In early 2006, BPA conducted the second phase, known as PFR II, allowing interested parties an opportunity to review these program levels. Workshops were held from January through March 2006. In April of 2006, BPA issued a draft closeout report for comment. After the close of comment, BPA reviewed all comments and issued the PFR II Final Closeout Report on June 1, 2006, documenting BPA's decisions. These updated program levels were then incorporated into BPA's WP-07 Final Proposal. *See* Homenick, *et al.*, WP-07-E-BPA-10, at 11.

For the WP-07 Supplemental Proceeding, BPA reviewed the FY 2009 program levels incorporated into the WP-07 Final Proposal that were developed through the Power Function Review I and II processes. BPA then evaluated whether these forecasts remained reasonable in light of current projections. From this evaluation, BPA determined that adjustments were needed in certain program areas to address significant changes in forecast program levels. Specifically, these cost areas include: the Residential Exchange Program; Columbia Generating Station

(CGS) operation and maintenance; interest; amortization; depreciation; renewables; energy efficiency; long-term generating projects; augmentation; purchased power; and fish and wildlife costs. BPA described the nature of the non-REP cost changes to interested persons in a rate case workshop on October 10, 2007. *See* http://www.bpa.gov/power/PL/RegionalDialogue/Implementation/Previous-meeting-materials/Documents/2007/10_October/2007-10-10_Non-REPWorkshop.pdf.

In the October workshop, BPA notified attendees that it intended to initiate a separate public process, called the Integrated Program Review (IPR), to address possible changes to the fish and wildlife cost forecast for FY 2009,[2] costs of operating the CGS, and other cost changes identified that were relevant to the WP-07 Supplemental Proceeding. This process was conducted from May through July 2008. IPR workshops were held May 15-22, 2008. 73 Fed. Reg. 7,542 (2008). In this separate forum, BPA provided interested persons an opportunity to review and comment on any adjustments to program levels. BPA issued a closeout report on July 23, 2008, detailing any necessary adjustments to program levels. These forecast costs are incorporated into BPA's final Supplemental rates for FY 2009. *See* Chapter 11, FY 2009 Revenue Requirement, in this Draft ROD for a description of the IPR process.

2.5.6 Post-2006 Conservation Program Structure Proposal

The Conservation Program Structure Proposal was finalized and issued June 28, 2005. It describes BPA's approach to offering conservation programs during FY 2007-2009. The decisions of this post-2006 proposal were used as inputs in the development of BPA's WP-07 Final Proposal. BPA is not incorporating any changes in this area for the WP-07 Supplemental Proceeding. 73 Fed. Reg. 7,543 (2008).

2.5.7 Transmission Rate Case

BPA is committed to marketing its power and transmission services separately in a manner modeled after the regulatory initiatives adopted in 1996 by FERC to promote competition in wholesale power markets. FERC's initiatives in Orders 888[3] and 889[4] directed public utilities regulated under the Federal Power Act 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. Because BPA is not regulated under the Federal Power Act, BPA is not required by law to follow FERC's regulatory directives that promote competition and open access transmission service. Nonetheless, BPA has elected to separate its power and transmission

[2] Such changes could result from, for example, the issuance by NOAA Fisheries of a final Biological Opinion regarding the impacts of the mainstem Federal Columbia River Power System dams on threatened and endangered salmon and steelhead, and from any related commitments BPA may make in a long-term Memoranda of Agreement currently being discussed with some regional governmental entities.

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

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

operations and unbundle its rates in a manner consistent with the directives concerning open access transmission service. As a result, BPA develops its transmission rates in separate proceedings from its power rates. 73 Fed. Reg. 7,543 (2008).

On February 5, 2007, BPA's Transmission Services (formerly known as the Transmission Business Line or TBL) initiated a rate case to establish transmission rates for the FY 2008-2009 transmission rate period. Prior to the initiation of that rate case, Transmission Services held several public meetings with parties from July through November 2006 to discuss transmission costs, revenues, and rate design issues for the FY 2008–2009 rate period. Customers expressed interest in meeting with Transmission Services to develop a settlement for the FY 2008-2009 rate period. Transmission Services continued meetings with parties between October and November 2006, resulting in the 2008 Transmission Rate Case Settlement Agreement. *Id*.

On April 23, 2007, BPA issued the "Final Transmission Rate Proposal Administrator's Record of Decision" which adopted the transmission and ancillary services rates reflected in the 2008 Transmission Rate Case Settlement Agreement. FERC granted interim approval to these rates on September 20, 2007. The Transmission Services rate case settlement established fixed rates for certain ancillary services and some transmission rates that incorporate ancillary services. The generation inputs that support the ancillary services and other control area services sold by Transmission Services are provided by Power Services. BPA is not changing its generation input costs for FY 2009.

2.5.8 Financial and Policy Objectives

BPA's six major financial and policy objectives helped shape the WP-07 Supplemental Proposal. Those objectives are: (1) a rate design that meets BPA's financial standards, including meeting a 97.5 percent one -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. This final Supplemental Proposal reflects BPA's efforts to balance these competing objectives.

2.5.9 Partial Resolution of Issues and Other Settlement Discussions

At the request of parties to the initial 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, 8, 14, and 22, 2006. The intention was to determine if all parties could come to agreement on certain issues, thereby limiting the contested issues in this rate proceeding, as well as limiting the workload associated with the remainder of the rate proceeding. The result of these discussions was the Partial Resolution of Issues. *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 issues regarding 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 agreed to support, or to not oppose, the non-precedential nature of section 7(b)(2) decisions related to Mid-Columbia resources, conservation, uncontrollable events, and the provision of power reserves from the sales of secondary energy.

This Supplemental Proceeding continues to adhere to the Partial Resolution of Issues, with the exception of the issues related to the REP and section 7(b)(2). Because these issues are at the core of establishing the level of REP benefits for the IOUs, they were opened for debate and decision in this proceeding.

In addition, a settlement discussion was held on May 14, 2008 to explore the possibility of settling the major issues in this WP-07 Supplemental Proceeding regarding the REP. Unfortunately this discussion did not bear fruit, largely due to the lack of time available for the type of detailed discussions necessary for settlement.

2.5.10 2008 Average System Cost (ASC) Methodology

BPA is statutorily responsible for establishing a methodology for determining the ASC of resources for regional electric utilities that participate in the REP. Section 5(c) of the Northwest Power Act established the REP and authorizes the BPA Administrator to determine utilities' ASCs based on a methodology developed by BPA in consultation with the Northwest Power and Conservation Council, BPA customers, and state regulatory agencies in the Pacific Northwest. *See* 16 U.S.C. § 839c(c)(7). The ASCM is used in the determination of monetary benefits paid by BPA to the residential consumers of utilities participating in the REP.

On August 1, 2007, the Administrator initiated a series of public meetings in which informal comment was taken on issues pertaining to the 1984 ASCM. *See* 73 Fed. Reg. 7,270 (Feb. 7, 2008). Based in part on public comment, BPA proposed to revise the methodology by redefining the types of capital and expense items includable in ASC, establishing new data sources from which ASCs were to be derived, and changing the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. BPA announced these proposed revisions in a Federal Register Notice (FRN) published on February 7, 2008. *Id*. Public comment on BPA's proposal closed on May 2, 2008. On May 29, 2008, BPA published a revised version of the ASCM. BPA's response to the public comments and an explanation of the proposed revisions to the ASCM were described in an accompanying Draft Record of Decision (Draft ROD). Comments on the revised ASCM and the Draft ROD were accepted until June 12, 2008. The final Record of Decision was published on June 30, 2008. The ASCM is now before FERC for confirmation and approval.

2.6 Legal Issues Regarding BPA's Response to the Court's Decisions

2.6.1 Introduction

As noted above, on May 3, 2007, the Ninth Circuit issued companion opinions in *PGE* and *Golden NW.* In *PGE*, the Court invalidated BPA's 2000 REP Settlement Agreements, holding that BPA exceeded its statutory settlement authority under section 2(f) of the Bonneville Project Act and section 9(a) of the Northwest Power Act. In *Golden NW,* the Court reviewed a challenge to BPA's WP-02 rates and addressed, in part, the rates BPA developed to recover REP Settlement Agreement costs. The Court remanded the WP-02 rates to BPA with instructions to set rates "in accordance with this opinion." In its discussion in *PGE*, the Court elaborated, finding that Congress's "clear instruction" in the Northwest Power Act was that "costs of the REP program must be charged in a supplemental rate against other BPA customers, and not against preference customers." *PGE,* 501 F.3d 1009 (9th Cir. 2007). "The net effect is that BPA's preference customers are paying for the REP settlement … in plain violation of the [Northwest Power Act]." *Id.* at 1036. Thus, it was not proper for BPA to allocate costs of the REP Settlement Agreements in excess of the section 7(b)(2) trigger amount to preference customers based on BPA's theory that such costs were incurred pursuant to the Administrator's section 2(f) contracting authority and could therefore be "equitably allocated" pursuant to section 7(g) of the Northwest Power Act.

As noted previously, the purpose of this WP-07 Supplemental Proceeding is to respond to the Court's remand order. With regard to REP payments made pursuant to the REP Settlement Agreements during the FY 2002-2006 period, the Administrator has considered a range of several options that are summarized as follows:

Leave the FY 2002-2006 rates untouched and reopen the 2007 rate case in such a fashion as to ensure that, on a prospective basis, preference customers do not pay for any REP costs other than those required by section 7(b)(2), but without making any adjustments or without "carrying forward" any over- or under-payments from the FY 2002-2006 rates.

Revisit the WP-02 rates charged during the FY 2002-2006 period, removing the REP Settlement Agreement costs from the rates and supplementing the record as necessary in order to calculate the rightfully due amount of REP benefits the IOUs would have received without the REP Settlement Agreements; after determining the lawful amount of REP benefits, return the resulting overcharges as "credits" to the preference customers for past overpayments, with offsetting "debits" against future REP benefits for the IOUs that were overpaid REP benefits under the REP Settlement Agreements.

Reopen the WP-02 rate case and rates in their entirety, recalculate all the rates and REP benefit levels, re-issue bills under the revised rates for all parties for the FY 2002-2006 period, refund overpayments to public preference customers, and recoup excess REP benefits from IOUs or designate some other source of revenue for refunding overpayments.

The Administrator has determined that the second option is the most lawful, appropriate, and equitable way to address the Court's remand in *Golden NW*. 73 Fed. Reg. 7,540 (Feb. 8, 2008).

Thus, this Supplemental Proceeding has two central components. First, BPA is establishing rates for FY 2009 that comply with the Court's order, and an amount of refunds will be made immediately available to preference customers. Second, in order to provide an adequate remedy to preference customers overcharged as a result of BPA's actions, BPA is adopting a Lookback analysis to determine the amount of REP costs that would have been incurred by BPA had it implemented the traditional REP in 2002 instead of implementing the 2000 REP Settlement Agreements with the region's IOUs. Based on that determination, BPA will establish the amount by which preference customers were overcharged and provide appropriate repayments to preference customers through lower rates or billing credits in the future. In other words, BPA is establishing a means to recover REP Settlement Agreement overpayments through offsets to future REP benefits that would otherwise be payable to the IOUs.

To properly calculate the amount of REP costs for the Lookback period, Staff proposed it would be necessary to review how REP benefits would have been determined in 2001 under the 1984 ASC Methodology, how BPA forecast REP costs in the WP-02 rate proceeding, and to make any adjustments that were necessary to more closely track the amount of REP benefits that would have been incurred during that period through implementation of the REP in the absence of the REP Settlement Agreements. Accordingly, Staff made a number of necessary adjustments to its calculation of the section 7(b)(2) rate test, adjustments that would have been incorporated into the WP-02 rates in the absence of the REP Settlement Agreements using information available when establishing the final WP-02 rates.

Not surprisingly, many parties to this proceeding have objected to BPA's approach, citing various legal and technical grounds. *See, e.g.,* APAC Br., WP-07-B-AP-01; Cowlitz Br., WP-07-B-CO-01; IPUC Br., WP-07-B-01; IOU Br., WP-07-B-JP6-01; OPUC Br., WP-07-B-PU-02; PPC, Seattle, Snohomish PUD, and Franklin PUD Br., WP-07-B-JP25-01; WPAG Br., WP-07-B-WA-01; and WUTC Br., WP-07-B-WU-01. This section discusses the legal framework that supports BPA's decisions, explains why other options were not adopted, and responds to specific issues raised by the parties. These include issues regarding retroactive rulemaking, retroactive ratemaking, the filed rate doctrine, and other issues. Technical considerations are addressed elsewhere in this ROD.

2.6.2 Scope of the Remand

Issue 1

Whether the Supplemental Proposal is arbitrary and capricious or an abuse of discretion because the Lookback proposal does not fall within the scope of the remand directed by the Court in Golden NW.

Parties' Positions

APAC argues that BPA's authority on remand is limited to eliminating the REP settlement costs from the PF Preference rate insofar as those costs exceed the limit set by the Northwest Power Act, and does not include changing the underlying section 7(b)(2) methodology used to establish the PF Exchange rates. APAC Br., WP-07-B-AP-01, at 32. APAC also argues that changing the 1984 Legal Interpretation cannot be done because such a change far exceeds the scope of the Ninth Circuit's remand order. *Id*. at 46. APAC states that to comply fully with the Ninth Circuit's mandate, BPA must revise its rates for the Lookback period to limit preference customers' exposure to any and all REP-related costs above those allowed by the requirements of section 7(b)(2). *Id*. at 23. APAC contends that the Staff proposal leads to a legally impermissible result because preference customers are not assured of full or timely repayment. *Id*. at 5.

Cowlitz contends that BPA cannot adequately and completely respond to the Court's remand by calculating legally significant rates, from which the precise amount of funds unlawfully collected from preference customers is known to a certainty, and then decline to offer any certainty of full and timely repayment. Cowlitz Br., WP-07-B-CO-01, at 72.

The IPUC argues that there is nothing in the Court's two decisions that requires BPA to provide retroactive relief to the prevailing parties in the *PGE* and *Golden NW* cases. IPUC Br., WP-07-B-ID-01, at 4. The IPUC argues that BPA cannot correct the WP-02 rates because they expired September 30, 2006 and have been superseded by the WP-07 interim rates, so any correction of the WP-07 rates would constitute impermissible retroactive ratemaking that is outside of the scope of the remand. *Id*. at 3-4.

The IOUs argue that the Court did not remand the PF Preference rate to BPA to fashion a Lookback remedy or to calculate refunds because "setting rates" necessarily refers to setting future rates. IOU Br., WP-07-B-JP6-01, at 15. They argue that the Court nowhere states that BPA is to determine "overcharges" or "undercharges" and certainly does not state that BPA is to determine "overcharges" by ignoring the full amount of reconstructed REP benefits. *Id*. at 144.

PPC, Seattle, Snohomish PUD, and Franklin PUD (hereafter, PPC) argue that the Court's remand order in *Golden NW* referred to the rates for FY 2002-2006 that the Court reviewed. PPC Br., WP-07-B-JP25-01, at 12-13. PPC contends that if BPA were to accept the arguments of the IPUC and the OPUC, it would have to read the word "remand" in *Golden NW* as meaning nothing. *Id*. at 13. PPC argues that if BPA failed to correct its FY 2002-2006 preference power rates and refund the charges unlawfully collected under them, it would violate the express direction issued by the Court. *Id*. PPC also argues that Staff assumes too much latitude on remand to reconsider decisions and calculations made in the WP-02 proceeding because BPA is prevented from recalculating the section 7(b)(2) rate test for the FY 2002-2006 period, and should instead give effect to its prior determinations. *Id*. at 30. PPC also states BPA must limit its reconsiderations on remand to those issues that the Court addressed, *i.e.*, the effect of the 7(b)(2) calculation on the preference customers' rates. *Id*. at 32.

The OPUC argues that the fact that a court has remanded rates to BPA does not mean that it can retroactively correct errors identified by the court in absence of statutory authority authorizing a retroactive correction. OPUC Br., WP-07-B-PU-02, at 4. The OPUC argues that the Court's remands do not provide BPA authority to address alleged overcharges to the COUs under the WP-02 rates because those rates were final when approved by FERC. *Id*. at 5. The OPUC states that Staff's proposal to conduct a lookback is arbitrary, capricious, and an abuse of discretion because Staff conducted no analysis to determine whether its Lookback proposal is equitable or warranted by the circumstances and Staff simply assumes that it is obligated by the *Golden NW* remand to pay to COUs amounts these utilities were allegedly overcharged during FY 2002-2007. *Id*. at 5-6. The OPUC argues that the Court did not direct BPA to calculate the amount the COUs were overcharged (and require IOUs to return that amount) and did not direct BPA to make retroactive reparations for any overcharges. *Id*. at 18. The OPUC states that *Golden NW* can reasonably be read to require only that BPA correct the errors identified in that opinion, and in *PGE*, on a prospective basis. *Id*.

WPAG argues that the Staff proposal has not fulfilled BPA's obligations to preference customers under the remand because (1) Staff has not determined how much COUs were overcharged due to the unlawful inclusion of the REP settlements in preference rates, and (2) Staff has not determined how to reimburse preference customers for these charges in a timely manner. WPAG Br., WP-07-B-WA-01, at 3. WPAG alleges that the WP-02 and WP-07 records contain the information needed to comply with the remand because both contained the preference customer rate produced with the lawful application of the section 7(b)(2) rate test, as well as the PF-02 and PF-07 rates with the unlawful inclusion of REP settlement costs. *Id*. at 6, 8. WPAG concludes that the difference between these two rates constitutes the amount the Court in the *Golden NW* decisions identified as being illegally allocated to preference customers and the amount that BPA is legally mandated to return to its preference customers. *Id*. at 8. WPAG argues that forecasting and backcasting the ASCs is both unnecessary to respond to the remand in the *Golden NW* decision and legally unsound, and Staff has engaged in a number of other legally unsustainable calculations. *Id*. at 23, 25. WPAG contends that, as a consequence, preference customers will not be reimbursed for overcharges under the PF-02 and PF-07 rates because Staff has proposed reductions to the illegal overcharges that are improper. *Id*. at 26.

WPAG states further that Staff's approach in the WP-07 Supplemental Proceeding has turned the remand order on its head, and ensures that those who benefited from the imposition of the illegal overcharges on the preference customers will continue to receive the bulk of the benefits of such overcharges in the future. *Id*. at 33. Finally, WPAG argues that the IOUs, the IPUC, and the OPUC arguments that BPA should not attempt to determine the amounts that preference customers were illegally overcharged and should make no effort to repay these wrongfully collected funds are as audacious as they are preposterous because BPA cannot disregard a direct order to it from the Federal court with jurisdiction over its activities. *Id*. at 34.

The WUTC argues that BPA should be very circumspect before it decides that a remedy is either required or necessary based on the remands from the Court in *Golden NW* or *PGE*. WUTC Br., WP-07-B-WU-01, at 3. The WUTC argues that although *PGE* declared the inclusion of the REP settlement costs in the PF Preference rate unlawful, only the *Golden NW* case was remanded to BPA. *Id*. at 4. Therefore, WUTC argues the Court did not require BPA to impose a refund remedy and many other equitable factors militate against a retrospective remedy. *Id*. at 4-6.

BPA Staff's Position

This proceeding responds to the decisions of the Court in *PGE* and *Golden NW*, which respectively declared the REP Settlement Agreements invalid and determined that BPA's WP-02 rates were therefore defective. To address these concerns, BPA has proposed to conduct this proceeding by revisiting the WP-02 rates and rate record, considering supplemental information and revising previous decisions only as necessary. 73 Fed. Reg. 7,552 (Feb. 8, 2008). To address the finding that preference customers were overcharged as a result of the defective rates, Staff calculated the level of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements and then calculated the resulting overcharges to the COUs. *See* Marks, *et al.*, WP-07-E-BPA-62. Staff proposed that BPA then "credit" preference customers for past overcharges. Staff also proposed that the IOUs that over-collected benefits under the REP settlements would be provided with offsetting "debits" against future REP benefits. *Id.*

<u>Evaluation of Positions</u>

As explained more fully below, BPA believes that Staff's WP-07 Supplemental Proposal was developed in a manner consistent with the Court's decision to remand the WP-02 power rates and require BPA to set rates consistent with the Court's decision. *See* Section 2.3. BPA's position is based on a reasonable interpretation of the remand order and is in accordance with existing law governing BPA's ratemaking activities. Thus, the Lookback analysis proposed herein is not arbitrary and capricious or an abuse of discretion.

A. Implications of the Court's Remand

At the outset, the implications of the Court exercising its authority to remand rates to BPA must be considered. A remand is not required in all cases where an agency action is held to be invalid. Where, for example, FERC committed a procedural error by holding an evidentiary hearing to review BPA's nonfirm energy rates, thereby making its review overbroad, the Court was not required to remand the matter to FERC, but could proceed on the merits. *Aluminum Co. of America v. Bonneville Power Admin.*, 903 F.2d 585 (9th Cir. 1989). *See also Canas-Segovia v. Immigration and Naturalization Service*, 902 F.2d 717 (9th Cir. 1990) (Board of Immigration Appeals erred by denying withholding of deportation; Court of Appeals ordered relief rather than remand since legal standards were identified and facts were undisputed); *Smolen v. Chater*, 80 F.3d 1273 (9th Cir. 1996) (appellate court may direct an award of disability benefits where record has been fully developed and further administrative proceedings would serve no useful purpose).

However, remand is generally the course taken by the courts when they find that an agency has committed legal error, as in this situation. The Ninth Circuit has stated that a court of appeals should remand a case to an agency for consideration of a matter that statutes place primarily in the agency's hands. *Ruiz-Vidal v. Gonzales*, 472 F.3d 1072 (9th Cir. 2007). A remand is especially appropriate where the agency can bring its expertise to bear upon the matter, evaluate the evidence, make a determination, and, through informed discussion and analysis, help a court later determine whether the agency's determination exceeds the leeway that the law provides. *Id.* *See also Alaska Trojan Partnership v. Gutierrez*, 425 F.3d 620 (9th Cir. 2005) (when agency commits an error of law, Court of Appeals remands to the agency to reconsider its decision as required by law); *Benecke v. Barnhart*, 379 F.3d 587 (9th Cir. 2004) (when court of appeals reverses an administrative determination, the proper course, except in rare instances, is to remand to the agency for additional investigation or explanation); *Loma Linda University v. Schweiker*, 705 F.2d 1123 (9th Cir. 1983) (reviewing court has inherent power to remand a matter to the administrative agency); *Dreisbach v. Murphy*, 658 F.2d 720 (9th Cir. 1981) (remand to administrative agency is appropriate if issue before the court involves technical questions of fact uniquely within the expertise and experience of an agency, or if remand would facilitate uniformity of regulation or an agency's determination would materially aid court's resolution of an issue).

In *Golden NW*, the Court determined that remand was the appropriate course for responding to the identified legal errors. The instruction that BPA set its rates in accordance with the Court's opinion means that BPA will be interpreting and applying various statutory rate directives, including sections 7(c), 7(b)(2) and 7(b)(3) of the Northwest Power Act. 16 U.S.C. §§ 839e(c), 839e(b)(2), 839e(b)(3). Thus, BPA's response to the remand order requires addressing technical issues uniquely within the experience and expertise of BPA and/or addressing issues that Congress has largely committed to agency discretion. In such a case, the Court has held that BPA is entitled to deference:

> We also give substantial deference to actions that BPA undertakes pursuant to its enabling legislation. *See Dep't of Water & Power v. Bonneville Power Admin.*, 759 F.2d 684, 690-91 (9th Cir. 1985); *see also Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-44, 104 S. Ct. 2778, 2781-82, 81 L.Ed.2d 694 (1984). And we have recognized that Congress "granted BPA an unusually expansive mandate to operate with a business-oriented philosophy. Accordingly, it seems particularly wise to defer to the [BPA's] actions in furthering its business interests…"

Ass'n of Pub. Agency Customers, Inc. v. Bonneville Power Admin., 126 F.3d 1158, 1171 (9th Cir. 1997). Similarly, in *Public Power Council, Inc. v. Bonneville Power Administration*, 442 F.3d 1204 (9th Cir. 2006), the Court found:

> Rate making decisions are also entitled to deference. *See Cal. Energy Comm'n*, 909 F.2d at 1306 ("BPA is entitled to … deference in ratemaking decisions, even where it has an interest in the outcome."). It is true that "final determinations regarding rates … shall be supported by substantial evidence in the rulemaking record … considered as a whole." 16 U.S.C. § 839f(e)(2). Yet, substantial evidence is simply "more than a mere scintilla. It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Richardson v. Perales*, 402 U.S. 389, 401, 91 S. Ct. 1420, 1427, 28 L.Ed.2d 842 (1971) (internal quotation marks omitted).

See also Golden NW, 501 F.3d 1037 (9th Cir. 2007); *Utility Reform Project v. Bonneville Power Admin.*, 869 F.2d 237 (9th Cir. 1989) (deference is especially appropriate in the present case because the enabling legislation is highly technical and because BPA was intimately involved in drafting much of that legislation.); *PacifiCorp v. F.E.R.C.*, 795 F.2d 816 (9th Cir. 1986). Moreover, "administrative agencies have broad discretion in fashioning remedies. This is particularly true when an agency is responding to a judicial remand. Courts have found that an agency can give effect to a judicial decision by taking action that it could not otherwise take under normal circumstances." *In the Matter of QualComm Incorporated*, FCC Order #FCC00-189, June 8, 2000.

The Supreme Court articulated this view in *United Gas v. Callery Properties*, 382 U.S. at 229 (1965), where it upheld a decision by the Federal Power Commission to issue refunds after a rate decision had been overturned, despite a previous holding that the Commission "has no power to make reparation orders." The Court found instead that, in this instance, "an agency, like a court, can undo what is wrongfully done by virtue of its order" (*quoting Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 618 (1944)). *Id*. Because the Commission "could properly conclude that the public interest required the producers to make refunds," the Court upheld the action as a proper response to the remand. *Id*. Even though the Court had previously held in *Hope Natural Gas* that the Natural Gas Act (NGA) did not provide any statutory authority for the Commission to make reparation orders, the Court in *United Gas v. Callery* held that where the agency's order is overturned by the reviewing court, "an equitable power to order refunds may fairly be implied." *Id*. at 234 (Harlan, J., concurring).

Other opinions are in accord. The D.C. Circuit has held, for example: "If a successful appeal of an erroneous FERC decision … could not be enforced retroactively, a [utility's] incentive to vindicate its rights under [law] through judicial review would be similarly diminished. We do not believe Congress intended [this] result." *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1074 (D.C. Cir. 1992). In a separate case, the Court described the *Clearinghouse* opinion as follows: "*Clearinghouse* involved a FERC order interpreting whether a section of the Natural Gas Act (NGA) dealing with periodic rate adjustments called for the periodic adjustment of depreciation expenses." *Pub. Utilities Comm'n of State of Cal. v. FERC*, 988 F.2d 154, 162 (D.C. Cir. 1993). There, FERC's initial order was reversed and remanded. On remand FERC adopted a different view and ordered that its new interpretation be applied retroactively to permit the pipeline company to bill its shippers for "recoupment" payments. *Id*.

Finding that "the NGA is silent as to the effect of a judicial invalidation of a FERC decision," the court applied "the general principle of agency authority" to uphold FERC's authority to order "recoupment of losses caused by its error." *Clearinghouse*, 965 F.2d at 1073-74. Similarly, the *Pub. Utilities Comm'n* court, evaluating an "illegal order" which "induced, even if it did not compel," a pipeline company to adopt a "gas inventory charge," held that FERC on remand had the authority to "order[] recoupment of losses caused by its errors" to prevent "pipelines [from being] 'substantially and irreparably injured' by FERC errors [leaving] judicial review … powerless to protect them from much of the losses so incurred." 988 F.2d at 162-163 (*quoting Clearinghouse*, 965 F.2d at 1074-1075).

Having considered these authorities, BPA determined that it would be within its authority to provide preference customers with some form of retroactive relief for overcharges that may have occurred during the FY 2002-2006 rate period, if the Court's remand order in *Golden NW* permitted or required such action. As described below, BPA interprets the order to require some sort of retroactive relief for preference customers.

B. Interpreting the Remand Order

At the outset, BPA believes it would be anomalous that preference customers, having prevailed in their challenge to BPA's FY 2002-2006 wholesale power rates, would be left with only a prospective remedy in the form of future rates and no relief for legal errors that occurred during the FY 2002-2006 time frame. To the contrary, BPA interprets the Court's opinions in *PGE* and *Golden NW* as supporting the view that some sort of retrospective relief is mandated.

In *Golden NW*, the Court found that the WP-02 (FY 2002-2006) PF rate was set in a manner that inappropriately allocated costs of the REP to BPA's preference customers. As a result, the Court remanded to BPA with instructions to set rates "in accordance with this opinion." In its discussion in *PGE*, the Court found that Congress's "clear instruction" in the Northwest Power Act was that costs in excess of the section 7(b)(2) trigger amount must be reallocated through "a supplemental rate against other BPA customers, and not against preference customers." *PGE*, 501 F.3d 1009 (9th Cir. 2007). "The net effect is that BPA's preference customers are paying for the REP settlement … in plain violation of the [Northwest Power Act]." *Id*. at 4880.

It does not seem particularly germane that the statement appears in *PGE*, which found the REP Settlement Agreements invalid, rather than in *Golden NW*, which found that the rates supporting those settlements were legally deficient. Instead, the two cases are companion cases that must be read in tandem to ascertain the Court's intent. The Court specifically found that (a) the REP Settlement Agreements were not supported by statutory authority; (b) the rates supporting those settlements were, therefore, defective; and (c) the effect of the statutory violation was that preference customers were charged impermissibly higher rates in contravention of the Northwest Power Act. Thus, BPA views the logic and language of the opinions as requiring retroactive relief for overcharges during the FY 2002-2006 period, based primarily on the conclusion that the remand order cannot be fully satisfied without rectifying what the Court itself describes as a "plain violation" of the law. In other words, because preference customers were charged higher rates than they should have been, it would be "in accordance with this opinion" for BPA to revise *existing and future* rates appropriately to restore preference customers, as much as possible, to the position they would have been in if not for the inappropriate allocation of costs.

Thus, as BPA interprets the Court's order, BPA is charged with the responsibility not just to adhere to statutory requirements in the future, but to rectify the harm that was caused by the rates that were successfully challenged; *i.e.*, the WP-02 rates. BPA concludes that preference customers who had been overcharged because of an unlawful rate determination are entitled to a refund or other appropriate remedy. Providing only prospective relief by proper development and implementation of future rates, as urged by some, would fall short of satisfying the Court's remand in *Golden NW*. Instead, BPA determines it is a reasonable response to the remand order to re-examine relevant issues surrounding BPA's WP-02 rates by conducting the Lookback analysis.

C. Prohibitions on Retroactivity are Inapplicable

Some parties have argued that it is impermissible for BPA to conduct the Lookback and adjust FY 2002-2006 REP benefit levels because to do so constitutes improper retroactive rulemaking, as well as a violation of the filed rate doctrine. OPUC Br., WP-07-B-PU-02, at 3-5 (retroactive rulemaking); IOU Br., WP-07-B-JP6-01, at 16-18 (retroactive rulemaking): WUTC Br., WP-07-B-WU-01, at 6-7 (retroactive ratemaking); APAC Br., WP-07-B-AP-01, at 26-33 (retroactive ratemaking and filed rate doctrine); and IPUC Br., WP-07-B-ID-01, at 4-9 (retroactive ratemaking). Specific arguments adopted by the parties are detailed elsewhere. However, in this case, the bottom line is that there is no prohibition on retroactive adjustments applicable to BPA, and if there were, the Lookback would constitute an appropriate exception to such standards. Similarly, the filed rate doctrine is not applicable in this instance.

1. *Discharge of a Judicial Order Does Not Require Congressional Authorization for Retroactive Rulemaking.*

BPA is mindful that retroactivity is often disfavored in the rulemaking and ratemaking contexts. Indeed, it has been stated that an agency can only make retroactive rules if Congress makes an express grant of that power, and Congress has not explicitly given BPA the express power to make retroactive rules or to set rates retroactively. The Supreme Court, for example, has ruled that "a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms." *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988).

This general prohibition in the absence of Congressional authorization is not applicable in this situation. The Ninth Circuit, in a case involving the ability of the Social Security commissioner to make adjustments to Supplemental Social Security Income (SSSI) benefits based on changes in a recipient's monthly income, noted that "[a]lthough the Court in *Bowen* … indicated only how retroactive rulemaking would 'generally' be received, the logic of the Court's decision clearly rests on an absolute bar against an agency's retroactive rulemaking absent statutory authority." *Newman v. Apfel*, 223 F.3d 937, 942 (9th Cir. 2000). Nonetheless, the court went on to distinguish *Bowen* – where the agency initiated the effort to apply rules retroactively – from cases such as *Livermore v. Heckler*, 743 F.2d 1396, 1405 (9th Cir. 1984), another Social Security benefit dispute where the court ordered "recalculation of benefits erroneously calculated as well as prospective implementation of the correct [rule]." The agency had the authority to make retroactive corrections in response to a judicial determination because "[*t*]*he capacity of the courts to order retroactive relief has never been questioned.*" *Newman*, 223 F.3d at 942 (emphasis added). For this reason, the Ninth Circuit upheld the district court's determination that "the Commissioner's *discharging a judicial order to make Newman whole would not require the Commissioner to promulgate retroactive regulations in the way that the Court contemplated in Bowen.*" *Id*. (emphasis added).

BPA finds itself in a similar situation. As BPA interprets the Court's order, the remand in *Golden NW* is clear that, due to the finding in *PGE* that the REP Settlement Agreements were contrary to law, certain cost allocations made in establishing the WP-02 rates were defective to the extent that preference customers were overcharged for REP benefits in excess of the rate ceiling established by sections 7(b)(2) and 7(b)(3) of the Northwest Power Act. In order to comply with the remand order, BPA must correct the overcharges to preference customers caused by the illegal REP Settlement Agreements.

2. *Prohibition of Retroactive Ratemaking Is Inapplicable, and the "Filed Rate Doctrine" Does Not Apply in this Case.*

As stated by APAC, the filed rate doctrine is a common-law doctrine that forbids a regulated entity to charge rates for its service other than those properly filed with the appropriate federal regulatory authority. APAC Br., WP-07-B-AP-01, at 28, *citing Consol. Edison Co. of N.Y. v. FERC*, 347 F.3d 964, 969 (D.C. Cir. 2003); *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 (1981). The filed rate doctrine is based upon the principle that "[n]o court may substitute its own judgment on reasonableness for the judgment of [FERC]. The authority to decide whether the rates are reasonable is vested by § 4 of the [Natural Gas Act] solely in the Commission," and "the right to a reasonable rate is the right to the rate which the Commission files or fixes." *Ark. La. Gas Co.*, 453 U.S. at 577, *citing FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 611 (1944) and *quoting Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251 (1951).

It has also been stated that "[t]he rule against retroactive rate increases prohibits the Commission from adjusting current rates to make up for a utility's over- or undercollection in prior periods." *Towns of Concord, Norwood, and Wellesley, Mass. v. FERC*, 955 F.2d 67, 71 (D.C. Cir. 1992) (*citing Columbia Gas Transmission Corp. v. FERC*, 831 F.2d 1135, 1139-42 (D.C. Cir. 1987)). "The retroactive ratemaking doctrine is thus a logical outgrowth of the filed rate doctrine, prohibiting the Commission from doing indirectly what it cannot do directly." *Associated Gas Distribs. v. FERC*, 898 F.2d 809, 810 (D.C. Cir. 1990). Generally, the doctrines apply to rates that a Federal regulatory agency has approved as "just and reasonable" according to controlling Federal regulations.[5] *See E. & J. Gallo Winery*, 503 F.3d at 1033-1034. "The considerations underlying the doctrine … are preservation of the agency's primary jurisdiction over the reasonableness of rates and the need to insure that *regulated companies* charge only those rates of which the agency has been made cognizant." *Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577-578 (1981) (*citing City of Cleveland v. FPC*, 525 F.2d 845, 854 (D.C. Cir. 1976)) (emphasis added).

However, neither the filed rate doctrine nor, by extension, the prohibition of retroactive action, applies to BPA because Federal power marketing administrations (PMA) such as BPA are "required by the plain language of [the Flood Control Act] to protect the public fisc by ensuring that federal hydro-electric programs recover their own costs and do not require subsidies from the federal treasury." *U.S. v. City of Fulton*, 475 U.S. 657, 668 (1986). In *Central Electric Power Cooperative, Inc. v. Southeastern Power Administration (SEPA)*, 338 F.3d 333, 335 (4th Cir. 2003), the Fourth Circuit reversed the district court's holding that a "rate schedule was arbitrary and capricious because it imposed a surcharge on plaintiffs in order to recover revenue shortages incurred during a prior period." The appellate court held that "the Flood Control Act

[5] The filed rate doctrine was first applied to rates for railroad freight tariffs filed with the Interstate Commerce Commission under the Interstate Commerce Act. *See Keogh v. Chicago & N.W. Ry. Co.*, 260 U.S. 156 (1922). The doctrine has been extended to natural gas rates filed with FERC under the Natural Gas Act, electricity rates filed with FERC under the Federal Power Act, and telephone service rates filed with the Federal Communications Commission (FCC) under the Communications Act, among others. *See Ark. La. Gas Co. v. Hall*, 453 U.S. at 577-578; *Montana-Dakota Utilities Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251-252 (1951); *MCI Telecomm. Corp. v. Am. Tel. & Tel. Co.*, 512 U.S. 218 (1994).

authorizes [SEPA, FERC, and the DOE] to recover such losses and affords them considerable discretion in structuring rate schedules in order to do so." *Id*. The court noted that "PMAs must sometimes set rates specifically aimed at recovering revenue shortages sustained during prior rate periods" and that "PMAs 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." *Id*. at 337.

In *Central Electric*, the surcharge imposed to compensate for past underrecoveries was applied to six specific customers who had refused to agree to a rate increase when SEPA became unable to meet its costs during the 1985-1990 rate period. SEPA could not meet its costs due to a regional drought that required the agency to purchase outside power to honor its contracts. *Central Electric*, 338 F.3d at 335. SEPA explained the predicament to its customers, and 168 out of 174 voluntarily amended their contracts, which FERC subsequently approved. *Id*. at 336, *citing Southeastern Power Admin.*, 49 F.E.R.C. ¶ 62,109 (1989). When a surcharge was applied to the refusing customers' rates during the next rate period, they objected on grounds that the surcharge was discriminatory. FERC determined that the surcharge was "not unduly discriminatory vis-à-vis other customers." *Southeastern Power Admin.*, 55 F.E.R.C. ¶¶ 61,016, 61,045 (1981). When the objecting customers filed suit, the Fourth Circuit agreed with FERC that "the decision to correct for past cost underrecoveries through a surcharge is not arbitrary or capricious, or in violation of the law and, therefore, is within Southeastern's discretion."

FERC has also specifically endorsed this concept:

> The prohibition against retroactive ratemaking contained in the Federal Power Act does not apply to PMAs, including Southeastern, that operate subject to a different statutory and regulatory scheme. Indeed, the Flood Control Act 1944, as amended, 16 U.S.C. § 825s (1988), and the relevant regulations, including Department of Energy Order RA 6120.2 at 4-5, expressly allow costs not recouped in one time period to be recovered in another, later time period so as to ensure recovery of both the costs of producing power and [recovering] the Federal investment.

Southeastern Power Admin., 55 F.E.R.C. ¶¶ 61,016, 61,045 (1981). In other situations, FERC has also approved rates that SEPA and the Southwestern Power Administration have designed to recover revenue shortfalls incurred under previous rate schedules. *Southwestern Power Admin.*, 18 F.E.R.C. ¶¶ 61,052, 61,088 (1982); *Southeastern Power Admin.*, 23 F.E.R.C. ¶¶ 61,403, 61,895 (1983). Indeed, BPA has availed itself of surcharges to recover past underrecoveries of costs. In the early 1980s, BPA included deferral adjustments in prospective rates to compensate for seven consecutive years of deferral of payments to the U.S. Treasury. *See*, *e.g.*, 1983 Final Administrator's ROD, WP-83-A-02, at 171.

Therefore, arguments that BPA has engaged in impermissible retroactive ratemaking lack merit; the courts and FERC have stated that the plain language of the Flood Control Act permits retroactive ratemaking. Indeed, BPA is different in other respects from the "regulated companies" subject to the filed rate doctrine under the FPA and Natural Gas Act such as those involved in cases cited by APAC, IPUC, and others. First, BPA is not governed by the FPA or the Natural Gas Act, 16 U.S.C. §§ 832-832m.[6] BPA's general authority is derived from five organic statutes, including the Flood Control Act; the Bonneville Project Act of 1937 (16 U.S.C. §§ 832-832m); the Regional Preference Act (16 U.S.C. §§ 837-837h); the Federal Columbia River Transmission System Act (16 U.S.C. §§ 838-838l); and the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the Northwest Power Act) (16 U.S.C. §§ 839-839h). BPA's ratemaking authority is derived from the Bonneville Project Act, the Federal Columbia River Transmission System Act, the Northwest Power Act, and the Flood Control Act of 1944 (16 U.S.C. § 825s).

All of BPA's enabling statutes underscore the importance of cost recovery as a primary goal. They emphasize further that BPA must recover those costs through its rates. Thus, costs that exist, regardless of when incurred, must be paid by BPA's customers through rates because there is no other source from which BPA can generate revenues.[7] In this instance, BPA improperly allocated costs to the PF Preference rate. Because monies had already been paid out under the now-defective REP Settlement Agreements, BPA also faces a cost recovery problem, *i.e.*, how to recover any excessive payments of REP benefits. BPA elects to do so through its ratemaking authority and, as shown above, is not constrained by doctrines prohibiting retroactive ratemaking or the corollary filed rate doctrine.

FERC's limited role in approving rates developed by BPA supports this view. Under section 7(a)(2) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2), FERC's role in approving BPA's power rates is limited to consideration of whether rates "are sufficient to assure repayment of the Federal investment" and "are based upon the Administrator's total system costs." Under sections 824d and e of the FPA, FERC has much broader discretion to review IOUs' rates to determine if they are "just and reasonable" based upon many factors.

As noted in PPC's Initial Brief, section 9(e)(5) of the Northwest Power Act grants exclusive jurisdiction over suits challenging "final actions" of BPA in "the United States court of appeals for the region." PPC Br., WP-07-B-JP25-01, at 10, *citing* 16 U.S.C. § 839f(e)(5). Under section 9(e) of the Act, "final rate determinations" are included in the list of "final actions subject to judicial review" within the exclusive jurisdiction of the Ninth Circuit. *Id*. Thus, although FERC has authority to determine if BPA's proposed rates assure recovery of BPA's costs, FERC is not the final arbiter of BPA's rates and cannot apply any legal review standard other than the one set forth in the Northwest Power Act. Instead, in case judicial review of BPA's rates is sought, Congress granted the Ninth Circuit exclusive jurisdiction to review such challenges.

Clearly, FERC has no authority to apply standards other than those found in the Northwest Power Act and cannot make determinations based on standards that are applicable only to utilities regulated under the FPA and the NGA. Nor can FERC determine whether BPA's rates are in accordance with the Northwest Power Act or other enabling legislation. Because BPA's rates, in this instance, were subject to a Ninth Circuit challenge, they are not final due to the

[6] As noted above, the Supreme Court discusses the relevant provisions of the FPA and the Natural Gas Act interchangeably. *Id*. at 577, *quoting FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1953).
[7] This is in contrast to privately owned utilities, which can, when appropriate or necessary, turn to their shareholders to bear part of the cost of doing business.

Court's finding that they were not in accordance with law. (Discussed below is the distinction between "final rates" and "final action" under section 9(e) of the Northwest Power Act.) Accordingly, there is no final rate and no basis for suggesting that revising some aspects of non-final rates offends the filed rate doctrine or the general prohibition on retroactive ratemaking. As a consequence, arguments that BPA cannot revise rates declared final by FERC, pursuant to the filed rate doctrine or otherwise, are without merit. Such rates are simply not final as a legal matter. Although this result may seem odd given that the rates expired prior to the completion of judicial review, it is the proper legal conclusion.

BPA understands that "[r]etroactivity is not favored in the law." *See Bowen v. Georgetown University Hospital*, 488 U.S. 204, 208 (1988) *citing*, *e.g.*, *Greene v. United States,* 376 U.S. 149, 160 (1964); *Claridge Apartments Co. v. Commissioner*, 323 U.S. 141, 164 (1944); *Miller v. United States*, 294 U.S. 435, 439 (1935); *United States v. Magnolia Petroleum Co.*, 276 U.S. 160, 162 (1928). As the IPUC has noted, "a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms" because the "power to require adjustments for the past is drastic. It … ought not to be extended so as to permit unreasonably harsh action without very plain words." IPUC Br., WP-07-B-ID-01, at 5, *quoting Brimstone R. Co. v. United States*, 276 U.S. 104, 122 (1928).

However, as previously noted, the Supreme Court has stated that PMAs are "required by the *plain language* of [the Flood Control Act] to protect the public fisc by ensuring that federal hydro-electric programs recover their own costs and do not require subsidies from the federal treasury." *U.S. v. City of Fulton*, 475 U.S. 657, 668 (1986). DOE has also interpreted the language of the Flood Control Act to require PMAs to recover "operation and maintenance costs, purchased and exchanged power costs, interest expenses on the power investment, costs associated with the amortization of the capital investment, and *any deficit of unrecovered expenses which prior years' revenues failed to cover.*" *Central Elec. Power Coop., Inc., v. Southeastern Power Admin.*, 338 F.3d 333, 337 (4th Cir. 2003), *citing* DOE Order RA 6120.2 (Sept. 20, 1979) (emphasis added). All of BPA's enabling legislation emphasizes the importance of cost recovery through rates designed to achieve certain statutory goals. Therefore, arguments that BPA is precluded from conducting the proposed Lookback by the filed rate doctrine, or because it constitutes prohibited retroactive ratemaking, are incorrect.

3. *Even if Applicable, Principles Disfavoring Retroactivity Are Not Offended.*

Even if retroactivity principles were applicable, conducting a Lookback analysis to determine the appropriate level of REP benefits for the FY 2002-2006 rate period does not constitute prohibited retroactive rulemaking. *See*, *e.g.*, OPUC Br., WP-07-B-PU-02, at 3-5; IOU Br., WP-07-B-JP6-01, at 16-18. Rules and statutes operate retrospectively only when they attach new *legal* consequences to events completed before their enactment. *Landgraf v. USI Film Prods.*, 511 U.S. 244, 269 (1994) (1991 Civil Rights Act amendments not applied retroactively to allow jury trial in sexual harassment claim by employee) (emphasis added).

The Supreme Court has provided guidance for courts in evaluating the "retrospective" operation of a statute:

> [T]he court must ask whether the new provision attaches new legal consequences to events completed before its enactment. The conclusion that a particular rule operates "retroactively" comes at the end of a process of judgment concerning the nature and extent of the change in the law and the degree of *connection between the operation of the new rule and a relevant past event*.

Id. at 269 (emphasis added). In *Landgraf*, the Court found that "[s]ince the early days of this Court, we have declined to give retroactive effect to statutes burdening private rights unless Congress had made clear its intent." *Id*. at 270. The Court noted that the presumption against retroactivity has "consistently been explained by reference to the unfairness of imposing new burdens on persons after the fact" and concluded that "[r]equiring clear intent assures that Congress itself has affirmatively considered the potential unfairness of retroactive application and determined that it is an acceptable price to pay for the countervailing benefits." *Id*. at 272.

At the same time, the Court was clear that "[a] statute does not operate 'retrospectively' merely because it is applied in a case arising from conduct antedating the statute's enactment, or upsets expectations based in prior law." *Id*. at 269-70. Only if a law "takes away or impairs vested rights acquired under existing laws, or creates a new obligation, imposes a new duty, or attaches a new disability, in respect to transactions or considerations already past" is it subject to challenge on grounds of retroactivity. *Soc'y for Propagation of the Gospel v. Wheeler*, 22 F. Cas. 756, 767 (C.C.N.H. 1814) (Story, J.). Thus "the presumption against retroactivity is not violated by interpreting a statute to alter the future legal effect of past transactions." *Landgraf*, 511 U.S. at 293 (Scalia, J., concurring).

In this instance, BPA's Lookback Proposal does not have retroactive effect, in the legal sense, because it does not "render unlawful … an act lawful at the time it was done." *Ralis v. RFE/FL Inc.*, 770 F.2d 1121, 1127 (D.C. Cir. 1985). Instead, it remedies the harm done by an act that was unlawful at the time it was done, *i.e.*, entering into the invalid REP Settlement Agreements. Thus, the Lookback does not impair or take away vested rights. Because the Court found the REP Settlement Agreements contrary to law, REP participants had no right to the REP settlement payments to begin with, at least to the extent that preference customers were overcharged through an improper cost allocation. Also, because the REP Settlement Agreements are void *ab initio*, there is, in legal terms, no past transaction or consideration to which a new duty or disability could attach. Thus, there is no basis to argue that retroactivity should be prohibited in this case.

The Ninth Circuit upheld an EPA decision to require storm water discharge permits for inactive mining operations because "EPA's rule does not penalize inactive mine owners for mining activities or contaminated discharges that occurred in the past; it regulates discharges of contaminated storm water that occur in the future." *Am. Mining Cong. v. U.S. EPA*, 965 F.2d 759, 770 (9th Cir. 1992). Even though the court acknowledged that "the present contamination is the result of past mining activities," and that "the rule may frustrate the economic expectations of some inactive mine owners," EPA's rule was valid because “regulations are not retroactive merely because they require a change in existing practices” or create “administrative and economic burdens” that were not contemplated at the time the underlying actions were taken. *Id*. at 771-72.

Thus, the law does not categorically forbid agencies from imposing costs or creating rates in response to past events, as demonstrated by the court’s approval of the EPA’s decision to require storm water discharge permits for old mines. Similarly, the Lookback takes into account past over- or under-payments, but that does not raise retroactivity concerns. BPA intends only to remedy a legal violation that occurred in the past (*i.e.*, entering into the invalid REP Settlement Agreements) by attaching altered consequences (*i.e.*, remedying the resulting overcharges to preference customers) to future events (*i.e.*, debits against future REP benefits).

Moreover, retroactivity is characteristically only disfavored in situations where the affected parties have a strong basis for reliance on the rule or rates staying in effect. Particularly, retroactive rules should not be put into effect where those affected by them have a reasonable expectation of finality in the existing rules. That is not the case in this instance. When parties are on notice of a potential change in the way a rate will be calculated, it is impossible for them to reasonably suffer detriment through reasonable reliance on the agency’s prior position. “The rule against retroactive ratemaking … ‘does not extend to cases in which [customers] are on adequate notice that resolution of some specific issue may cause a later adjustment to the rate being collected at the time of service.’” *OXY USA, Inc. v. FERC*, 64 F.3d 679, 699 (D.C. Cir. 1995), *quoting Clearinghouse*, 965 F.2d at 1075. The court listed “equity” and “predictability” as the policy goals behind the filed rate doctrine and found that these “are not undermined when the Commission warns all parties involved that a change in rates is only tentative and might be disallowed.” *Id*.

In a later case dealing with the same underlying controversy about the valuation of oil shipped in the Alaska pipeline, the court held that FERC abused its discretion in failing to apply retroactively a change in a rate calculation methodology because “[a]ny reliance that [the parties] may have placed on the rates in light of [the ongoing legal] proceedings was unwarranted.” *Exxon Co., U.S.A. v. FERC*, 182 F.3d 30, 49 (D.C. Cir. 1999). Thus, a timely petition for judicial review of an agency’s ratemaking decision led the court to conclude that it was unreasonable for any parties to have relied on the rates because of the possibility that the court would invalidate the agency’s rate determination.

Because a timely challenge was brought to FERC’s approval of the WP-02 rates, all parties were on notice that the rates had still not undergone review by the Ninth Circuit and, from that standpoint, they were not approved on a final basis and might have to be revised as the result of a Ninth Circuit order. In this instance, the very issue that BPA is attempting to resolve was brought before the Ninth Circuit through challenges to both the REP Settlement Agreements and the rates that supported them.

Parties cannot now be heard to argue that they had some expectation of finality or reasonably relied on the finality of the rates. It does not matter that FERC approved the rates, based on its limited scope of review, or that the rates had expired by their own terms when the Ninth Circuit reached its decision. The rates are simply not final until the Ninth Circuit has resolved timely challenges to the rates brought pursuant to section 9(e) of the Northwest Power Act. 16 U.S.C. § 839(e)(i). Thus, customers have no basis to argue that they reasonably relied on the rates being fixed.

D. Conclusion

Agencies can, and should, undo what they have wrongfully done, and an agency's power is at its maximum when attempting to remedy an injury of its own making. As discussed elsewhere, agencies have great power to craft appropriate remedies, especially when responding to remand orders. Failure to use that power in this instance, where the Court's command is clear, would be a violation of BPA's public duties. As the *Clearinghouse* court noted, "the general principle of agency authority to implement judicial reversals explored in *Callery*" is necessary so that aggrieved parties will have an incentive to vindicate their rights by seeking judicial review.

In this instance, the court found that the WP-02 PF Preference rate was not in accordance with law and, as a result, preference customers were overcharged. Preference customers who have overpaid because of an unlawful rate determination should be entitled to relief for injuries caused by the defective rates. In this case, even though the Northwest Power Act, like the NGA, does not provide explicit statutory authority for retroactively providing refunds, the equitable power of an agency to undo its mistakes allows it to give effect to the Court's decision by undertaking actions which might not typically be viewed as being in the normal course of the agency's activities. In sum, BPA has a responsibility to address the errors identified by the Court, with due regard to any equitable considerations that should be afforded the IOUs that entered into REP Settlements based on a good faith belief in their legality.

Decision

The Supplemental Proposal falls within the scope of the remand directed by the Court in Golden NW and is not arbitrary and capricious.

Issue 2

Whether BPA may adjudicate the contract rights of parties when determining the ratemaking treatment for those contracts.

Parties' Positions

The IOUs argue BPA may determine its ratemaking treatment of contracts and contract provisions, but such determinations do not constitute a binding adjudication of contract rights. IOU Br., WP-07-B-JP6-01, at 10-11.

BPA Staff's Position

Because this is a legal issue, BPA Staff did not address the issue.

Evaluation of Positions

The IOUs state if BPA seeks a declaration of the validity or invalidity of its rights and obligations under a BPA contract that is binding on the other party to that contract, BPA must seek that declaration from a court of competent jurisdiction (except as may be provided by a provision in the contract providing for such declaration of contract rights by an arbitrator or by some other party). IOU Br., WP-07-B-JP6-01, at 10, *citing*, *e.g.*, 28 U.S.C. § 2201, *et seq*. The IOUs further state that BPA cannot make a declaration of its own contract rights and obligations – or a declaration of the validity of such contract rights and obligations – binding on the other parties to the contract. *Id*.

BPA is not unilaterally declaring the validity or invalidity of its rights and obligations under a BPA contract. However, BPA must assess such factors, and many others, from its own perspective, in order to establish the ratemaking treatment for such contracts. BPA agrees that such actions are not a binding declaration of the rights of the parties under the contracts, and only a court vested with authority to make such determinations can adjudicate rights and obligations under a contract.

Decision

BPA may properly assess the relevance and significance of contracts in ratemaking, based on its own independent assessment, but such determinations do not constitute a binding adjudication of contract rights.

Issue 3

Whether BPA's Lookback proposal is flawed because it either provides retrospective relief to preference customers or provides such relief improperly.

Parties' Positions

WPAG argues that the Ninth Circuit's opinions in *PGE* and *Golden NW* can have only one meaning and that BPA must identify the amounts of the illegal REP Settlement costs included in the preference customer rates set in the WP-02 and WP-07 rate cases (the PF-02 and PF-07 rates, respectively) and return such amounts to the preference customers who suffered these illegal overcharges. WPAG Br., WP-07-B-WA-01, at 6.

The WUTC, in contrast, believes the rates before BPA in this docket are only the WP-07 rates and the FY 2009 rates, and BPA lacks authority to provide refunds in connection with the FY 2002-2006 rates. WUTC Br., WP-07-B-WU-01, at 4-9.

The IOUs argue the Lookback remedy is flawed because it is too speculative. IOU Br., WP-07-B-JP6-01, at 14.

BPA Staff's Position

This is a legal issue; BPA Staff had no position on this issue.

Evaluation of Positions

WPAG argues that in *PGE*, the Ninth Circuit determined that the REP Settlements violated sections 5(c) and 7(b)(2) of the Northwest Power Act, were beyond BPA's authority, and were void. WPAG Br., WP-07-B-WA-01, at 5, *citing PGE*, 501 F.3d at 1036-1037. WPAG contends the section 7(b)(2) rate test performed by BPA in the WP-02 rate proceeding limited the amount of REP Settlement costs BPA could include in preference customer rates and controls now. *Id*. Turning to *Golden NW*, WPAG states the Court relied on *PGE* for the proposition that the WP-02 rates improperly burdened preference customers with the costs of the REP Settlements, in plain violation of the section 7(b)(2) rate test performed by BPA in that case. *Id*. at 6. The Ninth Circuit remanded the matter to BPA to "…set rates in accordance with this opinion." *Id*. at 1053. WPAG concludes the Court's decisions require BPA to identify the amounts of the illegal REP Settlement costs included in the preference customer rates set in the WP-02 and WP-07 rate cases (the PF-02 and PF-07 rates, respectively) and return such amounts to the preference customers who suffered these illegal overcharges. *Id*. WPAG argues further that the records from the WP-02 and WP-07 rate cases contain all of the information needed by BPA to comply with the remand directive of the *Golden NW* decision. *Id*.

To the extent WPAG argues that BPA should develop a remedy for overcharges to the preference customers during the FY 2002-2006 period, BPA essentially agrees. However, BPA disagrees with WPAG's apparent assertion that the Lookback can be accomplished by reference only to the rate case record for that period. As explained elsewhere in this Draft ROD, BPA necessarily and properly reexamined certain issues from that case in order to more closely track what would have actually occurred in the absence of the REP Settlement Agreements. *See* Section 2.6.3. It is beyond doubt that events would have transpired very differently if the only option made available by BPA for the REP had been the traditional REP governed by the RPSAs, instead of the REP Settlement Agreements. In summary, the WP-02 record was based on the establishment of base rates which, soon after their establishment, proved to be inadequate to recover BPA's costs. BPA reopened its rate case and, based on the facts then before it, developed cost recovery adjustment clauses to ensure BPA could recover its costs. Due to significant increases in BPA's loads and market prices since the establishment of the base rates, such rates, which were developed using the section 7(b)(2) rate test, were fatally flawed. Because the base rates would have failed to recover BPA's costs as required by law, FERC could not have approved the rates and BPA could not have charged them to its customers. When BPA had to revise its base rates, the IOUs had already executed the REP Settlement Agreements. The PF Exchange rate was not relevant to the REP Settlement Agreements with the IOUs, and the IOUs had no reason to raise 7(b)(2) issues. BPA therefore was comfortable simply adopting adjustment clauses to ensure cost recovery. In the absence of the REP Settlement Agreements, however, BPA would not have simply adopted adjustment clauses, but would have revised base rates to ensure the proper incorporation of new section 7(b)(2) rate test results into the development of BPA's rates and the forecast of BPA's REP costs. If, for its Lookback analysis, BPA used its fatally flawed base rates, which relied on the flawed section 7(b)(2) rate test results and the limited record that established the preliminary base rates, the result would be an unjustifiable windfall to preference customers and an unjustifiable penalty to BPA's IOU customers. By reviewing the record on its true facts, including dramatic changes in loads and market prices, all parties have the ability to address all relevant issues. This compares favorably to a limited review ignoring the facts and producing an absurd result, as suggested by WPAG.

In its Brief on Exceptions, APAC makes arguments similar to WPAG's. APAC argues that revisiting the 2002-2006 rates exceeds the scope of the remand and constitutes retroactive ratemaking. In support of this conclusion, APAC states:

All that the Ninth Circuit decision allows the Administrator to do is determine the amount of overpayments and refund them. To determine the amount of overpayments requires only summing the total of the REP Settlement costs included in Preference Customer rates, and then determining the amount of REP benefits for which the Preference Customers are otherwise responsible through the §7(b)(2) rate test. Those two amounts are available without reopening the WP-02 case. This does not involve any unique agency experience or expertise entitled to deference. It is not necessary for BPA to re-run the § 7(b)(2) rate test as that test was already performed as part of the original WP-02 case resulting in the rates adopted by the Administrator and given final approval by FERC.

APAC Br. Ex., WP-07-R-AP-1 at 1. Making essentially the same argument in its Brief on Exceptions, WPAG argues that BPA has exceeded the scope of the Ninth Circuit remand, which limits BPA's discretion on remand to performing two functions:

The first is to determine the amount preference customers were overcharged due to the illegal inclusion of the costs of the REP Settlements in their BPA rates. The second is to determine a method to timely reimburse preference customers for the illegal overcharges imposed on them under the WP-02 and WP-07 rates.

WPAG Br. Ex., WP-07-R-WA-1 at 7. WPAG also appears to believe that the only way for BPA to calculate the overpayments under the REP Settlement Agreements is by way of reference to the existing WP-02 and WP-07 rate case records:

Hence, the record in both the WP-02 and WP-07 cases contains the preference customer rate produced with the application of the § 7(b)(2) rate ceiling test, as well as the PF-02 and PF-07 rates with the unlawful inclusion of REP Settlement costs. … The difference between these two rates established in each of the WP-02 and WP-07 rates cases constitutes the amount the *GNA* decision identified as being illegally allocated to preference customers.. … By failing to use the decision made in the WP-02 and WP-07 rate cases … BPA has exceeded the scope of permissible actions in responding to the remand order.

Id. WPAG and APAC generally describe some of the fundamental decisions that BPA must make in this proceeding. However, BPA does not agree that these are the only functions mandated by the Court. BPA also does not agree that the Court intended BPA's response to the remand to be reduced to essentially ministerial functions. In short, BPA does not read the Ninth Circuit's opinions in *PGE* and *Golden NW* as requiring the approach preferred by APAC and

WPAG. First, if there were only one way of reasonably responding to the remand, it seems logical to conclude that the Court would have given explicit instructions to BPA in that regard rather than an open-ended instruction to "set rates in accordance with this opinion." Indeed, the Court never expressed in its opinions that BPA make a refund of any kind.

Second, the general nature of the instruction provides further support to BPA's view that the Court expects BPA to apply its agency experience and expertise in this matter and does not intend for BPA to respond to the remand by simply making the calculations proposed by APAC and WPAG. The Court implicitly recognized the complexities involved in setting rates, which the Court remanded back to BPA to determine.

Third, BPA finds WPAG's and APAC's approach to be unnecessarily heavy handed and inequitable. The response proposed by WPAG and APAC makes no allowance for the possibility that the WP-02 record reflects an amount of traditional REP benefits that would not have been proper or sustainable in the absence of the REP Settlements. Such an approach would appear to unfairly place the risk of any errors in this regard squarely on the shoulders of the residential and small farm consumers of the IOUs who participate in the REP. These consumers were not responsible for development of the REP Settlement Agreements. BPA believes equity applies and that a reasonable attempt needs to be made to discern the level of benefits they would have received if the Settlement Agreements had not existed. Thus, it is reasonable to conduct this proceeding in a manner that assures that residential and small farm consumers of IOUs receive what they were due. WPAG and APAC's suggested approach does not provide any such safeguard and this strikes BPA as unreasonable.

The WUTC takes a different view, arguing the Court decisions do not require BPA to make refunds available to injured preference customers for overcharges that occurred under the FY 2002-2006 rates. As stated in its Initial Brief:

Notably, the Ninth Circuit did not find that the Priority Firm (PF Preference) rate in WP-02 was excessive, nor did the Court remand for BPA to calculate refunds. Rather, the Court remanded "to set rates." By May 3, 2007, when the Ninth Circuit ruled in *Golden* [*NW*], the WP-02 rates at issue in that case had expired. Consequently, when the Court referred to "setting rates," it must have meant either revising interim rates that are subject to refund (*i.e.*, WP-07 rates) or setting future rates (*i.e.*, FY 2009 rates), or both.

WUTC Br., WP-07-B-WU-01, at 4. In the WUTC's view, BPA has no ability to provide refunds applicable to the FY 2002-2006 rates because the rates have expired, leaving BPA with only the options of adjusting the interim WP-07 rates and the newly developed FY 2009 rates. *Id*. at 5.

The IOUs make similar arguments. They assert that the remedies proposed in this proceeding inherently involve speculative attempts to calculate how much of particular BPA costs were paid by various BPA customers. IOU Br., WP-07-B-JP6-01, at 14. In support, the IOUs point to Staff's testimony:

To begin with, it is virtually impossible for anyone to calculate how much of any particular BPA cost any particular customer pays. Any attempt to do so is extremely speculative and almost certainly overstated if done in isolation of the total picture of BPA's ratemaking allocations and adjustments.

Id., *citing* Fisher, *et al.*, WP-07-E-BPA-79, at 11. The IOUs conclude that such speculation is arbitrary and capricious. *Id*. Finally, they argue that the Ninth Circuit did not order BPA to fashion a Lookback remedy, so BPA is precluded from making that relief available. Consequently, when the Ninth Circuit referred to "setting rates", it was necessarily referring to setting *future* rates. In short, BPA was not ordered to, and cannot, "correct" expired rates. *Id*. at 15.

BPA does not agree with the WUTC and the IOUs in this regard. The WUTC's and the IOUs' positions appear to be grounded in the notion that the WP-02 rates cannot now be touched because they "expired," which they appear to believe gives the FY 2002-2006 rates some stamp of finality. This is not the case. The WP-02 rates were approved by FERC pursuant to the limited cost recovery standard articulated at section 7(a)(2) of the Northwest Power Act. That action alone, however, does not make the rates final. It means only that they are then a *final action* subject to review in the Ninth Circuit for legal sufficiency under section 9(e) of the Northwest Power Act. 16 U.S.C. § 839f(e). The WP-02 rates were, indeed, challenged in *Golden NW*. The fact that the lengthy review process did not end until after the rates had expired by their own terms does not provide a basis for essentially thwarting the Court's exercise of jurisdiction by rendering the rates immune from further action to correct legal errors on remand. Such a result would stand the statutory review scheme on its head and wrongly subvert the ability of the Ninth Circuit to perform its statutory function in reviewing BPA's final actions. Nor would it be just for BPA to essentially deprive preference customers of relief for the FY 2002-2006 time frame. Despite the fact that the WP-02 rates have been supplanted by other rates, preference customers, having prevailed by convincing the Court that the rates were legally defective, still retain the right to a remedy for overcharges during the FY 2002-2006 period.

As pointed out elsewhere, in *Golden NW*, the Court found that the WP-02 PF Preference rate was set in a manner that inappropriately allocated costs of the REP Settlement Agreements to BPA's preference customers. As a result, the Court remanded to BPA with instructions to set rates "in accordance with this opinion." In its discussion in *PGE*, the Court found that Congress's "clear instruction" in the Northwest Power Act was that "costs of the REP program must be charged in a supplemental rate against other BPA customers, and not against preference customers." *PGE*, 501 F.3d 1009 (9th Cir. 2007). "The net effect is that BPA's preference customers are paying for the REP settlement … in plain violation of the [Northwest Power Act]." *Id*. at 4880.

As to the IOUs' assertion that any Lookback remedy is fatally flawed because it involves "speculation," BPA notes that many, if not most, ratemaking involves some degree of forecasting regarding future events. Speculation and forecasting, however, are not the same. In the instant case, there are known facts and facts that necessarily result from such facts. For example, BPA knows that the REP Settlement Agreements were executed and implemented beginning in FY 2002. BPA knows that in the absence of the REP Settlement Agreements, the IOUs would have exercised their right to participate in the REP. BPA knows the 1984 ASC Methodology was in effect at that time. BPA knows the increased forecast loads and market prices that existed at the time BPA was revising its flawed WP-02 base rates. Thus, the Lookback is not an exercise in speculation. Furthermore, in BPA's view, the Court specifically found (a) that the REP Settlement Agreements were not supported by statutory authority; (b) the rates supporting those settlements were, therefore, defective; and (c) the effect of the statutory violation was that preference customers were charged impermissibly higher rates in contravention of the Northwest Power Act. Thus, the remand order plainly cannot be fully satisfied without rectifying what the Court itself describes as a "plain violation" of the law, which includes providing a remedy for unlawful REP costs included in the WP-02 PF Preference rate. This is true even if BPA is required to engage in some degree of reasonable forecasting or estimating.

Decision

Consistent with the Court's decisions, BPA will determine the amount by which preference customers were overcharged under BPA's WP-02 rates by conducting a Lookback that revisits certain salient issues from the WP-02 rate proceeding. BPA believes that this approach provides a lawful, reasonably accurate and equitable resolution of the legal deficiencies described in the Ninth Circuit's remand order.

Issue 4

Whether the Lookback remedy constitutes impermissible retroactive rulemaking.

Parties' Positions

The IOUs argue that the Lookback remedy constitutes impermissible retroactive rulemaking. IOU Br., WP-07-B-JP6-01, at 16-18. The IOUs note that, generally, under the retroactive rulemaking doctrine, an agency may not adopt retroactive rules in the absence of express Congressional authorization. *Id*., *citing Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988).

The OPUC makes similar arguments. OPUC Br., WP-07-B-PU-02, at 3-5.

BPA Staff's Position

BPA Staff noted that whether retroactive ratemaking applies to Federal power marketing agencies is a legal matter. Forman, *et al.*, WP-07-E-BPA-76, at 3-4. However, BPA's approach to respond to the Ninth Circuit's May and October 2007, rulings does not occur in the typical context in which retroactive ratemaking issues arise. *Id*. BPA is not proposing to adjust rates or bills from the past and collect or disburse funds from or to customers based on such adjustments; rather, BPA is rerunning its rate models for the specific purpose of determining the Lookback Amounts for the IOUs that will be dealt with on a prospective, and not retrospective, basis. *Id*. This is a much different procedure than reestablishing past rates and producing new bills for customers. *Id*.

Evaluation of Positions

The IOUs cite a judicial opinion stating:

It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress… Retroactivity is not favored in the law. Thus, congressional enactments and administrative rules will not be construed to have retroactive effect unless their language requires that result… By the same principle, a statutory grant of legislative rulemaking authority will not, as a general matter, be understood to encompass the power to promulgate retroactive rules unless that power is conveyed by Congress in express terms… Even where some substantial justification for retroactive rulemaking is presented, courts should be reluctant to find such authority absent an express statutory grant.

IOU Br., WP-07-B-JP6-01, at 17, *citing Bowen*, 488 U.S. at 208-209. The IOUs go on to say that the Northwest Power Act does not provide BPA with express authority to engage in retroactive rulemaking or to adopt rates retroactively. *Id*. Thus, the IOUs conclude, BPA does not have authority to adopt retroactive rates. *Id*. at 18, *citing Bowen*, 488 U.S. at 208-209.

The IOUs believe the prohibition on retroactive ratemaking prevents BPA from adopting a Lookback remedy and argue that such a result comports with the concept of fundamental fairness. *Id*. The IOUs note that parties to the REP Settlement Agreements relied on those Agreements, passing through the REP payments to their residential and small farm customers. *Id*. According to the IOUs, the Lookback is therefore inequitable and an exercise in speculation that cannot place parties in the position they might otherwise have been in, given so many variables. *Id*. Moreover, the IOUs contend that their argument is supported by the fact that:

> [n]o stay was sought or obtained of: (i) BPA's decision to enter into and perform the REP settlement agreements; (ii) BPA's adopting or implementing its (WP-02 or WP-07) power rates; (iii) BPA's disbursement of funds under the REP settlement agreements; or (iv) FERC's confirmation and approval of the WP-02 or WP-07 rates.

Id.

The OPUC similarly believes the Lookback remedy is prohibited retroactive rulemaking. The OPUC notes that ratemaking is a legislative function, rather than a judicial one:

A judicial inquiry investigates, declares and enforces liabilities as they stand on present or past facts and under laws supposed already to exist. That is its purpose and end. Legislation, on the other hand looks to the future and changes existing conditions by making a new rule, to be applied thereafter to all or some part of those subject to its power. *The establishment of a rate is the making of a rule for the future and therefore is an act legislative not judicial in kind*[.]

OPUC Br., WP-07-B-PU-02, at 3, *citing Prentis v. Atlantic Coast Line Co.*, 211 U.S. 210, 226 (1908) (emphasis by the OPUC). The OPUC points out that Congress has stated that BPA's rates are rules, and that the record for review of a final determinations regarding rates "shall be supported by substantial evidence in the *rulemaking* record required by section 839e(i) of this title." *Id*. *citing* 16 U.S.C. § 839e(i) (emphasis by the OPUC).

Based on its reading of the cases, the OPUC concludes that the ratemaking scheme embodied in section 7 of the Northwest Power Act contemplates that rates will be set prospectively, explaining that the Act provides that the Administrator shall establish rates and that such rates shall be "revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power." *Id*. at 4, *citing* 16 U.S.C. § 839e(a)(1). Because the Lookback Proposal is retroactive rulemaking and BPA has no express Congressional authorization to engage in retroactive rulemaking, the OPUC argues that the Administrator lacks authority to conduct the Lookback analysis. *Id*. This is true, according to the OPUC, even though BPA is responding to a remand order. *Id*. The OPUC argues that the Court's opinion in *Bowen* stands for the proposition that any authorization for retroactive rulemaking must be statutory, stating the fact that a court has remanded orders to BPA does not mean that it can retroactively correct errors identified by the court in absence of statutory authority authorizing a retroactive correction. *Id*. Finally, the OPUC argues that a Lookback remedy is inappropriate because the WP-02 rates became final when approved by FERC. *Id*. at 5. The OPUC states that an agency may make reparations orders for a rule that never became final, but FERC's approval of the rates divests the Administrator of that authority because the rates become "final" at that point. *Id*.

BPA respectfully disagrees. As noted earlier, FERC's approval of BPA's rates based on its limited scope of review, as outlined in section 7(a) of the Northwest Power Act, does not make BPA's rates final. The statute authorizing FERC's limited review states only that the rates "shall become effective" upon FERC review, not that the rates are vested with any finality. 16 U.S.C. § 839e(a)(2). FERC reviews BPA's power rates only for cost recovery purposes and has no power to review other substantive and legal challenges to the rates. If FERC's review made BPA's rates final, and therefore unreviewable by the Administrator after a subsequent judicial ruling, the result would be to divest the Ninth Circuit of its jurisdiction over the rates by creating a situation where BPA would be unable to address the Court's rulings because to do so would run afoul of the supposed "finality" created by FERC's approval. The result would be that parties litigating ratemaking issues in the Ninth Circuit and prevailing on those issues would be thwarted with respect to receiving a remedy and would essentially be left in the same place they were prior to the litigation.

To the contrary, BPA's rates are not, and cannot be, considered final (except for purposes of judicial review) if a timely petition for review of them has been filed with the Ninth Circuit Court of Appeals. To suggest otherwise, after years of litigating the propriety of the WP-02 rates in the Ninth Circuit, makes little sense. FERC's approval simply marks the point at which BPA's rates become a "final action," subject to judicial review pursuant to section 9(e) of the Northwest Power Act. 16 U.S.C. § 839f(e). Consequently, the WP-02 rates are still not final because they were found to be legally defective and remanded by the Ninth Circuit Court of Appeals.

Moreover, BPA disagrees with the OPUC's and the IOUs' assertion that any ability to conduct retroactive ratemaking must be expressly granted by Congress. The general prohibition in the absence of Congressional authorization, relied upon by the OPUC and the IOUs and described in *Bowen*, is not applicable in this situation. The Ninth Circuit, in a case involving the ability of the Social Security Commissioner to make adjustments to Supplemental Social Security Income (SSSI) benefits based on changes in a recipient's monthly income, noted that "[a]lthough the Court in *Bowen* … indicated only how retroactive rulemaking would 'generally' be received, the logic of the Court's decision clearly rests on an absolute bar against an agency's retroactive rulemaking absent statutory authority." *Newman v. Apfel*, 223 F.3d 937, 942 (9th Cir. 2000) (emphasis added). Nonetheless, the court went on to distinguish *Bowen* – where the agency initiated the effort to apply rules retroactively – from cases such as *Livermore v. Heckler*, 743 F.2d 1396, 1405 (9th Cir. 1984), another Social Security benefit dispute where the court ordered "recalculation of benefits erroneously calculated as well as prospective implementation of the correct [rule]." The agency had the authority to make retroactive corrections in response to a judicial determination because "*[t]he capacity of the courts to order retroactive relief has never been questioned.*" *Newman*, 223 F.3d at 942 (emphasis added). For this reason, the Ninth Circuit upheld the district court's determination that "the Commissioner's *discharging a judicial order to make Newman whole would not require the Commissioner to promulgate retroactive regulations in the way that the Court contemplated in Bowen.*" *Id*. (emphasis added). Thus, "administrative agencies have broad discretion in fashioning remedies. This is particularly true when an agency is responding to a judicial remand. Courts have found that an agency can give effect to a judicial decision by taking action that it could not otherwise take under normal circumstances." *In the Matter of QualComm Incorporated*, FCC Order #FCC00-189, June 8, 2000. The Supreme Court articulated this view in *United Gas v. Callery Properties*, 382 U.S. at 229 (1965), where it upheld a decision by the Federal Power Commission to issue refunds after a rate decision had been overturned, despite a previous holding that the Commission "has no power to make reparation orders." The Court found instead that, in this instance, "an agency, like a court, can undo what is wrongfully done by virtue of its order." *Id*., *quoting Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 618 (1944). *Id*. Because the Commission "could properly conclude that the public interest required the producers to make refunds," the Court upheld the action as a proper response to the remand. *Id*. Even though the Court had previously held in *Hope Natural Gas* that the NGA did not provide any statutory authority for the Commission to make reparation orders, the Court in *United Gas* held that where the agency's order is overturned by the reviewing court "an equitable power to order refunds may fairly be implied." *Id*. at 234 (Harlan, J., concurring).

Other opinions are in accord. The D.C. Circuit has held, for example: "If a successful appeal of an erroneous FERC decision … could not be enforced retroactively, a [utility's] incentive to vindicate its rights under [law] through judicial review would be similarly diminished. We do not believe Congress intended [this] result." *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1074 (D.C. Cir. 1992). In a separate case, the Court described the *Clearinghouse* opinion as follows: "*Clearinghouse* involved a FERC order interpreting whether a section of the Natural Gas Act (NGA) dealing with periodic rate adjustments called for the periodic adjustment of depreciation expenses." *Pub. Utilities Comm'n of State of Cal. v. FERC*, 988 F.2d 154, 162 (D.C. Cir. 1993). There, FERC's initial order was reversed and remanded. On remand, FERC adopted a different view and ordered that its new interpretation be applied retroactively to permit the pipeline company to bill its shippers for "recoupment" payments. *Id*. Finding that "the NGA is silent as to the effect of a judicial invalidation of a FERC decision," the Court applied "the general principle of agency authority" to uphold FERC's authority to order "recoupment of losses caused by its error." *Clearinghouse*, 965 F.2d 1073-74. Similarly, in *Pub. Utilities Comm'n*, 988 F.2d at 162-163 *quoting Clearinghouse*, 965 F.2d at 1074-1075, the Court, evaluating an "illegal order," which "induced, even if it did not compel," a pipeline company to adopt a "gas inventory charge," held that FERC on remand had the authority to "order[] recoupment of losses caused by its errors" to prevent "pipelines [from being] 'substantially and irreparably injured' by FERC errors [leaving] judicial review … powerless to protect them from much of the losses so incurred."

As BPA interprets the Court's remand in *Golden NW*, it is clear that, due to the finding in *PGE* that the REP Settlement Agreements were contrary to law, the WP-02 rates were defective to the extent that preference customers were overcharged for REP benefits in excess of the rate ceiling established by sections 7(b)(2) and 7(b)(3) of the Northwest Power Act. In order to comply with the remand order, BPA must correct the overcharges to preference customers caused by the illegal REP Settlement Agreements. Thus, BPA's choice to adopt a Lookback remedy does not offend the prohibition on retroactivity described in *Bowen*. Similarly, contrary to the IOUs' argument, this result is fundamentally fair. What would be unfair and inequitable would be to leave the preference customers without a remedy for rates that were found defective as a result of their legal challenge.

Although the parties have not specifically raised the issue, it is worth noting that the relief BPA intends to afford the preference customers is not prohibited by the Administrative Procedures Act (APA). The APA prohibits awards of money damages, but there is no bar to specific relief, even when it involves return of money wrongfully withheld. A court may not award money damages in response to a legal challenge under the APA. Provisions of the APA are explicit in this regard:

> A person suffering legal wrong because of agency action, or adversely affected or aggrieved by agency action within the meaning of a relevant statute, is entitled to judicial review thereof. An action in a court of the United States *seeking relief other than money damages* and stating a claim that an agency or an officer or employee thereof acted or failed to act in an official capacity or under color of legal authority shall not be dismissed nor relief therein be denied on the ground that it is against the United States or that the United States is an indispensable party… Nothing herein (1) affects other limitations on judicial review or the power or duty of the court to dismiss any action or deny relief on any other appropriate legal or equitable ground; or (2) confers authority to grant relief if any other statute that grants consent to suit expressly or impliedly forbids the relief which is sought.

5 U.S.C. § 702 (emphasis added).

In spite of the statutory bar on awards of money damages under the APA, the courts are able to award specific relief, which can include ordering repayment of money that a petitioner is entitled to by statute. As explained in *America's Community Bankers v. F.D.I.C.*, 200 F.3d 822 (D.C. Cir. 2000):

> [W]here a plaintiff seeks an award of funds to which it claims entitlement under a statute, the plaintiff seeks specific relief, not damages. *See e.g.*, *Bowen*, 487 U.S. at 901, 108 S. Ct. 2722; *Maryland Dep't of Human Resources*, 763 F.2d at 1446-1448; *National Ass'n of Counties v. Baker*, 842 F.2d 369, 373 (D.C. Cir.1988); *Aetna Cas. & Sur. Co. v. United States*, 71 F.3d 475, 478-79 (2d Cir.1995); *Dia Navigation Co. v. Pomeroy*, 34 F.3d 1255, 1266-67 (3d Cir.1994). In the present case, Bankers maintains that the statutory scheme, as it was for the fourth quarter of 1996, required the FDIC to provide for a FICO assessment refund in the revised assessment schedules promulgated in December 1996. If Bankers is correct that the FDIC violated its statutory obligation by adopting revised assessment schedules which permitted an overcharge, then under established and binding precedent, Bankers' claim represents specific relief within the scope of 5 U.S.C. § 702, not consequential damages compensating for an injury. That the FDIC no longer possesses the precise funds collected is not determinative of this analysis.

Id. at 829-830. *America's Community Bankers* also provides support for providing refunds prospectively over a period of time, as BPA is determining it will do in returning any Lookback overcharges to the preference customers:

> [E]ven *if we were to order a refund in this case, no transfer of funds would be necessary to follow our command*. At oral argument, the FDIC conceded that it had the authority to offset Bankers' members' future FICO assessments by the amount of any refund this court might order. In other words, if we found for Bankers on the merits, *we could order the FDIC to give them a credit against future FICO assessments as opposed to a cash refund of past assessments*. Bankers agreed that such a remedy would be functionally equivalent to the relief it seeks. These concessions render the FDIC's cash position both practically and legally irrelevant. For these reasons, we hold that the remedy sought by Bankers does not constitute money damages. Thus we have power under 5 U.S.C. § 702 to consider the merits of Bankers' claim.

Id. at 831. In sum, crediting public preference customers for their past overpayments would be restoring money to the preference customers that was taken due to an agreement that is not in accordance with law. Providing such credits would be providing specific relief and would not violate the APA's prohibition on the payment of money damages.

Nor does BPA believe that the preference customers should be deprived of a remedy simply because no stay was sought, as suggested by the IOUs and others. IOU Br.,WP-07-JP6-01, at 14. Such logic might have some force in a situation where there was a high probability of irreparable harm in the absence of a stay, as in a case, for example, where logging or mining was to be performed, and continued action might create irreversible environmental degradation. In that situation, a request for a stay might be expected or required. In this instance, however, the bottom line is that petitioners are entitled to relief. Recompense can be calculated and paid at a future time without injury to the parties. Thus, a stay would serve no useful purpose and would only delay the development and implementation of rates and contracts on an ongoing basis.

Decision

The Lookback remedy does not constitute impermissible retroactive rulemaking.

Issue 5

Whether the Lookback constitutes impermissible retroactive ratemaking.

Parties' Positions

The WUTC, APAC, and IPUC argue that the Lookback remedy is prohibited retroactive ratemaking. WUTC Br., WP-07-B-WU-01, at 6-7; APAC Br., WP-07-B-AP-01, at 26-33; and IPUC Br., WP-07-B-ID-01, at 4-9.

Cowlitz and PPC take the opposing view that BPA's actions do not involve prohibited retroactive ratemaking. Cowlitz Br., WP-07-B-CO-01, at 70-71; PPC Br., WP-07-B-JP25-01, at 10-13.

BPA Staff's Position

BPA Staff noted that whether retroactive ratemaking applies to Federal power marketing agencies is a legal matter. Forman, *et al.*, WP-07-E-BPA-76, at 3-4. However, Staff's approach to respond to the Court's May and October 2007, rulings does not occur in the typical context in which retroactive ratemaking issues arise. *Id*. Staff is not proposing to adjust rates or bills from the past and collect or disburse funds from or to customers based on such adjustments; rather, Staff is rerunning its rate models for the specific purpose of determining the Lookback Amounts for the IOUs that will be dealt with on a prospective, and not retrospective, basis. *Id*. This is a much different procedure than reestablishing past rates and producing new bills for customers. *Id*.

Evaluation of Positions

The WUTC notes that retroactivity in ratemaking is generally disfavored in regulatory policy. WUTC Br., WP-07-B-WU-01, at 6, *citing* Westerfield, WP-07-E-ID-01, at 9, and Grinberg, *et al.*, WP-07-E-WA-05, at 17-18. The WUTC distinguishes between the WP-07 rates, as interim rates subject to change, and WP-02 rates, which it characterizes as permanent rates, which were not conditioned on the possibility of a refund. *Id*. at 6-7. As explained elsewhere, however, it is only after FERC has approved BPA's rates for cost recovery purposes that judicial review of the rates for legal sufficiency and other substantive matters can take place in the Ninth Circuit. To accept the WUTC's argument would undermine the purpose of section 9(e) of the Northwest Power Act and discourage litigants from seeking judicial review because their only remedy, based on the WUTC's finality argument, would be prospective in nature. In other words, parties could prevail in litigation only to find themselves essentially no better off than they were prior to the commencement of judicial review.

APAC argues the Court identified a specific error (*i.e.*, inclusion of REP settlement costs in the WP-02 rates) and the scope of BPA's authority on remand is limited to correcting that specific defect. APAC Br., WP-07-B-AP-01, at 29. Further revisions to the rates would run afoul of the rule against retroactive ratemaking. *Id*. APAC states that there are only three exceptions to the rule against retroactive ratemaking: (1) when parties are on notice a rate may later be modified; (2) when parties agree to retroactive application of a rate; and (3) when the agency's earlier order regarding the rate is reversed on appeal. *Id*. at 30. Neither of the first two circumstances is applicable in this case, according to APAC. *Id*. Preference customers have not agreed to retroactive application of a revised 7(b) (2) methodology and

[p]rior to the WP-07 [Supplemental] proceeding, BPA had published no notice that the rule might be changed with respect to its rates for [FY] 2002-2006. Neither the REP settlements nor the LRAs contemplated any revision of the §7(b)(2) calculation. BPA's Preference Customers cannot be said to have received any indication that the §7(b)(2) methodology was tentative. To the contrary, BPA stated in its June 2001 ROD that the [FY] 2002-2006 PF Exchange rate, which was based on the existing §7(b)(2) methodology, would be used by the IOUs in the event that the REP settlements were held illegal.

Id.

The IPUC makes arguments similar to APAC's. IPUC Br., WP-07-B-ID-01, at 5-9. IPUC states it is not sound business practice to retroactively increase rates, and the Court requires that Congress expressly permit such a practice in no uncertain terms. *Id*. at 5. The IPUC supports this argument by noting that section 7 of the Northwest Power Act contains no provision for retroactive ratemaking and concludes that the statute therefore contemplates that rates will be set prospectively. *Id*. at 6. The IPUC also argues that, because FERC reviews BPA's rates, BPA is subject to the rule against retroactive ratemaking, which it describes as fundamental tenet of FERC jurisprudence. *Id*. The IPUC identifies two exceptions to the rule against retroactive ratemaking: (1) when parties have notice that a rate is tentative and may be later adjusted with retroactive effect, or (2) where they have agreed to make a rate effective retroactively. *Id*., *citing Consolidated Edison Co. of New York, Inc. v. FERC*, 347 F.3d 964 (D.C. Cir. 2003).

APAC states that the third exception, which the IPUC does not identify, is potentially relevant to the situation at hand. APAC Br., WP-07-B-AP-01, at 31. APAC notes that in the event of a judicial reversal of its rule, an agency may apply the "*general principle of agency authority to implement judicial reversals*." *Id*., *citing Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1073 (D.C. Cir. 1992) (*per curiam*). This principle includes the power to "*undo what* [*was*] *wrongfully done by virtue of [a prior] order*." *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) (emphasis added). Thus, APAC concedes that the third exception is relevant but dismisses it based on its view that the Court identified a specific error and BPA's authority is limited to correcting that specific error, *i.e.*, the establishment of rates for Preference Customers during 2002-2006 that, in violation of the Northwest Power Act, included the REP settlement costs in rates for Preference Customers with reference to the requirements of section 7(b)(2). *Id*. at 32. APAC then appears to argue, without providing specific support, that undoing what was wrongfully done by a prior order is itself a limited exception to the rule prohibiting retroactive ratemaking. *Id*. Thus, APAC argues, BPA's only option is eliminating the REP settlement costs from the PF Preference rate insofar as those costs exceed the limit set by the Northwest Power Act, and does not include changing the underlying section 7(b)(2) methodology used to establish the PF Exchange rates. *Id*.

As noted in response to the WUTC, BPA's rates cannot be considered final until judicial review by the Ninth Circuit has concluded. In this instance, the Court found the WP-02 rates legally defective. Throughout the period during which this matter was being litigated, all parties were on notice that the rates were tentative and that they could be subject to change depending on the outcome of the litigation. Those rates have now been remanded to BPA for corrective action, It is difficult to understand the logic of parties first availing themselves of the Court's power to review BPA's rates and then arguing, after that review has resulted in a remand, that they had an expectation of finality in the rates that the Court found to be legally defective at some of the petitioners' request.

Thus, while the preference customers did not explicitly agree to retroactive adjustment and application of a Section 7(b)(2) Implementation Methodology that was necessarily amended to be consistent with section 7(b)(2), they were most certainly on notice that the WP-02 rates would not be final until the Ninth Circuit completed its judicial review. Because of that review, BPA believes it is now required to take certain actions and make certain adjustments to the WP-02 rates, including the revision of one unlawful provision of the then-existing Legal Interpretation and Implementation Methodology, in order to properly calculate the amount by which preference customers were overcharged. APAC may disagree with BPA's methods, but it cannot reasonably argue that customers had reasonable grounds to rely on the alleged "finality" of the rates.

In sum, BPA disagrees with APAC's assessment regarding the limited nature of the exception on retroactive ratemaking, how the Court's decisions should be interpreted with regard to the scope of BPA's responsibilities pursuant to the Court's mandate, and ultimately what BPA must do to create a remedy that puts the parties in the position they would have been in had the error not been made, which APAC agrees is the "proper remedy." APAC Br., WP-07-B-AP-01, at 8-9, *citing AT&T Corp. v. FCC*, 448 F.3d 426 (D.C. Cir. 2006); *Exxon Co. v. FERC*, 182 F.3d 30 (D.C.Cir.1999) (additional internal citations omitted). Amending one unlawful provision of the Implementation Methodology, as explained elsewhere, is necessary to a complete, accurate, and equitable resolution of the issues surrounding the legally defective WP-02 rates.

In its Brief on Exceptions, APAC concludes that "[t]he Administrator's decision approving rates for the WP-02 case is final, and the FERC order approving the rates is also final." APAC Br. Ex., WP-07-R-AP-1 at 11. Once an appeal is made to the Ninth Circuit, APAC explains, "the finality of the rates became conditional, subject to the court's review." *Id.* However, the rates lose their finality "only to the extent they are rejected or qualified by the Ninth Circuit." *Id.* APAC therefore believes that "[i]f BPA exceeds those limitations and revised more than is necessary to correct the errors identified by the Court, then BPA's actions in revisiting the WP-02 rate determinations are prohibited as retroactive ratemaking." *Id*.

BPA disagrees. As explained above, BPA does not interpret the Court's opinions as limiting BPA's administrative alternatives on remand. On remand, BPA believes it is necessary to require some form of retrospective relief. BPA further interprets the remand order as requiring BPA to put its expertise and experience to bear in determining what issues should be resolved in order to come to a final conclusion as to the appropriate level of REP benefits and the relief to be afforded BPA's preference customers. BPA's response in this proceeding is, thus, fully consistent with the Court's mandate and does not constitute impermissible retroactive ratemaking.

APAC also quarrels with BPA's reliance on *Central Electric Power Cooperative, Inc. v. Southeastern Power Administration*, 338 F.3d 333,335 (4th Cir. 2003) (*Central Electric*). APAC admits that the court there stated that the "Flood Control Act does not prohibit retroactive ratemaking by PMAs." *Id* at 12. Yet APAC would limit this holding to "specific circumstances before the court and Commission—surcharges to recover previous deficits." *Id.* In its Brief on Exceptions, the IPUC makes similar arguments. IPUC Br. Ex., WP-07-R-ID-1 at 2. In making their arguments, however, neither APAC nor the IPUC provide any case or other authority that suggests the court's holding in *Central Electric* is limited to specific circumstances, or in which a PMA's rates were invalidated due to a prohibition on retroactive ratemaking. Nor does APAC provide any authority that explains why the recovery of REP payments that occurred in the past and which were declared unlawful by the Ninth Circuit would not be within the scope of the holding in *Central Electric* or inconsistent with BPA's duty under the Flood Control Act to protect the public fisc. In the final analysis, APAC's arguments, like those of IPUC, are not sustainable.

Similarly, APAC relies heavily on what the cases do not discuss, but offers no real explanation as to why these omissions relate to BPA's decisions in this proceeding, except for the rather unremarkable observation that "[t]he cases simply stated a rule from a single application on limited facts with no additional analysis." *Id.* at 13. Again, however, there is no citation to a case in which a court has applied the prohibition on retroactive rates to BPA or any other PMA. BPA is somewhat mystified by the purpose served by APAC listing a number of items not discussed by the court without articulating a reason why these omissions undermine BPA's conclusion that it is not subject, in this instance, to any prohibition on retroactive ratemaking. The courts have held that PMAs are not prohibited from retroactive ratemaking. The relevant duty to be considered is not, as implied by APAC, simply to "protect ratepayers." It is much broader than that. The PMAs are required to set rates in a manner that will protect the general public from inappropriately subsidizing activities and facilities that should be paid for by rates charged to consumers. Imposition of a prohibition on retroactive ratemaking would essentially ignore this fact.

Attempting to amplify its arguments, APAC analogizes the Flood Control Act to the Federal Power Act and the Natural Gas Act. *Id.* at 13. Such analogies are misplaced in this instance. The Flood Control Act is one of the statutes that govern the ratemaking activities of the PMAs. The Natural Gas Act and the Federal Power Act regulate private entities. Unlike the privately-owned utilities, the PMAs have no shareholders from whom to recover past deficits to the extent that they cannot be recovered from their customers and, ultimately, their consumers.

Instead, the risk of underrecovery for PMAs and any consequent failure to make timely Treasury payments can only be allocated to either the customers or the general treasury (*i.e.,* the public fisc). The Flood Control Act and *Central Electric* make it clear that the PMAs may not allocate unrecovered costs to the "public fisc" but instead must recover all costs, regardless of their nature, through the rates of their customers.

That duty to protect the public fisc is a key point that must be considered as BPA attempts to rectify the errors identified by the Ninth Circuit.[8] That is, pursuant to the authorities cited by BPA, it must recover the payment of any unlawful benefits to the IOUs and properly allocate the lawful costs of the REP pursuant to the Northwest Power Act, without creating additional risk to the "public fisc." BPA is doing exactly that by calculating the amount of REP benefits that would have actually been paid in the absence of the REP Settlement Agreements, allocating those costs appropriately through the section 7(b)(2) rate test, and recovering any overpayments to the IOUs through deductions to future benefits, creating an ultimate reduction in the amount paid to BPA by preference customers in derogation of the statutory framework.

The IPUC also argued that BPA cannot adjust the WP-02 rates because they have expired and been superseded. IPUC Br., WP-07-B-ID-01, at 4, *citing Order Approving Rates on an Interim Basis and Providing Opportunity for Additional Comments*, Docket No. EF06-2011-000, 116 F.E.R.C. Rec. ¶ 61,264 (Sept. 21, 2006). As a result, the IPUC believes the only "retroactive" relief that the COUs may be entitled to is the refund with interest of the interim WP-07 rates if these interim rates are determined to be too high. *Id.*, *citing* 18 C.F.R. § 300.20 and 18 C.F.R. § 300.21 (stating that BPA must provide refunds to the extent that a rate finally approved by FERC is less than the interim rate).

As pointed out earlier, however, the fact that BPA is required to provide refunds in one situation does not lead to the conclusion that BPA is precluded from providing refunds in other situations. The agency has the authority to make retroactive corrections in response to a judicial determination because "[*t*]*he capacity of the courts to order retroactive relief has never been questioned.*" *Newman*, 223 F.3d at 942 (emphasis added).

The IPUC, however, goes on to question whether the Court's two decisions require BPA to provide retroactive relief to the prevailing parties in the *PGE* and *Golden NW* cases. IPUC Br., WP-07-B-ID-01, at 4. The IPUC notes that *Golden NW* remanded to BPA "to set rates in accordance with this opinion" and concludes that "BPA should simply proceed to set lawful rates." *Id.*, *citing* 501 F.3d at 1053. This conclusion is based, in part, on the fact that in neither case did the Court vacate the BPA rates. IPUC Br., WP-07-B-ID-01, at 4. This argument also misses the point. Typically, a rule that has not been vacated remains in effect while the agency addresses a remand order and fashions a new rule to replace the old rule on a prospective basis. However, in this case, retrospective relief cannot be precluded on that basis. In situations where an order is not vacated, the courts have looked at two factors to determine whether the equities favor the preclusion of retrospective relief. In *Hawaii Longline Ass'n v. National Marine*

[8] Of course, BPA must adhere to all legal requirements, whether found in the Flood Control Act or BPA's other authorizing statutes. However, in analyzing whether BPA is subject to a prohibition of retroactive ratemaking, the Flood Control Act's mandate to "protect the public fisc" is of great importance.

Fisheries Service, 299 F. Supp.2d 7 (D.D.C. 2003), the court stated the general rule applicable to remand without vacatur: A court may remand without vacatur where "there is at least a *serious possibility* that the [agency] will be able to substantiate its decision, given an opportunity to do so, *and* when vacating would be 'disruptive.'" *Radio-Television News Directors Ass'n v. FCC*, 184 F.3d 872, 888 (D.C. Cir.1999) (*citing Allied-Signal*, 988 F.2d at 151) (emphasis added) (alteration in original).

In this instance as well, retrospective relief is not prohibited. Certainly, correcting BPA's errors has created disruption, but this legal error must be rectified regardless of the disruption it may cause. Moreover, vacating rates that expired by their own terms would essentially be a meaningless exercise since the rates were no longer being used to support BPA's power sales activities, but that does not mean the rates were ever "final" in the legal sense. Rates are *final actions* pursuant to section 9(e) of the Northwest Power Act. 16 U.S.C. § 839f(e). As such, if the final action is challenged in the Ninth Circuit, it cannot be considered *final* until the Ninth Circuit completes its review and dismisses the challenge. In this case, the Court did not dismiss the challenge, but found that the rates were legally deficient and remanded for further action consistent with the Court's opinions.

Thus, flowing from the foregoing conclusions, the most reasonable way to interpret the Court's failure to specifically vacate the rates, consistent with the Court's other instructions, is to conclude that it means only that BPA need not re-open the expired WP-02 rates to fix the problem, but may do so prospectively in future rate proceedings, even if a part of the prospective remedy includes retrospective relief in the form of the Lookback Amount due to the preference customers.

Similarly to APAC and WUTC, the IPUC argues that BPA is engaging in retroactive ratemaking, insisting that a Federal agency must have express statutory authority before it can engage in retroactive ratemaking or provide a retroactive remedy such as reparations or refunds. IPUC Br., WP-07-B-ID-01, at 5, *citing Bowen v. Georgetown University Hospital*, 488 U.S. 204 (1988). The IPUC maintains that IOU customers are not a fungible mass where future customers may be substituted for past customers to make up for past rate deficiencies. *Id.*, *citing Utah Power & Light Co. v. Idaho Public Utilities Commission*, 685 P.2d 276, 285 (Idaho 1984). The IPUC also quotes Staff recognizing that "residential customers of the IOUs are those who will ultimately bear the entire brunt of the application of the Lookback Amounts to reduce future REP benefits paid." *Id.*, *citing* Forman, *et al.*, WP-07-E-BPA-76-CC1, at 96.

The IPUC also makes much of the fact that section 7(a)(2) of the Northwest Power Act does not contain explicit language authorizing retroactive ratemaking and that FERC had approved the rates on a final basis. The IPUC cites a number of FERC cases in support of its positions, but its arguments nonetheless fall short, and the cases cited are inapposite. This case involves the regulatory regime under which BPA operates, which includes review by FERC for the limited purpose of cost recovery, and potential review by the Ninth Circuit. BPA agrees that it is insufficient to argue that a remedy is prospective merely because recovery of the overpayments will be collected in the future. *Id.* at 9. Nonetheless, the remedy proposed by BPA is an appropriate response to the Court's mandate.

More significantly, and as discussed earlier, BPA is not subject to the prohibition on retroactive ratemaking. PMAs are "required by the plain language of [the Flood Control Act] to protect the public fisc by ensuring that federal hydro-electric programs recover their own costs and do not require subsidies from the federal treasury." *U.S. v. City of Fulton*, 475 U.S. 657, 668 (1986). In *Central Electric Power Cooperative, Inc. v. Southeastern Power Administration*, 338 F.3d 333, 335 (4th Cir. 2003), the Fourth Circuit reversed the district court's holding that a "rate schedule was arbitrary and capricious because it imposed a surcharge on plaintiffs in order to recover revenue shortages incurred during a prior period." The appellate court, however, held that "the Flood Control Act authorizes [SEPA, FERC, and the DOE] to recover such losses and affords them considerable discretion in structuring rate schedules in order to do so." *Id*. The court noted that "PMAs must sometimes set rates specifically aimed at recovering revenue shortages sustained during prior rate periods" and that "PMAs 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." *Id*. at 337. FERC has also specifically endorsed this concept:

> The prohibition against retroactive ratemaking contained in the Federal Power Act does not apply to PMAs, including Southeastern, that operate subject to a different statutory and regulatory scheme. Indeed, the Flood Control Act 1944, as amended, 16 U.S.C. § 825s (1988), and the relevant regulations, including Department of Energy Order RA 6120.2 at 4-5, expressly allow costs not recouped in one time period to be recovered in another, later time period so as to ensure recovery of both the costs of producing power and [recovering] the Federal investment.

Southeastern Power Admin., 55 F.E.R.C. ¶ ¶ 61,016, 61,045 (1981).

In other situations, FERC has also approved rates that SEPA and SWPA have designed to recover revenue shortfalls incurred under previous rate schedules. *Southwestern Power Admin.*,18 F.E.R.C. ¶¶ 61,052, 61,088 (1982); *Southeastern Power Admin.*, 23 F.E.R.C. ¶¶ 61,403, 61,895 (1983). Thus, the IPUC's reliance on FERC cases involving regulation under the FPA and NGA is unavailing. *See, e.g.*, OPUC Br., WP-07-B-PU-02, at 7, *citing especially Columbia Gas Transmission Corp. v. FERC*, 895 F.2d 791 (D.C. Cir. 1990) (NGA had no provision allowing FERC to waive filed rate doctrine).

Like APAC, IPUC revisits this issue in its Brief on Exceptions. In its Brief on Exceptions, IPUC faults BPA's conclusion that BPA's proposed Lookback is not subject to the prohibition on retroactive ratemaking and the filed rate doctrine. IPUC Br. Ex., WP-07-R-ID-1 at 1. IPUC argues that the cases cited by BPA in support of its conclusion "have all been premised upon the presence of unanticipated additional costs leading to revenue shortages." *Id.* IPUC contends the decisions are grounded upon review of "exemptions" from the rule against retroactive ratemaking and the filed rate doctrine. *Id*. After reciting the facts of *Central Electric*, IPUC concludes that the PMA in that case was permitted to deviate from the rate schedule designated in its power supply contract because a severe drought created river conditions that forced the PMA to make separate power purchases in order to honor its power supply contracts. *Id*.

According to IPUC, this is unlike the factual posture of BPA's current rate proceeding because the present Lookback proposal is not imposing "a 'surcharge' in order to recover certain unanticipated costs," but is rather a "full-scale recalculation of the REP benefits already awarded to IOUs during the 2002-2006 rate period as part of its WP-07 supplemental proposal." *Id. citing* DROD at 15. This, according to IPUC, is unrelated to any duty under the Flood Control Act of "recovering revenue shortages" but is "concerned solely with extracting past REP benefit amounts already awarded to its [BPA's] IOU customers and reapportioning them amongst its preference customers." *Id.*

IPUC goes on to claim that "BPA's Lookback approach does not coincide with any demonstrated need by BPA 'to ensure recovery of both costs of producing power and recovering the Federal investment." *Id.* at 3, *citing Southeastern Power Admin.*, 55 F.ER.C. ¶¶ 61016, 61045 (1991). In this vein, IPUC concludes that BPA's payment to IOUs of REP benefits found to be illegal by the 9th Circuit does not create a "revenue shortage or revenue shortfall," nor is BPA "presented with unanticipated or additional costs associated with the 2000 REP Settlement Agreements for which BPA must recover or risk not being able to make its Treasury Payment on time." *Id.* Instead, the instructions in *PGE* and *Golden NW* "merely invalidate BPA's determination of which customer group should bear those costs." *Id., citing* DROD at 15.

The central problem with IPUC's analysis is that it fails to recognize that the REP Settlement Agreements were adjudged to be contrary to law, and therefore payments pursuant to those agreements are contrary to law. The purpose of this proceeding is, in part, to determine the level of REP benefits that participating IOUs were legally entitled to and make sure that they receive lawfully authorized benefits. BPA does not construe the *Central Electric* decision as the court proscribing a limited exemption under the Flood Control Act from the rule prohibiting retroactive ratemaking to only "protecting the public fisc," in cases where a "surcharge" is being imposed to address "unanticipated costs" that create a "revenue shortfall." Indeed, as the court stated in footnote 2 of the *Central Electric* decision:

Plaintiffs also argue that the surcharge constitutes illegal retroactive ratemaking. We need not decide whether the surcharge constitutes 'retroactive' ratemaking, however, because such ratemaking is not prohibited by the Flood Control Act.

338 F.3d at 338 (citing *Southeastern Power Admin*., 55 F.E.R.C. ¶ 61,045). Consistent with the *Central Electric* decision, BPA is not restricted by the prohibition against retroactive ratemaking in addressing an unanticipated event, *i.e.,* the Court's determination that the REP Settlement Agreements are contrary to law.

The remand order requires BPA to take actions to remedy a violation that occurred in the past and which has financial implications for the future. BPA must provide the preference customers with recompense to the extent that the PF rate was inflated due to improper REP payments. BPA must also collect, insofar as possible, overpayments that were made in derogation of statute. These facts, regardless of how they are characterized implicate BPA's duty to protect the public fisc, as required by the Flood Control Act and reinforced by *Central Electric*. BPA has been remanded its rates by the Court to set consistent with the Court's opinion. That alone compels the conclusion that BPA is not subject to a prohibition on retroactive ratemaking as BPA must correct for the misallocation of cost it made in the past and the allocation of cost it will make in the future. The fact that BPA is not recovering costs through a "surcharge" or that its situation is not identical to the one addressed in *Central Electric*, strikes BPA as irrelevant. BPA's actions are nonetheless consistent with the Flood Control Act and the holding in *Central Electric*.

IPUC also believes that BPA has no basis to argue that "its actions fall under the mandate found in Section 5 of the Flood Control Act of 1944 'to protect the public fisc' while it currently possesses $1.5 billion in its reserve account." *Id.* at 3. BPA's reserve account, IPUC notes, is available to cover risk and "is set aside in order to ensure that BPA meets its one-year Treasury Payment Probability (TPP) Standard goal of 97.5%." *Id.* Accordingly, IPUC concludes that BPA's actions are "inapposite" to the "aforementioned SEPA cases" and then provides an incomplete citation to a FERC decision that it claims stands for the proposition that PMAs can avail themselves of this protection [*i.e.,* exemption from the retroactive ratemaking prohibition and filed rate doctrine] "only in cases where they propose to implement rates that are the 'lowest possible consistent with sound business principles and will generate sufficient revenues to pay the cost of producing the power and repay the Federal investment with interest in a timely manner." *Id.* at 4 (citation omitted). According to IPUC, BPA does not "merit" this protection because the problem being addressed "is of its own making and does not require that it collect additional revenues in order to meet those costs." *Id.*

BPA finds the IPUC's arguments misplaced for several reasons. First, BPA is in the process of setting rates that conform to all legal requirements, as it is required to do. This includes, but is certainly not limited to, the requirement that rates be the lowest possible consistent with sound business principles and will generate sufficient revenues to pay the cost of producing the power and repay the Federal investment in a timely manner. *See* 16 U.S.C. § 832e; 16 U.S.C. § 825s; 16 U.S.C. § 838g; and 16 U.S.C. §839e(a)(1). Whether or not the problem being addressed "is of [BPA's] own making," BPA is subject to the same legal requirements, including protection of the public fisc. Thus, BPA does not understand why it would not "merit" the protection described by IPUC.

Second, IPUC apparently misapprehends the role of BPA's financial reserves, risk mitigation, and TPP standards. It is true that BPA begins each rate period with some amount of financial reserves. These reserves are typically available to pay costs associated with future events that are presently unknown or whose costs are too indefinite to calculate with certainty. Such events can truly be considered "risks." To the extent that BPA's risk analysis shows that reserves are not sufficient to capture these costs, BPA includes in its rates an additional amount of Planned Net Revenues for Risk. Among other things, these work together to support BPA's TPP goals. If BPA were to refund unlawful REP payments through cash reserves, that would mean Planned Net Revenues for Risk would need to be increased, or some other action taken, in order to maintain a TPP Standard of 97.5%. Thus, because BPA's TPP is implicated, IPUC is mistaken to conclude that resolution of this issue does not give rise to BPA's duty under the Flood Control Act to protect the public fisc.

Finally, BPA does not believe it is appropriate to consider a known past overpayment of REP benefits, which is subject to reasonably accurate calculation, as a risk. The term "risk" should be reserved to refer to known or unknown future events that might increase BPA's financial risk but which cannot be calculated with certainty. In this instance, BPA is collecting a past overpayment that has been calculated with reasonable certainty. Thus, collecting the overpayments through future rates, decrements, and/or credits, rather than exposing BPA to increased financial risk by using its reserves, is the proper course in this instance.

IPUC also argues that BPA has been inconsistent in the way it defines "retroactive." IPUC Ex. Br., WP-07-R-ID-1, at 4. IPUC notes that BPA concluded in the DROD that the "Lookback Proposal does not have retroactive effect, in the legal sense, because it does not 'render unlawful … an act lawful at the time it was done." *Id. citing* DROD at 28, *quoting Ralis v. REF/FL Inc.*, 770 F.2d 1121, 1127 (D.C. Cir. 1985). IPUC also rightly notes that the DROD indicated that BPA's interpretation of the *PGE* and *Golden Northwest* decisions compels it to institute "some sort of retrospective relief." *Id. citing* DROD at 22. Based on these two statements, IPUC questions how BPA "can admit on the one hand that it has fashioned a retrospective remedy and argue on the other that said remedy 'does not have a retroactive effect [in the legal sense].'" *Id.*

Perhaps BPA's DROD was not entirely clear in this regard and some clarification of BPA's position may be in order. The problem seems to lie in the manner in which BPA originally attempted to draw a distinction between retroactivity that is prohibited or inappropriate and retroactivity which is not. BPA tried to point out that while it was compelled to provide retroactive relief, DROD at 21, the current proposal is not prohibited retroactive ratemaking because it does "render unlawful … an act lawful at the time it was done." DROD at 28*, citing Ralis*. Instead, execution of the REP Settlement Agreements was an "unlawful" act at the time the agreements were consummated. *PGE*, 501 F.3d 1009. BPA is not now rendering them "unlawful" through its actions. They were unlawful at the outset. Thus, even if BPA were subject to the general prohibition on retroactive ratemaking, remedying such an unlawful act does not fall within the scope of the general prohibition against retroactive ratemaking. Perhaps it would be somewhat clearer to say that the Lookback can be considered temporally retroactive, but it is not legally impermissible due, in part, to the fact that the REP Settlement Agreements were adjudged to be unlawful.

IPUC also disagrees with BPA's conclusion that the 2000 REP Settlement Agreements are void *ab initio* and that, therefore, the prohibition on retroactive ratemaking could not be offended because there is "no past transaction or consideration to which a new duty or disability could attach." *Id.* at 4-5, *citing* DROD at 28. Instead, IPUC argues that the Court did not void the Agreements but "chose to simply grant the petitions, rule that the 'settlement agreements' entered into between BPA and the IOUs are inconsistent with the NWPA, and remand the case with an instruction that BPA 'set rates in accordance with this opinion'." *Id.* at 5, *citing Golden Northwest*, 501 F.3d at 1053; *PGE*, 501 F.3d at 1037.

Again, perhaps BPA should have been clearer as to the basis for its conclusion that the contracts are void *ab initio*. The general rule is that a contract which is found to be contrary to law is essentially void *ab initio* and unenforceable: "Without a doubt, contractual provisions made in contravention of a statute are void and unenforceable, and an agent acting *ultra vires* cannot bind the federal government." *California v. United States*, 271 F.3d 1377 (Fed Cir. 2001); *See, e.g., Federal Crop Ins. Co. v. Merrill*, 332 U.S. 380, 68 S. Ct. 1, 92 L. Ed. 10 (1947). While the Court in *PGE* and *Golden NW* did not expressly hold the settlement agreements to be void *ab initio*, the Court's finding that the agreements are inconsistent with statute produces the same result. The Ninth Circuit held the Settlement Agreements to be inconsistent with sections 7 and 5 of the Northwest Power Act. Clearly then, the Court's invalidation of the REP Settlement Agreements is predicated on a statutory violation. As such, the case is governed by Supreme Court precedents of *Mississippi Valley Generating Co.,* 364 U.S. 520 (1961) and *Acme Process Equip.Co.*, 385 U.S. 138, 146 (1966), where the Supreme Court invalidated and refused to enforce agreements due to a violation of statute. Thus, while the Court in *Golden NW* did not expressly hold the settlement agreements to be void *ab initio*, the Court's finding that the agreements are inconsistent with statute produces the same result.

Cowlitz and PPC view the issue differently than the parties already discussed. Cowlitz and PPC claim it is settled law that an agency may establish revised rates in response to judicial review of its order establishing excessive rates and make those new lawful rates retroactive as of the date of the prior order. Cowlitz Br., WP-07-B-CO-01, at 70, *citing United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965); *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1073 (D.C. Cir. 1992) (*per curiam*). PPC Br., WP-07-B-JP25-01, at 10-13. Beyond that, however, Cowlitz takes issue with how Staff proposes to collect overpayments to REP participants. Cowlitz first points to the Ninth Circuit's power to vacate rates and order refunds, including retroactive refunds: although the Ninth Circuit has never discussed the details of how BPA should respond if legal errors are found in its rates, the Court has repeatedly rejected efforts to direct BPA by mandamus with respect to assertedly illegal rates on the grounds, among other things, that the Court can vacate entire rate proceedings and "order refunds for any overcollections by BPA." Cowlitz Br., WP-07-B-CO-01, at 70, *citing Public Utilities Comm'n v. FERC*, 814 F.2d 560 (9th Cir. 1987) and *Oregon Public Utilities Comm'n v. BPA*, 767 F.2d 662, 630 (9th Cir. 1985). Cowlitz also maintains that the Ninth Circuit has declared that its authorities include "retroactive refunds." *Id*. at 71, *citing Public Utilities Comm'n*, 814 F.2d at 561.

Cowlitz claims further that Staff's sole justification for not providing refunds for the FY 2002-2006 period is the statement that "our remedy is following the typical ratemaking paradigm of making only prospective changes." Cowlitz Br., WP-07-B-CO-01, at 70, *quoting* Forman, *et al.*, WP-07-E-BPA-76, at 6. Cowlitz claims that this approach is wrong and that a purely prospective remedy has all the vices about which the OPUC and the IPUC complain: the longer it takes to restore the funds, the less likely the actual victims are made whole from the recipients of the unlawful collections. *Id*., *citing*, *e.g.*, Tr. 110; *id*. at 114; *see also* WP-07-E-JP17-01-CC1, at 41.

BPA views its responsibility under the remand order differently. BPA is not, as Cowlitz seems to imply, providing a "purely" prospective remedy. A purely prospective remedy would be one in which BPA fails to account for the overpayment of REP benefits during the FY 2002-2006 period and instead moves forward by developing future rates in accordance with the Court's opinion. BPA, however, is conducting a Lookback, which accounts for overcharges to preference customers during the FY 2002-2006 period. The remedy for those overcharges will occur in the future, as would any such remedy.

Cowlitz's complaints seem more related to the manner in which Staff has proposed to implement the remedy; *i.e.*, over an extended period of time as Lookback Amounts are recovered from the IOUs. Cowlitz seems to want immediate "refunds." BPA, however, does not believe that such a remedy would be equitable, if extracted somehow from the IOUs, or in keeping with BPA's business objectives and cost recovery responsibilities, if sourced, for example, from BPA's operating reserves. BPA determines, as explained elsewhere, that offsetting credits against future REP benefits is a more equitable means of recapturing the overcharges to preference customer from the FY 2002-2006 period.

PPC also argues that complying with the Court's order is not prohibited retroactive rulemaking:

The requirement that actions be final before they are subject to judicial review necessarily means that review will be after the fact. Given that "final rate determinations" under section 7 of the Act are among the matters expressly subject to the Ninth Circuit's jurisdiction, and that legal challenges cannot possibly run their course before proposed rates take effect, there would be no way for the court to carry out Congress's intent unless it had the power to remedy, retrospectively, BPA rate determinations that contravene the provisions of the Act.

PPC Br., WP-07-B-JP25-01, at 10. BPA fundamentally agrees with this perspective. As the PPC puts it, parties who argue that BPA is engaging in prohibited retroactive ratemaking are saying, in effect, that no matter how illegally BPA may have acted in setting its power rates, BPA's error is preserved perpetually in its rates and the most the Ninth Circuit Court of Appeals may do is admonish BPA not to engage in such misbehavior in the future. *Id*. PPC essentially argues, therefore, that BPA's proposal is "not retroactive ratemaking." *Id*. at 10-11.

BPA agrees, but for somewhat different reasons. First, as has been discussed at length earlier, it is important to note that under the relevant case law, BPA and the other PMAs are not subject to a prohibition on retroactive ratemaking, due to the cost recovery requirements of the Flood Control Act, as well as BPA's other enabling legislation. Moreover, the law does not forbid agencies from imposing costs or creating rates in response to past events as long as the legal consequences are in the future and not the past. The Lookback takes into account past over or underpayments, but that does not raise retroactivity concerns because BPA's actions do not attach new legal consequences to past events. BPA only intends to remedy a legal violation (*i.e.*, entering into the invalidated REP Settlement Agreements) that occurred in the past by attaching altered consequences (*i.e.*, remedying the resulting overcharges to preference customers) to future events (*i.e.*, debits against future REP benefits).

PPC also states that the rule against retroactive ratemaking does not bar changes to a rate when the parties are on notice that the rate is provisional and may change in the future. *Id*. at 10, *citing*, *e.g.*, *NSTAR Elec. & Gas Corp. v. FERC*, 481 F.3d 794, 801 (D.C. Cir. 2007); *Sithe New England Holdings, LLC v. FERC*, 308 F.3d 71, 78 (1st Cir. 2002); *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066, 1075 (D.C. Cir. 1992) (*per curiam*). PPC explains further that the rule against retroactive ratemaking does not apply in these circumstances because the rule "simply does not extend to cases in which buyers are on adequate notice that resolution of some specific issue may cause a later adjustment to the rate being collected at the time of service." *Id*., *citing Northwest Pipeline Corp. v. FERC*, 61 F.3d 1479, 1490-91 (10th Cir. 1995); *accord Alliant*

Energy Corp. v. FERC, 253 F.3d 748, 753-54 (D.C. Cir. 2001); *Natural Gas Clearinghouse*, 965 F.2d at 1073-1076. In this case, PPC notes that numerous parties from the outset challenged BPA's decision to provide benefits to the IOUs far in excess of BPA's statutory authority; all parties were fully on notice throughout the FY 2002-06 rate period that the benefits provided under the REP Settlement Agreements were not final and could be changed based on the outcome of the litigation challenging the level of those benefits. *Id*.

BPA generally agrees with this assessment. As stated in part above

> Because a timely challenge was brought to FERC's approval of the WP-02 rates, all parties were on notice that the rates had still not undergone review by the Ninth Circuit and, from that standpoint, they were not approved on a final basis and might have to be revised as the result of a Ninth Circuit order…

Parties cannot now be heard to argue that they had some expectation of finality or reasonably relied on the finality of the rates as a legal stratagem for hamstringing BPA's review of those rates in response to the Ninth Circuit's orders, which explicitly declared the rates to be defective… The rates are simply not final … until the Ninth Circuit reviews them for legal sufficiency. Thus, customers have no basis to argue that they reasonably relied on the rates being fixed.

See Section 2.7.C. Thus, it cannot be reasonably suggested that parties lacked adequate notice of a potential change in rates.

IPUC and APAC challenge this conclusion in their Briefs on Exceptions. IPUC tries to revive the notion that the IOUs did not have adequate notice that their benefits under the REP were subject to change. IPUC Ex. Br., WP-07-R-ID-1, at 6. After reciting the facts of *Exxon Co., U.S.A. v. FERC*, 182 F.3d 30,49 (D.C. Cir. 1999), IPUC concludes that since the IOUs did not receive a warning like the one in *Exxon*, the IOUs, utility commissions, and consumers "thus lacked 'adequate notice' that the WP-02 rates were subject to change." *Id.* at 6. In this connection, IPUC makes the observation that "the parties were not involved in an ongoing settlement of any issues pertaining to the WP-02 rates, much less a remand order and subsequent proceeding." *Id.* In support of this contention, IPUC argues that BPA's reliance on *Natural Gas Clearinghouse v. FERC*, 965 F.2d 1066 (D.C. Cir 1992) is "misplaced because the case is clearly distinguishable upon its facts." *Id.* In that case, IPUC concludes, "the parties were clearly on notice that the rates could be subsequently adjusted depending on the outcome of the pending proceeding." *Id.* at 7. The case is inapposite to the situation here because, IPUC argues, "[p]arties to this case had no notice that the rates were not 'final' because no party sought a stay of the WP-02 rates." *Id.*

As discussed above, because a timely challenge was brought to FERC's approval of the WP-02 rates, all parties were on notice that the rates had still not undergone review by the Ninth Circuit and, from that standpoint, they were not approved on a final basis and might have to be revised as the result of a Ninth Circuit order. Nor does BPA believe that IPUC improves its argument by relying on a provision in the Settlement Agreement which states that any cash payments and monetary benefits paid to the IOUs "shall be retained" by the IOUs in the event that the contract were found to be void, unlawful, or unenforceable. *Id.* at 7-8. IPUC leaps to the conclusion that this provision illustrates that the IOUs and BPA "did not contemplate that any legal challenge would necessitate a change in rates." *Id.* In fact, the existence of the provision shows exactly the opposite, *i.e.,* that the parties did contemplate that the REP Settlement Agreements were subject to further review in the Court of Appeals, which could rule that the Agreements were void, unlawful, or unenforceable. Thus, to argue that the parties lacked adequate notice that the rate could be changed is completely untenable.

It should be noted further that there is no indication that either BPA or the REP participants intended the cited passage to mean that it would be proper for the IOUs to retain any payments that were contrary to law. Any such interpretation of the provision would be an agreement to participate in an illegal act, which would similarly be void *ab initio*. To the extent that the parties intended for the IOUs to receive and retain a legally proper amount of benefits, the provision is consistent with what BPA is attempting to determine in this proceeding.

Finally, IPUC once again resurrects the notion that the WP-02 rates were final because FERC approved them, thereby providing a basis for reliance on the finality of the rates after FERC approval. This argument totally distorts the statutory scheme under which BPA's actions are reviewed. While IPUC insists that BPA "strains credulity" in this regard and refers to the "paucity of law" in support of BPA's "novel and legalistic distinction", it is IPUC that apparently fails to understand the statutory review process, not BPA. *Id.* IPUC offers the following analysis:

Congress has granted FERC final confirmation and approval authority over BPA rates submitted for approval under section 7(a) of the Northwest Power Act. *See* 16 U.S.C. § 839e(i); 16 U.S.C. § 839f(e)(4)(D) ("rate determinations pursuant to section 7 shall be deemed final upon confirmation and approval by [FERC].)"; see also 18 C.F.R. § 300.21. … "A 'final action' under the Regional Act exists when a decision made by the BPA is not subject to any further review by the BPA or the Federal Energy Regulatory Commission (FERC)." *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987).

Id. at 8-9. IPUC's analysis is wrong. As pointed out previously, FERC's approval of BPA's firm power rates is limited to a very narrow cost recovery standard. DROD at 5. The statute nowhere says that BPA's rates are "final" after this narrow review. Instead, it says the rates are "effective" upon FERC's review. 16 U.S.C § 839e(a)(2). The fact that the rates are "deemed" final after that review is not relevant to the legal finality of the rates, but rather marks the point at which the rate determination becomes a "final action," which speaks to the completion of the administrative steps that must precede any legal challenges in the Ninth Circuit pursuant to § 9(e) of the Northwest Power Act. 16 U.S.C. 839f(e)(5). In other words, a challenge in the Ninth Circuit is not cognizable when the Administrator issues his final ROD in a rate case. In the establishment of rates, such a challenge must await a threshold determination by FERC that the rates are sufficient to assure Treasury repayment and are based on total system costs. Once that determination is made, a party wishing to challenge has 90 days to challenge the rates in the Ninth Circuit. There, the Court can and does address legal and substantive concerns related to BPA's rates, including review of FERC's cost recovery finding and matters over which FERC has absolutely no authority.

To suggest that the rates are final when there has been no review of these issues defies logic, particularly when parties have filed petitions in the Ninth Circuit challenging a final action. Thus, BPA's position is not a "novel and legalistic" distinction, nor does it lead to an illogical result. IPUC's position would, by contrast, lead to the absurd result of essentially negating the Ninth Circuit's power to order changes to any rate, current or expired, and would essentially reduce the Court's role to an advisory opinion. Parties could thwart any remand of the rates by essentially arguing, as IPUC does, that the rates are "final" once FERC determines they will recover BPA's costs. Thus, despite the fact that the judicial review scheme is clearly articulated in the Northwest Power Act, parties would essentially be immune to any retroactive adjustments, in IPUC's view, because they are not adequately put on notice that the Ninth Circuit is empowered to determine whether rates are arbitrary, capricious, or otherwise inconsistent with applicable law and to order BPA to take appropriate remedial action to correct its errors.

Like IPUC, APAC also argues that parties did not receive adequate "notice that the § 7(b)(2) methodology was subject to modification." APAC Ex. Br., WP-07-R-AP-1, at 14. In support of its conclusion, APAC argues that "the Ninth Circuit's ruling affects only that discrete rate and does not authorize the wholesale revision of the PF Exchange Rate and its retroactive redetermination." *Id.* APAC asserts that the authorities relied on by BPA are inadequate because "they deal with situations where rates were suspended and then permitted to go into effect 'subject to refund following a hearing concerning their …lawfulness." *Id.* at 14-15, *citing Oxy USA, Inc. v. FERC*, 64 Fd.3 679, 686 (D.C. Cir. 1995).

As explained previously, BPA does not read the Ninth Circuit's remand order as narrowly as posited by APAC. Indeed, BPA believes that its actions are fully consistent with the orders in *PGE* and *Golden NW* and the statutory scheme that governs review of BPA's actions. That statutory review is designed so that BPA develops its rates pursuant to section 7(i) of the Northwest Power Act. 16 U.S.C. § 839e(i)(1). Thereafter, the rates are submitted to FERC for a determination of whether they are sufficient to recover BPA's costs and are based on total system costs. 16 U.S.C § 839e(a)(2). As previously indicated, FERC has no authority to review the rates for legal sufficiency. It has no authority to apply standards garnered from industry practices established by the Federal Power Act or the Natural Gas Act. Its sole authority is to confirm that the rates are sufficient to recover costs based on total system costs. *Id*. The statute does not state that FERC's review is final. Instead, it states that "the final decision of the Administrator shall become effective on confirmation and approval of such by the Federal Energy Regulatory Commission pursuant to subsection (a)(2) of this section." 16 U.S.C. § 839e(i)(6). As a matter of simple logic, then, it cannot reasonably be asserted that, based on this extremely limited review, the rates are "final" to the extent that the parties are not on notice that the rates may be required to be modified in the future as a result of further review. The statute makes this clear, explicitly stating that, once FERC confirms the rates for cost recovery, they become a final action subject to review in the Ninth Circuit pursuant to section 9(e) of the Northwest Power Act.

Of course, if no one files a petition challenging the rates within the 90 day window established for such challenges, then the rates become final. In this instance, however, such challenges were, in fact, timely filed. Because the prevailing parties to the litigation had sought review of the

REP Settlement Agreements, and the cost allocations emanating therefrom, it also follows that the petitions implicated BPA's application of the section 7(b)(2) rate test and the 1984 ASC Methodology, which further implicate the proper rate levels for preference customers and residential exchange participants. From all of this, it follows that parties were on sufficient notice that BPA might be required to take the actions embodied in this Record of Decision. Arguments to the contrary cannot be sustained.

In its Initial Brief, PPC notes too that nothing in the rule against retroactive ratemaking trumps BPA's obligation to comply with the *Golden NW* Court's remand. *Id*. at 11. Instead, PPC argues that an administrative agency may undo what was wrongfully done by virtue of a prior order. *Id*., *citing United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965). PPC also states that BPA has a duty where refunds are found due, to direct their payment at the earliest possible moment consistent with due process. *Id*. at 230, *quoting FPC v. Tennessee Gas Transmission Co.,* 371 U.S. 145, 155 (1962); *see also Consolidated Edison Co. v. FERC,* 347 F.3d 964, 972 (D.C. Cir. 2003) (agency must ordinarily provide full refunds); *Indiana & Michigan Elec. Co. v. FPC*, 502 F.2d 336, 339 n. 8 (D.C. Cir.1974), *cert. denied*, 420 U.S. 946 (1975) (refunds in response to remand do not violate rule against retroactive ratemaking).

BPA believes this argument goes more to the issue of retroactive rulemaking rather than retroactive ratemaking, both of which need to be considered in this case. Although retroactive rulemaking generally requires explicit Congressional authorization, BPA noted earlier that is not always the case because, as the Ninth Circuit has held,"[*t*]*he capacity of the courts to order retroactive relief has never been questioned.*" *Newman*, 223 F.3d at 942 (emphasis added). In this instance, BPA is required to engage in retroactive review in order to correct the deficiencies in the WP-02 rates identified by the Ninth Circuit. For this reason, the Ninth Circuit upheld the district court's determination that "the Commissioner's *discharging a judicial order to make Newman whole would not require the Commissioner to promulgate retroactive regulations in the way that the Court contemplated in Bowen.*" *Id*. (emphasis added).

BPA finds itself in a similar situation. As BPA understands the Court's order, the remand in *Golden NW* is clear that, due to the finding in *PGE* that the REP Settlement Agreements were contrary to law, certain cost allocations made in establishing the WP-02 rates were defective to the extent that preference customers were overcharged for REP settlement benefits in excess of the rate ceiling established by sections 7(b)(2) and 7(b)(3) of the Northwest Power Act. In order to comply with the remand order, BPA must correct the overcharges to preference customers caused by the illegal REP Settlement Agreements. Staff's Lookback proposal is a fair and reasonable means of accomplishing that objective.

<u>Decision</u>

The Lookback construct does not constitute impermissible retroactive ratemaking. BPA is not subject to a prohibition on retroactive ratemaking due to the cost recovery requirements of the Flood Control Act as well as BPA's other enabling legislation. The Lookback does not raise retroactivity concerns because BPA's actions do not attach new legal consequences to past events, but instead seeks to remedy an act that was unlawful at the time it occurred.

2.6.3 Reopening and Supplementing the Administrative Records

Issue 1

Whether BPA may supplement the WP-02 and WP-07 rate proceeding records with additional evidence and arguments in order to calculate the overcharges to the COUs.

Parties' Positions

The IOUs, though not conceding that BPA should conduct the Lookback, appear to agree with BPA's decision to revisit the WP-02 rate record. IOU Br., WP-07-B-JP6-01, at 149-150. The IOUs note that material changes of circumstances occurred between when BPA issued the WP-02 ROD on May 19, 2000, and when BPA would have decided the section 7(b)(2) rate test issues in 2001, requiring BPA to revisit the section 7(b)(2) rate test and recalculate the PF Exchange rate. *Id*.

APAC, WPAG, and PPC generally oppose BPA's proposal to revisit the rate record. APAC Br., WP-07-B-AP-01, at 26-28; APAC Br. Ex., WP-07-R-AP-01, at 15; WPAG Br., WP-07-B-WA-01, at 6-7; WPAG Br. Ex., WP-07-R-WA-01, at 8-9. PPC Br., WP-07-B-JP25-01, at 29-32; PPC Br. Ex., WP-07-R-PP-01, at 18. These parties generally argue that BPA should calculate the overcharges to the COUs using the existing WP-02 record only. *Id*.

In its Brief on Exceptions, Canby takes issue with BPA's statement that the IOUs would have objected to the adoption of CRACs, claiming that there is nothing in the record from that time that "supports that assertion." Canby Br. Ex., WP-07-R-CA-01, at 11.

Cowlitz took no position in its brief, but generally approved of the approaches advocated by APAC and WPAG. Cowlitz Br., WP-07-B-CO-01, at 67-68. Canby also argues that BPA has exceeded its discretion by reopening and considering supplemental information in this proceeding. *Id.*

The WUTC argues that BPA should compare only the forecast REP benefits and the forecast REP Settlement Agreement benefits used in the WP-02 rate record to determine the overcharges to the COUs. WUTC Br., WP-07-B-WU-01, at 10-12.

BPA Staff's Position

BPA Staff noted that the WP-02 rates and rate record were fundamentally flawed and must be supplemented to properly calculate the overcharge of REP benefits in the COUs' rates. Burns, *et al.*, WP-07-E-BPA-53, at 7. REP benefit costs are determined using three components: a utility's ASC, BPA's PF Exchange rate, and the utility's exchange load. *Id*. The WP-02 rate record is defective because it does not have this information. *Id*. First, the WP-02 record has only dated forecast ASC and load data, which would not have been used to calculate actual REP benefits during the WP-02 rate period. *Id*. Second, the PF Exchange rate developed in the WP-02 rate proceeding was fundamentally flawed because it did not reflect the significant changes in market prices and loads that occurred subsequent to the completion of the May 2000 rate proposal. *Id*. Had the REP Settlement Agreements not been executed in the fall of 2000, BPA would have adjusted the base WP-02 base rates to reflect these fundamental changes in prices and loads instead of adopting the Cost Recovery Adjustment Clauses (CRACs). *Id*. These adjustments must be made to accurately calculate the amount of REP benefits that would have been collected in rates had the REP Settlement Agreements not been executed. *Id*.

Evaluation of Positions

A. The WP-02 Rate Record and BPA's Basis for Considering Supplement Information

As described above, the Court's decisions in *PGE* and *Golden NW* concluded that BPA had improperly allocated the costs of BPA's unlawful 2000 REP Settlement Agreements to BPA's preference customers. To respond to these decisions, Staff proposed a four-step process that began with a determination of the amount of REP settlement costs that were charged to BPA's preference customers under BPA's WP-02 rates for FY 2002-06 and WP-07 rates for FY 2007-08. Bliven, *et al.*, WP-07-E-BPA-52, at 11-12. Staff then proposed to compare these costs with the REP benefits the IOUs would have received during those periods under the REP in the absence of the REP settlements. *Id*. Staff then calculated the difference between the two cases and proposed to recover the overcharges from the IOUs and return them to BPA's preference customers. *Id*.

Determining the amount of REP benefits the IOUs would have received in FY 2002-2006, however, is not a simple matter. *Id*. at 2. BPA must have three key pieces of information to calculate the lawful amounts of IOU REP benefits for FY 2002-2006: the IOUs' respective eligible exchange loads; the IOUs' respective ASCs; and the PF-02 Exchange rate. *Id*. at 3. The difference between an IOU's ASC and the PF Exchange rate is multiplied by the IOU's residential load to determine REP benefits. *Id*. BPA must have these three components to properly calculate the REP benefits that the IOUs would have received in the absence of the REP Settlement Agreements. *Id*.

As noted in the previous section, the Court remanded the WP-02 rates to BPA with the direction to "set rates in accordance with this opinion." *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007). While the Court held that BPA's fish and wildlife cost assumptions were not supported by substantial evidence, the Court did not directly address whether BPA could supplement the record with additional evidence and arguments when considering the REP aspects of its decision on remand.[9] *Id*. The Court noted, though, that in setting rates BPA must, at a minimum, "know[] its costs, or, at the very least, … estimate[] them 'in accordance with sound business principles.'" *Id.* The Court also stated that BPA's forecasts must be based on "realistic projections … that accurately reflected the information available at the time rates were set and the cost recovery mechanism adopted." *Id.* 1053. While this discussion was addressing the particulars of BPA's fish and wildlife costs, this direction is equally applicable in the context of

[9] BPA responds to parties' issues with respect to the fish and wildlife aspect of the Court's remand in section 8.12.

the REP. In addition to this guidance, it is a well established principle of administrative law that if a Court has *not* given explicit instructions to an agency on whether to reopen an administrative record, agencies generally have discretion to determine whether the existing record is sufficient to dispose of the remand issue. *See Eastern Carolinas Broadcasting v. FCC*, 762 F.2d 95, 102-103 (D.C. Cir. 1985). An agency's decision on whether to reopen the record will be reviewed by the Court under an abuse of discretion standard. *Cooley v. FERC*, 843 F.2d 1464, 1473 (D.C. Cir. 1988); *City of Anaheim v. FERC*, 941 F.2d 1234, 1247 (D.C. Cir. 1991).

In view of the Court's guidance in *Golden NW* and the discretion afforded an agency to consider the sufficiency of the record, BPA evaluated the WP-02 rate record to determine whether it had the necessary information to calculate the REP benefits the IOUs would have received in the absence of the REP Settlements. This review revealed that the WP-02 record alone was not sufficient and that it would have been patently unreasonable to rely solely on it. To begin, the WP-02 rate record did not have the necessary IOUs' ASC or exchange load data to estimate the appropriate level of REP benefits. When developing the WP-02 rates, BPA used forecasts of the IOUs' ASCs to set rates for the FY 2002-2006 period. Boling, *et al.*, WP-07-E-BPA-83, at 32-33. These forecasts were based on ASCs filed by the IOUs from the mid-to-late 1990s. Boling, *et al.*, WP-07-E-BPA-57, at 5. While these ASCs were the best information BPA had available for rate setting, they could not be used to determine the amount of REP benefits the IOUs would have received but for the REP Settlement Agreements. Bliven, *et al.*, WP-07-E-BPA-52, at 18-19; *see also* Section 7, ASC Reforecasts and Backcasts. REP benefits are based on the difference between each IOU's *filed* ASC and BPA's PF Exchange rate, multiplied by the utility's exchange load. Bliven, *et al.*, WP-07-E-BPA-52, at 16. No IOU filed ASCs with BPA from FY 2002-2006 because the REP Settlement Agreements did not require these filings. *Id*. Yet, had the IOUs *not* signed these agreements, and instead participated in the traditional REP through an RPSA, the IOUs would have made ASC filings with BPA pursuant to the 1984 ASC Methodology. *Id*. BPA must have these ASCs in order to reasonably estimate the likely REP benefits that would have been paid for the FY 2002-2006 period. *Id*. at 16-17. Since the WP-02 rate record develops rates based on forecasts, it did not have these vital ASC filings, which would have been made throughout the FY 2002-2006 rate period. Staff proposed to fill this gap in the rate case record by calculating annual ASCs for each IOU in a manner that approximates the ASC determinations that would likely have been made, consistent with the 1984 ASCM, had the IOUs submitted ASC filings during FY 2002-2006. Manary, *et al.*, WP-07-E-BPA-61, at 2-3; *see also* Chapter 7.

Furthermore, while the WP-02 rate record did have a calculated PF Exchange rate, this rate was fatally defective in two ways. First, it was developed using a rate design feature that the Court in *Golden NW* specifically found illegal. Although at the time the WP-02 rates were being developed BPA expected the REP Settlement Agreements to be signed, BPA could not be certain this would occur. Burns, *et al.*, WP-07-E-BPA-53, at 4. BPA thus established rates in its WP-02 rate proceeding in order to allow implementation of either the REP or the REP Settlement Agreements. *Id*. In order to establish rates for each alternative, BPA developed its proposed rates in two steps: a Rate Design Step and a Subscription Step. *Id*. In the Rate Design Step, BPA used its normal practice of forecasting costs, loads, and revenues. *Id*. In this step, BPA assumed the IOUs would elect to participate in the REP. *Id*. Also in this step, BPA conducted the section 7(b)(2) rate test. *Id*. The rate test triggered, causing BPA to allocate the 7(b)(3) trigger amount to non-preference rates, including the PF Exchange rate. *Id*. This established the PF Exchange rate for use in implementing the REP. *Id*. Because BPA did not expect the IOUs to sign RPSAs to implement the REP, issues affecting the section 7(b)(2) rate test and the 7(b)(3) trigger amount did not receive great scrutiny due to the expectation that the PF Exchange Rate would not be used to establish IOU REP benefits. *Id*.

BPA, however, still needed to establish rates reflecting the IOUs' expected election to execute the REP Settlement Agreements. *Id*. at 3-4. The Residential Load (RL) Firm Power rate was necessary to implement the power sales portion of the Agreements. *Id*. Therefore, BPA performed the Subscription Step to set rates to recover the costs of implementing the settlements. *Id*. The Subscription Step removed the costs of the REP and replaced them with the costs of the REP Settlement Agreements. *Id*. It is this latter step that the *Golden NW* Court found contrary to the Northwest Power Act.

Second, the PF Exchange rate in the WP-02 proceeding was developed using fundamentally flawed market price and load data. Shortly after completion of the WP-02 Final Proposal in May 2000, which established the PF Exchange rate, BPA's financial position began to deteriorate as a result of the West Coast energy crisis, coupled with the return of much more COU loads than expected. Burns, *et al.*, WP-07-E-BPA-53, at 5. This undermined the basis for all of the rates determined in the WP-02 Final Proposal and threatened BPA's ability to recover its costs through rates as required by the Northwest Power Act. *Id*. Market prices climbed dramatically and unpredictably, due in part to lack of resource additions and market manipulation in the California market. *Id*. BPA requested a stay of FERC's review of BPA's WP-02 Final Proposal rates in order to determine how to respond to these unprecedented conditions. *Id*. On August 3, 2000, Administrator Judi Johansen sent a letter to BPA's customers and rate case parties asking their advice on how to correct BPA's rates. *Id*. BPA's customers wanted to strengthen the Cost Recovery Adjustment Clause (CRAC) rather than modify base rates. *Id*. BPA took this advice and filed an Amended Rate Proposal in November 2000 that provided for a more robust CRAC. *Id*.

Unfortunately, BPA was in one of the worst water years on record, causing conditions to continue to deteriorate, and it was clear that even BPA's amended proposal was not sufficient to ensure the recovery of BPA's costs. *Id*. at 5-6. BPA requested a further stay of FERC's review of the WP-02 Final Proposal rates and immediately began additional discussions with parties. *Id*. There were two basic options: (1) the adoption of modified CRACs, or (2) revising BPA's base rates by reflecting the changed conditions in revised studies. *Id*. Through further discussions, and based on the circumstances at that time, BPA and parties agreed to leave the WP-02 Final Proposal rates in place and instead implement a set of three CRACs and a Dividend Distribution Clause (DDC), which BPA included in its WP-02 Supplemental Rate Proposal (WP-02 Supplemental case) in February 2001. *Id*. At the conclusion of the supplemental hearing, BPA filed its revised rates with FERC in July 2001. *Id*.

Heavily influencing BPA's decision to develop adjustment clauses rather than revise base rates in its WP-02 Supplemental case was the fact that the IOUs had already signed the REP Settlement Agreements. Forman, *et al.*, WP-07-E-BPA-76, at 11. The IOUs could not participate in the REP Settlement Agreements *and* the REP because the REP Settlement

Agreements required the IOUs to collectively choose one *or* the other. *Id*. Since the IOUs had signed the settlements, they would be purchasing power at the RL rate and receiving financial benefits, not exchanging power at the PF Exchange rate under the REP. *Id*. Therefore, the adoption of adjustment clauses that would have dramatically increased the PF Exchange rate was of no consequence to the residential consumers of regional IOUs. *Id*. This made it easier for BPA to decide to use adjustment clauses as the manner in which to respond to increased loads, drought conditions, and high and volatile market prices. *Id*. In the absence of the REP Settlement Agreements, however, the consequences of that decision would have been very different. *Id*. The base PF Exchange rate would have been adjusted by the CRACs to reach levels of about $90/MWh, effectively eliminating the REP for all six IOUs for the entire WP-02 rate period. *Id*. at 10. The IOUs obviously would have seriously opposed this type of adjustment if their REP benefits depended upon the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 149-150. But again, since the REP Settlement Agreements had been executed by this time, a high PF Exchange rate would not have been a material consideration.

Following the Court's decisions in *PGE* and *Golden NW*, BPA considered whether the PF Exchange rate, developed from the base WP-02 rate record, could be used to calculate the rightfully due amount of REP benefits. In light of the above history, BPA determined that it would be inappropriate to use the PF Exchange rate established in the first portion of the WP-02 rate case for purposes of reconstructing REP benefits. This PF Exchange rate had been established using costs, loads, and market prices that were fundamentally flawed. Forman, *et al.*, WP-07-E-BPA-76, at 7. These rates could not have been approved by FERC and could not have been charged to the preference customers or the IOUs had BPA not adopted the comprehensive CRAC construct in the supplemental proceeding. In the absence of the REP settlements, however, the dramatic changes in loads and market prices would have affected the implementation of BPA's section 7(b)(2) rate test and the establishment of the PF Exchange rate, which in turn is used to establish REP benefits. *Id*. at 10-11. Using these flawed rates to establish the REP benefits would distort the underlying REP results and thereby not reflect the best estimate of the overcharges to the COUs. It would also be counter to the Court's guidance that when setting rates, BPA must at least "know[] its costs, or, at the very least, that it estimates them 'in accordance with sound business principles'", and that BPA's forecasts must be based on "realistic projections … that accurately reflected the information available at the time rates were set and the cost recovery mechanism adopted." *Golden NW*, 501 F.3d at 1053.

To remove these defects, Staff proposed to return to the winter of 2000 and spring of 2001, during the West Coast energy crisis, and assume that instead of adopting CRACs, BPA would have recalculated base rates. Burns, *et al.*, WP-07-E-BPA-53, at 7. This period was chosen because it was during these months that BPA faced its pivotal decision to either retain its flawed base rates and adopt CRACs or reopen the rate record and revise base rates. In a scenario without the REP Settlement Agreements, BPA strongly believes it would not have adopted CRACs. Instead, BPA believes it would have adjusted base rates with the new load, market price, and REP information that was, or would have been, available during the same period in which the WP-02 Supplemental Proposal was developed. *Id*. at 8. Had BPA proposed to revise its base rates in the winter of 2000 and spring of 2001, the scope of the WP-02 supplemental proceeding would have been much broader, and BPA would have had to address certain critical section 7(b)(2) implementation decisions. BPA believes making those decisions now and affording an opportunity to the parties to respond to those decisions in this proceeding is both necessary and fundamentally fair. Without this supplemental information, BPA will be unable to respond to the Court's remand in *Golden NW* because it cannot reasonably determine, based on the existing record, what the appropriate amount of REP benefits would have been without the REP Settlement Agreements.

B. The WP-07 Rate Record and BPA's Basis for Considering Supplement Information

The WP-07 rates have yet to be finalized by FERC, and therefore, have yet to be litigated before the Court. Nevertheless, BPA recognizes that because the WP-07 rates contain the same legal errors discussed in the *Golden NW* decision, the WP-07 rate record must be reopened and the rates revised. Thus, as part of this proceeding, Staff has proposed to supplement the WP-07 rate proceeding record with additional information to correct for the errors in the WP-07 rates. In reopening the WP-07 proceeding, BPA is following the well established principle of administrative law that an agency may reconsider an interim or even final decision to correct for known errors. *Dun & Bradstreet Corp. v. United States Postal Service*, 946 F.2d 189, 193 (2nd Cir. 1991); *Alberta Gas Chemicals, Ltd. v. Celanese Corp.*, 650 F.2d 9, 12 (2nd Cir. 1981) (every decision-making body, judicial and administrative, has power to reconsider and correct its own errors); *Sudarsky v. City of New York*, 779 F. Supp. 287, 298 (S.D.N.Y. 1991), *aff'd*, 969 F.2d 1041 (2nd Cir.), *cert. denied*, 506 U.S. 1084 (1992) (agency may reconsider regardless of whether statute expressly so provides).

Supplementing the WP-07 rate record is necessary because, in addition to removing the legal errors associated with the allocation of REP Settlement costs, many of the key issues regarding the level of REP benefits, such as the implementation of the section 7(b)(2) rate test, have not been fully litigated due to a partial settlement of issues in the case. Bliven, *et al.*, WP-07-E-BPA-52, at 6. Specifically, parties to the case initially filed direct cases that included several issues related to the section 7(b)(2) rate test. *Id*. However, prior to the filing of rebuttal testimony in March 2006, rate case parties proposed settlement on certain issues. *Id*. These discussions led to the Partial Resolution of Issues With Parties (Partial Resolution), an agreement settling a number of issues in the rate case. *Id*. *See also* Evans, *et al.*, WP-07-E-BPA-31; Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-49, Attachment A. While issues regarding the allocation of REP settlement costs and the section 7(b)(2) rate test were not resolved, BPA stated that it would not treat as precedential or binding 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. *Id*. at 7; *see also* 2007 Administrator's Final Record of Decision, WP-07-A-02, at 10·5-10·6. BPA also concluded that it was not necessary to decide whether any alleged modeling errors existed. *Id*. The IOUs withdrew their rate test testimony, due in part to their reliance on their REP Settlement Agreements, which were not affected by the outcome of the rate test. *Id*.

As a consequence of the Court's remand in *Golden NW*, BPA must revisit its implementation of the section 7(b)(2) rate test in the WP-07 rate case. In this instance, BPA finds that it is both appropriate and necessary to reopen and supplement the WP-07 rate record to allow parties an opportunity to present their challenges to BPA's implementation of the section 7(b)(2) rate test. *Id*. To allow for this, BPA is setting aside the portions of the Partial Resolutions that dealt with the section 7(b)(2) rate test. *Id*. at 8. Without the REP Settlement Agreements, BPA believes parties would have pursued their challenges to BPA's implementation of the rate test and the legal interpretation of section 7(b)(2). *Id*.

C. Response to Parties' Positions

The IOUs, though not conceding that BPA should conduct the Lookback, appear to agree with BPA's decision to revisit the WP-02 rate record. IOU Br., WP-07-B-JP6-01, at 149-150. The IOUs note that material changes of circumstances occurred between when BPA issued the WP-02 ROD on May 19, 2000, and when BPA would have decided the section 7(b)(2) rate test issues in 2001, requiring BPA to revisit the section 7(b)(2) rate test and recalculate the PF Exchange rate. *Id*. The IOUs further maintain that if they had not been offered the REP Settlement Agreements and had instead received REP benefits under section 5(c) of the Northwest Power Act, they would have vigorously pursued in the WP-02 proceeding the full panoply of section 7(b)(2) issues, which BPA would have likely decided in 2001. *Id*.

APAC, WPAG, and PPC generally oppose BPA's proposal to revisit the rate record. APAC Br., WP-07-B-AP-01, at 26-28; WPAG Br., WP-07-B-WA-01, at 6-7; PPC Br., WP-07-B-JP25-01, at 29-32. Cowlitz took no position in its brief, but generally approves of the approaches advocated by APAC and WPAG. Cowlitz Br., WP-07-B-CO-01, at 67-68.

1. The WP-02 and WP-07 PF Exchange Rates Cannot be Used to Determine REP Benefits in this Proceeding.

APAC argues that BPA can satisfy the Court's remand by continuing to apply the PF Preference rates and PF Exchange rates that were previously adopted for FY 2002-2006. APAC Br., WP-07-B-AP-01, at 27. APAC contends that BPA established a rate for entities that wish to participate in the "traditional" REP program (the PF Exchange rate) for FY 2002-2006, and that BPA supplemented this decision in 2001, finding that the base rates set in the May 2000 ROD "remained valid." *Id*. at 26-27. WPAG raises a similar argument. WPAG Br., WP-07-B-WA-01, at 6-7; WPAG Br. Ex., WP-07-R-WA-01, at 8-9. WPAG argues that BPA is undertaking an unnecessary exercise by revisiting the rate records from the WP-02 and WP-07 rate cases since these records contain all of the information needed by BPA to comply with the remand directive of the *Golden NW* decision due to the legal error made by BPA in both of those cases. *Id*. WPAG asserts that in both cases BPA has already determined the PF-02 and PF-07 rates without including any REP Settlement costs. *Id*.

BPA does not find these arguments persuasive for several reasons. First, as already described above, the underlying PF Exchange rate developed in the WP-02 rate case was "fundamentally flawed" in several respects. For one, it did not reflect the dramatic market changes in the energy market that occurred after the finalization of the May 2000 proposal. Forman, *et al.*, WP-07-E-BPA-76, at 11. APAC attempts to obfuscate this fact by claiming BPA in the Supplemental proposal of 2001 made a finding that the WP-02 base rates "remained valid." APAC Br., WP-07-B-AP-01, at 27. The record, however, squarely refutes this assertion. Had the WP-02 "remained valid" by the spring of 2001, BPA would have had no need to commence two supplemental proceedings *seriatim* to attempt to fix an emergency cost recovery problem.

Market conditions had deteriorated so much during the winter of 2000 that had BPA not immediately commenced a supplemental proceeding to establish CRACs, BPA would have been unable to demonstrate cost recovery of the WP-02 rates to FERC. Bliven, *et al.*, WP-07-E-BPA-52, at 5. The conclusion to be drawn from BPA's decision to conduct two supplemental proceedings after completing the May 2000 proposal is not that the WP-02 rates were "valid" but, in fact, "unsustainable."

Second, WPAG's and APAC's comments also ignore the fact that the PF Exchange rate in the WP-02 proceeding reflects the results of the two-part "Rate Design Step" that the *Golden NW* Court found illegal. As discussed by Staff, unraveling this defect, when combined with the flawed market and load data, "is not a simple task." Forman, *et al.*, WP-07-E-BPA-76, at 7. Rates are not developed in a vacuum, and adjusting for one assumption has effects on others. For example, the "Subscription Step" that the Court found in error did more than address REP Settlement benefits. It also implemented the "Compromise Approach" rates for DSI customers. *Id*. The rates that WPAG and APAC urge BPA to recognize in lieu of the Subscription Step rates did not take the rates to the DSIs into account. As such, the rates resulting from a prior interim step in the rate setting process were not comprehensive in and of themselves. In order to properly resolve the overpayment of REP settlement costs by BPA's preference customers, BPA must determine the amount of the REP settlement benefits provided to the IOUs' residential consumers and the amount of lawful REP benefits the IOUs would have received in the absence of the REP Settlement Agreements. *Id*. The only way to answer these questions accurately, particularly because the determination of REP benefits depends in large part on the proper establishment of the PF Exchange rate, is to revisit BPA's WP-02 and WP-07 records and BPA's underlying rate decisions. *Id*. at 7-8. Thus, revisiting BPA's WP-02 and WP-07 ratemaking is both appropriate and necessary for this case.

APAC also points out that FERC granted final approval to these rates on July 21, 2003. APAC Br., WP-07-B-AP-01, at 27. Since these rates were not the subject of appeal and were not reversed by the Ninth Circuit, APAC concludes they remain the filed rates and are binding and enforceable. *Id*. This argument is not persuasive. FERC has limited authority to review BPA's rates under the Northwest Power Act. The Commission describes its authority to review BPA's rates as follows:

> Unlike the Commission's statutory authority under the Federal Power Act, the Commission's authority under Sections 7(a) and 7(k) of the Northwest Power Act does not include the power to modify the rates. The responsibility for developing rates in the first instance is vested with Bonneville's Administrator. The rates are then submitted to the Commission for approval or disapproval. In this regard, the Commission's role can be viewed as an appellate one: to affirm or remand the rates submitted to it for review.

United States Dep. of Energy – Bonneville Power Admin., 104 FERC ¶¶ 61,093, 61,334 (2003).

As this language indicates, the Commission does *not* review the substantive decisions that lead to BPA's proposed rates, such as BPA's decision to adopt a particular rate design or whether BPA's rate proceeding record adequately addresses the issues presented in the case. Rather, FERC's review is limited to ensuring that BPA's proposal will ensure recovery of BPA's total costs. In view of this limited authority, FERC's interim and final rate approvals only show that BPA's rates met the cost recovery standard FERC is statutorily required to evaluate. Further, FERC approved the whole of BPA's WP-02 rates, *including the June 2001 Supplemental Proposal*, not just BPA's May 2000 Final Proposal. Forman, *et al.*, WP-07-E-BPA-76, at 14-15. Indeed, FERC likely would not have approved BPA's May 2000 rate proposal given that the rates were fundamentally flawed and failed to ensure the recovery of BPA's costs as required by law. *Id*. Thus, these orders in no way inform whether the WP-02 record is sufficient today to dispose of the remand issues in this case. Further, while the confirmation and approval by FERC defines when rates become a "final action" of the Administrator, 16 U.S.C. § 839f(e)(4)(A) and 839f(e)(4)(D), the final permanence of the rates is not established until petitions to the court of appeals for the region have been resolved. 16 U.S.C. § 839f(e)(5). The rates were challenged in *Golden NW*, and the Court decided that they were in error. Through its decision in *Golden NW*, the Court has remanded the rates to BPA to "set rates in accordance with this opinion." *Golden NW*, 501 F.3d 1037, 1048, 1053 (9th Cir. 2007). The Court itself has determined that the rates were not final and binding.

APAC also argues that the PF Exchange rate is a "filed rate" that was not remanded to BPA by the Court. BPA has already addressed APAC's Filed Rate arguments and the effects the Court's remand has had on the WP-02 rates in section 2.6.2 above.

2. BPA's WP-02 Supplemental Proposal to Adopt Cost Recovery Adjustment Clauses (CRACs) Did Not Correct Defects in the WP-02 Rates and Rate Record.

APAC argues that when BPA adopted its WP-02 Supplemental proposal in June of 2001, it knew that the settlement agreements could be challenged and ruled invalid. APAC Br., WP-07-B-AP-01, at 28. Despite these pending challenges, APAC contends that BPA chose to rely on the original rate determinations as the basis upon which to apply the adjustment clauses. *Id*. APAC's observation is beside the point. BPA developed the PF Exchange rate, performed the 7(b)(2) rate test, and calculated forecast ASC in the May 2000 WP-02 Final Proposal, *not* the June 2001 ROD. When BPA was making these key decisions it did not know that the REP Settlement Agreements would be challenged. Forman, *et al.*, WP-07-E-BPA-76, at 19. The first REP Settlement Agreements were not signed until late October 2000, well after the publication of BPA's May 2000 ROD. *Id*. Therefore, it would have been impossible for BPA to know that the REP settlements were under legal challenge. *Id*. The legal challenges APAC refers to came after the unprecedented market changes in the winter of 2000 and spring of 2001 occurred, when BPA and its customers were faced with the pivotal decision to either revise all base rates or adopt CRACs. *Id*. Because at this point the IOUs had agreed to receive REP benefits under the REP Settlement Agreements, BPA did not propose, and the IOUs did not argue, to adjust the PF Exchange rate. As noted above, influencing BPA's decision to adopt CRACs was the reality that the IOUs had already signed the REP Settlement Agreements. Forman, *et al.*, WP-07-E-BPA-76, at 11-12. Influencing the IOUs' decision not to challenge the CRACs was the knowledge that their REP benefits were not based on the PF Exchange rate with the CRACs applied.

In its Brief on Exceptions, APAC argues that the IOUs had the opportunity to file ASCs with BPA, and BPA had the opportunity to revisit the entire WP-02 rate case record, all before the first appeals were filed on the REP Settlement Agreements. APAC Br. Ex., WP-07-R-AP-01, at 15. Consequently, APAC argues that the parties had ample opportunity to provide a full record from which BPA could make the necessary rate determinations assuming the appeal was granted. *Id.* On APAC's first point, BPA notes that the IOUs did *not* have the opportunity to file ASCs with BPA before the WP-02 rate case or anytime thereafter. Prior to the WP-02 rate case, several IOUs were operating under an early version of the REP Settlement Agreements, which did not provide for the filing of ASCs. Boling, *et al.,* WP-07-E-BPA-57, at 4-5. As the WP-02 rate case came to a close, the IOUs were given a choice – they could either sign the REP Settlements *or* an RPSA. Bliven, *et al.*, WP-07-E-BPA-52, at 4-5. The IOUs were not given the option of signing *both. Id*. Since the REP Settlement Agreements did not require the IOUs to submit ASCs, there would have been no basis for the IOUs to start submitting ASCs during the WP-02 rate period. Thus, APAC's statement that the IOUs had an opportunity to file ASCs is incorrect. It also entirely ignores a value that a settlement is intended to afford the parties – the freedom to avoid further litigation on the matter settled.

APAC's latter point, that BPA could have revisited the WP-02 rate record, fails to acknowledge that the decision to limit the scope of the WP-02 supplemental rate proceeding was not exclusively BPA's proposition, but the result of a partial settlement agreed to by BPA and a significant number of its customers. Burns, *et al.,* WP-07-E-BPA-53, at 5; *see also* 2002 Supplemental Power Rate Proposal, Administrator's Record of Decision, WP-02-A-09, at 1·14 - 1·15. This supplemental proposal was incorporated into BPA's staff's proposal, and supported by prefiled written testimony and studies. *Id.* As noted by Staff in this case, a primary influence in BPA's decision to adopt the CRAC approach rather than reopen the WP-02 rate record was the fact that REP benefits would be established pursuant to the REP Settlement Agreements. Forman, *et al.*, WP-07-E-BPA-76, at 11. Adopting CRACs that would have effectively eliminated the REP because of faulty market and load assumptions would not have been a reasonable option for BPA (or supported by the IOUs) had the REP Settlement Agreements not been in place. *Id.* 11-12. BPA, and presumably the IOUs, agreed to CRACs because it solved the immediate cost recovery problem without prejudicing the residential and small farm customers of the IOUs. *Id.* at 12. However, under the circumstances postulated in this proceeding, that the REP Settlement Agreements would not have existed, the only reasonable assumption is that the known defects in the administrative record would have been addressed to ensure the level of forecast REP benefits was accurate. APAC's observation that BPA had an "opportunity" to revisit the record ignores the significant influence that the REP Settlement Agreements had on BPA's and other parties' decision to consider the CRAC approach.

In its Brief on Exceptions, Canby takes issue with BPA's statement that the IOUs would have objected to the adoption of CRACs, claiming that there is nothing in the record from that time that "supports that assertion." Canby Br. Ex., WP-07-R-CA-01, at 11. This alleged "gap" in the WP-02 record, however, is immaterial. BPA's assumption that the IOUs would not have gone along with the CRACs is based on the logical inference that without the REP Settlement Agreements, the IOUs would not have remained placidly silent as BPA adopted a rate approach that effectively eliminated the REP benefits, particularly where the underlying PF Exchange was based on faulty load, market price, and ASC forecast assumptions. Furthermore, the IOUs have been very clear in this proceeding that they would have challenged BPA's decision not to revisit the WP-02 rate case 7(b)(2) rate assumptions had the REP Settlement Agreements not existed. IOU Br., WP-07-B-JP6-01, at 149; *See also* La Bolle, *et al.*, WP-07-E-JP6-08, at 79-80. Thus, Canby's argument is not persuasive.

APAC further claims that the rate determinations made in the WP-02 Supplemental ROD in June of 2001 remain "just and reasonable" for the FY 2002-2006 period except for the inclusion of the Settlement costs and are not "fundamentally flawed" as argued by Staff and IOU witnesses. APAC Br., WP-07-B-AP-01, at 27. APAC relies on testimony proffered by its witness that allegedly demonstrates that the rates set in the June 2001 ROD and the section 7(b)(2) rate test established in the 2000 final proposal are reasonable and will satisfy BPA's revenue requirement obligations. *Id*. APAC's arguments are misplaced. BPA's rates are not reviewed on a "just and reasonable" standard as alluded to by APAC, and any reference to such a standard is inapposite under the Northwest Power Act. Furthermore, APAC's observation that BPA's base WP-02 rates in combination with the June 2001 Supplemental proposal were sufficient to demonstrate cost recovery is irrelevant for purposes of the present inquiry. The WP-02 rates could not have been approved by FERC unless BPA's rates covered its costs. The fact that BPA was able to demonstrate cost recovery, however, does not answer the questions of whether the underlying WP-02 base rates were properly constructed or what amount of REP benefits should have been legally included in the COUs' rates absent the REP Settlements. APAC's reliance on the WP-02 Supplemental ROD is, therefore, misplaced.

3. *The "Rate Design Step" and the Annual Forecasts of $48 Million in REP Benefits in the WP-02 Rate Record and $30 Million in REP Benefits in the WP-07 Rate Record Do Not Establish the Amount of REP Benefits the IOUs would have Received Absent the REP Settlement Agreements.*

APAC asserts that the WP-02 final proposal set a section 7(b)(2) "rate test ceiling" of $48 million a year. APAC Br., WP-07-B-AP-01, at 27. APAC contends that when the PF Exchange base rates are combined with the CRAC adjustments and with "actual" ASCs and exchange loads (as estimated by BPA), they produce a payout of $46 million a year to the IOUs. APAC concludes that this suggests the original prospective rate test determination remains reasonable. *Id*.

APAC's reliance on the $48 million REP forecasts in the WP-02 rate case is misplaced for several reasons. First, as described above, the PF Exchange rate that was used to establish the $48 million REP forecast was found to be fatally flawed because it did not account for the significant changes in loads that occurred after the close of the WP-02 record. Foreman, *et al.*, WP-07-E-BPA-76, at 16. After the May 2000 ROD, BPA (and the region) learned that BPA's load forecast was egregiously in error due to the unanticipated return of over 1,000 aMW of public agency loads after such loads had previously left BPA service during a period of low market prices. *See* 2002 Final Supplemental Administrator's ROD, WP-02-A-09, at 1·11-1·12. Had BPA accounted for this new influx of load in its supplement WP-02 rate proposal, instead of adopting CRACs, the amount of *forecast* REP benefits determined by operation of the section

7(b)(2) rate test would have been considerably different than the $48 million assumed in the rate case.

Second, the WP-02 rate case forecast of $48 million in REP benefits is also defective because it does not reflect the unprecedented and enormous increases in market prices. Foreman, *et al.*, WP-07-E-BPA-76, at 16. BPA's forecasts market prices are critical to the development of the forecast of REP benefits. *Id*. For one, market prices are used to calculate forecasts of the ASC for the exchanging utilities during the rate period. As noted throughout this document, ASC forecasts are an integral part of forecasting the costs of the REP in BPA rate proceedings. *Id*. The forecast amount of REP benefits are determined by subtracting the PF Exchange rate from a forecast of the utility's ASC, and then multiplying the difference by a forecast of the utility's exchangeable load. In rate setting, BPA forecasts the ASCs through the rate period, and then subtracts the PF Exchange Rate from these forecasts to calculate an estimated amount of REP benefits. These REP benefits are then used to run the section 7(b)(2) rate test and to calculate base rates, including the PF Exchange rate. When BPA was forecasting the ASCs in the WP-02 rate case, BPA assumed that the IOUs would purchase power from the market to meet its load growth over the rate period at a price of only $28.1/MWh. Boling, *et al.,* WP-07-E-BPA-57, at 6. By the winter of 2000, however, the prevailing market price forecast was *$148 /MWh* -- almost five times higher than the market price forecast used in the rate case. *Id.* Had BPA adjusted its base WP-02 market price forecast to account for this *known* defect in the record in the winter of 2000 or spring of 2001, the resulting forecast ASC would have been generally higher, especially for FY 2002. *Id.* at 7. These higher ASCs, would consequently, also raise the level of forecast REP benefits above the $48 million in annual REP benefits relied upon by APAC.

Third, the faulty market price forecasts also had a major impact on BPA's "in lieu" assumption, which is another critical factor used in determining forecast REP benefits. Under section 5(c)(5) of the Northwest Power Act, BPA may elect to provide actual power deliveries to the exchanging utility "in lieu" of exchanging at the utility's ASC if BPA can obtain power from another source that is cheaper than the exchanging utility's ASC. 16 U.S.C. § 839c(c)(5). For example, if BPA's PF Exchange rate is $40/MWh and the exchanging utility's ASC is $60/MWh, BPA would normally have to pay the difference ($20/MWh) times the IOUs' exchangeable load. However, if BPA can buy firm power from another source for $55/MWh, BPA could elect to actually purchase power and sell it to the utility at the "in lieu" price of $55/MWh, thereby saving $5/MWh in REP costs. This feature of the Act allows BPA to reduce the costs of the REP. Doubleday, *et al.,* WP-07-E-BPA-60, at 34. In the WP-02 Final Proposal, BPA assumed a flat block market forecast of $28.1/MWh. *Id.* Based on this assumption, BPA forecasted that it would "in lieu" 50 percent of the exchangeable load as a cost savings strategy. *Id.* The result of this strategy was that 50 percent of the forecast exchange load was assumed *not to be exchanged* because the $28.1/MWh market rate was *less than* the forecast PF Exchange rate of $36.01/MWh. *Id.* In other words, *half* of the eligible exchange load of the IOUs was assumed not to be exchanged in the WP-02 rate record because of the assumption that power could be purchased at the faulty market rate of $28.1/MWh. In and around the spring of 2001, however, it became patently clear that market prices were significantly above the flat $28.1/MWh over five years forecast in the WP-02 Final Proposal. *Id.* Had BPA revisited the WP-02 rate record, rather than adopt CRACs, there can be little question that the assumption that 50 percent of the IOU's load would be in lieued would have been changed to zero. Boling, *et al.,* WP-07-EB-BPA-57, at 8-9. This change would have resulted in significantly *higher* forecast REP benefits.

Finally, even if the WP-02 record did not contain these significant defects, it would still not be appropriate to assume that the REP benefits are "limited" to the $48 million forecast in the WP-02 rate case. REP benefits are *not* based on forecast ASCs. Bliven, *et al.,* WP-07-E-BPA-52, at 18-19; *see also* Chapter 7. Rather, REP benefits are based on the difference between each IOU's *filed* ASC and BPA's PF Exchange rate, multiplied by the utility's exchange load. *Id*. at 16. However, no IOUs filed ASCs with BPA from FY 2002-2008 because the IOUs had executed the REP Settlement Agreements. Had the IOUs *not* signed these Agreements, and had they participated in the REP through an RPSA, the IOUs would have been making ASC filings with BPA pursuant to the 1984 Average System Cost Methodology (1984 ASCM). *Id*. BPA must have these "real time" ASCs in order to reasonably estimate the likely REP benefits that would have been paid during FY 2002-2008. *Id*. at 16-17. Thus, the WP-02 rate record and (the WP-07 rate record) are incomplete because they both do not contain the critical "real time" ASCs the IOUs would have been filing with BPA that are essential for determining the REP benefits that the IOUs would have received (and what the COUs would have paid in rates).

In light of these known defects in the record, BPA finds that it is unreasonable to assume in this proceeding that the $48 million forecast of REP benefits from the WP-02 rate record should serve as the basis for the IOU's reconstructed REP benefits. Indeed, using these known defective forecasts to calculate the REP benefits would be counter to the Court's guidance that BPA forecasts be made based on the best available information consistent with sound business principles. *Golden NW,* 501 F.3d at 1053. This is exactly what BPA is doing by revising the rate record and recalculating the PF Exchange rate and REP benefits using data that were known at the time and that were based on "sound business principles." BPA is updating the load and market price with information that was known at the time. Burns, *et al.,* WP-07-E-BPA-53, at 7. As noted in the above discussion, these defects would have been corrected in the winter of 2000 and spring of 2001, and as a result, the level of forecasted REP benefits also would have been significantly different. Moreover, it is very likely that had the REP Settlement Agreements not been executed by the time of the supplemental WP-02 case, the CRAC approach would not have been pursued. Burns, *et al.,* WP-07-E-BPA-53, at 7. Because of the REP Settlement Agreements, though, BPA decided to limit its review to the immediate issue of demonstrating cost recovery at FERC. Forman, *et al.,* WP-07-E-BPA-76, at 12. It defies common sense and any sense of real equity to suggest that the WP-02 rate record is now perfectly fine to use as a basis for calculating REP benefits when, in fact, it was because of the above noted glaring defects in the record that BPA was forced to commence the WP-02 supplemental proceeding to consider arrangements to remedy problems with it. Relying on known defective forecasts is not "in accordance with sound business principles."

In addition, no party has presented any convincing evidence in this case to suggest that these defects in the WP-02 rate case were not the primary factor behind BPA's decision to revisit the WP-02 rates in the winter of 2000 and spring of 2001. Even if BPA were to totally agree with the parties' request to use the defective WP-02 rate record, BPA would still need to supplement the record to develop the "real time" ASCs (referred to as "backcast ASCs" in Chapter 7) the

IOUs would have filed with BPA to calculate the rightfully due REP benefits. For these reasons, BPA finds that the $48 million estimate included in the WP-02 is not a supportable representation of the REP benefits that the IOUs would have received during the WP-02 rate period absent the REP Settlement Agreements, and rejects APAC's and other parties' arguments that it must be used.

APAC argues that the forecast of REP benefits of $48 million a year developed in the WP-02 record, when compared to BPA's backcast ASCs, results in an estimate of $46 million a year of REP benefits. APAC Br., WP-07-B-AP-01, at 27. APAC concludes that this suggests the original prospective rate test determination remains reasonable. *Id*. APAC's comparison of the flawed PF Exchange rate to BPA's backcast ASCs, however, does nothing to prove the validity of the PF Exchange rate or the $48 million. REP benefits are calculated by comparing *three* components: the PF Exchange rate, the IOU's ASCs, and the IOU's exchange load. As discussed in chapter 7, Staff proposed "backcast ASCs" to estimate the latter two of these components using the 1984 Average System Cost Methodology and utility data that was available during the WP-02 rate period. *See* Chapter 7. Comparing these ASCs with the original PF Exchange rate, as APAC suggests, is inaccurate because the PF Exchange rate still reflects erroneous load and market prices. The $46 million figure that APAC cites has no meaning since these defects in the PF Exchange rate must first be corrected. Once the PF Exchange rate is properly determined, as proposed in this proceeding, then and only then may the backcast ASCs be compared to the revised PF Exchange rate to calculate the appropriate amount of REP benefits that would have been recovered in rates.

WPAG argues that when performing the section 7(b)(2) rate test, BPA forecast ASCs for the IOUs assuming their participation in the REP and established PF Exchange Rates for use in calculating the REP payments that would be available to the IOUs. WPAG Br., WP-07-B-WA-01, at 7. In both the WP-02 and WP-07 rate cases, WPAG contends that BPA determined that the section 7(b)(2) rate test limited the REP costs that could be included in the PF-02 and PF-07 rates, which amounts were $48 million per year (or $240 million for the rate period) for the PF-02 rate, and $30 million per year (or $90 million for the rate period) for the PF-07 rate. *Id*.; *see also* WPAG Br. Ex., WP-07-R-WA-01, at 8-9, 36. WPAG further explains that, pursuant to section 7(b)(3), 16 U.S.C. § 839e(b)(3), BPA then allocated to other adjustable firm power rates, such as the PF Exchange rate, the REP costs in excess of those amounts that BPA had determined could be lawfully allocated to the PF-02 and PF-07 rates. *Id*. Hence, WPAG concludes that the record in both the WP-02 and WP-07 rate cases contains the preference customer rate produced by a lawful application of the section 7(b)(2) rate test *without* the inclusion of REP Settlement costs. *Id.* PPC makes a similar argument in its brief. PPC Br., WP-07-B-JP25-01, at 29-30; PPC Br. Ex., WP-07-R-PP-01, at 18.

The WUTC urges BPA to reject these arguments. The WUTC argues that the publics' position is fundamentally mistaken because BPA's forecast of REP benefits for purposes of rate design does not set a cap on actual benefits any more than any other rate case cost or revenue forecast creates a "cap" on costs or revenues actually experienced over the rate period. WUTC Br., WP-07-B-WU-01, at 14. The WUTC notes that this approach creates a classic "apples and oranges" comparison. *Id*.

As explained above in response to APAC's nearly identical proposal, WPAG's and PPC's proposal is simplistic, unfair, and would provide significant, undeserved benefits to BPA's COUs. As explained previously, BPA is comparing the REP benefits the IOUs' residential consumers received under the REP Settlements (as adjusted for benefits that should be retained by the IOUs' residential consumers) with the lawful REP benefits the IOUs would have received under the REP in the absence of the REP Settlements. Forman, *et al.*, WP-07-E-BPA-76, at 20. One cannot rationally assume the IOUs would not have participated in the REP in the absence of the REP Settlements. *Id*. Therefore, BPA must ensure that such REP benefits are estimated as accurately as possible by properly establishing the PF Exchange rate. *Id*. The PF Exchange rate established in BPA's May 2000 Proposal was based on market prices and load assumptions that were invalid by the winter of 2000 and spring of 2001. *Id*. at 20-21. BPA's WP-02 base rates developed under the Rate Design Step, including the PF Exchange rate, were insufficient to recover BPA's costs. *Id*. WPAG's argument also ignores the facts. The $48 million is not the amount included in the PF-02 rate, but the amount in *all* rates. This amount was not solely borne by the PF-02 rate, especially not just the PF-02 Preference rate. All of BPA's rates work together to collect BPA's costs, not just one particular rate. Second, the $48 million was the forecast amount included in rate level determinations; such forecast does not limit amounts that may be paid, that is, it does not become a cost ceiling. Proposing to use the PF Exchange rate arising out of a flawed Rate Design Step, which included a flawed section 7(b)(2) rate test, makes little sense. Finally, the $48 million REP forecast is defective because it is a product of the faulty market and load assumptions as described in BPA's response to APAC's arguments.

WPAG also fundamentally misstates the application of law to BPA ratemaking. WPAG states that "[p]ursuant to section 7(b)(3), 16 U.S.C. § 839e(b)(3), BPA then allocated to other adjustable firm power rates, such as the PF Exchange rate, *the REP costs in excess of those amounts* that BPA had determined could be lawfully allocated to the PF-02 and PF-07 rates." WPAG Br., WP-07-B-WA-01, at 7. This statement is in error because it misstates both the law and the facts. Section 7(b)(3) does not speak to the allocation of REP costs; it deals with the allocation of preference rate protection amounts determined under section 7(b)(2). There are no "REP costs in excess" of the amounts that can be lawfully included in the PF Preference rate. As of July 1, 1985, section 7 provides for no other source of REP benefits than those lawfully allowed in all rates in concert, including and foremost the PF Preference rate. It is mathematical verity that the amount of REP benefits established prior to the section 7(b)(2) rate test, less the amount of rate protection afforded by the rate test, equals the amount of REP benefits included in all rates, including the PF Preference rate. No other source of REP benefits exists.

Furthermore, BPA concurs with the observation made by the WUTC that the WP-02 *forecast* of REP costs does not set any sort of "ceiling" on the amount of REP benefits that would have been paid during the WP-02 rate period. *See* WUTC Br., WP-07-B-WU-01, at 13-14; *see also* Chapter 16. As noted previously, the rate case does not establish REP benefits; it establishes the PF Exchange rate based on a *forecast* of REP benefits included in the ratemaking process. Forman, *et al.*, WP-07-E-BPA-76, at 21. Actual payments are based on ASCs determined by BPA pursuant to the 1984 ASC Methodology, the PF Exchange rate, and the residential loads of the participating utilities. *Id*.; *see also* Chapter 7. To properly calculate what the IOUs would have received under the REP, BPA must have approximations of the ASCs the IOUs would have filed during the WP-02 rate period. *Id*. Without this key piece of information, BPA would be establishing the IOUs' REP benefits entirely on ASC forecasts, which is not how REP payments are determined. *Id*.

Another problem with relying only on the WP-02 rate case forecast of $48 million (and $30 million in WP-07) is that such an approach would not accurately reflect the amount of REP benefits the IOUs would have likely received, thereby distorting the repayment that the COUs are entitled to. This result would undermine BPA's key objective of calculating the overcharges as accurately as possible. To calculate the total amount of overcharges, Staff evaluated the *actual* costs of the REP Settlement Agreements by looking at the real-time costs the COUs experienced through CRACs, *not* the forecasts of REP Settlement Agreements costs BPA *assumed* would occur when establishing the base WP-02 rate case. To be consistent, Staff reconstructed the rightfully due REP benefits using a similar method. That is, Staff used estimates of real-time ASCs and exchange loads, rather than rely solely on the forecasts of REP benefits developed in the WP-02 base rate case. By focusing on the "real-time" costs and benefits of the REP from both the perspective of the COUs and the IOUs, Staff was able to recreate an "apples to apples" comparison when determining the amount of overcharges to the COUs. Having symmetry between these two perspectives is absolutely necessary to ensure that the final Lookback Amounts neither under- nor overcompensate the COUs. This balance, however, would be seriously tilted in the COUs' favor if BPA relied on forecast REP benefits from the WP-02, and then compared this amount to the *actual* costs of the REP Settlement Agreements. Under this approach, the IOUs' reconstructed REP benefits would be "limited" to the forecast of REP benefits from the WP-02 rate record. At the same time, the COUs would be entitled to receive as return payments the actual REP Settlement Agreement costs, uninhibited by the WP-02 rate case forecast of the REP Settlement Agreement costs. BPA does not believe adopting this "apples-to-oranges" comparison serves the objective of determining the overcharges to the COUs, nor is a required outcome from the Court's decisions in *Golden NW* or *PGE*, and therefore rejects this approach.

PPC argues that Staff proposes to remake BPA's decisions in a way that would allow it to pay about five times the amount of Residential Exchange Program benefits that it determined were lawful during 2002-2006. PPC Br., WP-07-B-JP25-01, at 30; PPC Br. Ex., WP-07-R-PP-01, at 19. PPC misunderstands Staff's proposal and how the REP operates. First, BPA did *not* determine in the WP-02 rate case that the "lawful" amount of REP benefits was only $48 million. As discussed above, the $48 million is a *forecast* of REP benefits, and as with any *forecast*, it may change as a result of the actual operation of the program. REP benefits are paid based on comparing the *filed* ASC of the exchanging utility (not the forecast ASC) with the PF Exchange rate and then multiplying the difference by the utility's *actual* exchange load (not the forecast exchange load). Burns, *et al.*, WP-07-E-BPA-53, at 3. A full discussion of the operation of the REP as it relates to the ASC filings of the exchanging utilities is provided in chapter 7 of this Record of Decision. The forecast amount of REP benefits, while a necessary component of BPA's rate directives, is not determinative of what REP payments may be made during the rate period. Second, as already discussed above, the $48 million REP benefit amount was determined using a PF Exchange rate that had fundamentally flawed market price and load data.

WPAG also argues that the difference between the Rate Design Step rate and the Subscription Step rate in each of the WP-02 and WP-07 rate cases constitutes the amount the Court in the *Golden NW* decision identified as being illegally allocated to preference customers. WPAG Br., WP-07-B-WA-01, at 8; WPAG Br. Ex., WP-07-R-WA-01, at 9. The PPC makes a similar erroneous statement, claiming that "BPA has been directed by the Ninth Circuit to give effect to 7(b)(2) as a cap on the amount of REP costs that can be imposed on preference customers …" PPC Br. Ex., WP-07-R-PP-01, at 19. These characterizations of the Court's decision are mistaken. The Court's decision in *Golden NW* states as follows:

> By burdening its preference customers with part of the cost of the REP settlement, BPA "ignored its obligations" under sections 7(b)(2) and (3). *Id*. at 1036. Our holding in *Portland General Electric* is dispositive here: BPA "plain[ly] violat[ed]" the rule that the rates it charges preference customers must be calculated "as if 'no purchases or sales … were made [under the REP program].' *Id*. (quoting 16 U.S.C. § 839e(b)(2)(C)).
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> * * * *
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> We agree with petitioners Western Public Agencies Group, Public Power Council, and Public Utility District No. 1 of Grays Harbor that BPA unlawfully shifted onto its preference customers the costs of its settlement with the IOUs. Their petitions are granted. … We therefore remand to BPA to set rates in accordance with this opinion.

Golden NW, 501 F.3d 1037, 1048, 1053 (9th Cir. 2007).

As the above text makes clear, the Court found that BPA violated the law by not applying the section 7(b)(2) rate test when it allocated the costs of the REP Settlement Agreements to the preference rates. The second paragraph finds that BPA "unlawfully shifted" the costs of the REP Settlement into the preference customers' rates. The instruction provided to BPA is in the final sentence, where the Court instructs BPA to "set rates in accordance with this opinion." As BPA interprets the Court's order, BPA is charged with addressing the legal defects in the WP-02 rates and providing an appropriate remedy. However, the Court did not identify what amount was overcharged, how to calculate such amount, whether BPA must rely on the existing record and rates, or whether BPA may consider additional evidence in responding to the remand. Furthermore, the Court did not hold that only the PF Preference rate be set in accordance with its opinion. Because all of BPA's rates work together, BPA cannot reestablish just one rate. WPAG is, therefore, incorrect in arguing that the Court required BPA to simply use the pre-Subscription Step rates, and the alleged $48 million, to calculate the overpayments.

The WUTC argues that any proper refund remedy should directly respond to the specific issue the Ninth Circuit identified; *i.e.*, in the "Subscription Step," BPA unlawfully shifted to its preference customers the cost of its REP settlement with the IOUs. WUTC Br., WP-07-B-WU-01, at 10. According to the WUTC, such calculation must compare the amount of *projected* REP Settlement benefits BPA actually included in the PF Preference rate in Dockets WP-02 and WP-07 to the amount of *projected* REP costs properly allocable to those rates. (WP-07-E-JP6-12). To make this comparison, the WUTC suggests BPA compare the annual forecast of REP benefits ($48 million) with the forecast of REP Settlement payments ($69.725 million) developed in the WP-02 rate case. *Id*. at 11. Using this approach for each year of the Lookback period results in a total Lookback of $246 million. *Id*. at 12. The WUTC explains that this approach is a direct, consistent, and transparent calculation of the ratemaking error determined by the Ninth Circuit. *Id*.

BPA does not disagree that the WUTC's proposal describes one possible method of calculating the Lookback Amounts. Unlike the proposals proffered by several other parties, the WUTC approach relies solely on information from the WP-02 record and does not mix forecast data with actual data. However, BPA does not agree that this approach is the most appropriate in the present circumstance. Using only the forecasts of REP benefits and REP Settlement Agreement costs to determine the Lookback would make sense if BPA had charged only the base WP-02 rates during the FY 2002-2006 period. In reality, however, BPA did not charge these rates alone. Rather, the COUs were subject to the base rates *and* the CRACs developed in the winter of 2000 and spring of 2001. It is worth noting that no jurisdictional review of the CRACs was sought on the basis that they recovered REP Settlement costs. Most of the costs associated with the REP Settlement Agreements were ultimately collected through both of these mechanisms. In this instance, it would not be a sufficient remedy to return only the difference between the forecast REP benefits and forecast REP Settlement Agreement costs because the COUs were not charged based only on forecasts.

Additionally, using only the WP-02 rate case forecasts of REP benefits and REP Settlement Agreement costs to calculate the overcharges would result in Lookback Amounts that are seriously disconnected from the reality of the REP Settlement Agreement costs that the COUs actually paid. In developing the Lookback construct, Staff proposed to determine as closely as possible the overcharges to the COUs. Bliven, *et al.*, WP-07-E-BPA-52, at 11-12. To accomplish this objective, Staff decided to consider the actual costs of the invalidated portions of the REP Settlement Agreements as collected in rates through time (and paid to the IOUs), not simply the costs forecasted in the WP-02 base rates. *Id*. at 11. The decision to use these costs was intentional because, as discussed earlier, the underlying WP-02 rate record was based on several fundamentally flawed assumptions. Relying solely on REP forecasts that are based on this fundamentally flawed record to calculate the overcharges would undermine BPA's main objective of determining as accurately as possible the amount of overcharges to the COUs in this proceeding.

The WUTC also claims that using its approach results in a total Lookback Amount of $246 million. WUTC Br., WP-07-B-WU-01, at 12. BPA notes that this is inaccurate because the WUTC mentions only the financial benefits aspect of the REP Settlement Agreements and does not taken into account the costs associated with the block power sale under the agreements. Ingram, *et al.*, WP-07-E-BPA-58, Attachment C, at 1. The annual amount of REP Settlement benefits forecast in the WP-02 rate proceeding was approximately $142 million. *Id*.

In its Brief on Exceptions, PPC objects to BPA's arguments that more information is needed to calculate the rightfully due REP benefits. In particular, the PPC argues that ASC information is not necessary because "the rate test is unaffected by ASC filing information—a point demonstrated by the law as well as the fact that BPA indeed ran the fully litigated rate test in the

WP-02 proceeding without the IOUs' ASC filings." PPC Br. Ex., WP-07-R-PP-01, at 20. This statement is unpersuasive because it inaccurately describes the operation of the REP, how BPA sets its rates, and the role that ASCs play in calculating REP benefits.

As described more fully in Chapter 7 of this document, ASCs play a *vital* part in calculating BPA's rates, particularly in the section 7(b)(2) rate test. When BPA is setting its rates, it includes *forecasts* of the exchanging utility's ASCs to determine the projected costs of the REP. These projected costs of the REP are subsequently "removed" from BPA's section 7(b)(2) Case pursuant to the third assumption in the rate test. *See* 16 U.S.C. § 839e(b)(2)(C). Having accurate ASC forecasts is, therefore, critical to ensuring that the rate test is properly run and that BPA's rates reflect a reasonable estimation of REP costs. Contrary to PPC's suggestion, BPA *did* use ASCs from the IOUs to forecast the IOUs' ASCs in the WP-02 rate proceeding. While these ASCs came from filings that were several years old in some instances, it is wrong to suggest that BPA did not use the IOUs' ASCs when establishing rates in the WP-02 proceeding. From these filings, BPA projected ASCs for the rate period. The problem that BPA is correcting for in the record is with the model BPA used to forecast these ASCs over the FY 2002-2006 timeframe. The model used the same faulty market price information that was used elsewhere in the rate record. Boling, *et al.,* WP-07-E-BPA-57, at 5-6. As explained before, the forecast ASCs were set assuming a market price of $28.1/MWh, when in fact the market was much closer to $148/MWh. *Id.* To correct this, BPA proposed to update the ASC forecasts by reflecting the known market prices at the time in order to run the section 7(b)(2) rate test with accurate assumptions to produce a PF Exchange rate unaffected by the faulty record information and the REP Settlement Agreements. Irrespective of which market assumptions are used, though, there is no question that BPA used IOU ASC filings to forecast the ASCs in the WP-02 rate case, and PPC's assertion stating otherwise is patently refuted by the record in this case.

Finally, even though BPA had a *forecast* of ASCs to use in its rate model in the WP-02 rate case, these forecasts ASCs in no way set or cap the ASCs that the IOUs could file with BPA during the rate period *after* BPA sets its rates. Under the 1984 ASC Methodology, and the Residential Purchase and Sales Agreement (RPSA), the IOUs had the obligation to file with BPA a new ASC filing every time a rate change was filed with the IOUs' state commissions. As noted in Chapter 7, the IOUs collectively submitted over 77 retail rate change orders during the FY 2002-2006 period alone. This means that the IOUs' ASCs could have changed at least 77 times during the WP-02 rate period. BPA's WP-02 rate case, therefore, does *not* control or otherwise dictate what REP benefits would have been paid *after* the rates were set. The IOUs' REP benefits would have been established based on these "real time" ASC filings, not the ASC forecasts used in BPA's rate proceedings. Consequently, to determine the rightfully due REP benefits, BPA must venture beyond the ASC forecasts to the actual implementation of the REP and calculate the "real time" ASCs the IOUs would have filed but for the REP Settlement Agreements. This last point must be emphasized. The WP-02 record as it stands, even with updated ASC forecasts, cannot be used alone to determine the amount of REP benefits the IOUs would have received. BPA must supplement the record to account for the ASCs the IOUs would have filed during this period. As explained in Chapter 7 and Chapter 16, establishing REP benefits on any other basis would be inconsistent with the traditional implementation of the REP, the plain language of sections 5(c) and 7(b)(2), the 1984 ASC Methodology, the RPSA, and result in windfall refunds to the COUs. For these reasons, then, it was proper for BPA to not rely on the erroneous rate case forecasts of REP benefits developed in the WP-02 and WP-07 rate proceedings, and instead, calculate REP benefits based on the supplemental information developed in this proceeding.

4. BPA Has Not Revisited the Rate Records Only To Reconsider the Treatment of Non-Federal Resources in the Section 7(b)(2) Rate Test.

WPAG claims in its Brief on Exceptions that BPA's decision to revisit the WP-02 and WP-07 rate records is based "solely" on BPA's decision to re-run the section 7(b)(2) rate test for the FY 2002-2008 periods in order to change the treatment of non-federal resources that are available in the 7(b)(2) case. WPAG Br. Ex., WP-07-R-WA-01, at 10-11. This assertion is flatly wrong. As the record in this case makes abundantly clear, BPA's decision to revisit the WP-02 and WP-07 record was influenced by several factors. First, and foremost, BPA's decision to revisit the rate record was influenced by the Court's decisions in *Golden NW* and, by extension, *PGE,* to set rates "in accordance with this opinion." *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007). As described above, BPA interpreted this direction to mean it must remove the cost of the REP Settlement Agreements from its rates and determine what the lawful amount of REP benefits would have been. Calculating the rightfully due REP benefits requires accurate representations of three components mentioned before – the PF Exchange rate, the IOUs' ASCs, and the IOUs' exchangeable load. Burns, *et al.*, WP-07-E-BPA-53, at 7. To do this, though, BPA cannot simply remove one set of numbers and insert another. Rather, BPA must consider whether the record is sufficient to respond to the remand. Influencing BPA's decisions in this regard is the Court's admonishment that BPA use "realistic projections … that accurately reflected the information available at the time rates were set and the cost recovery mechanism adopted." *Golden NW*, 501 F.3d at 1053.

Thus, as a second factor, BPA considered whether the WP-02 and WP-07 records contained reasonable estimates of these three components. As BPA Staff explained, the WP-02 rate record used seriously flawed market price and load assumptions that were openly acknowledged by BPA to be invalid well before the WP-02 rates went into effect. Bliven, *et al.,* WP-07-E-BPA-52, at 10-11; Burn, *et al.*, WP-07-E-BPA-53, at 5. These flaws, in turn, had major impacts on the PF Exchange rate and the forecast ASCs. It would have made no sense, and distorted the end results, to use rates that were built from a record that was so obviously defective. Thus, BPA properly decided to supplement the WP-02 record to remove these defects.

A third factor influencing BPA's decision was whether issues related to the implementation of the section 7(b)(2) rate test, a key determinant in the calculation of the PF Exchange rate and final REP benefits, had been fully addressed. Based on this factor, BPA found that both the WP-02 and WP-07 rate records were incomplete because key section 7(b)(2) issues had not been addressed. For example, in the WP-02 rate case, arguments were raised in the original WP-02 case that showed BPA's treatment of certain non-Federal resources (*e.g.,* the Mid-Columbia resources) was incorrect because of a clear error in the 1984 Section 7(b)(2) Legal Interpretation. *See* Chapter 16.10. These legal arguments, however, were never addressed because the treatment of Mid-Columbia resources in the 7(b)(2) rate test was rendered moot because of the faulty load and market assumptions used in the initial rate test. *Id.* The section 7(b)(2) rate test issues in the WP-07 rate proceeding were similarly not decided because of a partial settlement of issues. Bliven, *et al.*, WP-07-E-BPA-52, at 6. Yet, BPA cannot determine the lawful amount of REP benefits for FY 2002-2008 without making a decision on the treatment of the Mid-Columbia resources in the section 7(b)(2) rate test. Rather than leave this issue undecided, BPA determined that the most appropriate, and fair, approach would be to make a decision on this matter based on the supplemental records and allow parties an opportunity to address the issues. BPA's treatment of the Mid-Columbia resources is discussed in full in Chapter 16.10.

As can be seen by the above discussion, BPA's decision to supplement the WP-02 and WP-07 records was not made in order to revisit one particular issue, as WPAG suggests, but as part of BPA's overall objective to ensure that the final record in this proceeding contains complete and accurate information on the key components that determine lawful REP benefits. While WPAG may imply ignoble motives to BPA's decision to revisit the WP-02 and WP-07 records, the evidence presented in this case squarely establishes that this decision was made in order to supplement the record for *known* defects or to address issues that were not fully litigated. Burns, *et al.,* WP-07-E-BPA-53, at 6-7 (supplement to remove known defects); Bliven, *et al.*, WP-07-E-BPA-52, at 6 (WP-07 rates not fully litigated). On this point, it is telling that no party to this proceeding presented any evidence to refute BPA's position that the WP-02 rate record contained defective market and load assumptions or that the WP-07 record was incomplete because of the partial settlement of issues. Yet, WPAG and others believe that BPA should use these defective and incomplete records to calculate the PF Exchange rate, a key component of the REP benefits the IOUs would have received during the FY 2002-2008 period. BPA does not believe it reasonable to "pretend" that the WP-02 record is now perfectly fine to determine the IOUs' REP benefits when BPA, and the region, were well aware of the flaws in the rate record in the winter of 2000 and spring of 2001. BPA finds that it is equally unreasonable to "pretend" that critical section 7(b)(2) rate case issues were resolved in either the WP-02 or the WP-07 rate records. Consequently, BPA rejects WPAG's assertions that the WP-02 and WP-07 rates are now sacrosanct and must be used regardless of the known gaps and defects in their respective administrative records.

5. Response to Parties' Arguments that BPA is Prohibited from Supplementing the WP-02 or WP-07 Rate Records.

PPC points out in its brief that BPA dedicated over 60 pages in its Record of Decision in the WP-02 case to defending its section 7(b)(2) rate test determinations, and no party followed through with any challenge to those determinations at the Ninth Circuit. PPC Br., WP-07-B-JP25-01, at 29-30; PPC Br. Ex., WP-07-R-PP-01, at 18. The problem with PPC's argument is that it focuses on the May 2000 proposal. The original WP-02 Record of Decision explains BPA's rationale for adopting certain positions based on the record evidence that existed as of May of 2000. As such, the WP-02 Record of Decision addresses only the particular technical and legal issues the parties made in the WP-02 initial proceeding. It did not, and could not, account for the dramatic changes in market prices and loads that BPA would experience in the winter of 2000 and spring of 2001. The decisions made in the May 2000 proposal, consequently, in no way preclude BPA from *subsequently* deciding to rerun the rate test with more timely underlying numbers and information, as would have been the case had BPA revised the base rates instead of adopting CRACs. The specific section 7(b)(2) arguments raised by PPC are addressed in Chapter 16.

Moreover, the fact that BPA spent 60 pages addressing both the IOU and COU arguments in the ROD lends further support to BPA's proposal to revisit its decision to adopt CRACs in this proceeding. BPA's implementation of section 7(b)(2) is clearly an important issue in rate proceedings. Had the RPSAs been executed instead of the REP Settlement Agreements at the time of the WP-02 Supplemental proposal, it is nearly certain that the IOUs would have vigorously challenged BPA's decision not to reopen the WP-02 rate record. Yet, in the Supplemental Record of Decision for the WP-02 rate case, the IOUs were notably silent on whether BPA had to rerun these rate test directives. *See* 2000 Final Supplemental Administrator's ROD, WP-02-A-09, at 6·1. The IOUs specifically note they would have challenged BPA's section 7(b)(2) implementation and calculation of the PF Exchange rate vigorously in this Supplemental Proceeding had they not entered REP Settlements. IOU Br., WP-07-B-JP6-01, at 149; *See also* La Bolle, *et al.*, WP-07-E-JP6-08, at 79-80. In the interest of fairness to the parties, BPA believes it appropriate to allow all parties an opportunity to make these arguments in this proceeding.

PPC also complains that BPA has taken "too much latitude on remand" by reconsidering decisions and calculations made in the WP-02 proceeding. PPC Br., WP-07-B-JP25-01, at 30; PPC Br. Ex., WP-07-R-PP-01, at 19. BPA disagrees. The Court in *Golden NW* remanded the 2002 rates to BPA to provide a remedy for the defective WP-02 rates, but it did not provide BPA with any specific direction about whether BPA could consider new and additional evidence if necessary to respond to the Court's decision. The Court noted, though, that in setting rates BPA must at a minimum "know[] its costs, or, at the very least, that it estimates them 'in accordance with sound business principles'", and that BPA's forecasts must be based on "realistic projections … that accurately reflected the information available at the time rates were set and the cost recovery mechanism adopted." *Id.* 1053. As described above, the WP-02 rate proceeding record lacks essential ASC information for BPA to determine the amount of REP benefits that would have been paid to the IOUs but for the REP settlements. In addition, the PF Exchange rate was based a record that failed to take into account the fundamental changes in market prices and loads that occurred in the winter of 2000 and spring of 2001. Because of these gaps in the administrative record, BPA must consider supplemental information.

PPC appears to acknowledge that BPA has the discretion to determine whether the record is sufficient. PPC Br., WP-07-B-JP25-01, at 30; PPC Br. Ex., WP-07-R-PP-01, at 18-19. However, PPC states that because no party challenged BPA's section 7(b)(2) rate test in the WP-02 proceeding, and the Ninth Circuit did not comment on any perceived error in the section 7(b)(2) rate test, BPA is precluded from revisiting its decisions in the WP-02 rate case. *Id*. For support, PPC points to cases which allegedly stand for the proposition that a "judgment in a prior proceeding will bar relitigation on that issue in a subsequent proceeding involving the same parties." PPC Br., WP-07-B-JP25-01, at 30-31; PPC Br. Ex., WP-07-R-PP-01, at 20. For support, PPC cites to *Diamond v. Roskens*, 790 F. Supp. 350, 353 (1992). *Id.* This case, however, is inapposite to the present situation. In *Diamond,* the district court relied, wrongfully as it turns out, on a long line of cases that held a "government agency is bound by the results of an administrative determination favorable to its *employee upon a complaint of employment* *discrimination*, and is not entitled to a de novo trial and judgment in federal court." *Id.*; *reversed by Diamond v. Atwood*, 43 F.3d 1538 (D.C. Cir. 1995) (emphasis added). The principle cited in *Diamond* is a particular rule that applies in the context of employee complaints of discrimination that have been fully litigated in an administrative hearing before an agency. This rule has little value in the context of rate proceedings. It is one thing for an agency to revisit a record where a court or agency board has held that an agency of the United States government has violated an employee's civil rights. It is another thing entirely for an agency to revisit a rate case record to fill in obvious gaps or correct known defects. As the record in this case makes clear, the forecasts in the WP-02 rate record were terribly inaccurate almost immediately after the close of the administrative record. Whether BPA can fix these known errors in the rate case record can hardly call for the same "rule" that courts apply in the specific context of EEO proceedings, as PPC suggests.

To be sure, PPC is generally correct that the doctrine of administrative finality bars litigants from seeking review of administrative rulemaking after the statutory deadline for appeal has lapsed. *See UOP v. United States*, 99 F.3d 344, 347 (9th Cir. 1996). Indeed, issues that have not been raised previously and are not otherwise implicated by the Court's remand would still be precluded by section 9(e)(5) of the Northwest Power Act. However, for issues implicated by the Court's remand, the doctrine of administrative finality is simply not relevant. In response to the Court's remand, Staff proposed to supplement the record to reflect three changes that would have occurred between the close of the record in May of 2000 and the beginning of the WP-02 Supplemental proceeding: (1) the REP Settlements would not have been signed; (2) the volatile energy market prices would have been incorporated into BPA's market price forecasts; and (3) the load forecasts would have been updated to account for the enormous increase in loads. Burns, *et al.*, WP-07-E-BPA-53, at 8. Staff proposed to rerun the section 7(b)(2) rate test and to calculate the PF Exchange rate assuming these three key changes. The doctrine of administrative finality is not implicated in relation to these areas because no party has had an opportunity to comment on BPA's revised decisions based on this supplemental record.

Even assuming *arguendo* the doctrine of administrative finality were relevant, it still would not preclude BPA from revisiting issues implicated by the Court's remand. As a general matter, administrative finality principles are inapplicable "when an agency itself initiates a new rulemaking proceeding which reopens, and seeks public comment on, issues decided in the previous proceedings." *People of State of Cal. v. F.C.C.*, 905 F.2d 1217, 1245 (9th Cir. 1990). Here, BPA has initiated a new rulemaking (the WP-07 Supplemental Rate Proceeding) to revisit the issues implicated by the Court's remand in the WP-02 and WP-07 rate proceedings, supplementing only where necessary for any known defects or gaps in the record. Burns, *et al.*, WP-07-E-BPA-53, at 8. It follows that if BPA revises a previous assumption as a consequence of supplemental information, parties should have the opportunity to present comments on the revised assumption. The law is in accord on this point. *See People of State of Cal. v. F.C.C.*, 905 F.2d 1217, 1245 (9th Cir. 1990).

Furthermore, as PPC's own cases note, preclusive principles such as *res judicata* and claim preclusion are only relevant if the litigating party has had a "full and fair opportunity" to litigate the alleged barred claim. *See* PPC Br. Ex., WP-07-R-PP-01, at 19-20; *see also Kremer v. Chemical Constr. Corp.*, 456 U.S. 461, 480-81 & n. 22, 102 S. Ct. 1883, 1896-97 & n. 22, 72 L.Ed.2d 262 (1982); *see also General Dynamics Corp.*, 828 F.2d 1356, 1361 n. 6 (9th Cir. 1987) ("Administrative determinations may be afforded preclusive effect if an agency, acting in a judicial capacity, resolves issues properly before it so long as the parties are *afforded an adequate opportunity to litigate*.") (Emphasis added.) In the instant case, BPA is acting in its administrative and ratemaking capacity to set its rates consistent with the Court's opinion; consequently, the IOUs have not been afforded a "full and fair opportunity" to litigate the PF Exchange rate and the section 7(b)(2) rate test. While the IOUs did litigate the PF Exchange rate and section 7(b)(2) issues in the May 2000 proposal, they did not have a similar opportunity to challenge the PF Exchange rate and 7(b)(2) in the subsequent WP-02 Supplemental rate proceeding. As described above, in this subsequent proceeding market prices and load assumptions fundamentally changed. These changes would have had a significant impact on the PF Exchange rate and the level of REP benefits allowed under the section 7(b)(2) rate test. Nevertheless, because the REP Settlement Agreements had been executed, BPA focused the scope of the WP-02 Supplemental proceeding on the narrow cost recovery problem facing BPA. BPA did not reexamine issues previously decided in the May 2000 proposal, such as the PF Exchange rate or the section 7(b)(2) rate test. *See* 65 Fed. Reg. 75,272, 75,275 (Dec. 1, 2000). The Federal Register Notice of the WP-02 Supplemental proceeding provides

> Therefore, the scope of this second phase of the proceeding is limited only by those guidelines the Administrator established during the first phase of this proceeding, a summary which is described below, and the parameters of the specific problem that is being addressed in this phase of the proceeding.

Id. The IOUs specifically note they would have challenged BPA's section 7(b)(2) implementation and calculation of the PF Exchange rate vigorously in the WP-02 supplemental proceeding had they not entered REP Settlement Agreements. IOU Br., WP-07-B-JP6-01, at 149; s*ee also* La Bolle, *et al.*, WP-07-E-JP6-08, at 79-80. Instead, they relied on the REP Settlement Agreements, which they, and BPA, erroneously believed were valid. *Id*. Under these circumstances, there can be little question that the IOUs have not had a "full and fair opportunity" to challenge the PF Exchange rate and BPA's underlying section 7(b)(2) rate assumptions.

PPC argues that BPA cannot reevaluate its previous policy decisions on any issue in the WP-02 rate proceeding, such as the Mid-Columbia resources and the treatment of the trigger amount, and apply those decisions in this proceeding. PPC Br., WP-07-B-JP25-01, at 31-32. As described earlier, the legal bars on retroactive rulemaking, which PPC's argument implicates, is not at issue in this case. Moreover, as discussed in chapter 16.10, BPA's decision to address the treatment of Mid-Columbia resources in this proceeding is appropriate.

PPC asserts that BPA must limit the issues it reconsiders in this proceeding to those that the "court addressed." PPC Br., WP-07-B-JP25-01, at 32; PPC Br. Ex., WP-07-R-PP-01, at 20-21. PPC claims that these issues are solely related to the effect of the 7(b)(2) calculation on the preference customers' rates. *Id*. To address issues beyond this PPC-defined limited scope, according to the PPC, is an impermissible retraction of an agency's final determination. *Id*.

PPC's criticism of BPA's proposal is unfounded. As already discussed above, the Court in *Golden NW* remanded the defective WP-02 rates to BPA to provide a remedy for costs that should not have been included in the preference rate. In remanding the case, the Court did not provide BPA specific instructions regarding what must be done on remand to achieve the proper result. In the absence of such direction, BPA must determine whether the existing record is sufficient to dispose of the remand issue. *See Eastern Carolinas Broadcasting v. FCC*, 762 F.2d 95, 102-103 (D.C. Cir. 1985). As described above, BPA believes supplemental information is necessary to correct for *known* defects in the WP-02 administrative record that are relevant to calculating the rightful amount of REP benefits. Moreover, BPA has limited the scope of this proceeding to the issues the "court addressed" in *Golden NW*, that is, the appropriate amount of REP benefits that should have been collected in COU's rates. Bliven, *et al.*, WP-07-E-BPA-52, at 12. In defining this scope, Staff was explicit that the proposal should change as few assumptions as possible. Burns, *et al.*, WP-07-E-BPA-53, at 8. Staff described this limited scope:

> BPA proposes to recalculate FY 2002-2006 average base rates, which are needed in order to calculate the FY 2002-2006 PF Exchange rate, based on information available at the time work was being done for the WP-02 Final Supplemental Proposal that was published in June 2001, changing assumptions only as necessary. Specifically, only changes to the load and market price forecasts in the June 2001 Final Supplemental proposal, and several changes to revenue requirements resulting from known events are incorporated into the revised base rates.

Id. Thus, contrary to PPC's argument, BPA has properly limited the scope of this case to areas pertinent to what the Court "addressed" in *Golden NW*.

In its Brief on Exceptions, WPAG similarly objects to BPA's decision to revisit the WP-02 and WP-07 rate records, arguing that BPA's proposal does not constitute "reasonable supplementing." WPAG Br. Ex., WP-07-R-WA-01, at 13-14. What "reasonable supplementing" of the record means is not made clear by WPAG's brief. Nor does WPAG cite to any rule or law that would provide BPA guidance on this alleged standard. Regardless, BPA's proposal to supplement the record was reasonable. BPA proposed to consider supplemental information for the limited purpose of calculating the overcharges to the COUs. To do this, BPA introduced supplemental information that corrected for known problems in the WP-02 rate record. But even here, BPA did not arrogate to itself unlimited authority to consider new information. Rather, BPA made it expressly clear that such supplemental information, for purposes of calculating the PF Exchange rate, must be based on data that was "available at the time" and would result in changes from previous assumptions only "as necessary." Burns, *et al.*, WP-07-E-BPA-53, at 7-8. On this point, BPA notes that the source of the updated market price forecast came from the market price forecast study BPA had used at the time of its WP-02 Supplemental proceeding. Conger, *et al.,* WP-07-E-BPA-56, at 1. This market price study was, in fact, part of the WP-02 Supplemental rate record, but was only used in a limited fashion to establish CRACs. BPA proposed to use this study to update the faulty market price information used in the May 2000 rate record. *Id.* BPA fails to see how updating the WP-02 record with market price information from an existing BPA study that was part of the WP-02 Supplemental record constitutes "unreasonable" supplementing of the record.

Furthermore, it would have been far more *unreasonable* to leave the administrative record in its defective state to calculate the COUs overcharges. There has not been a serious debate in this proceeding that the WP-02 rate record contained known flawed data. The debate in this case is whether BPA must now use that flawed data to calculate the REP benefits the IOUs would have received without the REP Settlement Agreements. BPA cannot agree that reason, logic, or fairness would support a decision to use a record based on known fundamentally flawed information. At a minimum, BPA must be allowed to supplement the record to correct these errors. Consequently, WPAG's argument that BPA has "unreasonably supplemented" the record rings hollow.

To support its claim that BPA has "unreasonably supplemented" the record, WPAG argues that BPA has proposed to abandon the applicable regulation governing the implementation of the section 7(b)(2) rate ceiling test, and substitute for it substantive portions of the proposed 2008 Legal Interpretation and Implementation Methodology that has not yet been adopted; jettison the ASC determinations made in the WP-02 and WP-07 rate proceedings, and substitute for them new ASC determinations based on facts that were not available when the WP-02 and WP-07 rates cases were originally conducted; ignore the PF Exchange rates calculated in the WP-02 and WP-07 rate cases, and replace them with new PF Exchange rates based on the revised implementation of the section 7(b)(2) rate ceiling test; and eliminate the cost recovery adjustment clauses that preference customers paid throughout the FY2002-FY2006 rate period, and replace them with a completely new PF rate that was never established nor paid by preference customers during rate period. *Id.* WPAG argues that these actions do not constitute reasonable "supplementing" of the administrative records in the WP-02 and WP-07 rate cases. WPAG Br. Ex., WP-07-R-WA-01, at 13-14.

These observations by WPAG are not only incorrect, but they do not support WPAG's claim that BPA has unreasonably supplemented the record in this case. First, BPA is applying the applicable governing regulations to the section 7(b)(2) rate test and, as discussed at length in Chapter 16.10, BPA's decision to revisit certain section 7(b)(2) issues is supported by the record and a totally reasonable exercise of BPA's discretion. WPAG therefore incorrectly asserts that BPA has abandoned the applicable governing regulations for implementing the section 7(b)(2) rate test ceiling.

Second, BPA did not "jettison" the ASC determinations made in the WP-02 and WP-07 cases and rely on facts not available during these cases. As just discussed, BPA's proposal relied on information that was "available at the time" these cases were being developed. Burns, *et al.*, WP-07-E-BPA-53, at 8. As just noted, for the market price updates, BPA specifically used the Market Price study information that BPA had developed in the WP-02 Supplemental case when BPA was developing CRACs. Conger, *et al.,* WP-07-E-BPA-56, at 1. BPA used this Study as the source of data to make corrections to the ASCs for known defects in the data (such as market prices and in lieu assumptions for the WP-02 ASCs). *See* Boling, *et al.*, WP-07-E-BPA-57, at 6. In the WP-07 case, BPA corrected data entry errors and other known issues with the WP-07 ASC forecasts. *See* Chapter 7; *see also* Boling, *et al.*, WP-07-E-BPA-57, at 9-15 (describing corrections to the FY 2007-2008 ASC forecasts). Also, the rate record did not have the critical "real-time" ASCs the IOUs would have filed under an RPSA. Without an estimate of these ASCs, BPA would not have been able to accurately estimate the REP benefits the IOUs would have received in the absence of the REP Settlement Agreements.

Third, BPA did not "ignore" the PF Exchange rate developed in the WP-02 and WP-07 cases. As discussed earlier, BPA did not rely on the PF Exchange rate in the WP-02 case because of problems in the underlying rate case data. The WP-07 PF Exchange rate was similarly inadequate because it did not reflect the results of a fully litigated section 7(b)(2) rate test. As such, BPA did not "ignore" these rates but decided not to use them because of known issues. Fourth, BPA has already explained the unique circumstances that led to BPA's decision to adopt CRACs in the WP-02 Supplemental proceeding, and how that decision would have been different had the REP Settlement not been executed. For these reasons, BPA's proposal does not result in an alleged "unreasonable supplementing" of the record.

In its Brief on Exceptions, the PPC argues that the Court did not comment on any "perceived error" in BPA's conduct in running the rate test in the WP-02 rate case, and consequently, BPA is "precluded from re-determining its past decisions." PPC Br. Ex., WP-07-R-PP-01, at 19. APAC raises a similar argument in its Brief on Exceptions, arguing that all BPA needs to do to determine the amount of overpayments is to sum the total of the REP Settlement costs included in preference customer rates, and then determine the amount of REP benefits for which the preference customers are otherwise responsible through the section 7(b)(2) rate test. APAC Br. Ex., WP-07-R-AP-01, at 10. This reading of the Court's opinions, however, makes no sense when considering that the Court remanded the WP-02 rates back to BPA. The Court sent the entire case and record back to BPA to set rates in accordance with its opinion. *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007). In doing so, the Court was following the familiar tenet of administrative law that

> a court of appeals should remand a case to an agency for decision of a matter that statutes place primarily in agency hands … [because] [t]he agency can bring its expertise to bear upon the matter; it can evaluate evidence; it can make an initial determination; and, in doing so, it can, through informed discussion and analysis, help a court later determine whether its decision exceeds the leeway that the law provides.

INS v. Ventura, 537 U.S. 12, 16-17 (2002). By returning the case to BPA to "set rates in accordance with this opinion," the Court recognized that BPA was in the best position to craft a remedy consistent with the Court's opinions. *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007). Consistent with this direction, BPA has the authority, and indeed the duty, to evaluate the rate proceeding record to determine whether the defect in the WP-02 rates can be remedied without considering additional evidence. Based on the unique set of circumstances that led to the current WP-02 record as set forth above, BPA concludes that certain issues in the WP-02 case must be revisited and the rate proceeding record supplemented.

APAC argues in its Brief on Exceptions that determining the amount of overpayments does not require "any unique agency experience or expertise entitled to deference." APAC Br. Ex., WP-07-R-AP-01, at 10. APAC's argument would have some merit had the Court directed BPA to "calculate refunds in accordance with this opinion" or "determine the COUs overpayments in accordance with this opinion." The simple fact is, however, the Court did not give these instructions, but directed BPA to "set rates in accordance with this opinion." *Golden NW*, 501 F.3d 1037, 1053 (9th Cir. 2007). Setting rates is unquestionably within BPA's unique agency expertise and is entitled to substantial deference. *See Public Power Council, Inc. v. Bonneville Power Admin.,* 442 F.3d 1204, 1209 (9th Cir. 2006). A key component of setting BPA's rates is the operation of the section 7(b)(2) rate test. BPA cannot agree that in executing its duty to "set rates," it must leave untouched a known faulty record or adhere to a run of the section 7(b)(2) rate test that does not take into account all of the relevant facts. Having been ordered to review the WP-02 rate case by the Court, BPA believes it would be unresponsive to the Court's animadversions to base its decisions on a feeble rate record that contains several known faulty assumptions that directly impact the calculation of the rightfully due REP benefits. APAC's argument, therefore, must be rejected.

PPC claims that if BPA does not adhere to a limited view of the Court's remand, BPA would be able to revisit any issue of its choosing without recourse to the 90-day statute of limitations in the Northwest Power Act. PPC Br., WP-07-B-JP25-01, at 32; PPC Br. Ex., WP-07-R-PP-01, at 20-21. PPC then provides an example of the Low Density Discount as an issue not raised in the *Golden NW* decision that could be revisited in the remand under BPA's logic. *Id*. PPC claims that this result would be unfair and serve as an end-run around the 90-day statute of limitations in the Northwest Power Act. *Id*. This argument is unpersuasive. At no point in this case has BPA proposed or stated that it has plenary authority to reconsider all issues in the WP-02 rate case in this proceeding. Far from it, BPA has repeatedly stated that the issues to be reconsidered are those that directly relate to the calculation of the proper amount of REP benefits that should have been collected in COUs' rates. Burns, *et al.*, WP-07-E-BPA-53, at 8; Bliven, *et al.*, WP-07-E-BPA-52, at 15. As noted above, REP benefits are determined by comparing three component parts: the IOUs' respective eligible exchange loads; the IOUs' respective ASCs; and the PF-02 Exchange rate. Burns, *et al.*, WP-07-E-BPA-53, at 3. Updating the record for known defects in these three areas of the rate records is absolutely essential to ensure that BPA's final decisions are responsive to the Court's remand and based upon a fully developed record. PPC's request that BPA truncate this process by relying on a known faulty PF Exchange rate and an incomplete administrative record must be rejected. Doing otherwise would provide COUs a windfall at the expense of lawful REP benefits due the residential and small farm consumers of the IOUs.

In its Brief on Exceptions, Canby alleges there is no legal basis for BPA's unprecedented decisions to re-open the administrative record from 2000 with speculative materials about what "would have occurred" in that time period. Canby Br. Ex., WP-07-R-CA-01, at 3. Canby acknowledges that BPA has "some discretion" on how to comply with the court remands. *Id.* But, Canby objects to what it characterizes as "BPA's self-aggrandizing conclusion that its discretion is now at 'its zenith.'" *Id.* Canby then erroneously asserts that BPA has concluded it has more discretion now to interpret the Northwest Power Act than it did before it lost the *PGE* and *Golden NW* cases. *Id.* Canby then takes issues with BPA citation to certain cases, arguing that only federal agencies with express authority from Congress to "balance equities" may do so. *Id.* Canby claims BPA has no such authority. *Id.*

Canby's arguments are without merit. First, Canby seriously mischaracterizes BPA's position. BPA did *not* say its discretion at this point is at "its zenith." Rather BPA cited *cases* where the *courts* declare that an agency's discretion is at its "zenith" when the agency is fashioning a remedy to a past violation of law. *Pub. Util. Comm'n of Ca. v. FERC*, 988 F.2d 154, 163 (D.C. Cir. 1993) ("*CPUC*"); *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 160 (D.C. Cir. 1967). In those cases, the courts afforded the agency broad discretion because the agency was attempting to "put the parties in the position they would have been in had the error not been made." *CPUC*, 988 F.2d at 168; *see also AT&T Corp. v. F.C.C.*, 448 F.3d 426, 433 (D.C. Cir. 2006); *Exxon Co. v. FERC,* 182 F.3d 30 (D.C. Cir. 1999); *United Gas Improvements Co., v Callery Properties, Inc.,* 382 U.S. 223, 229 (1965). Granting an agency wide discretion in cases of legal error makes perfect sense because the agency is best situated to determine what position the parties would have been in had the legal error not been committed. The agency, unlike an appellate court, can conduct hearings, consider evidence, and weigh competing interests to find a resolution that makes the parties as whole as possible under the circumstances.

This is exactly what BPA is doing in the instant case. BPA has fashioned a remedy that corrects for its past violation of sections 5(c) and 7(b)(2), and puts the COUs and IOUs in the same position they would have been without the invalidated portions of the REP Settlement Agreements. In constructing that remedy, BPA did not presumptuously assume that it had unlimited discretion to consider new evidence and make new decisions in response to the Court's remand. The record is clear on this point. Burns, *et al.*, WP-07-E-BPA-53, at 7-8. Staff limited the scope of issues to be addressed, limited the information that could be used to supplement the record, and limited the changes to the assumptions in the WP-02 record. *Id.* Canby's characterization of BPA's position is without merit, and must be rejected.

Second, Canby's claim that BPA has no authority to revisit the record in this case is unfounded. The Court noted that in setting rates BPA must at a minimum "know[] its costs, or, at the very least, that it estimates them 'in accordance with sound business principles'", and that BPA's forecasts must be based on "realistic projections … that accurately reflected the information available at the time rates were set and the cost recovery mechanism adopted." *Id.* 1053. As the record in this case makes clear, the base WP-02 rate record does not meet these criteria. Also, as already explained above, an agency's authority to consider additional and supplemental information on remand is firmly established. *See Eastern Carolinas Broadcasting v. FCC*, 762 F.2d 95, 102-103 (D.C. Cir. 1985). The decision to exercise this authority is reviewed by the Court under an abuse of discretion standard. *Cooley v. FERC*, 843 F.2d 1464, 1473 (D.C. Cir. 1988); *City of Anaheim v. FERC*, 941 F.2d 1234, 1247 (D.C. Cir. 1991). Consequently, Canby's claim that BPA has no authority to revisit the record in this case is incorrect.

Canby also takes issue with BPA's reliance on cases which find that a federal agency has authority to balance equities. Canby Br. Ex., WP-07-R-CA-01, at 3, 11-13. The cases cited by Canby relate to BPA's decision to assume that the IOUs would have signed RPSAs and filed ASCs with BPA during the WP-02 and WP-07 rate periods. *See* Chapter 7.1. As explained in Chapter 7, these assumptions are perfectly legitimate because they are based on the record, consistent with the law, and do not result in an impermissible degree of discretion to BPA. BPA will address Canby's specific assertions that these cases are inapplicable to BPA's situation in Chapter 7.

WPAG claims in its Brief on Exceptions that though BPA has elected to reopen the WP-07 rate proceeding, it has not similarly "reopened" the WP-02 docket and administrative record in this case. WPAG Br. Ex., WP-07-R-WA-01, at 14. As such, WPAG claims BPA cannot now supplement the WP-02 record with the information from this proceeding. This alleged procedural problem is without merit. The fact that BPA did not commence a proceeding that declared that the WP-02 rate record was now "reopened" is immaterial to whether BPA may consider supplemental information. What matters is whether BPA made it clear that it intended to revisit the WP-02 rate record in this proceeding. BPA was clear from the beginning of this proceeding that it was going to reconsider the development of the WP-02 PF Exchange rate as part of this proceeding. *See* 73 Fed. Reg. 7539, 7552 (Feb. 8, 2008). The Federal Register notice announcing this proceeding stated as follows:

> In response to the Court's decisions, BPA proposes to determine the amount of benefits provided to each IOU under the REP settlements. BPA also proposes to calculate the amount of REP benefits each IOU would have received from BPA during the FY 2002-2006 rate period in the absence of the REP Settlement Agreements. In order to calculate such REP benefits, BPA proposes to remove the REP settlement costs from BPA's WP-02 power rates and replace them with costs associated with a traditional REP. This change will establish the PF Exchange rate that would have been used to implement the REP during the rate period. *This approach requires BPA to review and decide a number of issues in the WP-02 Final Proposal that were undecided or rendered moot by the presence of the REP Settlement Agreements*. Failure to allow parties to address these issues on the merits would be inequitable.

Id. (emphasis added). Thus, parties were put on notice that BPA would be revisiting the WP-02 rates to calculate the PF Exchange rate in a manner consistent with the Court's opinion, and were afforded an opportunity to challenge BPA's new assumptions.

Moreover, any question regarding BPA's intention to consider supplemental information in addition to the WP-02 rate record would have been dispelled once BPA issued its initial proposal. BPA's initial proposal included an entire study and ten pieces of testimony that related to the WP-02 rate record. *See* Lookback Study, WP-07-E-BPA-44; *see also* Bliven, *et al.,* WP-07-E-BPA-52 (Overall Policy); Burns, *et al.* WP-07-E-BPA-53 (Policy specific to WP-02 rates); Hirsch, *et al*., WP-07-E-BPA-54 (Loads and Resources); Lennox and Homenick, WP-07-E-BPA-55 (Revenue Requirement); Conger, *et al.,*WP-07-E-BPA-56 (Market Price Forecasts); Boling, *et al.*, WP-07-E-BPA-57 (ASC Forecasts); Bliven, *et al.,* WP-07-E-BPA-58 (COSA and Rate Design); Homenick, *et al.,* WP-07-E-BPA-59 (Slice Revenue Requirement and Rate); Doubleday, *et. al.,* WP-07-E-BPA-60 (Section 7(b)(2) Rate Test); Manary, *et al.*, WP-07-E-BPA-61 (Backcast ASCs). When a party tried to strike this testimony and the associated studies, the Hearing Officer denied this request, holding that the above noted evidence was within the scope of BPA's FRN. *See* Order Denying Motion to Strike, WP-07-HOO-46, at 3. Also, the *entire* WP-02 rate record was brought onto the record of this proceeding. Hr. Tr. at

311-312. In short, BPA has not hid its intention to consider supplemental information related to the WP-02 rate record, and no party has been prejudiced by BPA's decision to introduce that information in this proceeding.

Though not clear from its brief, WPAG appears to suggest that the only way BPA could supplement the WP-02 record would be to conduct a separate rate proceeding under the WP-02 rate docket number. The law, however, does not require BPA to follow a prescribed method for conducting its proceedings. Rather, agencies are afforded discretion to determine how best to handle related, yet discrete, issues in terms of procedures. *Mobil Oil Exploration & Producing S.E., Inc. v. United Distrib. Cos.,* 498 U.S. 211, 230, 111 S. Ct. 615, 112 L.Ed.2d 636 (1991). Courts defer to the agency to determine whether to conduct a proceeding through a consolidated hearing or through individual proceedings. *See American Airlines, Inc. v. CAB*, 495 F.2d 1010 (D.C. Cir 1974). Either way, unless interested parties will be precluded from participating in the hearing by the particular arrangement of the proceeding, or the proceeding will unreasonably delay a resolution, it is left to the agency's discretion as how best to arrange its business and order its dockets. *See La. Public Service Com'n v. FERC*, 482 F.3d 510, 520-522 (D.C. Cir. 2007); *Northern Border Pipeline Co. v. FERC*, 129 F.3d 1315, 1319 (D.C. Cir. 1997). These matters are, as one court put it, "housekeeping details addressed to the discretion of the agency." *Assn. of Mass Consumers, Inc. v. SEC*, 516 F.2d 711 (D.C. Cir. 1975).

In this case, BPA determined that the most efficient and effective means of responding to the Court's decisions in *Golden NW* and *PGE* was to conduct a single administrative hearing that considered supplemental information for both the WP-02 and WP-07 rate records. Several factors supported this decision. First, the Court's opinions affected the decisions BPA made in both the WP-02 rate case as well as the WP-07 rate case. Addressing these infirmities in a single proceeding ensured that BPA's response to the Court's decisions was unified and consistent. Second, BPA used similar approaches to calculate the Lookback Amounts for the WP-02 rate case time period (FY 2002-2006) and the WP-07 rate case time period (FY 2007-2008). Bliven, *et al.,* WP-07-E-BPA-52, at 17. Many of the decisions that BPA would be making to calculate the rightfully due REP benefits for the WP-02 rate period would also be applicable to FY 2007-2008 of the WP-07 rate period. A single administrative hearing allowed BPA (and the parties) to make only one filing that addressed both time periods, thereby avoiding the burden of filing duplicative materials in two proceedings. Third, supplementing the records in one proceeding allowed BPA to immediately implement a remedy in response to the Court's opinions. Had this case been conducted in two totally different proceedings, it is very likely that the cases would have ended at very different times. In that event, BPA would have been unable to immediately return Lookback Amounts to the COUs through both cash payments *and* rate credits beginning on October 1, 2008. Fourth, and finally, administrative efficiencies strongly support BPA's decision to conduct one proceeding. Conducting two separate cases would have been an immense burden to BPA and the parties. In addition to the burden of producing duplicative filings mentioned earlier, BPA and the parties would have had to grapple with the immutable problem of finding time on the calendar to add another proceeding that provided for discovery, clarification, settlement discussions, cross-examination, oral arguments, briefs, a Draft ROD, brief on exceptions, and a Final ROD. The administrative efficiencies gained by combining the supplementation of the WP-02 and WP-07 records into one proceeding strongly supported BPA's decision to use this proceeding to respond to the Court's decisions.

BPA also notes that by adopting this one proceeding approach, no party has been prejudiced or precluded from participating in this proceeding. The Federal Register Notice was clear that *any* party with an interest could intervene in the proceeding. 73 Fed. Reg. 7539, 7545 (Feb. 8, 2008). All parties that previously intervened in the WP-07 proceeding were automatically made parties of this proceeding. *Id.* In addition, the FRN stated that any "[o]ther persons wishing to become a formal party to the proceeding must file a petition to intervene, notifying BPA in writing of their intention to do so in conformance with the requirements stated in this Notice." *Id.* Several new parties took this opportunity to enter the case, and no party was denied intervention status. As such, no party has been prejudiced by BPA's decision to consider the supplemental information in a single proceeding. WPAG's claim that BPA cannot consider supplemental information must be rejected.

6. The Parties Use Supplemental Information to Support their Arguments.

Finally, BPA finds WPAG's, APAC's, and PPC's objections to supplementing the record is inconsistent with these parties' position that BPA return over $2 billion in refunds. According to these parties, the alleged "total harm" to the COUs from the REP Settlement Agreements for the WP-02 rate period is approximately $2 billion. WPAG Br., WP-07-B-WA-01, at 4; APAC Br., WP-07-B-AP-01, at 6. This $2 billion figure, however, is not to be found at all in the WP-02 rate record. Indeed, BPA did not forecast in the base WP-02 rates that the cost of the REP Settlement Agreements would be $2 billion. Instead, BPA forecast that the cost of REP Settlement Agreements in the WP-02 rate proceeding would be approximately $142 million a year, resulting in a total of $713 million in rates for the WP-02 rate period. Ingram, *et al.*, WP-07-E-BPA-58, Attachment C, at 1. If BPA were simply to subtract the forecast costs of the REP Settlement Agreements ($713 million) from the forecast amount of REP benefits ($240 million), the total "overpayment" from the REP Settlement Agreements allocated in the base WP-02 rates, the rates found in error by the Court, is only $473 million. Consequently, if BPA were to rely *solely* on the WP-02 rate record, as requested by WPAG, APAC, and PPC, the total overcharges would be $473 million. This is the solution advocated by the WUTC. WUTC Br., WP-07-E-WU-01, at 10-13.

Ironically, WPAG, APAC, and PPC do not rely solely on the WP-02 rate record when claiming that BPA overcharged the COUs by over $2 billion. Rather, these parties point to extra-record material supplied by BPA that describes the *actual* costs of the REP Settlement Agreements collected in rates. WPAG Br., WP-07-B-WA-01, at 4; APAC Br., WP-07-B-AP-01, at 6. The total cost of the REP Settlement Agreements could not have been known at the time the base WP-02 rates were developed because a significant amount of the costs were recovered in automatic cost adjustment clauses that applied *subsequent* to the development of the WP-02 rates. The data that made the $2 billion an issue in this case was not derived from the existing WP-02 record, but came from supplemental information provided by BPA Staff in the hearing phase of this proceeding. *See* Lookback Study Documentation, WP-07-E-BPA-44A, Table 15.3, at 1041-1043. WPAG, APAC, and PPC appear to be arguing that in this one instance BPA must depart from strictly relying on the WP-02 rate record and consider the actual cost of the REP Settlement Agreements when determining the amount of refunds to be provided in this proceeding. BPA finds this inconsistency troubling, and rejects the parties' request to selectively rely on the WP-02 rate record.

In its Brief on Exceptions, WPAG attempts to obfuscate the fact that the WP-02 rate record alone is insufficient to support its $2 billion refund claim by arguing that the additional costs of the REP Settlements, such as the alleged "litigation penalty" and Load Reduction Agreements, were recovered through "cost recovery adjustment clauses throughout the applicable rate period", and as such, "these amounts are also part of the record in these cases, and are known and determinable." WPAG Br. Ex., WP-07-R-WA-01, at 9. Interestingly, WPAG omits articulating exactly *how* this information became part of this proceeding. The WP-02 rate record is silent on the "litigation penalty" costs and the cost impacts of the LRAs. The WP-02 record is equally silent on how much of the REP Settlement Agreement cost was recovered through cost recovery mechanisms. Without explanation, WPAG now declares that these amounts "are also part of the record in these cases, and are known and determinable." *Id.* Though WPAG's brief studiously avoids mentioning it, the reason the total REP Settlement Agreement cost are matters in this case is because *BPA* supplemented the record with this information. Try as it might, WPAG simply cannot avoid relying on supplemental record information to support its claim for refunds. If WPAG believes it is appropriate to rely on supplemental information to determine the total cost to the COUs of the REP Settlement Agreements, BPA sees no reason why it cannot introduce supplemental information in order to determine the appropriate amount of REP benefits that would have been paid absent the REP Settlement Agreements. Supplementing the record is particularly appropriate in this case because, as described earlier, the WP-02 base rates contained fundamentally flawed load, costs, and rate design assumptions. There is no reasonable basis for BPA to confine itself to the known faulty information in the WP-02 rate record while WPAG and other preference customers rely on supplemental record information to support their claims for refunds. BPA rejects this selective use of the supplemental record and finds WPAG's position unpersuasive.

D. Conclusion

As noted throughout the above discussion, BPA's has gone to great lengths to consider the information that would be needed to calculate REP benefits in the absence of the REP Settlement Agreements. The calculation of the refunds in this proceeding, known as Lookback Amounts, will have impacts on the residential and small farm customers of the IOUs for years to come. Forman, *et al.*, WP-07-E-BPA-76, at 23. Fundamental fairness requires that the parties affected by the Lookback Amounts (both those who pay, and those receiving the payments) have a full and fair opportunity to respond to the assumptions and information that BPA relies on to make these calculations. BPA has provided the parties with that opportunity in this proceeding by revisiting the administrative records in a limited fashion, supplementing only where necessary. The record that has been developed in this case clearly reflects the views and arguments of a wide array of interests. While there may have been other less arduous ways of addressing the Court's opinions, BPA firmly believes that without the aid of the supplemental information developed in this case the end results would have been fundamentally flawed and inaccurate. For these reasons, it is proper for BPA to consider supplemental information in addition to the WP-02 and WP-07 rate records to calculate the overcharges to the COUs.

Decision

BPA properly supplemented the WP-02 and WP-07 rate records with additional evidence and arguments in order to calculate the overcharges to the COUs.

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3.0 FY 2002-2008 LOOKBACK LOADS AND RESOURCES

3.1 Introduction

The Load Resource Study for the FY 2002-2008 Lookback 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 Chapter 2 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. Documentation supporting the results is presented in the Load Resource Study Documentation, WP-07-FS-BPA-08A. The Load Resource Study is also described in the direct testimony of Hirsch, *et al.*, WP-07-E-BPA-54, and the rebuttal testimony of Hirsch, *et al.*, WP-07-E-BPA-80.

The Load Resource Study and supporting documents are used to (1) provide data to determine resource costs for the Revenue Requirement Study, Chapter 3 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08; (2) provide data to derive billing determinants for the revenue forecast in the Wholesale Power Rate Development Study (WPRDS), Chapter 5 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08; and (3) provide Pacific Northwest (PNW) regional hydro data for use in the secondary revenue forecast for the Market Price Forecast Study, Chapter 4 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08.

The Load Resource Study for the 2002-2008 Lookback includes the following interrelated components: (1) a forecast of the Federal System Load Obligations, which is comprised of BPA's firm requirements Power Sales Contract (PSC) Obligations and Other BPA Contract Obligations; (2) Federal System Resource Forecasts, which include the output from hydro and other generating resources purchased by BPA, and Other BPA Contract Purchases; (3) the Federal System Load Resource Balance, which relates Federal sales, loads, and contract obligations to the Federal system generating resources and contract purchases; (4) total PNW Regional Hydro Generation; and (5) forecast power purchases that are eligible for the Northwest Power Act section 4(h)(10)(C) credit.

For the Final Supplemental Proposal, the Load Resource Study for the FY 2002-2008 Lookback will be updated as described below.

Issues raised in the parties' Initial Briefs regarding the Load Resource Study are addressed below. No additional issues were raised in parties' Briefs on Exceptions.

3.2 Federal System Load Obligations

The Federal System Load Obligations forecast includes BPA's forecast firm requirement PSC obligations to the public body utilities, cooperative utilities, and Federal agencies (together referred to as Public Agencies), IOUs, and DSIs; contractual obligations to the Bureau of Reclamation (Reclamation); contract obligations outside the PNW (exports); and contractual obligations within the PNW (intra-regional transfers-out). In general the forecasts for the PSC Obligations for the Public Agencies did not change from the 2002 Final Supplemental Load Resource Study. Contractual obligations to five DSIs decreased for FY 2002-2006, as specified in section 3.2.1 below. The IOU firm power sales forecast was decreased to zero in this study to reflect the fact that the 2000 REP Settlement Agreements have been declared invalid. These forecasts are further described below.

3.2.1 Power Sales Contract Obligations

The Federal system PSC obligation forecasts, comprised of customer group sales forecasts for Public Agencies (including Slice), DSIs, IOUs, and other BPA PSC obligations, were updated for the FY 2002-2008 Load Resource Study. These forecasts are derived as follows:

- 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 Agency customers. These forecasts began as projections of annual total retail load, and were then shaped to reflect monthly variations using historical relationships and peak energy use. These forecasts were also reduced for conservation savings. *See* WP-07 Load Resource Study, WP-07-FS-BPA-01, at 5-7.
- Slice product sales are forecast as 22.63 percent of the Slice resource stack. 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.
- There are no actual power deliveries to the IOUs forecast for this period. *Id*.
- BPA contractual commitments to the DSIs, originally totaling approximately 1,440 average megawatts (aMW), have been reduced due to the Load Reduction Agreements (LRAs) with Alcoa, Atofina, Columbia Falls, Longview, and Oremet to 636 aMW for FY 2002; 884 aMW for FY 2003; 1,389 aMW for FY 2004; 1,389 aMW for FY 2005; and 1,396 aMW for FY 2006. *See* Issue 3, below, and section 1.1.2 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08.

Issue 1

Whether BPA should reflect the effects of price elasticity on load following forecasts of its Public Agency customers for FY 2002-2008.

Parties' Positions

APAC argues that Staff should have reduced the PSC Obligation forecasts for the load following Public Agencies to reflect the effects of price elasticity due to increasing BPA wholesale power rates. APAC Br., WP-07-B-AP-01, at 52-53; APAC Br. Ex., WP-07-R-AP-1, at 27. APAC argues that in the estimate of Preference Customer loads, Staff overstates those loads due to the failure to account for commonly recognized price elasticities. APAC Br., WP-07-B-AP-01, at 52-53. APAC argues that Staff admits Western energy prices were increasing significantly, and that BPA anticipates in 2001 that its rates would probably increase by 50 percent to 250 percent. *Id*. APAC argues Staff agrees that such rate increases would have reduced loads. *Id*. However, because Staff could not precisely determine the rate increases at a retail level, it decided to make no adjustment at all. *Id*. APAC reasons this renders the estimate of Preference Customer loads inherently unreliable. *Id*.

BPA Staff's Position

BPA Staff did not include price elasticity in forecasting loads served at the PF rate for several reasons. Hirsch, *et al.*, WP-07-E-BPA-80, at 2.

Although Staff subscribes to the general economic theory that increasing the real price of a good will often result in decreased demand for that good, the theory holds only if the ultimate consumer is faced with the higher price and the consumer expects the higher price to remain into the future. *Id*. Because BPA's power rate, and therefore any BPA rate increase, is at the wholesale level, the retail rates of BPA's Public Agency customers must reflect the wholesale rate changes for consumers to be susceptible to an elasticity effect. *Id*. Retail rates are also influenced by many factors beyond BPA's wholesale power rate, such as transmission costs; distribution costs; purchase power costs for power other than power provided by BPA; equipment, staff, and other overhead costs; and the retail utility's desire to build or use financial reserves. *Id*. It is unknown whether any particular BPA rate increase will lead to a retail rate increase. *Id*. Also, Public Agency customer loads are influenced by many factors other than consumer responses to retail rates. Factors such as weather and economic conditions can also impact load changes. *Id*.

Given these circumstances and the many unknowns in the uncertain energy environment that existed in 2001, price elasticity was not a reliable consideration to include in the load forecasts.

Evaluation of Positions

APAC contends that Staff's load forecast is inherently unreliable because it did not measure effects on retail consumptive behavior of higher wholesale power rates. APAC Br., WP-07-B-AP-01, at 52-53. BPA disagrees with APAC's contention that Staff's forecast is unreliable. Hirsch, *et al.*, WP-07-E-BPA-80, at 2.

In 2001, when rates were being set for 2002-06, assuming elasticity effects would have lowered BPA's load forecasts, its costs, and its rates. But doing so would have also exposed BPA to unacceptable financial risks because with extremely high market price forecasts higher than expected loads would have exposed BPA to major additional power purchase costs not covered in rates. Given the high degree of uncertainty in elasticity-induced load effects, relying on such effects to bring rates down would have been imprudent. In short, BPA believes that relying on price elasticity to solve the augmentation issue would be irresponsible, and to have done so would have put at risk BPA's ability to recover its costs. Furthermore, as WPAG acknowledged, price elasticity would only impact BPA's load-following customers paying the PF rate. WPAG Direct Testimony, WP-07-E-WA-05, at 33. Since BPA would not see elasticity effects on Slice/block customers in its load obligations, and since presubscription customers were not subject to the rate increases, any elasticity effect would be limited to load-following customers, who were well under half of BPA sales to preference customers. It would have had a de minimis effect on BPA's load forecast.

While in 2001 BPA cautioned that its power rate increase for the FY 2002-2006 period could be as high as 250 percent, BPA was pursuing efforts such as voluntary load reductions, load buy-downs, DSI load reduction agreements, irrigation programs, etc., to ensure that actual rate increases would not reach that level. To have assumed a 250% increase in assessing price elasticity effects, at a time when BPA was making significant efforts to mitigate any potential rate increase, would have significantly overstated load declines and inappropriately assumed away a part of BPA's augmentation problem.

Decision

BPA will not reflect price elasticity reductions in the load following forecasts for FY 2002-2008 of its Public Agency customers.

Issue 2

Whether BPA should use actual load numbers rather than recreating load forecasts.

Parties' Positions

In its Brief on Exceptions, APAC argues that BPA should use the actual load numbers that occurred rather than creating a forecast based on the information available to BPA in 2001. APAC Br. Ex., WP-07-R-AP-1 at 27. APAC argues that the actual loads would provide a more accurate load number than recreated forecasts. *Id.*

BPA Staff's Position

BPA's policy direction for the Lookback Analysis was to use load forecasts that are based on information available in winter/spring of 2000/2001. *See* Bliven, *et al.*, WP-07-E-BPA-52. Accordingly, BPA's load numbers are forecasts based on information available in winter/spring of 2000/2001.

Evaluation of Positions

APAC argues that the actual loads would provide a more accurate load number than recreated forecasts. APAC Br. Ex., WP-07-R-AP-1 at 27. Staff agrees that it is unlikely that any forecast would precisely reflect what actually occurred. However, the policy directions (*see* Bliven, *et al.*, WP-07-E-BPA-52) for the Lookback analysis was to use the load forecasts that would have been available in the winter/spring of 2000/2001. At the time, BPA did not have actual numbers since no one could have known with 100 percent accuracy the actual load that would be supplied through power marketed by BPA during the effective rate period. Therefore, it is not appropriate for Staff to use the actual recorded data for FY 2002-2006 in the Lookback analysis because such information was not available to BPA prior to the spring of 2001, when BPA would have been setting the PF Preference rate.

Decision

To be consistent with its policy direction, BPA will not use actual load data. BPA will use load forecasts based on information available in the winter/spring of 2000/2001.

Issue 3

Whether BPA has failed to sustain its burden of proof on load data because some data records for loads are no longer available.

Parties' Positions

In its Brief on Exceptions, APAC states that "BPA could not produce the data, equations and backup material to support the forecasts of Preference Customer load that were made. The data records were not retained and BPA has failed to sustain its burden of proof." APAC Br. Ex., WP-07-R-AP-1, at 27.

BPA Staff's Position

The aggregate total retail load forecasts were produced in the following manner for the 2002 Final Rate Case:

- BPA used excel workbooks, containing equations and model statistics, to calculate the individual utility total retail load forecasts.
- Individual utility total retail load forecasts were uploaded to BPA's data repository--the Loads and Resources Information System (LaRIS).
- LaRIS reported the aggregate total retail load forecast and produced BPA's load resource balance and supporting data for the rates process.

While the individual utility total retail load forecasts were preserved in the LaRIS database for the 2002 Final Rate Case, the excel workbooks used in preparing those forecasts were not saved. Instead, as new individual utility total retail load data became available, the workbooks were updated to incorporate the new information. Although previous versions of the excel workbooks were not archived, the utility specific total retail load forecasts used in the rates process were permanently stored in the LaRIS database.

The aggregate total retail load forecasts used in the 2002 Final Rate Case were accepted without objection. For the 2002-2006 Lookback analysis, the aggregate total retail load forecast was not changed.

Evaluation of Positions

APAC claims BPA failed to sustain its burden of proof because it could not produce the data, equations and backup material to support the forecasts of Preference Customer load that were made. APAC Br. Ex., WP-07-R-AP-1, at 27. It is not clear what "data, equations and backup material" APAC is referring to in this statement, but BPA assumes APAC is raising the same concern it raised in its Direct Testimony (*Wolverton*, WP-07-E-AP-1 at 38) that BPA does not have documentation of individual utility load forecasts. APAC fails to articulate what the burden of proof is that BPA must meet and simply misconstrues and mischaracterizes BPA's position with respect to its load forecast. Assuming APAC is referring to whether or not BPA is basing its rate determinations on substantial evidence in the record, BPA has records to support its total retail load calculations and has fully explained the logic and reasoning behind its total retail load numbers throughout the record in this rate proceeding. While the actual workbooks are no longer available the model structure is available and has been described in the Supplemental Load Resource Study (WP-07-E-BPA-45, at 6).

Also the individual forecasts and the supporting documentation, while they may be instructive or interesting, are largely irrelevant. Rather the total of the forecasts, the aggregate of BPA's load obligation, is what is important in producing the rates. No argument has been made that the aggregate forecast is in error beyond (1) the desire of some parties for BPA to have included a price elasticity adjustment to the overall forecast, or (2) the desire to use actuals in place of the forecast under the obvious argument that actuals are more accurate than forecasts, issues that are addressed separately in this ROD.

Decision

BPA has maintained full records for the vast majority of the load data required to conduct the Lookback Study, and where full data records were not available, BPA used the best available data to create load forecasts. BPA fully explained the method employed in developing the Preference Customer load forecasts. Further, the aggregate load data used in the Lookback Study is the same as that used in the 2002 Final Rate Case. Accordingly, BPA has included substantial evidence in the record to sustain its burden of proof on total retail load data.

Issue 4

Whether BPA should reflect the potential risk of price elasticity on DSI loads for its FY 2002 2008 DSI load forecast.

Parties' Positions

APAC sets forth the same price elasticity argument for DSI loads as it set forth in its Public Agency load argument discussed above – that BPA should have reduced the PSC Obligation forecasts for the DSIs to reflect the effects of price elasticity due to increasing BPA wholesale power rates. APAC Br., WP-07-B-AP-01, at 53; APAC Br. Ex., WP-07-R-AP-1, at 27. APAC argues that Staff acknowledged that they conducted studies of the amount of DSI load "at risk" and determined that under certain economic scenarios all of the DSI load could be curtailed. Pursuant to *Golden NW*, BPA cannot ignore information that it had on hand at the time that load determinations were being made. APAC Br., WP-07-B-AP-01, at 53.

Cowlitz argues that BPA should have predicted only 365 aMW of smelter load would have operated. Cowlitz Br., WP-07-B-CO-01, at 60. Cowlitz states that this forecast was based on a "calculated" IP rate of $43.60/MWh after replicating BPA's smelter sensitivity work and a five-year aluminum price forecast in the record and that 365 aMW is the reasonable forecast of DSI load that should have been used, not the entire 1,440 aMW. *Id*.

PPC states that BPA should at least rely on the estimate of aluminum prices it developed for the WP-02 rate proceeding, as well as its analysis of risks that DSI loads would not operate if applicable rates for BPA power rose above specified levels. PPC Br., WP-07-B-JP25-01, at 34.

BPA Staff's Position

BPA Staff did not rely on price elasticity when forecasting DSI loads for the reasons stated in Staff's position on Issue 1 above. BPA had to stand ready to serve the entire DSI load it was contractually obligated to serve. To deviate from its contractual requirements because of speculation over price elasticity would cause unnecessary exposure to BPA's ability to recover its costs.

Evaluation of Positions

While the parties come at this issue from different approaches, BPA understands the issues raised to mean that the parties claim that, as for the Public Agency load-following load forecast, Staff should have accounted for the effects of price elasticity in its DSI load forecast. Cowlitz and PPC point out that BPA's smelter sensitivity analysis and information were available to Staff, and hence its DSI load forecast should have been less than the 1,440 aMW. Cowlitz Br., WP-07-B-CO-01, at 60; PPC Br., WP-07-B-JP25-01, at 34. APAC contends that DSI studies of "at risk" DSI load existed at the time BPA did its forecast, and the *Golden NW* decision means that BPA cannot ignore such information. APAC Br., WP-07-B-AP-01, at 53.

While Staff had analysis from the 1999 period that indicated a range of DSI load amounts that could be "at risk" under various prices for aluminum and various prices for electricity, such analysis was theoretical and speculative. Hirsch, *et al.*, WP-07-E-BPA-80, at 13-19. That DSI load was theoretically "at risk" because of price elasticity does not reduce or eliminate BPA's contractual responsibility to serve 1,440 aMW of DSI load during the FY 2002-2006 time period. *Id*. Had Staff considered price elasticity and put more weight on the "at risk" analysis, BPA would have been in danger of setting power rates to recover the cost of serving an amount of DSI load significantly smaller than the amount to which the DSIs were contractually entitled. Staff's DSI load projection was based on the amount of energy BPA was contractually obligated to serve when the power sales contracts were executed – 1,440 aMW. Hirsch, *et al.*, WP-07-E-BPA-80, at 11-19. This contract amount was a set amount that BPA had to stand ready to serve. For reasons stated in Staff's position on Issue 1 above, BPA does not rely on price elasticity when forecasting DSI loads.

Decision

BPA will not reflect the possibility that some DSI loads were "at risk" because of price elasticity when setting the DSI load forecast for FY 2002-2006.

Issue 5

Whether BPA should account for the DSI Load Reduction Agreements in the DSI load forecast for FY 2002-2008.

Parties' Positions

Several parties, including APAC, Cowlitz, and PPC, argue that Staff should have considered the LRAs when setting the DSI load forecast. Cowlitz argues that BPA had entered LRAs with most DSIs by June 2001, very "substantially reducing the expected 1,440 aMW load under those contracts." Cowlitz Br., WP-07-B-CO-01, at 61. Cowlitz argues BPA cannot ignore its own contracts when setting the DSI forecast. *Id*. APAC states that most of the DSIs had signed load-reduction agreements, agreeing to reduce specified portions of their load for several years prior to June 2001. APAC Br., WP-07-B-AP-01, at 53. Similarly, PPC argues that Staff's assumption that it would forecast 1,440 aMW of DSI loads in the spring of 2001 was unreasonable given that BPA had, at that time, entered into Load Reduction Agreements with almost all of the DSI customers to buy down those loads. PPC Br., WP-07-B-JP25-01, at 34. Parties argue, therefore, that Staff's DSI load forecast must be decreased by the amount of load contractually reduced in the DSI LRAs for the FY 2002-2008 Lookback analysis.

BPA Staff's Position

BPA Staff's DSI load projection was based on the power amount BPA was contractually obligated to serve when the DSI power sales contracts were originally executed – 1,440 aMW. Hirsch, *et al.*, WP-07-E-BPA-80, at 11. It is reasonable not to consider the DSI LRAs when setting the DSI load projection because some of the DSI LRAs were still being negotiated in the days leading up to and beyond June 21, 2001. *Id*. Therefore, the details of which DSIs would enter LRAs and the amount of possible load reductions were not fully evident in time to be included in the DSI load projection. *Id*. Accordingly, it was reasonable for Staff to use the full contract amount of 1,440 aMW as the DSI load projection in order to ensure cost recovery. *Id*.

Evaluation of Positions

While Staff believes it was reasonable not to consider the DSI LRAs when setting the DSI load projection for FY 2002-2006, Staff also believes it would be reasonable to consider the impact on DSI loads that resulted from DSI LRAs that BPA was aware of by the time it was setting rates in 2001. Hirsch, *et al.*, WP-07-E-BPA-80, at 17.

Parties make a compelling argument that BPA should include such DSI LRAs because they had effectively reduced the total contract obligation of 1,440 aMW to a lesser amount, and such amount was known by the time BPA was setting rates in 2001. By June 21, 2001, BPA had executed LRAs with Alcoa, Atofina, Columbia Falls, Longview, and Oremet, for total load reduction amounts of 804 aMW for FY 2002, 556 aMW for FY 2003, 51 aMW for FY 2004, 51 aMW for FY 2005, and 44 aMW for FY 2006. *See* section 1.1.2 of the FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. The original contract obligation of 1,440 aMW minus these load reductions would provide DSI load projections of 636 aMW for FY 2002, 884 aMW for FY 2003, 1,389 aMW for FY 2004, 1,389 aMW for FY 2005, and 1,396 aMW for FY 2006. To the extent that BPA entered LRAs with DSIs after June 21, 2001, such LRAs should not be considered, because BPA would not have had reliable information on such LRAs to use for setting rates.

Decision

BPA will include the DSI LRAs for Alcoa, Atofina, Columbia Falls, Longview, and Oremet in its DSI load forecast for FY 2002-2006.

Issue 6

Whether BPA should use a forecast load amount rather than an actual load amount for DSIs for FY 2002-2006 in its Lookback analysis.

Parties' Positions

APAC argues that Staff should have used the actual load numbers for DSIs rather than using a forecast amount. APAC Br., WP-07-A-AP-01, at 53. APAC states that the most accurate measure of loads is what actually occurred during the 2002-2006 rate period. *Id*.

BPA Staff's Position

In accordance with the policy direction of Bliven, *et al.*, WP-07-E-BPA-52, BPA Staff used DSI load forecasts based on the most reliable data available to BPA in the winter/spring of 2000-2001.

Evaluation of Positions

In establishing rates for a given rate period, BPA relies on forecasts of load, not actual loads. See BPA's evaluation of positions in issue 2 above. This has been BPA's historical practice and is consistent with industry practice. Consistent with using such forecasts of load, the Lookback analysis was to use the information that would have been available in the winter/spring of 2000-2001. Hirsch, *et al.*, WP-07-E-BPA-80, at 19. Given this policy direction and historical and industry practice, it would be inconsistent for BPA to use DSI load amounts based on actual load numbers.

Decision

BPA will use a DSI load projection rather than the actual DSI loads for FY 2002-2006 in its Lookback analysis.

3.2.2 Other BPA Contract Obligations

BPA provides Federal power to customers under a variety of contract arrangements in addition to the Public Agency, IOU, and DSI PSC load obligation forecasts. These contracts are categorized as (1) power sales; (2) power or energy exchanges; (3) capacity sales or capacity-for-energy exchanges; (4) power payments for services; and (5) power commitments under the Columbia River Treaty. These arrangements are collectively called "Other BPA Contract Obligations," and they can have differing rate structures. Other BPA Contract Obligations are assumed to be served by the Federal system firm resources regardless of weather, water, or economic conditions.

For FY 2002-2008, there were no updates to Other BPA Contract Obligations. *See* WP-02 Load Resource Study, WP-02-FS-BPA-01, at 6-7 for FY 2002-2006, and WP-07 Load Resource Study, WP-07-FS-BPA-01, at 11-12 for FY 2007-2008.

No party raised issues regarding BPA's Other BPA Contract Obligations forecast for FY 2002-2008.

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. For FY 2002-2006, the Federal System Resource Forecast was unchanged from the 2002 Final Load Resource Study (WP-02-FS-BPA-01, at 7-18) except for changes to the Federal system augmentation purchase forecasts. These changes were incorporated in the Rate Analysis Model (RAM). *See* FY 2002-2008 Lookback Study, WP-07–FS-BPA-08, at 37. For FY 2007-2008, the Federal System Resource Forecast was unchanged. *See* WP-07 Load Resource Study, WP-07-FS-BPA-01, at 13-20.

No party raised issues regarding BPA's Federal System Resource Forecast for FY 2002-2008.

3.3.1 Regulated Hydro

BPA markets the generation from the Federal system regulated hydro projects, which are owned and operated by either Reclamation or the U.S. Army Corps of Engineers (COE). These hydro projects are described as "Regulated Hydro" because their operation is coordinated to meet power and non-power requirements. Generation forecasts for the regulated hydro projects are derived by BPA's hydro regulation model (HYDSIM).

The forecast of the Federal system Regulated Hydro generation was not changed for FY 2002-2008. *See* WP-02 Load Resource Study, WP-02-FS-BPA-01, at 10-13 for FY 2002-2006, and at 13-17 for FY 2007-2008.

No party raised issues regarding BPA's Regulated Hydro generation forecasts for FY 2002-2008.

3.3.2 Independent Hydro

BPA markets the power from independent hydro projects that are owned and operated by Reclamation, COE, and/or other project owners. Independent hydro projects are dams whose generation is not modeled or regulated in BPA's HYDSIM; rather, generation forecasts are provided by individual project owners.

The forecast of the Federal system Independent Hydro generation was not changed for FY 2002-2008. *See* WP-02 Load Resource Study, WP-02-FS-BPA-01, at 8 for FY 2002-2006, and at 17-18 for FY 2007-2008.

No party raised issues regarding BPA's Independent Hydro generation forecasts for FY 2002-2008.

3.3.3 Other Federal System Generation

Other Federal System Generation includes the purchased output from non-Federally owned projects and project generation directly assigned to BPA.

There were no changes to Other Federal System Generation resource forecasts for FY 2002-2008. *See* WP-02 Load Resource Study, WP-02-FS-BPA-01 at 9, and WP-07 Load Resource Study, WP-07-FS-BPA-01, at 18-19.

No party raised issues regarding BPA's Other Federal System Generation resource forecasts for FY 2002-2008.

3.3.4 Other Federal System Contract Purchases

BPA purchases power from sellers under a variety of contractual arrangements to meet Federal load obligations. The contracts are categorized as (1) power purchases; (2) power or energy exchange contracts; (3) capacity sales or capacity-for-energy exchange contracts; and (4) power purchased or assigned to BPA under the Columbia River Treaty. These sources of power are considered firm resources.

For FY 2002-2008, BPA's Other Federal System Contract Purchases were not changed in the Study. *See* WP-02 Load Resource Study, WP-02-FS-BPA-01, at 9-10 and at 19-20.

No party raised issues regarding BPA's Other Federal System Contract Purchases forecast.

3.4 Federal System Load Resource Balance

The Federal System Load Resource Balance completes BPA's load and resource picture by comparing forecast Federal system load obligations to Federal system resource output assuming 1937 water conditions for hydro resources. The result of the subtraction of loads from Federal system resources yields BPA's forecast Federal system monthly firm energy surplus or deficit. 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, BPA must purchase power or otherwise secure resources through augmentation to meet Federal system energy deficits.

For FY 2002-2006, the load obligations, contracts, and generation resources incorporated in the Federal System Load Resource Balance were unchanged, with the exception of updates to the Federal system augmentation purchase forecast, which was updated in the RAM. *See* FY 2002-2008 Lookback Study, WP-07-FS-BPA-08, at 37. The Federal System Load Resource Balance for FY 2007-2008 was not changed. *See* WP-07 Load Resource Study, WP-07-E-BPA-01, at 20-21.

No party raised issues regarding BPA's Federal System Load Resource Balance forecast for FY 2002-2008.

3.5 Pacific Northwest Regional Hydro Generation

The total PNW Regional Hydro Generation forecasts, which include regulated, independent, and Non-Utility Generation (NUG) hydro projects, were not changed for FY 2002-2008. *See* WP-02 Risk Analysis Study and Documentation, WP-02-FS-BPA-03A, at 9-11 for FY 2002-2006, and WP-07 Load Resource Study Documentation, WP-07-FS-BPA-01, at 22 for FY 2007-2008.

No party raised issues regarding BPA's PNW Regional Hydro Generation projections for FY 2002-2008.

3.6 Forecast of 4(h)(10)(C) Credit

BPA funds actions to protect, mitigate, and enhance fish and wildlife affected by Federal hydro operations, as directed by the Northwest Power Act, 16 U.S.C. §§ 839-839h. These program costs are allocated to hydro project purposes for both power and non-power uses. The Northwest Power Act directs BPA to annually recoup its funding of non-power purposes through credits, known as "section 4(h)(10)(C) credits" in reference to the authorizing statutory provisions, so that ratepayers pay only their power share of the fish and wildlife costs. 16 U.S.C. § 839b(h)(10)(C). BPA uses a specific methodology to determine the appropriate annual amount of section 4(h)(10)(C) credits.

For FY 2006-2008, there were no changes to the 4(h)(10)(C) power purchase credit forecast. *See* WP-07 Risk Analysis Study and Documentation, WP-07-FS-BPA-03A, at 136-156 for

FY 2002-2006, and WP-07 Load Resource Study, WP-07-FS-BPA-01, at 22-25 for FY 2007-2008.

No party raised issues regarding BPA's Forecast of 4(h)(10)(C) Credits for FY 2002-2008.

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4.0 FY 2002-2008 LOOKBACK MARKET PRICE FORECAST

4.1 Introduction

In the WP-07 Supplemental Proposal, BPA Staff proposed using the same market price forecast for the FY 2002-2006 Lookback analysis that was used in the WP-02 Final Supplemental Proposal. Conger, *et al.*, WP-07-E-BPA-56, at 1. This market price forecast was described in the 2002 Supplemental Power Rate Proposal Final Study, WP-02-FS-BPA-09.

Staff reviewed the WP-02 record for the best market price forecast information available at the time of the WP-02 Final Supplemental Proposal, published in June 2001. The market price forecast in the WP-02 Supplemental Final Proposal was based on the best market price information available at that time. *Id*. at 2.

Throughout the WP-07 Supplemental rate proceeding, the use of this market price forecast for the FY 2002-2006 Lookback analysis was not raised as an issue. No other testimony was filed on the topic, and no party raised the issue in its Initial Brief or Brief on Exceptions. Thus, BPA will use the market price forecast as proposed by Staff.

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5.0 FY 2002-2008 LOOKBACK REVENUE REQUIREMENT

5.1 Introduction

The purpose of the Lookback Revenue Requirement study, section 3 of WP-07-FS-BPA-08, is to establish the level of revenues from wholesale power rates that, in retrospect, would have been necessary to recover, in accordance with sound business principles, the Federal Columbia River Power System (FCRPS) costs associated with the production, acquisition, marketing, and conservation of electric power assuming that BPA had recalculated base rates in the WP-02 Supplemental Proposal.

5.2 Revenue Requirement Development

The development of spending levels reflected in the WP-02 Final Proposal revenue requirement was largely driven by the Regional Cost Review (Cost Review), a review of FCRPS costs launched in September 1997 by BPA and the Northwest Power and Conservation Council (NPCC). Both the Comprehensive Review and the Cost Review are described in the WP-02 Revenue Requirement Study, WP-02-BPA-FS-02, chapter 2.

5.2.1 Adjustments to Program Expenses Used in the WP-02 Proceeding for the FY 2002-2006 Lookback

The forecasts of program expenses used in the WP-02 Final Proposal were not changed for the Lookback Revenue Requirement Study, WP-07-FS-BPA-08. Lennox, *et al.*, WP-07-E-BPA-55, at 4. The program expense assumptions used in the WP-02 Final Proposal were the only complete set of program expense forecasts available during the WP-02 Supplemental Proposal proceeding. *Id*.

5.2.2 Capital Investments

FCRPS capital investments include Corps, Reclamation, and BPA capital investments and third-party resource investments for which debt is secured by BPA (capitalized contracts). The WP-02 Final Proposal FCRPS capital outlay projections were $1,399 million for the FY 2002-2006 rate period. Revenue Requirement Study, WP-02-BPA-FS-02, chapter 2, Table 4. With the exception of the following items, these investment projects were not adjusted as part of the Lookback process.

The Lookback Revenue Requirement Study includes changes to two capital investment assumptions that would have been updated if BPA had revised power rates in the WP-02 Supplemental Proposal. First, this study includes a forecast of capital spending for the Conservation Augmentation (ConAug) program, which was not included in the WP-02 Final Proposal. This program was created in 2000 to aid in meeting BPA's power augmentation needs. A forecast of ConAug capital investment, totaling $300 million for the FY 2002-2006 rate period, was available near the end of the WP-02 Supplemental Proposal process. Lennox, *et al.*, WP-07-E-BPA-55, at 3. Second, this study incorporates a different plant-in-service forecast for the Columbia River Fish Mitigation (CRFM) project, which had changed by the end of the WP-02 Supplemental Proposal process and would have been used if the revenue requirement had been revised. The new forecast reduced CRFM capital investment by approximately $225 million beginning in FY 2001 through the FY 2002-2006 rate period. *Id.* at 2-3. *See* FY 2002-2008 Lookback Documentation, WP-07-FS-BPA-08A, section 3.

In addition to these changes, the WP-02 Final Proposal included projected investments for FY 2000. At the time of the WP-02 Supplemental Proposal, the actual investments for FY 2000 were known. In cases where the actual results for FY 2000 differed from the forecast, the forecasted investments and plant-in-service dates have been modified in the development of interest expenses and depreciation/amortization expenses for this study.

5.3 Issues

No issues were raised by parties in their Initial Briefs or their Briefs on Exception.

6.0 FY 2002-2008 LOOKBACK SLICE RATE AND REVENUE REQUIREMENT

6.1 <u>Introduction</u>

The Slice product is a sale of a fixed percentage of the generation output of the Federal Columbia River Power System (FCRPS). It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The Slice product is a power sale based upon a Slice customer's annual firm net requirement load and is shaped to BPA's generation output from the FCRPS. BPA's Subscription sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

Because the Slice product is calculated as a percentage of the FCRPS generation output, the actual amount of power delivered to the Slice customer varies throughout the year. During certain periods of the year and under certain water conditions, the power delivered exceeds the Slice customer's firm net requirement and may, at times, exceed the Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements power and surplus power.

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatt-hour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay a percentage of the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's power revenue requirement, with certain limited exceptions. *See* the Slice Product Costing and True-Up Table for a detailed list of the line items and forecasted dollar amounts in the FY 2007-2009 Slice Revenue Requirement that was determined in the WP-07 Final Proposal. 2007 Wholesale Power Rate Schedules and General Rate Schedule Provisions, November 2006, Appendix A, Table 1.

In 2003, BPA was involved in litigation before the United States Court of Appeals for the Ninth Circuit concerning the appropriate interpretation of the Slice rate and the Slice Rate Methodology. *Northwest Requirements Utilities, et al. v. Bonneville Power Administration*, No. 03-73849, *Northwest Requirements Utilities v. Bonneville Power Administration*, No. 04-71311, *Benton County PUD, et al. v. Bonneville Power Administration*, No. 03-74179. In July 2006, BPA, the Slice customers, and the Northwest Requirements Utilities agreed on a settlement of the issues. The Slice Settlement (No. 07PB-12273) was approved by the U.S. Department of Justice and was signed and executed by all parties on November 22, 2006. The Slice Settlement resolved all Slice True-Up disputes for Contract Years 2002-2005, along with some previously disputed substantive issues in a way that will have precedential effect beyond 2005. The Slice Settlement provided for refunds to Slice customers in the form of credits to their bills that settled disputes over the magnitude of Slice True-Up Adjustment Charges for FY 2002-2005. The Slice Settlement also included a new dispute resolution provision and a Memorandum of Understanding regarding BPA's Debt Optimization Program.

As part of the WP-07 Final Proposal, BPA, along with many Slice customers, non-Slice customers, IOUs, and Tribal entities, signed the Partial Resolution of Issues that included modifications to the Slice rate and Slice True-Up. Evans, *et al.*, WP-07-E-BPA-31, Attachment A. The Partial Resolution of Issues was adopted by the Administrator in the WP-07 Administrator's Final Record of Decision, WP-07-A-02, at 2-6, and Attachment 1. The Partial Resolution of Issues was not changed in this Supplemental Proposal.

In the Supplemental Proposal, BPA proposed modifications of the rate treatment of certain Slice Rate and Slice Rate Methodology matters, consistent with the Slice Settlement. Johnson, *et al.*, WP-07-E-BPA-59, at 2-5.

6.2 Annual Slice True-Up Adjustment Charge Calculation

Issue 1

Whether the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal should be the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2008.

Parties' Positions

The Slice Customers Group supports the approach of using the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2008. Slice Customers Group Br., WP-07-B-JP22-01, at 2.

BPA Staff's Position

BPA Staff proposed that the calculation of the Slice True-Up Adjustment Charge for FY 2008 would be the difference between the Actual Slice Revenue Requirement for FY 2008 and the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal. Johnson, *et al.*, WP-07-E-BPA-59, at 4; Lee, *et al.*, WP-07-E-BPA-84, at 3.

Evaluation of Positions

The Slice Customers Group supports BPA's approach of using the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2008. Slice Customers Group Br., WP-07-B-JP22-01, at 2. For the calculation of the Slice True-Up Adjustment Charge for FY 2008, Staff proposed to compare the Actual Slice Revenue Requirement for FY 2008 with the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal. Johnson, *et al.*, WP-07-E-BPA-59, at 4. The Slice Customers Group agreed with this approach and stated that it made sense for BPA to calculate the Slice True-Up Adjustment Charge for FY 2008 by using the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal, which is the same average Slice Revenue Requirement that the FY 2008 Slice rate is based on. Brawley and Gregg, WP-07-E-BPA-JP22-01, at 8. Staff agreed and affirmed that it would calculate the

Slice True-Up Adjustment Charge based on the three-year average Slice Revenue Requirement established in the WP-07 Final Proposal. Lee, *et al.*, WP-07-E-BPA-84, at 3.

<u>Decision</u>

BPA will use the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2008.

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7.0 AVERAGE SYSTEM COST REFORECASTS AND BACKCASTS

7.1 Introduction

7.1.1 Overview of Average System Cost

The Northwest Power Act, 16 U.S.C. §839, *et seq*., established the REP to provide residential and small farm customers of Pacific Northwest utilities a form of access to low-cost Federal power. McHugh, *et al.*, WP-07-E-BPA-71, at 1-5. Under the Northwest Power Act, BPA "purchases" power from each participating utility at that utility's ASC. *Id*. BPA then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's PF Exchange rate. *Id*. The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. *Id*. The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities. *Id*.

The REP does not involve a conventional purchase and sale of power. *Id*. Under the normal implementation of the REP, no actual power is transferred either to or from BPA. *Id*. The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the generally less expensive power "sold" to the participating utility. *Id*. As discussed below, however, actual power sales may occur under "in-lieu" transactions, where BPA purchases power from a source other than the utility and sells actual power to the utility. *Id*.

When a utility's ASC is less than the PF Exchange rate, the utility may elect to deem its ASC equal to the PF Exchange rate. Boling, *et al.*, WP-07-E-BPA-57, at 3. By doing so, it avoids making monetary payments to BPA. *Id*. The amount that the utility would otherwise pay BPA is tracked in a "deemer account." *Id*. At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." *Id*. Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive monetary payments from BPA. *Id*. Avista Corporation (Avista), Idaho Power Company, and NorthWestern Energy have deemer balances. *Id*. The issue of deemer balances with Idaho Power Company and Avista is currently in dispute. Forman, *et al.*, WP-07-E-BPA-76, at 64-75.

A utility's ASC is the sum of a utility's production- and transmission-related costs (Contract System Costs) divided by the utility's Contract System Load. Boling, *et al.*, WP-07-E-BPA-57, at 4. Pursuant to section 5(c)(7), BPA established a methodology for determining a utility's ASC. 16 U.S.C. § 839c(c)(7). The ASC methodology in effect during the FY 2002-2008 period was the 1984 Average System Cost Methodology. Forman, *et al.,* WP-07-E-BPA-76, at 38-39. Section 5(c)(7) of the Northwest Power Act also lists the costs and loads that cannot be included in an exchanging utility's ASC. 16 U.S.C. § 839c(c)(7)(A), (B), (C). They include the costs to serve a new large single load (NLSL); the costs to serve extraregional load that occurs after December 5, 1980; and the costs of any generating facility terminated prior to commercial operation. A utility's Contract System Load is defined as the utility's total retail load. The resulting quotient from dividing the utility's Contract System Costs by Contract System Load is the utility's ASC.

7.1.2 Lookback ASCs

The Lookback construct is designed to estimate as closely as possible the amount of REP benefits that should have been included in consumer-owned utilities' (COUs') rates for the FY 2002-2008 period. Bliven, *et al.*, WP-07-E-BPA-52, at 18-19. The resulting REP benefit amounts, subject to certain rules, are compared to what the investor-owned utilities (IOUs) actually received under the REP Settlement Agreements. Marks, *et al.*, WP-07-E-BPA-62, at 9. The difference between these two amounts, in general, is referred to as the Lookback Amount, which must be recovered from the IOUs and returned to the COUs. *Id.; see also* Chapter 8.

To construct the Lookback Amounts, BPA assumed that there were no 2000 REP Settlement Agreements, which were held unlawful by the U.S. Court of Appeals for the Ninth Circuit, and BPA would have implemented the REP for both the WP-02 and WP-07 rate periods under the terms of a traditional RPSA. Bliven, *et al.*, WP-07-E-BPA-52, at 14. In addition, BPA assumed that if the REP Settlement Agreements had not existed, BPA would have been forced to revisit the development of the PF Exchange rate in the winter of 2000 and spring 2001, because the base rates developed at that time assumed the existence of the REP Settlement Agreements, did not reflect significantly increased loads and market prices, were inadequate to recover BPA's costs, and therefore could not have been approved by FERC or used to recover BPA's costs. Burns, *et al.*, WP-07-E-BPA-53, at 8. Consequently, BPA assumes it would have developed its PF Exchange rate differently had it known it would have implemented the REP for the WP-02 rate period. *Id*. at 8-9.

ASCs play a central role in determining the level of REP benefits that would have been paid to the IOUs but for the REP Settlement Agreements. They do so in two ways. First, forecast ASCs are used to estimate the amount of REP costs that BPA must collect in rates over the rate period. While these ASCs do not replace the ASCs that may be filed by the IOUs during the rate period under the REP and that are used to calculate actual REP benefits, they are vitally important for setting rates, including the PF Exchange rate. Second, ASCs are used to determine the actual amount of REP benefits the IOUs will receive. Actual REP benefits are determined by comparing the PF Exchange rate with the IOUs' filed ASCs. These "filed" ASCs may occur any number of times during the rate period and typically vary from the forecast ASCs BPA develops in the rate proceeding.

In both the WP-02 and the WP-07 rate proceedings, BPA used forecast ASCs for purposes of setting rates. In preparing for the Supplemental Proposal, BPA discovered that these forecast ASCs included a number of errors and omissions that would likely have been discovered and corrected had the REP been active during these periods. Boling, *et al.*, WP-07-E-BPA-57, at 9-10. In addition, the ASCs used in the WP-02 rate proceeding would have been updated with more current market purchase information had BPA reopened the rate proceeding in the winter of 2000 and spring of 2001. *Id*. at 4. To correct these errors and omissions, BPA "reforecast" the ASCs that would have been used in setting rates for the WP-02 and WP-07 rate periods. *Id*.

at 1. BPA corrected these errors and updated the forecast ASCs to better reflect the costs of the REP in the Lookback.

As just noted, REP benefits are not based on rate case forecast ASCs. Bliven, *et al.*, WP-07-E-BPA-52, at 18-19. Rather, REP benefits are based on the difference between each IOU's *filed* ASC and BPA's PF Exchange rate, multiplied by the utility's exchange load. *Id.* at 16. No IOU filed ASCs with BPA from FY 2002-2008, because the IOUs had executed the REP Settlement Agreements. However, had the IOUs *not* signed these Agreements, and instead participated in the traditional REP through a Residential Purchase and Sale Agreement (RPSA), the IOUs would have been making ASC filings with BPA pursuant to the 1984 ASC Methodology (1984 ASCM). *Id.* BPA must estimate these ASCs in order to reasonably approximate the likely REP benefits that would have been paid for the FY 2002-2008 period. *Id.* at 16-17. Consequently, BPA proposed to calculate annual ASCs for each IOU in a manner that approximates the ASC determinations that would have been made, consistent with the 1984 ASCM, had the IOUs submitted ASC filings during FY 2002-2008. Manary, *et al.*, WP-07-E-BPA-61, at 2-3. These ASC filings are known as "backcast ASCs." *Id.* In general, the backcast ASCs are a best estimate of the ASC determinations that would have been made by the Administrator for each IOU had the REP been active during the FY 2002-2008 period. *Id.* at 2.

7.2 <u>BPA's Authority to Construct Reforecast ASCs and Backcast ASCs</u>

<u>Issue 1</u>

Whether BPA may calculate backcast ASCs to determine the amount of REP costs that would have been included in rates for the FY 2002-2008 period.

<u>Parties' Positions</u>

Cowlitz argues that BPA is not required or permitted to calculate a "backcast" ASC. Cowlitz Br., WP-07-B-CO-01, at 62. Cowlitz contends that to calculate the costs of REP benefits, BPA needs only to look at the forecast ASCs in the rate cases, and not the actual costs of the REP. *Id.* APAC makes a similar argument in its Brief on Exceptions. APAC Br. Ex., WP-07-R-AP-01, at 28.

WPAG similarly argues that BPA's backcast ASCs are both unnecessary to respond to the remand in the *Golden NW* decision and legally unsound. WPAG Br., WP-07-B-WA-01, at 23.

<u>BPA Staff's Position</u>

BPA has the legal authority to conduct backcast ASCs. Calculating backcast ASCs is a critical component to accurately calculate the proper amount of REP costs that would have been collected in rates for the FY 2002-2008 period. Bliven, *et al.*, WP-07-E-BPA-52, at 16.

Evaluation of Positions

REP benefits are based, in part, on the difference between each IOU's ASC and BPA's PF Exchange rate. Bliven, *et al.*, WP-07-E-BPA-52, at 16. Had the IOUs signed RPSAs, they would have been making ASC filings with BPA pursuant to the 1984 ASCM or a subsequent ASC methodology. *Id*. Because the REP Settlement Agreements were meant to settle disputes over implementation of the 1984 ASCM, and the determination of REP Settlement benefits did not use ASCs, the IOUs were not required to make ASC filings during the term of the REP Settlement Agreements. *Id*. BPA must have ASC information in order to reasonably estimate the likely REP benefits that would have been paid for the FY 2002-2008 period. *Id*. As such, BPA directed Staff to use the best available data and information to estimate the ASC determinations BPA would likely have made for each IOU for FY 2002-2008. *Id*. In calculating these estimates, BPA directed Staff to review the ASCs for each utility in a manner that aligns as closely as practicable with the requirements of the 1984 ASCM. *Id*.

Cowlitz argues that nothing in the Northwest Power Act or the Ninth Circuit's opinions requires or permits "backcasting" of ASCs. Cowlitz Br., WP-07-B-CO-01, at 62. Cowlitz contends that instead, the lawful implementation of sections 7(b)(2) and 7(b)(3) would have eliminated virtually the entire REP throughout the Lookback period. *Id*. According to Cowlitz, if BPA adopted WPAG's "minimalist" approach (*e.g.,* Grinberg, *et al*., WP-07-E-WA-05, at 12), BPA would not recalculate ASCs at all for FY 2002-2006, and would instead use the section 7(b)(2) trigger amounts developed in the WP-02 case. *Id*. WPAG similarly argues that calculating backcast ASCs is both unnecessary to respond to the remand in the *Golden NW* decision and legally unsound. WPAG Br., WP-07-B-WA-01, at 23. APAC also contends that BPA should not "unilaterally" calculate backcast ASCs because the IOUs did not file any during 2001. APAC, Br. Ex., WP-07-R-AP-01, at 28.

These arguments are not persuasive. The absence of specific statutory language or Court direction does not mean BPA is without authority to construct backcast ASCs. As described earlier, the Court in *Golden NW* remanded the WP-02 rates back to BPA. Cowlitz and WPAG appear to recognize that this remand was not without consequence and that BPA must fashion a remedy to respond to the Court's order. *See* Cowlitz Br., WP-07-B-CO-01, at 3 ("BPA must adopt a plan to pay back the full amount of REP benefits for which preference customers were illegally charged, with greater certainty and at a fair interest rate."); *see also* WPAG Br., WP-07-B-WA-01, at 3. That being the case, it is a well-established principle of law that an agency's discretion is at its "zenith" when it is constructing remedies to past violations of law. *See Pub. Util. Comm'n of Ca. v. FERC*, 988 F.2d 154, 163 (D.C. Cir. 1993) ("*CPUC*"). Within that broad authority is the discretion to rely upon the "familiar principle of equity to regard as being done that which should have been done." *See Central Main Power Co. v. FPC*, 345 F.2d 875, 876 (1st Cir. 1965); *see also Plaquemines Oil & Gas Co., v. Federal Power Comm'n*, 450 F.2d 1334, 1337-1338 (D.C. Cir. 1971). Federal agencies, just like courts, may call upon these equitable powers to construct a remedy that is consistent with the law as well as fundamental principles of fairness and justice. *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 160 (D.C. Cir. 1967). As the Court in *Niagara* observed:

> The principles of equity are not to be isolated as a special province of the courts. They are rather to be welcomed as reflecting fundamental principles of justice that properly enlighten administrative agencies under law. The courts may not rightly treat administrative agencies as alien intruders poaching on the court's private preserves of justice. Courts and agencies properly take cognizance of one another as sharing responsibility for achieving the necessities of control in an increasingly complex society without sacrifice of fundamental principles of fairness and justice.

Id.

In this regard, BPA is appropriately considering "doing what should have been done" in the absence of the REP Settlement Agreements. The record evidence demonstrates that the IOUs would have participated in the REP had the REP Settlement Agreements not been signed. *See* Forman, *et al.*, WP-07-E-BPA-76, at 45-46. The IOUs had submitted letters notifying BPA of their intent to participate in the REP beginning October 1, 2001, and RPSAs had been drafted and offered to these utilities. *Id*. Consequently, it is reasonable to assume that if BPA had not entered the REP Settlement Agreements, these utilities would have signed 10-year RPSAs with BPA and, thereby, would have received REP benefits during FY 2002-2008. Bliven, *et al.*, WP-07-E-BPA-52, at 14. Indeed, this assumption is logically sound because the IOUs, supported by the state utility commissions, would not willingly forgo REP benefits available for their residential and small farm consumers unless it was to their advantage to do so. *Id*. Assuming that the IOUs would have executed the RPSAs, it follows that the IOUs would have made ASC filings, because the RPSAs *require* the utilities to file ASCs with BPA. *See* Forman, *et al.*, WP-07-E-BPA-76, at 45-46. If BPA is to assume that the IOUs would have signed RPSAs, the only rational outcome is that the IOUs would have complied with the contracts and made ASC filings. *Id*. Calculating backcast ASCs as an estimate of the ASC filings that would have been filed in the absence of the REP Settlement is, therefore, both a permitted, and in fact necessary, component of BPA's duty to respond to the Court's remand.

In its Brief on Exceptions, Canby objects to BPA's reliance on *CPUC* and *Niagara Mohawk* because "Congress had expressly granted authority to FERC to balance equities." Canby Br. Ex., WP-07-R-CA-01, at 11-12. Canby asserts that, in contrast, BPA has no such authority.

Canby's arguments are without merit. Canby asserts that the cases cited by BPA are distinguishable because FERC is statutorily empowered to "balance equities." This assertion is patently incorrect. Nothing in the Natural Gas Act or Federal Power Act says FERC is supposed to "balance equities." Rather, the *courts* have made these statements in cases where the Commission is responding to a judicial *reversal* or is correcting for a past legal mistake or omission. *See Central Main Power Co. v. FPC*, 345 F.2d 875, 876 (1st Cir. 1965); *Plaquemines Oil & Gas Co., v. Federal Power Comm'n*, 450 F.2d 1334, 1337-1338 (D.C. Cir. 1971); *Borough of Ellwood City v. FERC*, 583 F.2d 642 (3rd Cir. 1978); *see also CPUC,* 988 F.2d at 162-163. In these circumstances, the Commission is faced with the knotty question of how to remedy its own legal error. That was the concern in *CPUC*. In *CPUC*, the Commission had issued an order that allowed pipelines to recover certain "take-or-pay" cost obligations from their customers under one of two methods. *CPUC,* 988 F.2d at 156-157. The Commission put a sunset date on one of the methods, referred to as the "equitable sharing mechanism." *Id.* at 157-158. If a party failed to file revised tariffs sheets under this method before the sunset date, it would then be limited to the second method, known as the "gas inventory charge" (GIC). *Id.* at 158. Transwestern Pipeline Company (Transwestern) filed after the sunset date, and was therefore required to take the GIC mechanism. *Id.* at 162. Subsequently, though, the D.C. Circuit held that the sunset provision in the "equitable sharing" mechanism was arbitrary and capricious. *Id.* On remand, Transwestern claimed that had it not been for the sunset provision, it would have filed for relief under the "equitable sharing" mechanism. *Id.* Transwestern petitioned to change its designation from the GIC mechanism to the equitable sharing mechanism. *Id.* The Commission agreed, and Transwestern's customers filed suit. *Id.* at 159-160.

In sustaining the Commission, the Court found that it was proper for the Commission to allow Transwestern, as well as any other pipeline that was affected by the illegal sunset provision, to change its designation from the GIC mechanism to the equitable sharing mechanism. *Id.* at 163. The Court, in agreeing with the Commission, did *not* rely on a provision of the Natural Gas Act or other statute that authorized the Commission to undue Transwestern's election. Rather, the Court found that under the unique circumstances of the case, "[w]e have no inclination, even if we had the authority, to say that this approach exceeded the Commission's remedial authority, particularly since agency discretion 'is often at its 'zenith' when the challenged action relates to the fashioning of remedies.'" *Id.* The Court's overriding concern in allowing the Commission to exercise these powers was to ensure that the Court's reversal was given some effect. Otherwise, without this corrective power, party's challenging an agency's order would be irreparably harmed, and judicial review would be "powerless." *Id.*

What the Court allowed the Commission to do in *CPUC* is directly analogous to what BPA is doing in the present case. BPA committed legal error by implementing the REP through the REP Settlement Agreements. The IOUs' decision to accept these agreements was undoubtedly influenced by BPA's belief that the REP Settlement Agreements were a proper exercise of the agency's statutory authority. Now that the Court has found the REP Settlement Agreements to be invalid, the only logical inference is to assume the IOUs would have taken the other alternative – the RPSAs. The Lookback construct implements the consequences that would have naturally followed had the IOUs adopted this alternative. That is, the IOUs would have executed the RPSA and received REP benefits based on filed ASCs and exchange loads. By considering what would have transpired without the REP Settlement Agreements, BPA is following the long line of cases that afford agencies the ability to put the parties in the position they would have been in had the legal error not been made. *See CPUC,* 988 F.2d 168; *see also AT&T Corp. v. F.C.C.*, 448 F.3d 426, 433 (D.C. Cir. 2006); *Exxon Co. v. FERC,* 182 F.3d 30 (D.C. Cir. 1999); *United Gas Improvements Co., v. Callery Properties, Inc.,* 382 U.S. 223, 229 (1965). That is what the Commission did in *CPUC* and that is what BPA is doing in this case.

Canby objects to BPA's reliance on these cases on the grounds that BPA is not a "regulatory commission, like FERC." Canby, Br. Ex., WP-07-R-CA-01, at 12. While BPA is not a "regulatory commission" like FERC, there are, nonetheless obvious similarities between FERC and BPA's respective roles. The Commission is required by statute to establish rates for jurisdictional utilities that meet the "just and reasonable" standard of the NGA and FPA. BPA is required by statute to establish rates that meet the cost recovery principles of section 7 of the Northwest Power Act. If the Commission has committed an error in approving a utility's rates, the Courts remand the rates to the *Commission* to address the problem. Similarly, if BPA commits an error in establishing its rates, the Court remands the rates back to *BPA* for correction, as has been done in the present case. Since the Commission is afforded equitable powers to correct its legal errors by the Courts, there is no basis to assume that BPA will not similarly be afforded equitable discretion in responding to the Court's decision in *PGE* and *Golden NW.*

Canby also argues that there is nothing in the Bonneville Project Act or Northwest Power Act that gives BPA the statutory right to "balance equities" among competing customers in the region. Canby, Br. Ex., WP-07-R-CA-01, at 12. Canby asserts that if BPA thought it had that discretion, the Ninth Circuit's opinions in *PGE* and *Golden NW* should now persuade it otherwise. *Id.* The fact that BPA's equitable authority is not spelled out in the Northwest Power Act or some other law, however, is immaterial. There is no "statute" that says FERC has the authority to assume a utility would have taken certain action "but for" the Commission's legal error. Yet, the Courts have allowed the Commission to assume that numerous times. *See Central Main Power Co. v. FPC*, 345 F.2d 875, 876 (1st Cir. 1965); *Plaquemines Oil & Gas Co., v. Federal Power Comm'n*, 450 F.2d 1334, 1337-1338 (D.C. Cir. 1971); *Borough of Ellwood City v. FERC*, 583 F.2d 642 (3rd Cir. 1978); *see also CPUC,* 988 F.2d at 168. It is just a matter of common sense that an agency must have flexibility when crafting a remedy for parties injured by a legal error. In the instant case, the Court found BPA had committed legal error by not determining REP benefits in accordance with sections 5(c) and 7(b)(2) of the Northwest Power Act for the FY 2002-2006 period. The most obvious way to remedy these errors is for BPA to determine REP benefits in accordance with sections 5(c) and 7(b)(2) for that period, which is what the Lookback construct does. Canby's assertion that BPA is repeating the same legal errors in *Golden NW* and *PGE* by calculating REP benefits in accordance with the law makes no sense.

Canby's argument also proves too much. The Northwest Power Act says nothing about BPA's authority to provide *refunds* to Canby or any other preference customer for past overcharges. Nor did the Court expressly direct BPA to make such refunds. If Canby is correct that BPA can only take actions that are specifically authorized by the Northwest Power Act and the Bonneville Project Act, then BPA would not have the power to return the overcharges in this case. This result, however, would make no sense in light of the Court's findings in *PGE* and *Golden NW* that BPA has committed legal error. BPA is using the same equitable principles to "put the parties in the same place had BPA not committed a legal error" that Canby assails to recover funds from the IOUs to repay the COUs. If BPA is unable to use these powers to construct the Lookback, then BPA's authority to provide the COUs with relief would equally be in jeopardy. Canby's Brief on Exceptions does not take issue with BPA's decision to provide these funds to the preference customers, and therefore, Canby must believe BPA possesses *some* authority to correct for past legal errors. Canby's arguments are therefore unpersuasive.

Cowlitz argues that if BPA had conducted a "lawful implementation of §§ 7(b)(2) & (3) the REP costs would have eliminated virtually the entire REP program throughout the Lookback period." Cowlitz Br., WP-07-B-CO-01, at 62. This argument goes to BPA's implementation of sections 7(b)(2) and 7(b)(3) and has nothing to do with whether BPA may reconstruct REP benefits using backcast ASCs. Although Cowlitz's claim is wrong, BPA will respond to Cowlitz's specific concerns with the operation and implementation of sections 7(b)(2) and 7(b)(3) in chapter 16 of this Record of Decision.

As an alternative, Cowlitz cites with approval the "minimalist" approach (*e.g.,* Grinberg, *et al*., WP-07-E-WA-05, at 12), proffered by WPAG. Cowlitz Br., WP-07-B-CO-01, at 62. Under that approach, BPA would not recalculate ASCs at all for FY 2002-2006 and would instead use the section 7(b)(2) trigger amounts developed in the WP-02 rate case. *Id*. As support for this approach, Cowlitz advises BPA to remember that rates are based on *forecasts*, including forecast REP load that is a function of forecast ASC rates. *Id*. This approach, however, is faulty for several reasons.

First, as a ratemaking matter, Cowlitz is simply wrong that a proper determination of the REP benefits the IOUs would have received during FY 2002-2008 is in any way constrained by the ASC or exchange load *forecasts* used in BPA's rate setting process. A central component of BPA's Lookback approach is to determine the REP benefits the IOUs would have received under the actual implementation of the REP during FY 2002-2008, not what an earlier and fatally flawed REP rate case forecast would have estimated. *See* Chapter 2.6.3. It must be emphasized that when BPA estimates IOUs' ASCs and exchange loads in a rate case, it does so only for *ratemaking* purposes. Forman, *et al.*, WP-07-E-BPA-76, at 45. These forecasts are used to *estimate* the amount of REP costs that BPA will need to recover in rates. The *actual* amount of an REP benefit payment is determined during the actual implementation of the REP by comparing an IOU's filed ASC with the PF Exchange rate, multiplied by the utility's actual exchange load. *Id*. BPA's ASC forecasts are developed from the best available data at the time of the rate case, which in most instances pre-dates the actual year the utility would be exchanging with BPA by two to seven years. *Id*. Just as with any other forecast in the rate case, however, these forecasts are *no substitute* for the information that would have become available during the rate period. *Id*.

In simple terms, BPA is trying to determine the REP benefits the IOUs would have received during FY 2002-2008 under the REP in the absence of the REP Settlement Agreements. Relying solely on a rate case forecast would ensure that BPA *did not* have an accurate estimate of the REP benefits the IOUs would have received during FY 2002-2008. This is because BPA would be using a forecast of such benefits before the benefits had actually been calculated and paid during the implementation of the REP. Furthermore, the forecast ASCs were based on load and market price information that became outdated immediately after the WP-02 rates were first developed. *See* Chapter 2.6.3. Relying on outdated information makes the rate case ASC forecast fatally flawed and inappropriate for determining the REP benefits the IOUs' residential consumers would have received.

Thus, BPA can determine REP benefits the IOUs would have received during FY 2002-2008 much more accurately than a rate case forecast. The IOUs would have filed ASCs and exchange loads with BPA within the rate period (after BPA had set its rates) that would have some, little, or no relationship to the ASC and exchange loads forecast in the rate case. *Id*. As the REP is implemented through time, the concomitant amount of REP payments made varies from the forecast in rates, resulting in either lower or higher REP payments. If the REP payments are higher than forecast, then rates are affected by a reduction in BPA's financial reserves or the triggering of a cost recovery mechanism *(e.g.,* CRAC) to address any revenue shortfall. This is how the REP has always operated. *Id*. As such, Cowlitz is wrong that rate case forecasts of ASC and exchange loads are somehow the best approximation of what REP benefits the IOUs would have been entitled to under the REP. *Id*.

Additionally, Cowlitz's alternative is logically unsound. Under Cowlitz's alternative, BPA would assume the IOUs would be participating in the REP because the IOUs are receiving *some* benefits. This means BPA would also assume the IOUs had executed RPSAs to receive those REP benefits. Yet Cowlitz's approach would then require BPA to make the illogical assumption that even though the IOUs signed the RPSAs, they would not have filed ASCs within the rate period when such filings would have provided benefits to their residential and small farm consumers. Bliven, *et al.*, WP-07-E-BPA-76, at 45-46. BPA considers this result highly illogical considering the IOUs' historical participation in the REP. *Id*.

Finally, Cowlitz's alternative would be inconsistent with the language of the Northwest Power Act. Cowlitz recommends that BPA use the outdated and fatally flawed rate case forecast ASCs and exchange loads in order to use "the § 7(b)(2) trigger amounts developed in the WP-02 case." Cowlitz Br., WP-07-B-CO-01, at 62. In effect, Cowlitz requests that BPA extend the protections afforded to the COUs under section 7(b)(2) of the Northwest Power Act to the *actual* cost of the REP rather than the *forecast* cost of the REP. This position is inconsistent with the law. Section 7(b)(2) of the Northwest Power Act, by its terms, is designed to provide COUs rate protection from *forecast* costs. *See* 16 U.S.C. § 839e(b)(2). Section 7(b)(2) begins, "[a]fter July 1, 1985, the *projected amounts to be charged for firm power* … may not exceed in total … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes … [the five rate assumptions]." *Id*. (emphasis added). As this language makes clear, the 7(b)(2) rate test protection applies to the "projected amounts to be charged," that is, the forecast amount of cost in BPA's rates, and not to the actual costs BPA experiences within the rate period. Cowlitz's recommendation would lock in the REP costs to what BPA forecast in the rate case, thereby creating additional windfall protection to COUs that was not intended or allowed by the statutory language. Since passage of the Northwest Power Act, the exchange program has never been administered in the fashion Cowlitz now argues for. Even more, Cowlitz's approach would violate the plain language of section 5(c) of the Act. Section 5(c) requires:

> Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the *average system cost of that utility's resources in each year*, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.

16 U.S.C. § 839c(c)(1) (emphasis added). The key phrase is "average system cost of that utility's resources in each year." *Id*. This language shows that Congress expected utilities to

enter into the REP with ASCs that could change over time. A utility's ASC would change as the utility's cost of resources changed. These changes could occur before, during, or after BPA had estimated the ASCs in a rate proceeding. This is, in fact, how the REP was implemented when it was active. Because Cowlitz's recommendation is based on fatally flawed information, is contrary to the plain language of section 7(b)(2) and 5(c) of the Act, and is contrary to the historical implementation of the REP, it must be rejected.

Decision

BPA properly decided to calculate backcast ASCs in order to determine the amount of REP costs that should have been included in COUs' rates for FY 2002-2008.

Issue 2

Whether BPA properly assumed that certain IOUs would have executed RPSAs if the REP Settlement Agreements had not been executed.

Parties' Positions

Cowlitz argues that BPA cannot reconstruct past ASCs because none of the IOUs had RPSA contracts with BPA. Cowlitz Br., WP-07-B-CO-01, at 63. Cowlitz claims that the IOUs must have these contracts in order to receive payments under the REP. *Id*. Cowlitz asserts that no law or rule permits BPA to assume the IOUs would have signed RPSAs for the FY 2002-2008 period. *Id*.

BPA Staff's Position

There is significant evidence in the record, in addition to common sense, to support BPA's assumption that the IOUs would have signed RPSAs in the absence of the REP Settlement Agreements. Bliven, *et al.*, WP-07-E-BPA-52, at 14. The IOUs had sent letters to BPA prior to the execution of REP Settlement Agreements stating their intention to participate in the REP. *Id*. BPA offered the IOUs RPSAs. *Id*. The IOUs signed the REP Settlement Agreements in lieu of the RPSAs, and the record establishes that the REP Settlement Agreements were entered into in place of the RPSAs. *Id*. The administrative record, general principles of equity, and common sense permit BPA to assume that the IOUs would have signed RPSAs had the REP Settlement Agreements not been offered.

Evaluation of Positions

As Staff described in its direct testimony, the WP-02 rate case had its roots in the regional Comprehensive Review process and the associated Cost Review process. Bliven, *et al.*, WP-07-E-BPA-52, at 4-5. The Comprehensive Review led to the Federal Power Subscription Work Group process, resulting in the Subscription Strategy ROD and Subscription contracts. *Id*. The Subscription Strategy proposed that BPA would offer RPSAs to regional utilities, including the IOUs, to implement the REP for FY 2002 through FY 2011. *Id*. The Strategy also proposed that BPA would offer the IOUs settlement agreements to resolve disputes arising under BPA's implementation of the REP. *Id*. The IOUs could execute only RPSAs *or* REP Settlement Agreements. *Id*. BPA did not give the IOUs the option to execute both.

In light of this, BPA directed Staff to assume that certain IOUs would have executed RPSAs and participated in the REP during the WP-02 and WP-07 rate periods. Bliven, *et al.*, WP-07-E-BPA-52, at 14. This assumption was founded in part on the fact that five IOUs filed letters of intent with BPA to participate in the REP prior to the WP-02 rate proceeding. *Id*. This was a reasonable assumption, because had BPA not entered into the REP Settlement Agreements, these utilities would have signed 10-year RPSAs with BPA and thereby would have received REP benefits during FY 2002-2008. *Id*. Indeed, this assumption is logically sound, because the IOUs, supported by the state utility commissions, would not willingly forgo REP benefits available for their residential and small farm consumers unless it was to their advantage to do so. *Id*.

Cowlitz argues that none of the IOUs executed RPSAs and that execution of such RPSAs is necessary to have been eligible for REP benefits. Cowlitz Br., WP-07-B-CO-01, at 63. Cowlitz then asserts that no RPSAs were executed and no relevant transactions other than those rendered void by the Ninth Circuit decisions exist. *Id*. As such, Cowlitz states that no law or rule permits BPA to "pretend" that additional qualifying contracts exist. *Id*. Cowlitz claims that BPA may "exercise only the powers granted by the statute reposing power in it," *citing FTC v. National Lead Co.*, 352 U.S. 419, 428 (1957). *Id*. Cowlitz concludes that those powers do not include disbursing funds to IOUs in the absence of bona fide exchange contracts between BPA and the IOUs. *Id*.

Cowlitz's arguments once again ignore the strong record evidence and common sense that establish that the IOUs would have executed RPSAs in the absence of the REP Settlement Agreements. Cowlitz also ignores the law that authorizes BPA to make this assumption.

First, the record is replete with evidence that the IOUs would have executed RPSAs in the absence of the REP Settlements. Bliven, *et al.*, WP-07-E-BPA-52, at 16; Forman, *et al.*, WP-07-E-BPA-76, at 45-46. The IOUs had submitted letters notifying BPA of their intent to participate, and the RPSAs had been drafted and offered to these utilities. *Id*. Consequently, it is reasonable to assume that had BPA not offered the REP Settlement Agreements, these utilities would have signed 10-year RPSAs with BPA and received REP benefits during FY 2002-2008. Bliven, *et al.*, WP-07-E-BPA-52, at 14. Indeed, this assumption is logically sound because the IOUs, supported by the state utility commissions, would not willingly forgo REP benefits available for their residential and small farm consumers unless it was to their advantage to do so. *Id*. Thus, it is completely reasonable to assume that the IOUs would have entered into RPSAs had the REP Settlement Agreements not been available.

Second, Cowlitz's observation that no RPSAs were in fact signed is irrelevant. The obvious reason that the RPSAs were not signed and in effect for the FY 2002-2008 period is that the IOUs opted to accept the REP Settlement Agreements. In agreeing to the Settlements, the IOUs could *not* sign RPSAs. Bliven, *et al.*, WP-07-E-BPA-52, at 4-5. BPA required this because it did not want to incur the administrative burden of implementing the REP if the REP Settlement Agreements were executed. In addition, it would have made no sense to require the IOUs to sign *both* RPSAs *and* REP Settlement Agreements. The RPSA would have required the IOUs to conduct filings with BPA under the 1984 ASCM, report loads, and undertake numerous other burdensome duties and responsibilities. A primary benefit of the REP Settlement Agreements was to eliminate these filings because of their contentious nature and susceptibility to dispute. Bliven, *et al.*, WP-07-E-BPA-52, at 8. Thus, there is nothing significant about the fact that the IOUs did not sign RPSAs for the FY 2002-2008 period when they could not have done so under the terms of the REP Settlement Agreements.

Cowlitz's argument is also overreaching. All reasonable parties recognize that the IOUs would have participated in the REP during FY 2002-2008 in order to receive REP benefits to which their residential and small farm consumers are statutorily entitled. (The IOUs themselves, of course, do not receive a single dollar from the REP.) By proposing the illogical assumption that the IOUs would have given up statutory benefits in the absence of the REP Settlement Agreements, Cowlitz argues that BPA should give preference customers enormous windfall benefits. The law, the administrative record, and common sense do not support such an absurd result.

Cowlitz claims that no law or rule permits BPA to "pretend" that additional qualifying contracts exist, and that BPA is limited to "exercise only the powers granted by the statute reposing power in it," citing *FTC v. National Lead Co.*, 352 U.S. 419, 428 (1957). Cowlitz Br., WP-07-B-CO-01, at 63. BPA is not "pretending" that the RPSAs would have been signed. The record evidence is clear that but for the REP Settlement Agreements the IOUs would have executed RPSAs. Furthermore, the law supports BPA's decision to make this assumption. As BPA described above in the evaluation of Issue 1, BPA has authority to rely upon the "familiar principle of equity to regard as being done that which should have been done." *See Central Main Power Co. v. FPC*, 345 F.2d 875, 876 (1st Cir. 1965); *see also Plaquemines Oil & Gas Co. v. Federal Power Comm'n*, 450 F.2d 1334, 1337-1338 (D.C. Cir. 1971). Federal agencies, just as courts, may call upon these equitable powers to construct a remedy that is consistent with the law as well as fundamental principles of fairness and justice. *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 160 (D.C. Cir. 1967). Contrary to Cowlitz's claims, courts have allowed agencies such as BPA to assume that parties would have taken certain actions in the past that were in fact not taken in order to regard "as being done that which should have been done."

For example, in *Plaquemines Oil & Gas Co. v. Federal Power Comm'n*, 450 F.2d 1334, 1337-38 (D.C. Cir. 1971), the Federal Power Commission (FPC) (the precursor agency to FERC) was faced with a factual situation similar to the facts of this proceeding. In 1961, the FPC held for the first time that if natural gas intended for intrastate use is commingled with gas destined for sale in interstate commerce, the Commission has jurisdiction over the sale under the Natural Gas Act (NGA). *Id*. at 1335 *citing California v. LoVaca Gathering Co*., 379 U.S. 366 (1965). Although reversed by the Fifth Circuit, the FPC was ultimately sustained by the Supreme Court. *Id*. After the Supreme Court affirmed the FPC's decision, Plaquemines Oil & Gas, a transporter of natural gas that had previously not been making filings with the FPC pursuant to section 4(d) of the NGA, submitted a 1956 contract to comply with the Supreme Court's ruling. *Id*. at 1336. Plaquemines' contract contained an escalation clause that had increased the price of gas sold under the contract from 17 cents to 19 cents. *Id*. The state of New York then intervened and objected, arguing that the only rate Plaquemines Oil & Gas could charge was the 17-cent rate from the original contract. *Id*. All subsequent rate increases were, in New York's view, void *ab initio* and required to be refunded. *Id*. Instead of issuing refunds, however, the Commission forgave any violations of the statute for the years Plaquemines charged rates from 1956-1961. *Id*. From 1961-1964, the FPC found that Plaquemines was not required to provide any refunds, because the rates Plaquemines charged were reasonable and would likely have been accepted by the Commission if filed. *Id*. On review before the D.C. Circuit, the Court sustained this aspect of the FPC's authority, finding that it was appropriate to "regard as being done that which should have been done by recreating the past, insofar as is reasonably possible, to reflect compliance with the Act and to order refunds to be paid if necessary to achieve that goal." *Id*. at 1337.

In like manner, BPA is approaching the Lookback in general, and the RPSAs in particular, as the FPC did in *Plaquemines.* BPA is proposing to regard "as being done that which should have been done"; namely, that the IOUs would have executed RPSAs in the absence of the REP Settlement Agreements and made filings under those Agreements in compliance with the 1984 ASCM. As noted earlier, the record evidence establishes that the RPSAs would have been executed by the IOUs if the REP Settlement Agreements had not been entered. Assuming that the IOUs would have executed these agreements is no different than the FPC assuming in the *Plaquemines* case that Plaquemines Oil & Gas would have filed its subsequent contract revisions with the Commission.

Cowlitz also argues that BPA is limited to "exercise only the powers granted by the statute reposing power in it" and cites *FTC v. National Lead Co.*, 352 U.S. 419, 428 (1957) for support. Cowlitz is once again incorrect. Not every action an agency takes needs to be explicitly authorized by statute. *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 158 (D.C. Cir. 1967). Instead, the key question is whether the agency action taken reaches beyond "the scope of administrative discretion entrusted to [the agency]" under its enabling statutes. *Id*. This power is particularly at its "zenith" when the agency action assailed relates to the "fashioning of … remedies and sanctions … in order to arrive at maximum effectuation of Congressional objectives." *Id*. at 159. In the instant case, BPA is adjusting for the legal errors of executing the REP Settlement Agreements and improperly allocating the costs of those agreements in contravention of the section 7(b)(2) rate test. *Golden NW Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1047-48 (9th Cir. 2007); *Portland Gen. Elec. v. Bonneville Power Admin.*, 501 F.3d 1009, 1036-37 (9th Cir. 2007). This approach is further supported by the familiar legal principle that an agency may put the parties in the position they would have been in had the agency not committed a legal error. *See CPUC,* 988 F.2d 168; *see also AT&T Corp. v. F.C.C.*, 448 F.3d 426, 433 (D.C. Cir. 2006); *Exxon Co. v. FERC,* 182 F.3d 30 (D.C. Cir. 1999); *United Gas Improvements Co., v. Callery Properties, Inc.,* 382 U.S. 223, 229 (1965). Had BPA not made the first legal error of offering and executing the REP Settlement Agreements, it naturally follows that the IOUs would have executed the only other alternative – the RPSAs. BPA's decision to assume the IOUs would have signed the RPSAs "but for" the REP Settlement

Agreements is therefore legally sound, consistent with the record evidence, and entirely reasonable.

<u>Decision</u>

BPA properly assumed that certain IOUs would have signed RPSAs in the absence of the REP Settlement Agreements.

7.3 ASC Reforecasts

<u>Issue 1</u>

Whether BPA has properly calculated the ASC reforecasts for FY 2002-2006 (WP-02 rate period).

<u>Parties' Positions</u>

Cowlitz argues that BPA's revised ASC forecasts for the WP-02 rate period are unreasonably high. Cowlitz Br., WP-07-B-CO-1, at 65. Cowlitz argues that BPA could have used other "jurisdictional" filings that would have produced more accurate results. *Id*. It also claims BPA has violated the 1984 ASCM by not using jurisdictional filings. *Id*.

The WUTC supports BPA's proposal. WUTC Br., WP-07-B-WU-1, at 18. The WUTC urges BPA to reject arguments that the 1984 ASCM prescribes any particular method or means for forecasting ASCs in the rate case. *Id*.

<u>BPA Staff's Position</u>

The revised ASC forecasts were properly calculated. The 1984 ASCM does not prescribe any particular methodology for estimating ASCs in a BPA rate case. Boling, *et al.*, WP-07-E-BPA-57, at 7. BPA used its historical approach to calculating ASCs by using the last filed ASC and escalating the results with a forecasting model over the rate period. *Id*. at 4-5. BPA has made appropriate adjustments to the ASC forecasting model to reflect changes in the energy market that would have been known and available in the winter of 2000 and spring of 2001. *Id*.

<u>Evaluation of Positions</u>

As noted earlier, BPA reconstructed the PF Exchange rate for FY 2002-2006 as if the rates were being developed in the winter of 2000-2001. Burns, *et al.,* WP-07-E-BPA-53, at 9. When developing these rates, BPA limited itself to the data used in the actual WP-02 rate proceedings, with the exception of data changes that were a logical consequence of the no-REP Settlement Agreements assumption or that reflected information that was known at the time and would have made a material difference in the conduct of the rate setting process and the level of the rates. *Id*.

These assumptions were made to achieve, as well as possible, rates without the effects of the REP Settlement Agreements. *Id*. In light of this direction, BPA revisited the ASC forecasts that were developed in the original WP-02 rate proceeding. The ASC forecasts are a key assumption in the development of the PF Exchange rate. BPA uses these forecasts in its ratemaking to establish the PF Exchange rate, which is essential for determining what the IOUs would have received in the absence of the REP Settlement Agreements. Boling, *et al.*, WP-07-E-BPA-57, at 4.

The ASC forecasts used in the original WP-02 rate record were developed from the previous ASC filings of the exchanging utilities. Most exchanging utilities had executed Residential Exchange Termination Agreements prior to the commencement of the WP-02 rate proceeding. Boling, *et al.*, WP-07-E-BPA-57, at 5. These termination agreements, which were executed in the mid-to-late 1990s, removed the utility's obligation to file ASCs with BPA. *Id*. BPA thus did not have any recently filed ASCs from which to estimate ASCs for the rate period. Therefore, to estimate ASCs for the WP-02 rate case, BPA used the last officially filed ASCs from these utilities and escalated the data therein over the rate period using an ASC forecast model. *Id*. In most instances, the data used in the ASC model came from utility filings that occurred in the mid-to-late 1990s. *Id*.

The ASC forecast model used in the WP-02 rate case used data that were available around September of 1999. *Id*. at 6. When setting up the model, BPA assumed that the IOUs' load growth would be served with purchased power. *Id*. at 6. In making this assumption, BPA estimated that this power could be purchased from the market at 28.1 mills/kWh, which was BPA's then most current forecast of five-year flat block purchases, plus a transmission charge of 2.63 mills/kWh. The resulting forecast ASCs were adjusted to reflect this market price. *Id*. By the time of the WP-02 Supplemental Final Proposal, however, market conditions had changed dramatically. BPA's AURORA model price forecast for the period in and around June 2001 showed purchase power costs at 148 mills/kWh in 2002, roughly five times higher than what had been assumed in the earlier ASC forecasts. *Id*.

As a consequence of these dramatic market changes, BPA Staff testified that the ASC forecasts would have been one of the areas re-evaluated had BPA revisited the rate case record in the winter of 2000 and spring of 2001. *Id*. The 28.1 mills/kWh price used in the original ASC forecast model no longer reflected, by any measure, an accurate estimate of purchase power costs. *Id*. Staff testified it is very likely that BPA would have updated the purchase power expenses in the ASC forecasts to reflect this market volatility, because ASCs are a critical component of REP benefit determinations. *Id*.

The WUTC supports BPA's proposal to revise the WP-02 ASC forecasts. WUTC Br., WP-07-B-WU-1, at 18. The WUTC urges BPA to reject assertions that the revised forecast ASCs violate the 1984 ASCM because, in fact, the 1984 ASCM does *not* require BPA to rely solely on filings based on jurisdictional retail rate orders for forecasting ASCs. *Id*. The WUTC notes that the 1984 ASCM addresses the method for calculating an ASC BPA would pay under an RPSA. *Id*. However, during the period 2000 to the present, no RPSAs have existed with

IOUs. *Id*. Moreover, the 1984 ASCM does not prescribe any particular method for BPA to *forecast* ASCs in rate cases, even assuming RPSAs with IOUs existed at the time. *Id*.

Cowlitz opposes BPA's proposal to revise the ASC forecasts from the WP-02 rate proceeding. Cowlitz Br., WP-07-B-CO-1, at 65. Cowlitz argues that BPA's revised forecasts of ASCs are unreasonable, because BPA proposed to make substantial upward adjustments in the forecasts, as summarized in Tables 5.1.3 of the Lookback Study Documentation, WP-07-E-BPA-44A. *Id*. Cowlitz asserts that it demonstrated in its testimony that BPA had upwardly adjusted these IOU ASC "forecasts" for the Lookback period to unreasonably high levels. *Id*., *citing* Schoenbeck and Beck, WP-07-E-JP17-01-CC1, at 32-35.

Cowlitz's criticisms of BPA's revised ASC forecasts are unfounded. First, as BPA Staff explained, the original ASC forecasts assumed that power could be purchased from the market during the rate period at a price of 28.1 mills/kWh. Boling, *et al.*, WP-07-E-BPA-57, at 5-6. This was based on a forecast market power price developed in September of 1999. *Id*. The market price information available by the winter of 2000 and spring of 2001, however, indicated that a more accurate forecast was almost five times greater. *Id*. Had BPA reopened the WP-02 rate record in its entirety in the winter and spring of 2000/2001, BPA's low market assumption in the ASC forecast model would have undoubtedly been challenged by the parties, because ASCs are an integral part of REP benefit levels. Forman, *et al*., WP-07-E-BPA-76, at 9. BPA would have had to make the adjustment, because BPA's own analysis indicated that its earlier market price assumption was no longer valid. In terms of "reasonableness," then, it is far more reasonable to reflect this fundamental market change in this reopened proceeding rather than adhere to a figure inconsistent with BPA's own market price forecasts at the time.

Second, Cowlitz overstates the impacts that this change had on the revised ASC forecasts for exchanging utilities during the WP-02 rate period. In its testimony, Cowlitz and Clark point to a single instance where BPA's revised ASC forecasts result in an ASC of $82.61 MWh for PacifiCorp's Idaho jurisdiction for FY 2002. Schoenbeck and Beck, WP-07-E-JP17-01, at 32. This ASC forecast would not have been unreasonably high at the time, however, considering the circumstances. As BPA Staff explained in testimony, at the time BPA would have revisited the ASCs (*i.e.,* winter/spring 2001), BPA would likely have determined that a high ASC forecast for FY 2002 was a reasonable deviation from the normal ASC projections because of the astoundingly high market price forecast of $148 per megawatt-hour. Boling, *et al*., WP-07-E-BPA-83, at 3. BPA Staff testified that, at the time, they had no basis to assume that this high market price would abate in the coming fiscal year. *Id*. Therefore, there would not have been an obvious need to adjust the ASC forecast model's algorithm or, in the alternative, rely on any other data to establish a lower ASC as Cowlitz and Clark recommend. *Id*. at 3-4.

Even if this single-year deviation were considered unreasonably high, which is not correct, the overall effect of this one year was small. *Id*. at 4. This single ASC counted for *only one year* of a five-year rate period. *Id*. The remaining four years of ASC data remained at reasonable levels. *Id*. In addition, this one ASC affected only PacifiCorp's Idaho division exchange load for 2002, which equates to *less than three percent* of total IOU exchange load. *Id*. *See also* WPRDS

Documentation, WP-02-FS-BPA-05A, at 146-147. Based on these factors, the revised ASC forecasts are reasonable estimates of ASCs for the WP-02 rate period.

Cowlitz also claims the revised ASC forecasts are unreasonable because they result from BPA's refusal to analyze the available forecast "jurisdictional" data upon which ASCs must be based, rather than *post hoc* data from FERC Form 1s, which, according to Cowlitz, are irrelevant under the 1984 ASCM. Cowlitz Br., WP-07-B-CO-1, at 65, *citing* Shoenbeck and Beck, WP-07-E-JP17-01-CC1, at 36. Cowlitz misunderstands the requirements of the 1984 ASCM and BPA's proposal. The 1984 ASCM *does not* prescribe any particular method or formula regarding how BPA is to *forecast* ASCs for purposes of setting rates. Boling, *et al*., WP-07-E-BPA-83, at 32-33. The 1984 ASCM is silent on this issue. *Id*. ASC forecasts therefore can be calculated like any other forecasts in the rate case, which use available information and reasonable assumptions. *Id*. To be clear, the 1984 ASCM plays a critical role in forecasting ASCs and is the basis of BPA's ASC forecasts, but that does not mean BPA has to conduct an exhaustive review of a utility's state regulatory filings to calculate an ASC forecast. *Id*. Indeed, historically, BPA would use the last ASC filed by the utilities as the base year and then forecast the ASCs over the rate period. *Id*. This practice is in no way contrary to the 1984 ASCM, because BPA is not actually setting ASCs, but only estimating the ASCs to provide inputs that will be used to establish rates. *Id*. What the "actual" ASCs end up being is a function of the within-rate period ASC determinations. *Id*.

BPA used its historical method of forecasting ASCs for the WP-02 rate period. *Id*. For the WP-02 ASC forecasts, BPA used the last-filed ASCs from the IOUs for BPA's "base year data" of ASC estimates. *Id*. These ASCs were then escalated through the rate period and 7(b)(2) period using a forecast model. *Id*. BPA therefore has not violated the 1984 ASCM in any way by using the last filed ASCs, which were based on the 1984 ASCM, as the basis for the ASC forecast in the WP-02 rate period.

Cowlitz claims that BPA should have used an assortment of "jurisdictional" filings from the utilities to forecast ASCs for the WP-02 period rather than rely on FERC Form 1s. Cowlitz Br., WP-07-B-CO-1, at 65, *citing* Shoenbeck and Beck, WP-07-E-JP17-1-CC1, at 36. Cowlitz's description of BPA's position is wrong. First, BPA is *not* proposing to revise its WP-02 ASC forecasts with FERC Form 1 data. To the contrary, BPA is using the last filed ASCs, which are based on jurisdictional Appendix 1 filings made by the utilities under the 1984 ASCM. Boling, *et al.,* WP-07-E-BPA-57, at 4-6; Boling, *et al.,* WP-07-E-BPA-83, at 33. Thus, Cowlitz is factually incorrect in stating that BPA has used FERC Form 1 data to revise the WP-02 ASC forecasts in any manner.

Furthermore, Cowlitz claims that it would have been more reasonable for BPA to use a hodgepodge of "jurisdictional" rate filings for calculating ASC forecasts. Cowlitz Br., WP-07-B-CO-1, at 65. Cowlitz is incorrect. First, BPA has never used bare jurisdictional filings as a basis for an ASC forecast. Rather, ASC forecasts were developed using the most recent ASCs filed by the exchanging utilities, which are then escalated over the rate period. Boling, *et al.,* WP-07-E-BPA-57, at 4-6; Boling, *et al.,* WP-07-E-BPA-83, at 33. There is nothing in the record to suggest it would have been reasonable or necessary for BPA to abandon this historical approach to forecasting ASCs and adopt a completely new method for forecasting ASCs in the WP-02 proceeding. Boling, *et al.,* WP-07-E-BPA-83, at 3-7. In addition, from a temporal perspective, collecting, evaluating, and incorporating the information contained in these filings could not have been completed in the winter 2000/spring 2001 period. Boling, *et al*., WP-07-E-BPA-83, at 6.

Decision

BPA has properly calculated the reforecast ASCs for FY 2002-2006.

Issue 2

Whether BPA has properly calculated revised ASC forecasts for FY 2007-2008.

Parties' Positions

WPAG asserts that BPA has improperly calculated the ASC forecasts for FY 2007-2008 by relying upon FERC Form 1 data. WPAG Br., WP-07-B-WA-1, at 24. WPAG also claims that BPA has used its proposed 2008 ASCM to revise its ASC forecasts for this period. *Id*. WPAG argues that BPA must use the 1984 ASCM and rely solely on jurisdictional rate filings to forecast ASCs for the 2007-2008 period. *Id*.

The WUTC supports BPA's proposal. WUTC Br., WP-07-B-WU-1, at 18. The WUTC urges BPA to reject arguments that the 1984 ASCM prescribes any particular method or means for forecasting ASCs in the rate case. *Id*. The WUTC also supports BPA's proposal because it is the least burdensome and has not been proven to be inaccurate by any party. *Id*.

BPA Staff's Position

The ASC forecasts for FY 2007-2008 are properly calculated. Boling, *et al.,* WP-07-E-BPA-83, at 13-14. BPA used the 1984 ASCM to calculate the base year ASCs to forecast ASCs for the rate period. The 1984 ASCM does not prescribe any particular methodology for estimating ASCs in the rate case. *Id*. at 32. Use of historic ASC filings would have been inappropriate, because these filings were roughly a decade old. *Id*. at 33-34. Instead, BPA used the next best source of data, which is the FERC Form 1. *Id*. The FERC Form 1 is an industry standard document that produces ASC results similar to the results of state retail proceedings and provides a uniform data source for all utilities for all years. Boling, *et al.,* WP-07-E-BPA-61, at 4. Using the FERC Form 1 also leads to results similar to benchmarks proffered by parties in this proceeding. Boling, *et al*., WP-07-E-BPA-83, at 15-25. Moreover, the administrative time and expense of compiling ASCs in any other way would have been prohibitive and unlikely to lead to significantly different results. *Id*. at 45-48.

Evaluation of Positions

In the original WP-07 rate proceeding, BPA used a two-step process to forecast ASCs for the WP-07 Final Proposal. Boling, *et al.,* WP-07-E-BPA-57, at 9; Boling, *et al.,* WP-07-E-BPA-16, at 8. First, a base-year ASC was calculated using 2004 information from the IOUs' 2004 FERC Form 1s, which were the most recent data available at the time of the WP-07 Initial Proposal. *Id*. Second, BPA escalated the base year ASC data using BPA's ASC Forecast Model to forecast ASCs for the FY 2007-2013 periods (study period). *Id*. When the WP-07 record was reopened in this proceeding, BPA evaluated what aspects, if any, of the ASC and load forecasts used in the WP-07 Final Proposal would have been updated or adjusted to reflect the implementation of the REP. *Id*. at 9. After evaluating the ASCs, BPA proposed a number of changes to the ASCs to reflect more recent data and to correct errors. *Id*. at 10-17. These revisions were necessary to ensure an accurate estimate of the REP benefits the IOUs would have received under the REP. *Id*. at 9.

The WUTC supports BPA's proposal to revise the WP-07 ASC forecasts. WUTC Br., WP-07-B-WU-1, at 18. The WUTC urges BPA to reject assertions that the revised ASC forecasts violate the 1984 ASCM because, in fact, the 1984 ASCM does *not* require BPA to rely solely on filings based on jurisdictional retail rate orders for forecasting ASCs. *Id*. The WUTC notes that the 1984 ASCM addresses the method for calculating an ASC BPA would use to calculate REP benefits under a Residential Purchase and Sale Agreement. *Id*. However, during the period 2000 to the present, no RPSAs have existed with IOUs. *Id*. Moreover, the 1984 ASCM does not prescribe any particular method for BPA to *forecast* ASCs, even assuming RPSAs with IOUs did exist. *Id*.

WPAG contends that the 1984 ASCM requires that the ASC of each utility be based on information obtained from the most recent retail rate filing approved by the appropriate regulatory body. WPAG Br., WP-07-B-WA-1, at 24. WPAG then claims that in performing the ASC forecasts used in the recalculation of the section 7(b)(2) rate test for the WP-07 rate case, BPA did not use or rely upon the information from the most recently approved retail rate filing of each IOU. *Id*. Rather, BPA based its forecasts on information it obtained from the FERC Form 1 of each IOU. *Id*. By doing so, WPAG asserts, BPA has disregarded the applicable requirements of the 1984 ASCM and has instead applied a proposed regulation that has not yet been adopted to determine the forecast ASCs for the historical FY 2007-2008 period. WPAG Br., WP-07-B-WA-1, at 24.

WPAG also rejects the idea that the "administrative burden" on BPA should be a consideration in this case. WPAG Br., WP-07-B-WA-1, at 24-25. WPAG claims that the fact that compliance with an agency's own applicable regulation may be laborious does not excuse an agency from complying with such regulations and that it is not a legally sufficient excuse for BPA's failure to do so in this case. *Id*.

WPAG is incorrect on all fronts. First, WPAG misconstrues the requirements of the 1984 ASCM. As noted in the discussion of the preceding issue, the 1984 ASCM is silent on the means by which BPA must *forecast* ASCs for purposes of its power rate cases. Boling, *et al.,* WP-07-E-BPA-83, at 32-33. BPA may, therefore, create forecasts of ASCs like any other forecasts in the rate case, which use available information and reasonable assumptions. *Id*. To be clear, BPA must still use the substantive requirements of the 1984 ASCM, but that does not mean BPA has to perform an exhaustive review of a utility's state regulatory filings to calculate an ASC forecast if accurate data is available from other sources. *Id*. BPA could have relied upon the last filed ASCs that the exchanging utilities had filed with BPA in the mid-1990s. *Id*. However, this reliance would have been unreasonable, because by the time BPA commenced its WP-07 case in 2005, these filings were almost 10 years old. *Id*. at 33. BPA had little basis to believe that the information supplied in the 1995-96 period was still pertinent for forecasting ASCs for the 2007-2008 period. *Id*.

The better alternative was to use the utilities' most recent FERC Form 1 data, which at the time were for 2004, and then use the 1984 ASCM to estimate an ASC for each IOU. *Id*. The FERC Form 1 is a standard financial reporting document that is used throughout the utility industry. *Id*. at 30. Many features of the FERC Form 1 make it an appropriate substitute for jurisdictional filings. A typical filing shows energy balance information that shows the utility has energy sources to meet all its energy needs. *Id*. A filing is required by FERC on an annual basis and is reviewed by the Commission. *Id*. Also, at least one regulatory commission in the region, the Idaho Public Utilities Commission, accepts the FERC Form 1 for the annual Results of Operations filings. *Id*. In view of these factors, BPA determined that the FERC Form 1 was a reasonable data substitute for the jurisdictional information necessary to calculate ASC forecasts. When BPA presented this approach as part of its original WP-07 rate filing, no party objected, including WPAG. *Id*. *See* responses to BPA Data Request No. BPA-JP17-7 and BPA-WA-24. For purposes of the FY 2007-2008 ASC forecast, BPA's reliance on this recognized industry standard document in no way contravenes the letter or intent of the 1984 ASCM.

Second, WPAG argues that BPA should have relied upon the information from the most "recently approved retail rate filing" of each IOU to forecast ASCs for FY 2007-2008. WPAG Br., WP-07-B-WA-1, at 24. What "recently approved" retail orders WPAG refers to is unclear. Indeed, no party during the hearing phase of this proceeding, including WPAG, proffered any state retail rate filings that could have been relied upon by BPA to forecast ASCs for its FY 2007 and 2008 rates. BPA rejected this approach to forecasting ASCs because identifying a single or even a group of retail rate filings from which ASC data could be used was extremely burdensome. BPA witnesses identified no fewer than 77 jurisdictional rate orders that were issued during the FY 2002-2006 period. Boling, *et al.,* WP-07-E-BPA-83, at 47. Of these, approximately 68 were issued prior to the initiation of the BPA WP-07 rate proceeding. *Id*. at Attachment 13. Because each of these jurisdictional rate filings was filed for different purposes, each contains varying degrees of financial information. In many instances, BPA would not even be able to decipher the order because BPA had not intervened in the underlying rate proceeding. *Id*. at 44-45. Interpreting these rate orders becomes even more difficult because the PUCs' decisions do not always describe in detail the basis for the final rates. In many cases, the final order will only briefly address certain cost issues. As such, BPA would have had to review not only the PUCs' rate orders, but also the original rate filings by the IOUs, to obtain the necessary data to accurately forecast ASCs for the WP-07 rate period. Such a task would have been a huge administrative burden, and unprecedented, for purposes of calculating a *forecast* for rate setting purposes. *Id*. at 12.

WPAG rejects the notion that "administrative burden" should play a role in determining whether BPA's actions in this proceeding are reasonable or not. WPAG Br., WP-07-B-WA-1, at 24-25. WPAG claims that the fact that compliance with BPA's own applicable regulation may be laborious does not excuse BPA from complying with such regulations and that it is not a legally sufficient excuse for BPA's failure to do so in this case. WPAG Br., WP-07-B-WA-1, at 24-25. WPAG fails to acknowledge that BPA used the substantive requirements of the 1984 ASCM for its ASC forecasts. WPAG's argument also fails to recognize that the 1984 ASCM does not prescribe *any method* for calculating a forecast ASC. In the absence of instructions in the ASCM, factors such as administrative burden and reasonableness are clear considerations. Furthermore, BPA finds particularly persuasive the comments of the WUTC. They urge BPA to reject WPAG's arguments, noting that a recalculation of the 2002-2008 ASCs on the basis of jurisdictional rate changes would be administratively burdensome and not cost-effective, because it would require BPA to process no fewer than 77 separate ASC reviews. WUTC Br., WP-07-B-WU-1, at 19.

Furthermore, WPAG has failed to explain in what ways BPA's ASC forecasts are inaccurate. In its direct case, WPAG's' witnesses made the statement that BPA's reliance on the FERC Form 1 likely made the ASC forecast a paltry 2.3 percent higher than under WPAG's benchmark. Grinberg, *et al.*, WP-07-E-WA-05, at 37-38. Later, WPAG amended this portion of its testimony to state that the difference *was only a mere 1.6 percent.* Boling, *et al.,* WP-07-E-BPA-83, at 13. WPAG attempts to evade this point in its brief by now complaining that BPA is putting the parties in the "impossible position" of trying to prove a negative. WPAG Br., WP-07-B-WA-1, at 25. WPAG claims that it cannot prove that using the FERC Form 1 is inappropriate because such a proposition is essentially impossible to prove in the absence of ASC filings based on retail rate information as required by the 1984 ASCM. *Id*. Putting aside the apparent inconsistency with WPAG's direct case, these statements lend even more support to BPA's position. WPAG clearly admits that it is "impossible," absent ASC filings from the IOUs, to calculate ASC forecasts based on the retail rate orders that are available. Yet, according to WPAG, this is exactly what BPA must do in order to comply with the 1984 ASCM. Because BPA cannot simply leave the ASC forecast blank in the rate case, another reasonable alternative source of data must be used, which is what BPA has done by turning to the FERC Form 1 for the FY 2007-2008 period.

BPA also considers the 1.6 percent differential that WPAG identified in its direct case as extraordinarily reasonable. Boling, *et al.,* WP-07-E-BPA-83, at 14. To prove its reasonableness, BPA tested WPAG's assertion that there would be an upward bias in using the FERC Form 1 as the source of data for calculating the IOUs ASCs. *See* Boling, *et al.,* WP-07-E-BPA-83, at 16-17. The test compared actual results of historical ASC filings with the corresponding data from the FERC Form 1s of two separate utilities. In both cases, the ASCs calculated with the FERC Form 1 were *lower* than the historical ASCs. *Id*.

WPAG claims throughout its brief that BPA has used its "proposed regulation" when calculating the forecast ASCs. WPAG Br., WP-07-B-WA-1, at 24-25. In essence, WPAG claims BPA has used its 2008 ASCM, which was filed with FERC, to recalculate the forecast ASCs. WPAG's assertion is egregiously misleading and baseless. BPA maintained throughout this case that it would use the substantive provisions of the 1984 ASCM in recalculating the forecast ASCs. *See* Bliven, *et al.,* WP-07-E-BPA-52, at 16; Boling, *et al.,* WP-07-E-BPA-57, at 9-17; and Boling, *et al.,* WP-07-E-BPA-83, at 35. In taking this position, BPA has had to rebut vigorous arguments from the IOUs and the public utility commissions that objected to BPA's use of the 1984 ASCM, requesting instead that BPA adopt its 2008 ASCM or some other methodology for the Lookback ASCs. *See* Forman, *et al.,* WP-07-E-BPA-76, at 38-42; *see also infra,* Section 7.5. As BPA has stated repeatedly throughout this case, BPA proposes to use *only the 1984 ASCM* in the Lookback portion of this proceeding. *See* Bliven, *et al.*, WP-07-E-BPA-52, at 16 ("BPA is directing staff to review the ASC for each utility in a manner that aligns as closely as practicable with the requirements of the 1984 ASC Methodology."); Boling, *et al.,* WP-07-E-BPA-83, at 32. WPAG's brief fails to explain how BPA has violated this directive. BPA explained at length in its testimony how it complied with the 1984 ASCM provisions. *Id.; see also* Boling, *et al.,* WP-07-E-BPA-83, at 25-27. A cursory review of the 2008 ASCM and 1984 ASCM also demonstrates that BPA has complied with this instruction. *Id*. at 26. Two of the main features of the proposed 2008 ASCM are that it includes in the ASC calculation the costs of a utility's return on equity and Federal income taxes. *Id*. These costs, however, are excluded from every ASC calculated in the Lookback. *Id*. WPAG appears to argue that BPA's use of the FERC Form 1 in the FY 2007-2008 ASC forecasts is evidence that BPA is using the 2008 ASCM. Yet, as already explained, BPA used the FERC Form 1 in the forecasting of ASCs for the FY 2007-2008 period out of necessity, for lack of better information, not because it has any relationship to BPA's proposed new ASCM. *Id*. at 26-27.

Finally, BPA had proposed to use the FERC Form 1 to forecast ASCs in its original WP-07 proposal in the fall of 2005, almost two years before BPA even began considering developing a new ASC methodology. Boling, *et al.,* WP-07-E-BPA-16, at 9. When BPA proposed its forecast ASCs in its original WP-07 rate proceeding, no party objected to BPA's use of the FERC Form 1 as a data source, including WPAG. Boling, *et al.,* WP-07-E-BPA-83, at 34. Consequently, WPAG's assertion that BPA is now somehow surreptitiously using its new 2008 ASCM in its ASC forecasts because the ASCs rely on FERC Form 1 data is unequivocally incorrect.

Decision

BPA has properly calculated the ASC forecasts for FY 2007-2008.

7.4 Backcast ASCs

Issue 1

Whether BPA has properly calculated the backcast ASCs in compliance with the 1984 ASCM.

Parties' Positions

Cowlitz argues that BPA's backcast ASCs are improper because they have not been developed in strict compliance with the 1984 ASCM. Cowlitz Br., WP-07-B-CO-1, at 63. Cowlitz claims that BPA must comply with all of the procedural aspects of the 1984 ASCM to properly calculate ASCs and that failing to do so denies parties their procedural rights. *Id*. Cowlitz further argues that the backcast ASCs are inappropriate because they increase the cost of the REP, which is then recovered in the COUs' rates. *Id*. at 64. Cowlitz claims that regardless of how BPA develops the backcast ASCs, the resulting costs must be subject to the section 7(b)(2) rate test. *Id*.

WPAG also disagrees with BPA's proposal to calculate backcast ASCs. WPAG Br., WP-07-B-WA-1, at 24. WPAG argues that the 1984 ASCM requires that ASCs be based on financial data from the IOUs' last approved retail rate order and not FERC Form 1 data, which is what BPA is proposing to use. *Id*. WPAG asserts that administrative burden and time constraints are not proper considerations when determining ASCs. *Id*. at 24-25. WPAG also objects to BPA's reliance on benchmarks as support for the use of FERC Form 1 data. *Id*.

The WUTC generally supports BPA's proposal to calculate backcast ASCs. WUTC Br., WP-07-B-WU-1, at 18. WUTC notes that there is no evident bias with using the FERC Form 1 for the ASCs, and nothing in the 1984 ASCM precludes BPA from calculating ASCs as BPA has done in the Lookback. *Id*.

APAC claims that BPA's backcast ASCs are flawed because they rely on BPA's proposed new 2008 ASC methodology. APAC Br. Ex., WP-07-R-AP-01, at 28. APAC also claims that use of this new methodology denies it the right to intervene and "protest at the state or jurisdictional level to protest ASCs." *Id.*

BPA Staff's Position

BPA's backcast ASCs were properly calculated. BPA followed the 1984 ASCM's functionalization rules and Appendix 1 to calculate the ASCs for each IOU over the FY 2002-2008 period. Boling, *et al.,* WP-07-E-BPA-83, at 35. BPA evaluated several sources of data to determine the most accurate and efficient way to estimate the backcast ASCs. Boling, *et al.,* WP-07-E-BPA-61, at 4-5. BPA's use of the FERC Form 1 was reasonable because it provided a ready source of financial information for all of the IOUs, was not subject to the vagaries of retail rate orders, and produced results that were in line with benchmarks and "test cases" presented on the record by BPA and the parties. Boling, *et al.,* WP-07-E-BPA-83, at 36-37. Using jurisdictional rate filings and the procedural schedule in the 1984 ASCM to calculate the backcast ASCs would not have been reasonable because of the massive administrative burden BPA and rate case parties would have had to undergo in order to review no fewer than 77 retail rate orders from regional state public utility commissions. *Id*. at 45-49. BPA also would have had to obtain the underlying retail rate dockets to access the necessary level of information to calculate ASCs. *Id*. at 37-38. Reviewing backcast ASCs in this manner would have taken years and would not have produced results significantly different from those produced by BPA's proposal. *Id*. at 46-48.

Evaluation of Positions

The Lookback construct is designed to estimate as closely as possible the amount of REP benefits that should have been charged to the COUs' rates for FY 2002-2008. Bliven, *et al.,* WP-07-E-BPA-52, at 18-19. The resulting REP benefit amounts, subject to certain rules, are compared to what the IOUs actually received under the REP Settlement Agreements. Marks, *et al.,* WP-07-E-BPA-62, at 9. The difference between these two amounts is referred to as the Lookback Amount, which must be recovered from the IOUs and returned to the COUs. *Id*. In both the WP-02 rate proceeding and the WP-07 rate proceeding, BPA used forecast ASCs for purposes of setting rates. REP benefits, however, are not based on these forecast ASCs. Bliven, *et al.,* WP-07-E-BPA-52, at 18-19. Rather, REP benefits are based on the difference between each IOU's *filed* ASC and BPA's PF Exchange rate, multiplied by the utility's exchange load. *Id*. at 16. No IOUs filed ASCs with BPA from FY 2002-2008 because the IOUs had executed the REP Settlement Agreements. Had the IOUs *not* signed these Agreements, and instead participated in the REP through an RPSA, the IOUs would have been making ASC filings with BPA pursuant to the 1984 ASCM. *Id*. BPA must have ASCs in order to reasonably estimate the likely REP benefits that would have been paid during FY 2002-2008. *Id*. at 16-17. Consequently, BPA proposed to calculate annual ASCs for each IOU in a manner that approximates the ASC determinations that would likely have been made, consistent with the 1984 ASCM, had the IOUs submitted ASC filings during FY 2002-2008. Manary, *et al.,* WP-07-E-BPA-61, at 2-3.

These ASC filings developed by BPA are known as "backcast ASCs." Manary, *et al.,* WP-07-E-BPA-61, at 2-3. In general, the backcast ASCs are a best estimate of the ASC determinations that would have been made by the Administrator for each IOU had the REP been active during FY 2002-2008. *Id*. at 2. Because the IOUs did not submit Appendix 1 ASC filings during FY 2002-2008, BPA did not have a source of data from which to determine the backcast ASCs. Therefore, BPA had to create backcast ASCs from sources that were readily available. *Id*. BPA considered a number of sources for this data, including the IOUs' Securities and Exchange Commission (SEC) 10-K filings, the publicly available jurisdictional rate orders from state regulatory commissions, annual results of operations filings from state regulatory commissions, and annual Form 1 submittals to FERC. *Id*. at 4-5. When evaluating these data sources, BPA looked for a source that provided financial data contemporaneous with the time period to which the ASC would have applied and that would be uniformly available for each of the IOUs. *Id*. at 4. BPA rejected using SEC 10-K filings because those reports did not contain sufficient detail to prepare ASCs. *Id*. at 5. BPA also considered the available retail rate orders from the state public utility commissions for each IOU. *Id*. This option was not pursued because of the volume of retail rate orders and the lack of detail included in the available orders. Many retail rate orders end with stipulated rate adjustments or settlements, which provide little to no underlying cost data from which an IOU's resource costs can be determined. *Id*. The IOUs' annual result of operations reports were also rejected because these filings were not required by all of the state utility commissions, and the data submitted within the filings were not standardized among the state commissions that did require them. *Id*. BPA ultimately decided that the FERC Form 1 was the best source of data to calculate ASCs in a uniform manner consistent with the 1984 ASCM. *Id*. at 4-5. The FERC Form 1 is filed annually by each of the IOUs with FERC, is an industry standard reporting document, uses the same accounts that are included in the 1984 ASCM, and reasonably represents the costs that would likely emerge in an IOU's traditional jurisdictional filing. *Id*.

The WUTC supports BPA's proposal to backcast ASCs. WUTC Br., WP-07-B-WU-1, at 18. The WUTC urges BPA to reject assertions by other parties that BPA's reliance on backcast ASCs violates the 1984 ASCM because, in fact, the 1984 ASCM does *not* require BPA to rely solely on filings based on jurisdictional retail rate orders for forecasting ASCs. *Id*. The WUTC notes that the 1984 ASCM addresses the method for calculating an ASC BPA would pay under an RPSA. *Id*. However, during the period 2000 to the present, no RPSAs existed for IOUs. *Id*. The WUTC concludes that the 1984 ASCM simply does not preclude BPA's proposed calculation of ASCs in the "Lookback" analysis. *Id*. at 19.

Cowlitz opposes BPA's proposal to backcast ASCs. Cowlitz argues that a fatal defect with BPA's "backcasting" approach is that the backcast ASCs have not been created in full compliance with the terms and conditions of the 1984 ASCM. Cowlitz Br., WP-07-B-CO-1, at 63. Cowlitz notes that the 1984 ASCM is an administrative rule of both BPA and FERC and is codified at 18 C.F.R. § 301.1. *Id*. Cowlitz asserts that the ASCM provides important procedural protections for BPA and the non-IOU customers that appear throughout the regulation in mandatory terms, including the requirement that participating IOUs "shall report" costs on the form attached as Appendix I to § 301.1 with supporting documentation. Cowlitz Br., WP-07-B-CO-1, at 63. Cowlitz points to the *PGE* decision as support for its contention that BPA must follow the letter of the 1984 ASCM to calculate backcast ASCs. *Id*. Cowlitz concludes that the backcast ASCs are "manifestly" not calculated pursuant to 18 C.F.R. § 301.1. *Id*.

WPAG raises similar arguments in its brief. WPAG Br., WP-07-B-WA-1, at 24. WPAG contends that to calculate ASCs, BPA must comply strictly with the 1984 ASCM, which requires that ASCs be based on information obtained from the most recent retail rate filing approved by the regulatory body of the exchanging utility. WPAG Br., WP-07-B-WA-1, at 24. WPAG argues that BPA did not rely on the latest retail filings, but instead FERC Form 1 data. *Id*. WPAG concludes that BPA has violated the 1984 ASCM by basing ASCs on FERC Form 1 data. *Id*.

BPA disagrees with WPAG's and Cowlitz's characterization that BPA has not complied with the 1984 ASCM when calculating the backcast ASCs. Before addressing the specific arguments raised by WPAG and Cowlitz, a brief overview of the purpose and actual operation of the 1984 ASCM is necessary. The primary objective, if not the only objective, of the 1984 ASCM is to establish an ASC that includes allowable exchangeable costs. Boling, *et al.*, WP-07-E-BPA-83, at 35. As noted earlier, the ASC is simply an equation that divides a utility's cost of resources (referred to as Contract System Costs) by the utility's total system load (Contract System Load). *See supra,* Section 7.1 Introduction. The ASCM provides the rules for determining which costs go into the numerator (Contract System Costs) and which loads go into the denominator (Contract System Loads). The quotient of this equation is the ASC. *See* 1984 ASCM at § I.A. Under the 1984 ASCM, the Contract System Costs portion of this equation includes the costs for "production and transmission resources, including power purchases and conservation measures, which Costs are includable in, jurisdictionally allocated by, and subject to the provisions of Appendix 1." 1984 ASCM at § I.C. The Appendix 1 is a form that contains four schedules that itemize virtually all of a utility's financial data into specified accounts of costs and credits. For each line item in the Appendix 1, the 1984 ASCM has specific rules on whether the costs or credits in the account may be included in the utility's Contract System Cost. Generally speaking, the 1984 ASCM requires that costs associated with a utility's production and transmission function be included in Contract System Costs (thereby including the item in the calculation of the ASC), while costs associated with the utility's distribution or other functions must be excluded from Contact System Costs (thereby excluding the item from the calculation of the ASC). The process of allocating costs to the production, transmission, and distribution/other functions is referred to as "functionalization" and is the central feature of the 1984 ASCM for determining a utility's ASC. BPA's role in implementing the ASCM is to make an independent determination of (1) the appropriateness of the inclusion of costs in the utility's revenue requirement; (2) the reasonableness of the costs included in the Contract System Costs; and (3) the appropriateness of Contract System Loads. *See* 1984 ASCM at § III.B.

As BPA Staff explained in direct and rebuttal testimony, BPA made these independent determinations by using the Appendix 1 and the 1984 ASCM functionalization rules to calculate backcast ASCs. *See* Manary, *et al.,* WP-07-E-BPA-61, at 2-3, and Boling, *et al.*, WP-07-E-BPA-83, at 35. BPA converted the 1984 Appendix 1 into an Excel-based spreadsheet (referred to as a "cookbook") and populated it with the exchanging utilities' data. Manary, *et al.,* WP-07-E-BPA-61, at 3. BPA then used the 1984 ASCM functionalization rules to allocate the costs and credits included in the Appendix 1 "cookbook" between exchangeable cost categories (*i.e.*, production and transmission) and non-exchangeable categories (*i.e.*, distribution/other). BPA followed these functionalization rules to calculate backcast ASCs for each IOU for each year of the FY 2002-2008 period. Boling, *et al.*, WP-07-E-BPA-83, at 35. BPA also made adjustments to the accounts to comply with updated descriptions of the accounts in the FERC Uniform System of Accounts. Manary, *et al.,* WP-07-E-BPA-61, at 22. During the hearing phase of this proceeding, no party presented evidence or arguments on the record objecting to BPA's implementation of the 1984 ASCM's functionalization rules to calculate ASCs. In other words, no party has claimed that BPA misapplied the substantive requirements of the 1984 ASCM in developing the backcast ASCs.

Cowlitz's specific objection to the backcast ASCs focuses on BPA's alleged failure to follow the procedural minutiae of the 1984 ASCM to establish ASCs. Cowlitz Br., WP-07-B-CO-1, at 63. These procedural rules are primarily concerned with the mechanics of the utility filing a proposed ASC with BPA and the commencement of a process to review the exchanging utility's data. The procedural guidelines generally require the exchanging utility to file a preliminary Appendix 1 with BPA within five days after filing for a retail rate change with a state public utility commission. *See* 1984 ASCM § II.B.2. These preliminary filings allow BPA Staff to review an IOU's ASC filing and determine if intervention before the relevant state commission is necessary to review information being used in the retail rate proceeding. Thereafter, BPA initiates a 210-day ASC review process in which outside parties may intervene and request data and other relevant information from the exchanging utility. *See* 1984 ASCM at § III.C.1-6. Cowlitz claims that by not following these procedural rules, such as this 210-day review process, BPA is violating the ASCM. Cowlitz Br., WP-07-B-CO-1, at 63.

Cowlitz's arguments are unpersuasive. The 1984 ASCM's procedural rules were designed to apply to the situation where an exchanging utility had executed an RPSA and then files an ASC with BPA for its review. In that instance, the 210-day process was appropriate because it ensured that the information filed by the exchanging utility had been properly vetted by BPA and any intervenors. Traditional ASC determinations have a prospective effect on the level of REP costs BPA actually pays. BPA's ASC determinations are actual rates of the IOUs and must be filed with FERC under the Federal Power Act. 18 C.F.R. § 35.30(c). The backcast ASCs, however, serve a purpose different from the traditional ASC determination. The backcast ASCs are BPA's best *estimates* of the ASCs that would have been made by the IOUs during the FY 2002-2008 period. Manary, *et al.,* WP-07-E-BPA-61, at 2, 6. They are being developed as part of a general construct that responds to the unique circumstances created by the Court's remands in *PGE* and *Golden NW*. Bliven, *et al.,* WP-07-E-BPA-52, at 16. Unlike traditional ASCs, the force and effect of the backcast ASCs is to a historical period in which REP costs have already been collected from the COUs. In this context, the backcast ASCs serve the important, but more limited, role of determining whether BPA overcharged the COUs for the costs of the REP. *Id*. at 18. The estimated nature of the backcast ASCs and their application to past periods make reviewing these ASCs under the prospective-looking procedural rules of the 1984 ASCM inappropriate.

This is not to say, however, that the parties to this proceeding have been denied an opportunity to challenge the backcast ASCs. Indeed, BPA's customers and intervenors have been given ample opportunity to review the backcast ASCs in the context of the WP-07 Supplemental Proceeding. Boling, *et al.,* WP-07-E-BPA-83, at 40. In the instant proceeding, parties are provided opportunities for oral clarification and discovery, electronic discovery, direct testimony, rebuttal testimony, legal memoranda to accompany their testimonies, cross-examination, initial briefs and briefs on exception, and oral argument to the Administrator. *Id*. The number of procedural tools available to parties to challenge an ASC is much greater in a section 7(i) proceeding, such as the instant proceeding, than in the typical ASC review process. *Id*. As noted by BPA Staff, "parties in ASC review proceedings generally conducted limited written discovery and filed issue lists containing their arguments on ASC issues." *Id*. Because BPA has chosen to estimate the backcast ASCs within the context of a section 7(i) hearing, the parties to this proceeding have been provided the full panoply of procedural rights available through such a hearing. *Id*.

Furthermore, Cowlitz's demand that BPA apply the strict procedural requirements of the 1984 ASCM must be denied when balanced against the massive administrative burden that would be placed on BPA and rate case parties. Under the 1984 ASCM, the exchanging utility is required to file with BPA an Appendix 1 for every retail rate change the utility requests from its state public utility commission(s). During the 2002-2008 period, BPA Staff identified no fewer than 77 retail rate change filings made by the IOUs in the four regional state jurisdictions where the

IOUs have service territories. Boling, *et al.,* WP-07-E-BPA-83, at 46, and Attachment 13. If BPA were to follow Cowlitz's suggestion that BPA strictly adhere to the procedural dictates of the 1984 ASCM, BPA would have been forced to commence at least 77 210-day ASC review processes. *Id*. As BPA Staff explained, such an undertaking would be a massive effort that would take years to complete. *Id*. Moreover, this burden would not be on BPA alone, but also on the IOUs and any COUs that intervened in the ASC review processes. *Id*. Compounding the difficulties of administering such a process would be the added complexity that many of the retail rate filings would be based on rate orders that are several years old. *Id*. at 47-48. Merely acquiring the underlying data would be a daunting task. *Id*. The huge administrative cost and strain that would be placed on BPA and the region would far outweigh any benefit these after-the-fact hearings would provide in the present proceeding.

Cowlitz relies on statements made in the *PGE* decision to support its argument that BPA must apply the procedural rules of the 1984 ASCM to the backcast ASCs. Cowlitz Br., WP-07-B-CO-1, at 63. The specific statements relied upon by Cowlitz are observations by the Court that the 1984 ASCM remains in place until modified for purposes of establishing utilities' ASCs and determining actual REP benefits during the implementation of the REP. *PGE*, 501 F.3d at 1035. In making these statements, the Court in no way opined on whether BPA must comply with the procedural minutiae of the 1984 ASCM to calculate backcast ASCs for ratemaking purposes. More specifically, in the *PGE* case, the Court took issue with BPA's decision to calculate REP benefits in a manner unrelated to the IOUs' ASCs. *Id*. at 1033. BPA is now in the process of correcting that legal error by calculating those ASCs. As BPA has explained above, the procedural steps of the 1984 ASCM are ill-suited for this purpose and would lead to years of administratively burdensome proceedings. BPA has properly remedied the problems noted by the Court in *PGE*, in part, through the calculation of backcast ASCs under the 1984 ASCM. Consequently, BPA's proposal to calculate backcast ASCs as it has done in this proceeding is not in derogation of any direction in the *PGE* decision.

Finally, when fashioning a remedy for a statutory violation, it is proper for an agency to consider the practical consequences of applying a strict application of the law and whether that outcome furthers any purpose of the underlying statute. *See Sunray Mid-Continental Oil Co. v. F.P.C.*, 364 U.S. 137, 147 (1960); *see also Borough of Ellwood City v. FERC*, 583 F.2d 642, 649 (3d Cir. 1978). In the instant case, BPA applied all of the substantive requirements of the 1984 ASCM in developing its ASC estimates. This is not disputed. BPA also considered the practical consequences of applying a strict application of the 1984 ASCM's 210-day procedural review period for estimating each utility's numerous ASCs during the FY 2002-2008 period and whether such an application would further the purposes of Northwest Power Act. First, applying a strict procedural application of the 1984 ASCM means BPA would have had to conduct years of administratively burdensome ASC review processes to produce ASC estimates that could be developed just as accurately and with less administrative burden. If BPA were required to follow the 1984 ASCM's procedural timeline, BPA could not have promptly responded to the Court's opinions in *PGE* and *Golden NW,* thereby further delaying the return of the overpayments to BPA's preference customers and the implementation of the REP for the region's residential and small farm consumers. The purpose of the Northwest Power Act would not be furthered by such unreasonable delay. The underlying concern of section 5(c) of the Northwest Power Act and the

1984 ASCM is to establish an ASC based on the exchanging utility's allowable average cost of resources. This objective has been met, because the ASCs being established in this proceeding were determined using the substantive functionalization rules and requirements described in the 1984 ASCM. Furthermore, BPA correctly determined not to follow the procedural timeline of the 1984 ASCM to estimate those ASCs, because that timeline was intended for the separate administrative proceedings that *establish* ASCs in implementing the REP and not for *estimating* ASCs in BPA's ratemaking hearings.

Cowlitz claims generically in its brief that a defect of the backcast approach is that BPA's models use the backcasts of higher ASCs to raise REP costs, thereby increasing BPA's costs (*see* Brodie, *et al.,* WP-07-E-BPA-58, at 18 (costs up in four of the five years)), and increasing CRAC effects on all rates, including the PF Preference rate. Cowlitz Br., WP-07-B-CO-01, at 64. Cowlitz argues that by making rising ASCs increase the rates applicable to preference customers by allocating increased exchange costs, BPA is evading sections 7(b)(2) and 7(b)(3) of the Northwest Power Act, and BPA must apply sections 7(b)(2) and 7(b)(3) to the CRAC rates whenever exchange costs contribute to the CRAC. Cowlitz Br., WP-07-B-CO-01, at 64. In response, however, although higher backcast ASCs increase REP costs, Cowlitz fails to explain why this result is unjustified. As described above, BPA *forecasts* ASCs in the rate proceeding to estimate REP costs. These forecasts of ASCs in no way cap or limit the amount of REP costs that BPA may ultimately pay during the rate period, because exchanging utilities may file actual ASCs with BPA at any time. Thus, the fact that BPA's backcast ASCs "increase" REP costs is simply a normal consequence of the proper implementation of the REP.

Furthermore, Cowlitz's assertion that the 7(b)(2) rate test creates an absolute cap on REP benefits paid in the actual implementation of the REP is inconsistent with the language of the Northwest Power Act. *See also* Chapter 2.6.3. Cowlitz recommends that BPA use the original flawed forecast ASCs and exchange loads in order to use "the § 7(b)(2) trigger amounts developed in the WP-02 case." Cowlitz Br., WP-07-B-CO-1, at 62. In effect, Cowlitz asks BPA to extend the protections afforded to the COUs under section 7(b)(2) of the Northwest Power Act to the *actual* cost of the REP rather than the *forecast* cost of the REP. This is an incorrect reading of the law. Section 7(b)(2) of the Northwest Power Act, by its terms, is designed to provide COUs rate protection from *forecast* costs. *See* 16 U.S.C. § 839e(b)(2). Section 7(b)(2) begins "[a]fter July 1, 1985, the *projected amounts to be charged for firm power* … may not exceed in total … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes … [the five rate assumptions]." *Id.* (emphasis added). As this language makes clear, the 7(b)(2) rate test protection applies to the "projected amounts to be charged," that is, the forecast amount of costs in BPA's rates, and not to the actual costs BPA experiences from implementing the REP within the rate period. Cowlitz's recommendation would lock in the REP costs to what BPA incorrectly forecast in an earlier phase of the rate case, thereby creating an additional protection for COUs that is not intended or allowed by the statutory language. BPA declines to expand the section 7(b)(2) protection beyond its statutory moorings.

WPAG contends that BPA has violated the 1984 ASCM because BPA is not using retail rate filings as the basis for the backcast ASC calculations. WPAG Br., WP-07-B-WA-1, at 24.

WPAG notes that the backcast ASCs are based on FERC Form 1 data, which is not specifically listed as a source of data under the 1984 ASCM. *Id*. As explained previously and below, there were no actual ASC filings made during FY 2002-2008, and therefore BPA did not receive the information from retail rate filings that it would normally use to establish ASCs. The reconstruction of such information would be extremely impractical. In any event, BPA does not agree that it has violated the 1984 ASCM by relying on FERC Form 1 data to calculate backcast ASCs. First, although an exchanging utility generally must base an Appendix 1 filing on information contained in the last retail rate order approved by the state public utility commission, the 1984 ASCM gave BPA latitude to consider other information when determining an ASC. In the 1984 ASCM Record of Decision, it was specifically recognized that though the state retail rate orders will be the typical source of ASC information, BPA may nevertheless look to other sources of data to calculate ASC:

> Retail rate orders will continue to be the primary source of data on generating resources. However, where necessary, BPA will independently determine costs (including costs of generating resources) for inclusion in ASC under the jurisdictional costing approach. The costs of any generating resource improperly included in a utility's ASC filing will be excluded from the ASC calculation.

1984 ASCM ROD at 66. Thus, contrary to WPAG's assertion, BPA is not prohibited by the 1984 ASCM from looking to sources of data other than the retail rate orders issued by the state public utility commissions to determine ASCs. The 1984 ASCM also notes that, although jurisdictional cost data would be used, it simply provides the starting point for BPA's review. 1984 ASCM ROD at 86.

Second, as noted in the 1984 ASCM Record of Decision, "where necessary" BPA may independently determine the costs for inclusion in ASC under the jurisdictional costing approach. The current factual situation necessitates that BPA make this independent decision using the FERC Form 1. BPA's witnesses explained that the retail rate orders of the state commissions were evaluated as a possible choice for the source of data of the backcast ASCs. Manary, *et al.,* WP-07-E-BPA-61, at 3-5. However, BPA ultimately chose not to use these filings as the applicable source of the backcast ASCs for several reasons. Boling, *et al.,* WP-07-E-BPA-83, at 37-38. As already noted above, many of the retail rate orders that were published during the 2002-2008 period were the result of stipulated settlements. *Id*. These filings are generally silent regarding changes to specific costs, leaving BPA with little to no real financial information from which to calculate a utility's ASC. *Id*. Thus, many of these orders could not be used even in the first instance as a source of data for an ASC calculation.

Even when filings contain *some* resource cost information, the value of such information for ASC calculation purposes is dubious. *Id*. at 44. The state utility commissions are not tasked with adopting retail rate orders that comply with the ASCM. *See* 1984 ASCM ROD, at 12. Rather, their duty is to approve retail rates for IOUs consistent with the laws of the applicable state. *Id*. Consequently, when approving a rate, the commissions need not be explicit in their orders on how a particular result was reached. *Id*. The give and take of retail ratemaking processes often results in compromises and adjustments that cannot be deciphered from or through the final order of the state public utility commission that approves the final rates. *Id*.; *see also* Boling, *et al*., WP-07-E-BPA-83, at 44. This lack of clarity was a primary driver behind BPA's decision to revise the 1984 ASCM. As noted in the 1984 ASCM ROD:

> Reliance on state regulatory agencies to determine the level of costs included in the ASC of a participating utility, the "jurisdiction costing approach," has caused several problems of administration for BPA. Routinely, the orders of regulatory agencies do not contain the specific numbers necessary for ASC computation. In such instances, values for ASC accounts must be imputed.

1984 ASCM ROD, at 12.

In response to these problems, BPA added provisions to the 1984 ASCM that made it possible for BPA (and preference customers) to intervene in the IOUs' state retail rate proceedings. *See* 1984 ASCM at § II.C (noting that if BPA or a regional power sales customer is denied the right to participate in a jurisdictional rate review proceeding, then no change in ASC based on a change of costs authorized in that proceeding will be exchanged until BPA completes its review). By participating in these proceedings, BPA could obtain valuable insight into how the underlying costs of the utility were determined. Boling, *et al.,* WP-07-E-BPA-83, at 44-45. It also provided BPA with important data that could not otherwise be obtained through an after-the-fact published order. BPA routinely participated in such proceedings when the REP was operable. *Id*. WPAG's contention that BPA should use these jurisdictional rate orders fails to recognize that BPA did not participate in any of the 77 retail rate proceedings that resulted in rate changes to the IOUs over the past eight years. Without this factual context, BPA has no way of knowing whether the information contained in the retail orders is the result of a compromise in the rate proceeding or accurately reflects the utility's cost of resources. Consequently, these rate orders are not necessarily any more reflective of an IOU's resource costs than other sources of utility financial data. In this instance, BPA believes it is "necessary" to rely on another, more transparent, source of data for the backcast ASCs – the FERC Form 1.

Another factor BPA considered was the administrative burden of compiling, reviewing, and evaluating the retail rate orders. BPA Staff testified that the administrative burden of compiling and reviewing state jurisdictional filings for six IOUs, two of which operate in two jurisdictions and one in *three* jurisdictions, for a span of eight years would have been enormous. Boling, *et al.,* WP-07-E-BPA-83, at 37. The last ASC filed with BPA was from the mid-1990s. Boling, *et al*., WP-07-E-BPA-57, at 5. Since then, utilities have adopted a number of "automatic adjustment" clauses that increased dramatically the number of rate changes that would trigger an ASC review under a strict reading of the 1984 ASCM. As noted above, BPA Staff discovered there were 77 of these filings made during just the 2002-2006 period. Boling, *et al.,* WP-07-E-BPA-83, at 46, and Attachment 13. For each of these filings, BPA would have had to evaluate the effect of the retail rate order on the backcast ASC calculation. Additionally, BPA would have had to obtain, if possible, the initial filing documents and documentation, which is the record underlying the rate proceeding for each adjustment, to determine whether the costs reflected were accurate. *Id*. at 44. BPA viewed this enormous undertaking as a massive waste of administrative and participant resources if another viable alternative source of data could be used. *Id*. at 46-47.

The FERC Form 1 was one such alternative. First, the FERC Form 1 provides actual financial and operations data for each year of the FY 2002-2008 period. Boling, *et al*., WP-07-E-BPA-83, at 36. This information thus would not suffer from the vagaries of compromises and adjustments that are commonplace in retail rate orders. *Id*. Second, using the FERC Form 1 made the backcast ASC estimation process uniform for all of the IOUs. *Id*. The FERC Form 1 is an industry standard form that is used by all of the IOUs to report their actual utility information to FERC. *Id*. Using it as the data source allowed BPA to maintain consistency in the data as well as consistency in calculating the backcast ASCs. *Id*. This would not have been the case if BPA had to review numerous state filings from various jurisdictions that have different reporting and filing requirements. *Id*. In addition, the FERC Form 1 provides detailed information in the areas of Purchased Power, Sales for Resale, and Deferred Asset accounts, which are key pieces of information for calculating the ASC and are not available in certain jurisdictional filings. *Id*. Finally, practical considerations also made the FERC Form 1 data superior. The FERC Form 1 data was readily available from FERC's website and could be electronically downloaded directly from the IOU's filings into the ASCM Appendix 1 form. Furthermore, because the FERC Form 1s are publicly available from FERC's website, any party in this proceeding has direct access to the information that BPA relied upon to calculate the backcast ASCs. In light of all of these factors, BPA determined that the more reasonable approach for estimating backcast ASCs for purposes of the Lookback was to use the FERC Form 1s as the source of data.

WPAG objects to BPA's position that compliance with the 1984 ASCM would be too laborious and time-consuming and that reliance on the FERC Form 1 data source in the proposed regulation is accurate enough. WPAG Br., WP-07-B-WA-1, at 24-25. WPAG contends that the fact that compliance with all the aspects of the 1984 ASCM may be laborious does not excuse BPA from complying with all aspects of the regulation. *Id*. WPAG claims that administrative burden is not a legally sufficient excuse for BPA's failure to comply with the 1984 ASCM in every case. *Id*.

WPAG is mistaken. Courts have recognized an agency's authority to apply equitable principles to regard as done "what should have been done" to remedy a legal error committed by the agency. *Plaquemines Oil & Gas Co., v. Federal Power Comm'n,* 450 F.2d 1334, 1337-38 (D.C. Cir. 1971). In these instances, the Courts have allowed agencies to use a "reasonableness" standard to determine the most appropriate remedy. *Id*. For example, in *Plaquemines,* the D.C. Circuit affirmed the Federal Power Commission's authority to use its equitable power to "recreat[e] the past, *insofar as is reasonably possible*, to reflect compliance with the [Natural Gas Act] and to order refunds to be paid if necessary to achieve that goal." The Court clarified in a footnote that its reference to "as is reasonably possible" was intentional, because the Court recognized that

> … instances may arise where attempts by the Commission to determine what it would have done in previous years, had filing been made in compliance with the Act, may be unavailing because of lack of absolutely essential data, or may be so

> financially burdensome on the Commission (and hence the public purse) or the parties as to be prohibitive.

Id. at 1338, n. 13.

In a similar way, BPA is using a "reasonableness" standard to decide what source of data is the most reasonable for purposes of estimating ASCs under the 1984 ASCM for this proceeding. Under this standard, factors such as financial strain and administrative burden of obtaining and reviewing the data are key considerations, particularly where that burden would be imposed not only on BPA but all of the IOUs, the PUCs, and all other parties interested in the backcast ASCs. BPA has evaluated these factors, in addition to the quality of the FERC Form 1 data, the practical realities of the present circumstances, and the need to efficiently and effectively respond to the Court's decisions in *PGE* and *Golden NW,* and determined that the FERC Form 1 is the most reasonable source of data to use in estimating the backcast ASCs. Manary, *et al.,* WP-07-E-BPA-61, at 4; Boling, *et al.,* WP-07-E-BPA-83, at 48.

Finally, using the FERC Form 1 as the basis for the backcast ASCs has not resulted in any demonstrable bias in such ASCs when compared to all of the available benchmarks provided by the parties on the record. BPA tested the general accuracy of using the FERC Form 1 for an ASC determination. Boling, *et al.,* WP-07-E-BPA-83, at 16. To do this, BPA looked at an ASC filing that had gone through the procedural timeline of the 1984 ASCM jurisdictional process and then compared it to an ASC calculated from the concurrent FERC Form 1 data for the same utility. *Id*. The test case was Puget Sound Energy's (PSE) last jurisdictional ASC filing with BPA (BPA Docket No. 7-A2-9501), which used a test period of October 1, 1995, through September 30, 1996. *Id*. BPA compared this jurisdictional ASC with an ASC BPA determined using PSE's 1996 FERC Form 1 data. *Id*. The final ASC determination in BPA Docket No.-7-A2-9501 was $36.53 per megawatt-hour, and the ASC calculated using the 1996 FERC Form 1 data for PSE resulted in an ASC of $35.79 per megawatt-hour, $0.67 per megawatt-hour *lower* than the ASC determined using the jurisdictional approach. *Id*. BPA conducted a similar test using PacifiCorp's last jurisdictional ASC filing, which was from July 1, 1996, to June 30, 1997. *Id*. at 16-17. Once again, the results of the jurisdictional-based ASC and the FERC Form 1-based ASC were extremely close. *Id*. at 17. The jurisdictional ASC was $27.00 per megawatt-hour, and the FERC Form 1 ASC was $26.95 per megawatt-hour, a mere $.05 difference. *Id*. These comparisons provided strong indications that using FERC Form 1 data as the source to calculate the utilities' ASCs would result in ASC determinations very close to the ASCs determined from a jurisdictional filing. *Id*. BPA also compared its FERC Form 1-based backcast ASCs with every benchmark provided by the parties on the record. *Id*. at 18-25. In almost all instances, the backcast ASCs were either extremely close to or below the rates the parties identified as legitimate benchmarks that BPA should have considered. *Id*.

WPAG objects to these comparisons on the grounds that it places the parties in the impossible position of trying to prove a negative – that BPA's use of the yet-to-be-adopted proposed regulation and reliance on the FERC Form 1 data is not accurate. WPAG Br., WP-07-B-WA-1, at 25. WPAG contends that such a proposition is essentially impossible to prove in the absence of ASC filings based on retail rate information as required by the 1984 ASCM. *Id*.

WPAG's complaint is unfounded. First, to clarify a factual error in WPAG's brief, BPA has not used its proposed 2008 ASCM to calculate the backcast ASCs. As BPA already explained above, BPA has relied solely on the 1984 ASCM for the Lookback portion of this proceeding. BPA is using the FERC Form 1 in this proceeding because of the reasons articulated earlier, not because it has any relationship to the proposed 2008 ASCM. Boling, *et al.,* WP-07-E-BPA-83, at 27. Second, WPAG is flatly wrong that WPAG has no way of "testing" the reasonableness of the backcast ASCs. BPA presented one viable alternative in its testimony by comparing the last filed ASCs under the 1984 ASCM with an ASC built from FERC Form 1 data. Boling, *et al.,* WP-07-E-BPA-83, at 16. Cowlitz also offered up a number of benchmarks to test the accuracy of the backcast ASCs. *See* Schoenbeck and Beck, WP-07-E-JP17-01, at 33-35. In each of these instances, the backcast ASCs were either extremely close or below the presented benchmark. Boling, *et al.,* WP-07-E-BPA-83, at 18-25. The fact that WPAG may not like the outcome of these comparisons does not detract from the strong record evidence that using the FERC Form 1 creates ASCs that are similar to ASCs derived from jurisdictional-based rate orders.

Finally, WPAG complains that without the ASC filings from the IOUs it is "impossible" to calculate ASCs to "test" against BPA's backcast ASCs. WPAG Br., WP-07-B-WA-1, at 25. Ironically, WPAG essentially states that it was too burdensome for it to determine an ASC using state retail rate orders in the absence of IOU filings. This argument further justifies BPA's use of the FERC Form 1. BPA also does not have the IOUs' ASC filings for the 2002-2008 period, so consequently it is equally "impossible" for BPA at this point to calculate ASCs using state retail rate orders. This "impossibility," however, means nothing more than that BPA must consider another viable alternative source of data. The FERC Form 1 is such a source for all of the reasons described above and, as a result, BPA's decision to use it as the data source for the backcast ASC is legally sound, allowed by the 1984 ASCM, and reasonable.

APAC, in its Brief on Exceptions, claims that in calculating the backcast ASCs, BPA is applying its new proposed ASC methodology with only "minor or cosmetic" changes. APAC Br. Ex., WP-07-R-AP-01, at 28. This characterization of BPA's actions is patently incorrect. First, as described in section 7.3, Issue 1, BPA used the substantive provisions of the 1984 ASCM in calculating the backcast ASCs. At no point did BPA propose to use its new 2008 ASCM or some hybrid methodology in this case. The record evidence on this point is clear. *See* Bliven, *et al.*, WP-07-E-BPA-52, at 16 ("BPA is directing staff to review the ASC for each utility in a manner that aligns as closely as practicable with the requirements of the 1984 ASC Methodology."); Manary, *et al.,* WP-07-E-BPA-61, at 2 ("We, therefore, were directed to estimate annual ASCs for each IOU in a manner that approximates the ASC determinations that would likely have been made, consistent with the 1984 ASCM, had the IOUs submitted ASC filings during FY 2002-2008.").

Furthermore, APAC's brief fails to explain how BPA has violated this directive. BPA explained at length in its testimony how it complied with the 1984 ASCM provisions. Manary, *et al.,* WP-07-E-BPA-61, 2-4; Boling, *et al.,* WP-07-E-BPA-83, at 25-27. A cursory review of the 2008 ASCM and 1984 ASCM also demonstrates that BPA has complied with this instruction. Boling, *et al.,* WP-07-E-BPA-83, at 26. Two of the main features of the proposed 2008 ASCM are that it includes in the ASC calculation the costs of a utility's return on equity and Federal income taxes. *Id*. These costs, however, are excluded from every ASC calculated in the Lookback. *Id*. While APAC may call these "cosmetic changes," eliminating equity and taxes were two of the most significant changes BPA made in developing the 1984 ASCM, resulting in extensive litigation with the IOUs that went all the way to the Ninth Circuit. *Id.* at 26; *see also* discussion in Section 7.5 *supra.* Had these changes been mere "cosmetic changes," as APAC suggests, the IOUs and state commissions should have welcomed BPA's calculation of the backcast ASCs. The record in this case, however, shows that these parties vigorously disputed BPA's decision to exclude these costs in the backcast ASCs. *See* Forman, *et al.,* WP-07-E-BPA-76, at 38-42. Indeed, as discussed in section 7.5, the IOUs and state commissions *oppose* BPA's decision to use the 1984 ASCM in the backcast ASCs and argue that BPA should use its *new 2008 ASCM.* Unless the IOUs and state commissions are feigning opposition to BPA's proposal, which the discussion in section 7.5 clearly shows they are not, APAC's suggestion that BPA is using its 2008 ASCM in the backcast ASCs is fundamentally misplaced.

To the extent that APAC's assertion is referring to BPA's use of the FERC Form 1 instead of jurisdictional filings as the source of data, BPA has already exhaustively explained above its rationale for that decision. Simply put, BPA used the FERC Form 1 because it was the best information available, not because it had any relationship to BPA's proposed 2008 ASCM. Boling, *et al.,* WP-07-E-BPA-83, at 26-27. APAC's general claim that BPA is using its new 2008 ASCM, without any support or explanation, must be rejected.

Finally, APAC claims that BPA's alleged use of the "formula approach" from the new ASC methodology deprives preference customers of their right to intervene at the state or jurisdictional level to protest the ASCs. APAC, Br. Ex., WP-07-R-AP-01, at 28. APAC asserts that these rights stemmed from the rights under the 1984 Methodology. *Id.* This argument is wrong for several reasons. First, as explained above, BPA has not used its proposed 2008 ASCM to develop the backcast ASCs. Second, APAC's claim that it is being denied rights to intervene at the state or jurisdictional level to protest the ASCs makes little sense. Parties have never had the right to appear before a state commission during an investor-owned utility retail rate proceeding to protest a utility's ASC filing with BPA. Boling, *et al.*, WP-07-E-BPA-83, at 28. The intervention rights were reserved to the retail rate filings in the states and the subsequent use of the state order in the ASC determination, and to intervene in the actual ASC filing before FERC. *Id.* Thus, APAC is factually wrong in suggesting that it would have had a right to protest BPA's ASC determination before a state commission.

Third, as mentioned above, APAC is being given extensive procedural rights through this proceeding to contest BPA's backcast ASCs. This includes the ability to conduct oral and electronic discovery of BPA's proposal, file direct and rebuttal testimony, file legal memoranda, conduct cross-examination, file initial briefs and briefs on exception, and to present oral argument before the Administrator. *Id.* at 28. These procedural protections exceed those provided to parties in a BPA ASC review during implementation of the REP. *Id.* APAC's claim that BPA's proposal denies it procedural protections is unfounded.

Decision

BPA has properly calculated the backcast ASCs in compliance with the 1984 ASCM.

Issue 2

Whether BPA should update the market prices for coal, natural gas, and wholesale power purchases in the backcast ASCs for FY 2007 and FY 2008.

Parties' Positions

The IOUs urge BPA to update the market prices for coal, natural gas, and electricity used in the backcast ASCs for FY 2007 and FY 2008. IOU Br., WP-07-B-JP6-1, at 152. The IOUs argue that BPA's proposal relies on price forecasts developed in 2006 and does not properly reflect current market costs. *Id*. The IOUs also note that BPA is proposing updates to the prices of natural gas and electricity in other parts of its direct case, and that to be consistent, BPA should make a similar update in the backcast ASCs for FY 2007 and FY 2008. *Id*. at 153.

BPA Staff's Position

BPA agrees that it should use updated market prices to calculate the coal, natural gas, and electricity cost components of the IOUs' backcast ASCs for FY 2007-2008. Boling, *et al.,* WP-07-E-BPA-83, at 30-31.

Evaluation of Positions

The backcast ASCs for FY 2007 and FY 2008 were developed following the same general approach used for the backcast ASCs for FY 2002-2006. Manary, *et al.,* WP-07-E-BPA-61, at 23-24. However, unlike the FY 2002-2006 backcast ASCs, BPA did not have 2007 or 2008 FERC Form 1 data to input into the ASC cookbook model. *Id*. The most recent available FERC Form 1 data is for 2006. *Id*. Therefore, to calculate estimates of the backcast ASCs for FY 2007 and FY 2008, BPA had to escalate the 2006 FERC Form 1 data through FY 2007 and FY 2008. *Id*. at 23-24. BPA used a forecast model for this purpose. *Id*. BPA assumed exchanging utilities would have met any load growth that occurred during these years with power purchases from the energy market. *Id*. at 24. BPA used the market pricing information that was developed from the original WP-07 final proposal. Boling, *et al.,* WP-07-E-BPA-83, at 31.

The IOUs do not object to BPA's use of 2006 FERC Form 1 data for the FY 2007 and FY 2008 backcast ASCs. IOU Br., WP-07-B-JP6-1, at 152. However, the IOUs do object to BPA's proposed use of outdated forecasts of prices for natural gas, coal, and wholesale energy. *Id*. The IOUs argue that rather than rely on outdated price forecasts, BPA should use the most current data available when determining the ASCs for purposes of determining reconstructed REP benefits for the Lookback. *Id*. Further, the IOUs argue that actual 2007 price data are available for wholesale electricity, natural gas, and coal, so there is no need to rely on forecast prices for

2007. *Id*. The IOUs also note that BPA is proposing to update prices for these commodities in other parts of its direct case. *Id*. The IOUs urge BPA to update these features in the backcast ASCs. *Id*.

Staff agreed to update the FY 2007 and FY 2008 ASC backcast calculations with revised energy market, coal, and gas price actual and forecast tables. Boling, *et al.,* WP-07-E-BPA-83, at 31. Updating the backcast ASCs for the components described above is consistent with the updates BPA typically makes when finalizing studies. *Id*. Also, the updated market price forecasts should capture most of the price and cost variability that has occurred since the 2006 FERC Form 1 was developed. *Id*. BPA considers it reasonable to update the backcast ASCs for market prices and believes that such updating should address any issues created by the passage of time since BPA's original backcast ASCs were developed. *Id*.

Decision

BPA will update the market prices for coal, natural gas, and wholesale power purchases in the backcast ASCs for FY 2007 and FY 2008.

Issue 3

Whether BPA has excluded New Large Single Loads (NLSLs) from the calculation of the backcast ASCs.

Parties' Positions

APAC claims BPA has violated the 1984 ASCM by not adjusting the IOUs' backcast ASCs for NLSLs as required by the Northwest Power Act. APAC Br., WP-07-B-AP-01, at 4.

The WUTC argues that APAC's claim has been addressed by BPA's agreement to exclude such costs. WUTC Br., WP-07-B-WU-01, at 19.

BPA Staff's Position

Staff acknowledged that the ASCs developed in the Lookback were not adjusted for NLSLs pursuant to the 1984 ASCM. Boling, *et al.,* WP-07-E-BPA-83, at 39. To correct this error, BPA proposed to incorporate into this proceeding the NLSL determinations made as part of BPA's concurrent Expedited ASC Review Process. *Id*.

Evaluation of Positions

APAC argues BPA has failed to make statutorily required adjustments in the IOUs' ASC determinations for New Large Single Loads. APAC Br., WP-07-B-AP-1, at 4. APAC claims that this failure causes BPA to use faulty and inappropriate data to reconstruct its section 7(b)(2) rate test for FY 2002-2006. *Id*. at 48, 54.

The WUTC notes that APAC's issue regarding NLSLs is addressed by BPA's stated intention to revise its backcast ASCs to exclude such loads. WUTC Br., WP-07-B-WU-01, at 19, *citing* Boling, *et al.,* WP-07-E-BPA-83, at 39.

Staff acknowledges that the ASCs contained in the Supplemental Proposal did not incorporate adjustments for NLSLs. Boling, *et al.,* WP-07-E-BPA-83, at 39. In preparing the Supplemental Proposal, Staff did not have enough time to research the load data of BPA's utility customers in order to make NLSL adjustments. *Id*. However, Staff noted that concurrent with this proceeding, BPA was developing a revised ASCM through a regional consultation proceeding. *Id*. As part of such development, BPA was conducting an expedited review of exchanging utilities' ASCs under the proposed ASCM. *Id*. All interested parties were provided the opportunity to intervene in the expedited ASC review process. *Id*. In the expedited review process, BPA was gathering information to identify NLSLs for each exchanging utility. *Id*. To the extent any NLSLs were identified in that process, BPA proposed to incorporate the results into this proceeding. Adopting these results in this proceeding addresses APAC's concern. In addition, to ensure the record in this proceeding is complete, BPA will add to the record the proposed NLSL determinations as well as any comments that were filed by parties on these determinations.

In its Brief on Exceptions, APAC argues that BPA has not removed resources supplying NLSLs from the determination of IOU ASCs. APAC Br. Ex., WP-07-R-AP-01, at 29. This statement is incorrect. In this proceeding, BPA incorporated into the record the NLSL results from the Expedited Process. To the extent that BPA found that an NLSL adjustment was necessary, the respective IOUs' ASCs was adjusted. The final backcast ASCs reflect these adjustments. The final rate studies explain the effects that the NLSLs had on the final backcast ASCs. *See* Lookback Study, Chapter 7, WP-07-FS-BPA-44.

Decision

BPA properly adjusted the backcast ASCs for NLSLs by incorporating the results of the expedited review process regarding NLSLs into this proceeding. The proposed NLSL determinations, as well as any comments filed by parties, are also incorporated into the record in this proceeding.

Issue 4

Whether BPA's backcast ASCs have properly accounted for transmission costs.

Parties' Positions

The IOUs argue that BPA should not adjust the backcast ASCs for transmission as requested by some parties. IOU Br., WP-07-B-JP6-01, at 175. The IOUs claim that since the imposition of

FERC Order No. 888, the IOUs have separated their transmission plant costs in a fashion that accounts for the reductions in transmission costs required by the 1984 ASCM. *Id*.

BPA Staff's Position

Staff stated that it would review the data WPAG submitted, as well as any other relevant evidence filed on this issue. Boling, *et al.,* WP-07-E-BPA-83, at 41. Staff stated that it would adjust Transmission Plant and Transmission expenses in the final Supplemental Proposal to be consistent with the 1984 ASCM. *Id*.

Evaluation of Positions

Under the 1984 ASCM, all transmission facilities built and operational before July 1, 1984 were to be included in ASC. 1984 ASCM ROD, at 42-43. For transmission facilities built *after* July 1, 1984, transmission costs could be included in ASC provided they met a two-part test: first, the facilities had to be used for generation integration; second, the cost of the facilities had to be less than the cost of constructing facilities to connect the same resource to BPA's transmission system plus any transmission charges BPA would charge to transmit the resource to the utility. *Id*. at 17 of Average System Cost Methodology (Footnote a). The point of this limitation was to avoid subsidizing the cost of "duplicate or redundant" transmission facilities. 1984 ASCM ROD, at 42. In addition, BPA was concerned about subsidizing the costs of transmission decisions that were "clearly beyond the bounds of integrating a resource." *Id*. at 43. Nevertheless, the 1984 ASCM contemplated that transmission expense would be allowed into ASC *unless* it failed to meet the two-part test of Footnote a.

Staff noted that it would review the positions of the parties and any data submitted by the parties before proposing an adjustment consistent with the 1984 ASCM. Boling, *et al.,* WP-07-E-BPA-83, at 41. Staff noted that WPAG suggested that the adjustment to transmission plant should be a reduction of 18 percent. *Id*.

The IOUs state that an adjustment is *not* necessary in this case because the data source BPA chose for the ASCs, the FERC Form 1, already has an *inherent* adjustment that reduces the IOUs' exchangeable transmission costs. IOU Br., WP-07-B-JP6-01, at 173-75. The IOUs note that the FERC Form 1 transmission plant data reflects a revised functionalization scheme that requires utilities to separate their facilities among transmission, generation, and distribution in accordance with Order No. 888. *Id*. at 174. The effect that this reallocation of facilities has on the transmission plant expense that is exchangeable with BPA under the 1984 ASCM is significant. The IOUs analysis shows that, in the case of Puget Sound Energy, BPA's backcast ASCs have 25-35 percent less transmission plant expense than the forecast ASC, which for the FY 2002-2006 period was based on a jurisdictional ASC filing. IOU Br., WP-07-B-JP6-01, at 173-75.

BPA concurs with the IOUs' position. The forecast ASCs, although based on ASCs from the mid-1990s, were nevertheless constructed from the last jurisdictional ASC filings processed in accordance with the 1984 ASCM. Boling, *et al*., WP-07-E-BPA-57, at 4-5. These filings necessarily would have contained an adjustment for transmission plant expenses that failed to meet the two-part 1984 ASCM test. The IOUs compared these ASCs with the ASCs BPA developed for the backcast, which uses the FERC Form 1 as its data source. IOU Br., WP-07-B-JP6-01, at 173-75. The results indicate that the total dollar amount of transmission plant expense in BPA's backcast ASC tends to be 20-30 percent *less* than what BPA forecasted using a jurisdictional ASC filing. Although not dispositive, this analysis demonstrates that using the FERC Form 1 as a source of data inherently adjusts the IOUs' transmission expenses downward, which conforms with the intent of Footnote a in the 1984 ASCM.

WPAG's witnesses argue that BPA should reduce the ASCs to reflect an increase in new transmission plant expenses and the depreciation of older facilities. Grinberg, *et al.,* WP-07-E-WA-05, at 34-35. WPAG notes that using historical data, the IOUs' transmission plant data should be reduced by 18 percent. *Id*. Ironically, this argument supports the IOUs' position. WPAG's witnesses, in advocating an 18 percent reduction, did not mention whether FERC's Order No. 888 refunctionalization changed the underlying transmission expense plant cost allocation. Thus, BPA presumes that WPAG did not take the effects of Order No. 888 into account when suggesting that, in general, an 18 percent reduction in transmission plant expense would be reasonable. In light of the IOUs' evidence, which indicates that the transmission reduction is already closer to 20-30 percent, a sufficient adjustment for transmission has already been made in the ASCs.

Finally, as a practical matter, the IOUs' position is the most reasonable. Determining which transmission facilities are "in" and "out" of ASC is not a simple matter. The facilities must have been built after July 1, 1984; be used for generation integration; and be less expensive than facilities that could have been built to the BPA system, plus applicable wheeling costs. 1984 ASCM at 17 of Average System Cost Methodology (Footnote a). To make this determination requires a detailed understanding of a number of factors, such as the date of operation of all of the IOUs' transmission facilities before July 1, 1984; a list of all transmission projects constructed since July 1, 1984; a complete list of the IOUs' resource locations; and the cost of constructing facilities from these resources to BPA's transmission facilities. Under the traditional implementation of the Residential Exchange Program, all of these details would have been tracked by BPA Staff and IOU representatives. The fact remains, however, that because of the REP Settlement Agreements, BPA did not track these adjustments during the FY 2002-2008 period. This omission is understandable because, as Staff explained, the last ASC processed by the agency occurred in the mid-1990s. Boling, *et al.,* WP-07-E-BPA-57, at 5. This is not to say that a correction to the transmission plant expense of the IOUs should not be made if such an adjustment is necessary. But, as the IOUs' analysis makes clear, the backcast ASCs already have an inherent reduction in the transmission cost component because of the requirements of Order No. 888. The clear intent in the 1984 ASCM is to include all transmission except for facilities that fail the two-part test. Because the transmission plant costs included in the FERC Form 1 data already have been adjusted pursuant to Order No. 888, reducing the total amount of transmission plant costs, BPA believes that a sufficient correction inherently exists in the FERC Form 1 data, and no further adjustments are necessary.

Decision

BPA will use the Transmission Plant as reported in the Annual FERC Form 1 for each of the IOUs to calculate the 2002-2008 backcast ASCs.

7.5 Use of 1984 ASCM in Lookback

Issue 1

Whether it is reasonable for BPA to assume that the 1984 ASCM would have been the ASC methodology in effect during the FY 2002-2008 period.

Parties' Positions

The IOUs argue that BPA should assume that the 1984 ASCM would have been revised had the IOUs not executed the REP Settlement Agreements. IOU Br., WP-07-B-JP6-01, at 151. The IOUs state that they had historically objected to the 1984 ASCM and would have vigorously challenged the imposition of the 1984 ASCM in 2000. *Id*. The IOUs state that BPA should assume revisions similar to what BPA proposed in the 2008 ASCM would have been made in 2000. *Id*.

The OPUC also argues that BPA must not rely on the 1984 ASCM in the Lookback to calculate ASCs. OPUC Br., WP-07-B-PU-02, at 10-11. OPUC notes that the IOUs did not fully litigate issues related to the 1984 ASCM because of the REP Settlements. *Id*. The OPUC claims that it is unreasonable for BPA to assume that the 1984 ASCM would not change, even though BPA is assuming other changes in the WP-02 rate case. *Id*. The OPUC also claims that BPA's rationale for using the 1984 ASCM in the Lookback is unconvincing. *Id*.

WPAG urges BPA to reject requests by the IOUs and the OPUC to presume that another ASCM would have been in place in 2000. WPAG Br., WP-07-B-WA-01, at 35-36. WPAG argues that the section 7(i) proceeding is not the proper forum to address ASCM issues. *Id*.

BPA Staff's Position

The 1984 ASCM was the ASC methodology that was in effect before and during the FY 2002-2008 period. It was previously approved by FERC and sustained by the Ninth Circuit in 1986. The Court in *PGE* further noted that the 1984 ASCM was "in effect" until modified and that potential threats or challenges to its validity were not a proper basis for the REP Settlement Agreements. In light of these facts, Staff believes that relying on the substantive provisions of the 1984 ASCM to calculate ASCs for purposes of the Lookback is a reasonable assumption.

Evaluation of Positions

When developing the ASCs to be used in the Lookback, BPA relied on the 1984 ASCM. Bliven, *et al.,* WP-07-E-BPA-52, at 16; *see also* Manary, *et al.,* WP-07-E-BPA-61, at 2. The 1984 ASCM requires BPA to exclude certain items from ASCs, such as costs associated with return on equity and taxes. Boling, *et al.,* WP-07-E-BPA-83, at 26. When constructing the ASCs to be used in the Lookback, BPA excluded these cost items in conformance with the instructions in the 1984 ASCM. *Id*. at 26-27.

WPAG argues that the 1984 ASCM is currently in place and was produced in accordance with a statutory consultation process, was reviewed and approved by the FERC, and has withstood legal challenges in the Court. WPAG Br., WP-07-B-WA-01, at 35-36, *citing* Order 400, *Final Rule*, 49 Fed. Reg. 39,293 (1984); *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986). WPAG contends that the 1984 ASCM has been an approved regulation used by BPA since 1984 and will continue to be the applicable ASCM until it is replaced by one that is formulated in accordance with section 5(c)(7) of the Northwest Power Act, 16 U.S.C. § 839c(c)(7). *Id*. WPAG notes that proceedings under section 7(i), such as the instant case, do not provide an alternative to the process described in section 5(c)(7) for the revision of an adopted regulation governing the calculation of ASCs. *Id*. WPAG concludes that the IOU and OPUC suggestion that this section 7(i) process should be used to modify the substantive content of an existing regulation is contrary to the express language of the Northwest Power Act, and this suggestion should be rejected. *Id*.

The IOUs argue that BPA should take into account changes to the ASCM BPA proposed to make in its February 7, 2008 Federal Register Notice. IOU Br., WP-07-B-JP6-01, at 150-51. The IOUs contend that the exclusions of costs such as return on equity and income taxes were not "permanently" sanctioned by the Court. *Id*. As such, the IOUs state that, had they not signed REP Settlement Agreements in 2000, they would have vigorously pursued ASCM issues. *Id*. The IOUs contend BPA would have, of necessity, addressed ASCM issues, including the ASCM issues identified by BPA in the 2008 ASCM Federal Register Notice. *Id*. According to the IOUs, BPA should consider ASCM issues, including those identified by BPA in the 2008 ASCM Federal Register Notice. *Id*.

The OPUC similarly objects to BPA's use of the 1984 ASCM. OPUC Br., WP-07-B-PU-02, at 10-11. The OPUC notes that among the issues not litigated in connection with the WP-02 rate proceeding were issues related to BPA's 1984 ASCM. *Id*. Accordingly, the OPUC recommends that BPA recalculate the Lookback Amounts using reasonable assumptions about the outcome of litigation about BPA's ASCM that would have been concomitant with the WP-02 rate proceeding. *Id*. at 10-11. The OPUC specifically asks BPA to assume that the 1984 ASCM would have been revised to include taxes, all transmission costs, and return on equity. *Id*. By not making these adjustments, the OPUC argues that BPA has not made a reasonable assumption. *Id*.

BPA recognizes that the IOUs have historically opposed the substantive provisions of the 1984 ASCM and that litigation would have ensued had BPA continued to use the 1984 ASCM in 2000 to implement the REP. Forman, *et al.,* WP-07-E-BPA-76, at 40. However, BPA does not believe that the threat of litigation before the Ninth Circuit requires BPA to assume that a different ASCM existed in 2000. The 1984 ASCM was approved by FERC and affirmed by the Ninth Circuit on appeal in 1986. Order No. 400, *Final Rule,* 49 Fed. Reg. 39,293 (1986); *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986). The 1984 ASCM was used to review all ASC filings made by exchanging utilities from 1984 to 2000 and is still in effect today. Forman, *et al*., WP-07-E-BPA-76, at 39. The IOUs' argument that the 1984 ASCM is "temporary" or "not permanent" refers to the Ninth Circuit's decision affirming the 1984 ASCM. In that case, the Court approved the 1984 ASCM, but stated that it did not sanction a permanent exclusion of certain costs from the ASC. *See PacifiCorp v. FERC*, 795 F.2d 816, 823 (9th Cir. 1986). Nevertheless, the 1984 ASCM was approved, affirmed, and remains in place until revised. The Court in *PGE* emphasized that the 1984 ASCM was the methodology in effect at the time the REP Settlement Agreements were executed and that threats of litigation to its continued viability were not a basis for BPA to enter into the REP Settlement Agreements. *PGE,* 501 F.3d at 1036. As the Court in *PGE* stated:

> BPA has not identified any problem in the 1984 methodology that it fears may be exploited by those seeking to challenge it. Until BPA adopts new regulations, FERC or this court disapprove the existing regulations, or Congress changes the law, BPA is bound by its regulations.

Id. at 1035. BPA, therefore, believes it is reasonable to assume that the 1984 ASCM was in effect for the Lookback period.

Even if BPA could reasonably assume that threats of litigation would have resulted in changes to the 1984 ASCM, it is impossible to know what revisions would have ultimately been made. *See* Forman, *et al*., WP-07-E-BPA-76, at 40. Although one could suggest that a revised ASCM would have been similar to the proposed 2008 ASCM, this is not certain. *Id*. at 41. BPA has filed its 2008 ASCM with FERC and has not yet received interim approval. *See Department of Energy Submits Its Proposed Average System Cost Methodology*, FERC Docket No. EF08-2011, available at www.ferc.gov. The OPUC would have BPA assume without question that these changes would have existed in 2002 and would have been approved by FERC and the Court. BPA does not consider this reasonable when the 1984 ASCM, which was in effect in 2002 (as it had been since 1984), was a readily available source to determine utilities' ASCs. *Id*.

The OPUC contends that BPA has taken inconsistent positions by assuming that certain changes would have been made in the WP-02 rate case but not in the context of the 1984 ASCM. OPUC Br., WP-07-B-PU-02, at 11. The OPUC's criticism is misplaced. Unlike the 1984 ASCM, the WP-02 rates were never affirmed by the Court, and consequently, were never "final" rates. BPA may, therefore, propose changes in the WP-02 rate case to "undo what is wrongfully done by virtue of its order" to respond to the Court's remand in *Golden NW*. *See United Gas Improvements Co, v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965). As BPA Staff explained, in the absence of the REP Settlement Agreements, the IOUs would have participated in the REP. Burns, *et al.,* WP-07-E-BPA-53, at 2. The Court did not instruct BPA as to the benefits the IOUs would have received under the REP that would have been properly allocated to preference customers in BPA's WP-02 rates. *Id*. Therefore, to determine the amount of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements (and thus permit the determination of how much the REP Settlement Agreements provided the IOUs in excess of the REP benefits), BPA must determine the PF-02 Exchange rate. *Id*. Issues raised in the WP-02 rate case that affect the level of REP benefits are therefore within the scope of the issues to be considered in this proceeding.

The 1984 ASCM, in contrast, is in a completely different legal posture. The 1984 ASCM was approved by FERC and subsequently affirmed by the Court. *See* Order 400, *Final Rule*, 49 Fed. Reg. 39,293 (1984); *PacifiCorp v. FERC*, 795 F.2d 816 (9th Cir. 1986). No party had filed any challenges to the 1984 ASCM at the time of the REP Settlement Agreements, and BPA had only committed to begin regional discussions on whether to change the ASCM. *See PGE*, 501 F.3d at 1035. Furthermore, whether the 1984 ASCM should or should not be modified is not the type of issue decided in BPA rate proceedings. As WPAG notes in its brief, section 7(i) proceedings, such as the instant case, do not provide an alternative to the process described in section 5(c)(7) of the Northwest Power Act for the revision of an adopted regulation governing the calculation of ASCs. WPAG Br., WP-07-B-WA-01, at 35-36. Consequently, the 1984 ASCM and the WP-02 rates are in vastly dissimilar legal positions today. In light of these differences, BPA's decision not to revisit the 1984 ASCM in this proceeding is in no way contrary to its position to revisit issues that were remanded to BPA by the Court in *Golden NW.*

The OPUC objects to BPA's argument that it is not clear what revisions might have been made to the 1984 ASCM had ASCM issues been litigated in the WP-02 rate case. OPUC Br., WP-07-B-PU-02, at 12. The OPUC contends that the "drivers" for BPA's current recommendation to include transmission costs, certain income taxes, and return on equity in utilities' ASCs existed prior to the WP-02 rate case. *Id*. Given that BPA proposed in its 2008 ASCM to modify the 1984 ASCM to include transmission costs, certain income taxes, and return on equity in utilities' ASCs, the OPUC claims it is reasonable to conclude that BPA would have made such recommendations based on the same information in the WP-02 rate case. *Id*.

The OPUC's reference to the 2008 ASCM consultation process is understandable but not persuasive. The decisions BPA made in the 2008 ASCM were the result of 10 months of meetings, comments, and discussions between all participants. *See* 2008 ASCM Final Record of Decision, at 14-16. At the end of that process, the Administrator, *based on the record,* made a finding that return on equity, transmission, and certain taxes can be included in the ASC. *Id*. at 102-142. The OPUC's suggestion that BPA assume that these same changes would have been made in 2000 requires BPA to make the questionable inference that a similar record would have been developed eight years ago. BPA cannot make that inferential leap. BPA has no basis in the record or in law to assume that the participants, arguments, positions, and discussions expressed in an administrative process conducted from August of 2007 to June of 2008 reflect the same conditions as eight years in the past. There are simply too many variables in such an assumption to make it reasonable for purposes of this proceeding. Forman, *et al.,* WP-07-E-BPA-76, at 41.

The OPUC also contends that it is reasonable to assume that the Administrator would have adopted these recommendations, particularly in light of pressure the Administrator would have likely felt from the Ninth Circuit's decision in *PacifiCorp* that affirmed the 1984 ASCM. OPUC Br., WP-07-B-PU-02, at 12-13. The OPUC points out that the Court in *PacifiCorp* found BPA's exclusion of IOUs' return on equity from the utilities' ASCs "troublesome" and that this exclusion was not sanctioned on a permanent basis. *Id*. As such, the OPUC states the Ninth Circuit's opinion placed "pressure" on BPA to include the IOUs' return on equity in their ASCs and that this "pressure" would have been felt by the Administrator in 2001. *Id*.

Again, BPA understands this argument but finds it unpersuasive. The Court in *PacifiCorp* did not hold that BPA had to allow taxes and return on equity in ASC at a certain point in time. *See PacifiCorp v. FERC*, 795 F.2d 816, 823 (9th Cir. 1986). Rather, the Court simply held that it did not sanction a "permanent exclusion" of taxes and return on equity. *Id*. In the absence of a court-mandated deadline, there is no basis to assume that the Administrator would have been "pressured" to change the 1984 ASCM in 2001, although BPA acknowledges that the exclusions had been in effect for 17 years. Even if the record supported such "pressure," BPA still would not agree with OPUC's assertions that the Administrator would have adopted the OPUC's recommended changes to the ASCM (*i.e.*, inclusion of taxes and equity) without question. Forman, *et al.,* WP-07-E-BPA-76, at 41. To change the ASCM, the Administrator must commence a consultation process on the 1984 ASCM pursuant to section 5(c) of the Northwest Power Act. *See* 16 U.S.C. 839c(c)(7). A consultation process most likely would include parties with views contrary to the OPUC's position. *Id*. If a record had been developed that strongly objected to the IOU and OPUC recommendations, the Administrator may have decided not to change the ASCM in 2000. In any case, trying to guess what all the various parties would have said and how their positions would have modified the 1984 ASCM is too speculative and uncertain to support use of the provisions of BPA's proposed 2008 ASCM for this proceeding.

Finally, the OPUC takes issue with BPA's rationale that practical considerations support using the 1984 ASCM. OPUC Br., WP-07-B-PU-02, at 13. The OPUC argues that there is no evidence that the region is familiar with the 1984 ASCM. *Id*. The OPUC explains that the 1984 ASCM had not been used for several years prior to 2001. *Id*. The OPUC further argues that adding back in transmission, taxes, and return on equity would not be difficult to implement. *Id*. The OPUC points to the FY 2009 ASC forecasts, which were calculated using the 2008 ASCM and include all of these costs. *Id*.

The OPUC's arguments are not convincing. First, practical considerations support BPA's use of the substantive provisions of the 1984 ASCM. Despite the OPUC's claim that there is "no record evidence" of the region's familiarity with the methodology, the OPUC need look no further than the spirited debate that BPA, Cowlitz, WPAG, and APAC have had on the provisions of the 1984 ASCM to find such evidence. *See* Boling, *et al.,* WP-07-E-BPA-83, at 32-45. Furthermore, the fact that the 1984 ASCM has not been used for several years does not negate BPA's and the region's experience with the methodology. It would have been far more difficult for BPA to craft backcast ASCs using a methodology that BPA staff and others had never implemented. Forman, *et al.,* WP-07-E-BPA-76, at 39. The OPUC argues that adding transmission, taxes, and return on equity would not be difficult to implement, pointing to the FY 2009 ASC forecasts. OPUC Br., WP-07-B-PU-02, at 13. However, this would require the assumption that BPA would adopt only the changes the OPUC recommends. As noted previously, there is no record evidence to suggest that only the three changes the OPUC recommends would have been made to the 1984 ASCM. Forman, *et al.,* WP-07-E-BPA-76, at 41. Finally, contrary to the OPUC's contention, making the adjustments to the forecast ASCs for FY 2009 to reflect the 2008 ASCM was not a simple task. The FY 2009 ASC forecasts were the subject of a review process that began in February of 2008 and focused exclusively on ASCs. For these reasons, practical considerations do support using the substantive provisions of the 1984 ASCM in the Lookback.

Decision

BPA properly assumes that the 1984 ASCM would have been the ASC methodology in effect during the FY 2002-2008 period.

7.6 Other Issues

Issue 1

Whether BPA has made inconsistent assumptions regarding preference customer REP participation in the Lookback analysis.

Parties' Positions

WPAG argues that BPA has selectively applied its Lookback analysis. WPAG Br., WP-07-B-WA-01, at 25; WPAG Br. Ex., WP-07-R-WA-01, at 32. It claims BPA has updated "virtually every fact" related to the IOUs' participation in the REP, but has not made a similar adjustment to the COUs that were potential participants in the REP, such as Clark Public Utilities (CPU). *Id*. at 25-26. WPAG argues that BPA must be consistent and update all of the ASC information for the COUs that may have participated in the REP. *Id*. at 26. WPAG argues that if BPA updated CPU's ASC in the same manner as BPA did for the IOUs, then CPU would have been eligible for substantial REP benefits. *Id*. at 40.

BPA Staff's Position

BPA properly assumed in June 2001 that the retail loads of Snohomish PUD, City of Idaho Falls, and CPU would have been served by BPA at the lower-than-market PF rate, with an effect on ASCs that would not lead to REP benefits. Boling, *et al.,* WP-07-E-BPA-83, at 7-8.

Evaluation of Positions

BPA did not apply the revised market forecast to the three COUs' ASCs. Boling, *et al.,* WP-07-E-BPA-57, at 7. CPU reentered the REP in 2005 and signed a termination agreement with BPA in February 2006. *Id*. With respect to Snohomish and Idaho Falls, BPA would reasonably have assumed in June 2001 that their retail loads would not have been served by market purchases but instead would have been served by power purchases from BPA at the much-lower-than-market PF rate. *Id*. Although the WP-02 Supplemental Final Proposal established Cost Recovery Adjustment Clauses (CRACs), anticipated PF rates with CRACs applied were still expected to be far lower than market prices. *Id*. Meeting load growth with somewhat higher-priced PF power would have increased public agencies' ASCs a bit, but far less than the increase to IOUs' ASCs based on serving load growth at market prices. *Id*. Considering that the COUs' starting ASCs were generally quite low to begin with, BPA would reasonably have assumed that revising ASCs would not have led to REP benefits. *Id*.

WPAG argues that in calculating the amount of reimbursement preference customers are entitled to for the FY 2002-2006 period, BPA has updated "virtually every fact related to the IOU participation in the REP." WPAG Br., WP-07-B-WA-01, at 25; WPAG Br. Ex., WP-07-R-WA-01, at 32. WPAG states that this included updating the costs used to forecast the IOUs' ASCs, including purchased power costs, and revising the operation of the section 7(b)(2) rate test to permit the payment of substantially higher REP benefits. *Id*. WPAG then notes that BPA has not performed a comparable update for potential preference customer participants in the REP, such as CPU. *Id*., *citing* Grinberg, *et al.,* WP-07-E-WA-05, at 39-43. WPAG claims that as a consequence, in the context of the Lookback analysis, BPA has materially understated the portion of the REP payments that would be made to preference customers and substantially overstated the amount of REP payments the IOUs would receive in the FY 2002-2006 period. WPAG Br., WP-07-B-WA-01, at 26. WPAG concludes that if BPA persists in its "what if" analysis and calculations, it must apply the same assumptions and make the same forecasts consistently for both IOUs and preference customers. *Id*. Failure to do so for whatever reason leads to the conclusion that the focus of this effort is not to calculate the reimbursement due to preference customers, but to ensure that the REP benefits credited to the IOUs match as closely as possible the payments they received under the illegal REP Settlements. *Id*.

WPAG's criticism is misplaced. BPA knew with virtual certainty that, in the absence of the REP Settlement Agreements, that certain IOUs would have participated in the REP during the WP-02 rate period. Boling, *et al.,* WP-07-E-BPA-83, at 8. This assumption is based on the fact that the IOUs submitted letters requesting to participate in the REP. *Id*. BPA offered the IOUs both RPSAs and REP Settlement Agreements, and the IOUs signed the REP Settlement Agreements. *Id*. This series of events created a strong evidentiary foundation supporting BPA's assumption that, but for the REP Settlement Agreements, the IOUs would have participated in the REP. *Id*.

No such foundation, however, exists for CPU (or any other preference customer). *Id*. CPU did not submit a letter notifying BPA of its intent to participate in the REP in FY 2002; nor did it request that BPA provide it with an RPSA. *Id*. Thus, BPA is unaware of any direct evidence that would support WPAG's assertion that CPU would have participated in the REP as was the case for the IOUs. *Id.* at 8-9. BPA has also been unable to substantiate, even through circumstantial facts, CPU's intent to participate in the REP. *Id*. at 9. In discovery, BPA asked for data from WPAG to substantiate that CPU was intending to enter the program. *Id*. None of the answers to discovery requests supports such a conclusion. *Id*. For example, CPU had hedged gas prices through 2004, three years of BPA's five-year rate period, at levels considerably lower than the generally accepted market price forecasts of the time. *Id*. *See* responses to Data Request Nos. BPA-WA-21 and 22. In addition, BPA was unable to obtain any data or analyses relied upon by CPU to estimate future gas prices. *See* response to Data Request No. BPA-WA-36. Nor had CPU apparently taken even the preliminary step of estimating its ASC any time within two years prior to winter/spring 2001. *Id*. *See* response to Data Request No. BPA-WA-23. Taken together, the foregoing responses demonstrate CPU's general intent not to participate in the REP during the period prior to winter/spring 2001, which supports BPA's original position not to assume for reforecast purposes that CPU would have participated in the REP. *Id*.

In its Brief on Exceptions, WPAG argues that BPA has not performed a comparable update for potential preference customer participants in the REP, and as a consequence, BPA has materially understated the portion of the REP payments that would be made to preference customers, and substantially overstated the amount of REP payments the IOUs would receive in the FY 2002-2006 period. WPAG Br. Ex., WP-07-R-WA-01, at 32. This argument is incorrect. As a practical matter, BPA could not have updated CPU's ASC in the same way the IOUs' ASCs were updated because the WP-02 record does not have the model necessary to do the update. *Id*. at 9-10. Nevertheless, to test WPAG's assertion, BPA escalated CPU's ASC by 30 percent based on WPAG's claim that the IOUs' ASCs increased by about 30 percent as a result of BPA's updating. Grinberg, *et al.,* WP-07-E-WA-05, at 35-36. Using this assumption, CPU's ASC changed from $27.57 per megawatt-hour to $35.84 per megawatt-hour. Boling, *et al.,* WP-07-E-BPA-83, at 9-10; WPRDS Documentation, WP-02-FS-BPA-05A, at 112. In the instant proceeding, BPA recalculated what the PF Exchange rate would likely have been if the REP Settlement Agreements had not been in effect. Boling, *et al.,* WP-07-E-BPA-83, at 9-10. The revised PF Exchange rate for 2002 in the Supplemental Proposal is $39.95 per megawatt-hour. *Id.;* Lookback Study, WP-07-E-BPA-44A, at 138. As can be seen, CPU's forecast ASC would *still have been lower* than the revised PF Exchange rate by $4.11 per megawatt-hour. Thus, even if BPA had increased CPU's ASC by 30 percent, CPU still would not have been eligible to participate in the REP. Consequently, BPA's decision to assume that CPU would not have participated in the REP consideration is reasonable. Boling, *et al.,* WP-07-E-BPA-83, at 9-10.

WPAG argues that BPA should assume that CPU would have made "different decisions" regarding its participation in the REP because of the different conditions postulated in this case. WPAG Br. Ex., WP-07-R-WA-01, at 32. This argument is unpersuasive because, as just noted, even assuming that CPU's ASC was substantially higher it would not have qualified for REP benefits. Furthermore, assuming CPU would have been in the REP during the Lookback period would require BPA to make the additional assumption that CPU would *not* have signed its own REP Settlement Agreement in 2005. *Id*. at 10. This is not a reasonable assumption for several reasons. First, CPU's REP Settlement Agreement was not challenged in court by any party. *Id*. CPU's REP Settlement Agreement, therefore, is not in the same situation as BPA's other REP Settlement Agreements with the IOUs, which were found unlawful by the Court. *Id*. CPU's REP Settlement Agreement has been operating since the Court's May 2007 decisions and remains in effect. *Id*. As a general matter, then, BPA does not find it reasonable to assume away an agreement that is in full force and effect even today. *Id*. Second, CPU's REP Settlement Agreement included certain other matters that were not present in BPA's other REP Settlement Agreements. *Id*. That is, there were other rights and obligations determined in CPU's agreement. *Id*. If BPA were to assume CPU would not have signed an REP Settlement Agreement, BPA would also have to assume that CPU would not have wanted these other terms. *Id*. BPA cannot determine with any degree of certainty, however, what CPU's motivations were for entering into the REP Settlement Agreement. *Id*. Any attempt by BPA to make such an assumption would be based on pure speculation. *Id*. at 10-11. The better and more reasonable assumption is to assume in the Lookback analysis what actually happened: CPU signed an REP Settlement Agreement that remains in effect today. *Id*. at 11.

Decision

BPA has properly calculated the COUs' ASCs. In calculating these ASCs, BPA has not acted inconsistently in its development of the COUs' ASC forecasts. The COUs' ASCs were below BPA's proposed PF Exchange rate. Even if BPA were to update CPU's financial information, it would not have made CPU's ASC higher than the PF Exchange rate.

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8.0 CALCULATIONS OF LOOKBACK AMOUNTS

8.1 Introduction to Lookback Calculations

In its response to the Court's rulings, BPA Staff proposed to perform an analysis to determine the amount by which the COUs were overcharged for REP settlement costs during FY 2002-2008. Bliven, *et al.*, WP-07-E-BPA-52, at 12. In performing this analysis for FY 2002-2006, Staff proposed to examine what would have happened in rate setting during the winter of 2000 and spring of 2001 had RPSA agreements been signed instead of the invalid REP Settlement Agreements. Burns, *et al.*, WP-07-E-BPA-53, at 9. Similarly, for FY 2007-2008, Staff proposed to revisit the assumptions and decisions in the WP-07 Final Proposal in a manner consistent with the construct used for FY 2002-2006.

BPA proposed to calculate the REP settlement benefits that the IOUs received, or would have received, in each year for FY 2002-2008. Bliven, *et al.,* WP-07-E-BPA-52, at 11-12. These amounts are collectively referred to in this proceeding as "REP settlement benefits." *Id.* Additionally, BPA proposed to calculate the amount of REP benefits that each IOU would have received under the REP in the absence of the REP Settlement Agreements, referred to as "reconstructed REP benefits." *Id.* BPA calculated the appropriate differences between the first two components for each year for each IOU, after certain additional considerations. *Id.* The considerations included the treatment of related issues, such as deemer balances, interest on the Lookback Amounts, and the LRA payments. *Id.* The resulting amounts are called the annual Lookback Amounts.

8.2 Validity of Load Reduction Agreements

Issue 1

Whether BPA should continue to treat the 2001 Load Reduction Agreements between BPA and PacifiCorp, and BPA and Puget, as valid and binding contracts.

Parties' Positions

Many preference customers argue that, in light of *PGE, Golden NW*, and *Snohomish*, BPA should no longer treat the LRAs with Puget and PacifiCorp as valid and binding agreements. Cowlitz Br., WP-07-B-CO-01, at 47-59; PPC Br., WP-07-B-JP25-01, at 37-38; WPAG Br., WP-07-B-WA-01, at 29-30; APAC Br., WP-07-B-AP-01, at 19-24. Cowlitz, and to a lesser extent APAC, devote the most extensive attention to this issue. In varying degrees, these arguments are reiterated by these parties, as well as by Canby and Tillamook, in their Briefs on Exceptions. Cowlitz Br. Ex., WP-07-R-CO-01, at 31-49; APAC Br. Ex., WP-07-R-AP-01, at 5-6; WPAG Br. Ex., WP-07-R-WA-01, at 15-17; PPC Br. Ex., WP-07-R-PP-01, at 23; Tillamook Br. Ex., WP-07-R-JP24-01; Canby, Br. Ex.,WP-07-R-CA-01, at 5-9.

According to Cowlitz, all "follow-on" agreements to the 2000 REP Settlement Agreements, which Cowlitz claims includes the LRAs, are "part and parcel of the same attempt by BPA to implement the 'new residential exchange benefit system' it created in the REP Settlement Agreements …" Cowlitz Br., WP-07-B-CO-01, at 48. As a result, Cowlitz contends that all of these agreements "are void and of no effect like any other administrative action taken in violation of statutory authorization and requirement." *Id*. APAC is in accord. APAC Br., WP-07-B-AP-01, at 20, 23.

The IOUs take the opposite position. According to the IOUs, the LRAs "remain valid and enforceable agency actions." IOU Br., WP-07-B-JP6-01, at 11. The IOUs argue that "no party timely filed a petition for review of the 2001 LRAs" and that, in *Snohomish*, the Ninth Circuit dismissed an untimely challenge to the LRAs for lack of jurisdiction. *Id*. at 12. The IOUs contend that it is fully consistent with *Snohomish* to recognize the continued validity of the LRAs, separate and apart from the reduction of risk discount provision. According to the IOUs, "the propriety of the LRAs aside from any reduction of risk discount provision was not remanded to BPA and is not properly before BPA in this or any other proceeding." *Id*. at 13. CUB and the WUTC are generally in accord with the IOUs. CUB Br., WP-07-B-CU-01, at 15-16; WUTC Br., WP-07-B-WU-01, at 19-21.

No party raised an issue regarding Staff's proposed treatment of the reduction of risk discount provision of the LRAs.

BPA Staff's Position

In the WP-07 Supplemental Proposal, BPA Staff proposed to treat the LRAs as valid and binding contracts. Bliven, *et al*., WP-07-E-BPA-52, at 19-20. As a result, Staff proposed that the LRA payments to PacifiCorp and Puget Sound Energy would be "protected" payments that are not subject to recovery as part of their Lookback Amounts. *Id*. at 20. Staff explained that the LRAs were contracts with PacifiCorp and Puget where BPA purchased power from these utilities to limit BPA's exposure to volatile energy prices during the West Coast energy crisis of 2001. Marks *et al*., WP-07-E-62, at 15. Staff further explained that petitions to review the LRAs did not challenge final actions and that petitions that attempted to challenge only the reduction of risk provision of the LRAs, were dismissed as moot. Bliven, et al., WP-07-E-BPA-52, at 2-3.

Staff proposed that the reduction of risk payments the IOUs received, or would have received, should be treated as invalid payments in the same manner that the payments under the REP Settlement Agreements are treated. *Id*.

Evaluation of Positions

A. The Load Reduction Agreements

Many preference customers argue in their Initial Briefs and in Briefs on Exceptions that, in light of *PGE, Golden NW*, and *Snohomish*, BPA should no longer treat the LRAs with Puget and PacifiCorp as valid and binding agreements. Cowlitz Br., WP-07-B-CO-01, at 47-59; PPC Br., WP-07-B-JP25-01, at 37-38; WPAG Br., WP-07-B-WA-01, at 29-30; APAC Br., WP-07-B-AP-01, at 19-24; Cowlitz Br. Ex., WP-07-R-CO-01, at 31-49; APAC Br. Ex., WP-07-R-AP-01, at 5-6; WPAG Br. Ex., WP-07-R-WA-01, at 15-17; PPC Br. Ex., WP-07-R-PP-01, at 23; Canby, Br. Ex., WP-07-R-CA-01, at 5-9.

According to Cowlitz, all "follow-on" agreements to the 2000 REP Settlement Agreements, which Cowlitz claims includes the LRAs, are "part and parcel of the same attempt by BPA to implement the 'new residential exchange benefit system' it created in the REP Settlement Agreements …" Cowlitz Br., WP-07-B-CO-01, at 48. As a result, Cowlitz contends that all of these agreements "are void and of no effect like any other administrative action taken in violation of statutory authorization and requirement." *Id*. APAC is in accord. APAC Br., WP-07-B-AP-01, at 20, 23.

Cowlitz states that the LRAs "are merely a change in the form of settlement consideration to be paid – from low-cost power to cash." Cowlitz Br., WP-07-B-CO-01, at 49. Cowlitz, as well as Tillamook cite Staff testimony and studies that allegedly bolster this argument. *Id*.; Tillamook Br. Ex., WP-07-R-JP24-01, 4-5. APAC, PPC, and WPAG raise substantially the same point. APAC Br., WP-07-B-AP-01, at 19-24; PPC Br., WP-07-B-JP25-01, at 37-38; WPAG Br., WP-07-B-WA-01, at 29-30. Cowlitz as well as Canby cite BPA's 2004 Record of Decision supporting the amendments to the 2000 Settlement Agreements where BPA acknowledged that, if the 2000 Settlement Agreements were declared invalid, the 2004 amendments would also be invalid because the "foundation" for the amendments would disappear. Cowlitz Br., WP-07-B-CO-01, at 50; Canby Br. Ex.,WP-07-R-CA-01, at 7-8. These parties conclude that the same rationale applies to the LRAs. *Id*. Cowlitz acknowledges that, even though the Court has not invalidated the LRAs, "the law compels the conclusion that the BPA should now declare the LRAs and 2004 Amendments, including the litigation penalty, to be invalid." Cowlitz Br., WP-07-B-CO-01, at 52.

According to Cowlitz, the Court expects BPA to examine the continuing validity of the LRAs and 2004 Amendments, and BPA "cannot find that either the LRAs or the 2004 Amendments represent an 'independent benefit or program' within the meaning of *Snohomish* and other law" because "[a]s an 'outgrowth and continuation' of the void REP Settlement Agreements, they are void as well." *Id*. at 54-55; Cowlitz Br. Ex., WP-07-R-CO-01, at 43-48. Lastly, Cowlitz argues that for BPA to contend that the LRAs are valid because no party challenged them within 90 days "confuses a question of the jurisdiction of the Ninth Circuit made moot by *Grays Harbor* with the issues now before the agency." Cowlitz Br., WP-07-B-CO-01, at 54.

While the arguments presented by Cowlitz, APAC and other preference customers are not without some merit, BPA believes that in several important respects, these parties overstate aspects of the Court's opinions, do not properly characterize the true nature of the LRAs, and minimize the significance of the 90-day statute of limitations. For these reasons, BPA believes it is important to explain more fully the basis for the LRAs with Puget and PacifiCorp and why BPA believes the LRAs should continue to be treated as valid and binding agreements.

In 2000 and 2001, poor water conditions in the Columbia River basin, coupled with a dysfunctional power market on the West Coast, led to an unprecedented power crisis. By the spring of 2001, the Pacific Northwest experienced its second worst drought since recordkeeping began in 1928. By April 2001, the Administrator announced that due to the power crisis, BPA was facing a rate increase of "250% or more." *Snohomish*, 506 F.3d at 1148. In response to the power crisis, BPA developed a three-pronged Load Reduction Program "involving conservation by consumers, reduction in power demand by utilities, and load curtailments by its direct service industrial customers." *Snohomish*, 506 F.3d at 1148; *Bell v. Bonneville Power Administration*, 340 F.3d 945, 948 (9th Cir. 2003). Given that the Load Reduction Program was purely voluntary, its success depended upon participation by a critical mass of BPA customers. BPA successfully negotiated a total of 71 load reduction agreements with preference customers, DSIs, and all of the IOUs. These agreements enabled BPA to reduce the projected rate increase from 250 percent to 46 percent. *Snohomish*, 506 F.3d at 1148. In *Bell*, the Ninth Circuit found that BPA's Load Reduction Program was "an astounding success." *Bell*, 340 F.3d at 948.

The LRAs with Puget and PacifiCorp were an important component of BPA's Load Reduction Program. As the Court explained in *Snohomish*, "[t]he LRAs eliminated BPA's obligation to deliver virtually all power to PacifiCorp and PSE for the FY 2002-2006 time period in exchange for cash payments," thereby eliminating BPA's need to purchase that same amount of power at exorbitant prices in an extremely volatile energy market. *Snohomish,* 340 F.3d at 1148.

As discussed below, the LRAs also contained a "reduction of risk discount" provision, generally referred to by BPA's preference customers as a "litigation penalty" provision. In *Snohomish*, the Court found that the reduction of risk discount "operated as a strong incentive for the PUDs to settle their ongoing litigation (including litigation over the 2000 REP Settlement Agreements) with BPA because, if they settled, BPA's payments to Puget and PacifiCorp under the LRAs would be reduced by $200 million." *Id.* at 1149.

B. The Snohomish Decision and Challenges to the Reduction of Risk Discount and the 2004 Amendments to the 2000 Settlement Agreements

1. Introduction

In *Snohomish*, the Court reviewed a challenge to the 2004 Amendments to the 2000 Settlement Agreements. In the context of that decision, the Court also reviewed the "litigation penalty" provisions of the LRAs and concluded that "the 'litigation penalty' provisions … are directly related to the 2000 REP Settlement Agreements … and [are] not a part of a separate agreement." 506 F.3d at 1154. The Court determined that the "litigation penalty" provisions were "a direct response to the litigation over the 2000 REP Settlement Agreement and not an independent benefit or program." *Id.*

In its remand order in *Snohomish*, the Court distinguished between the "litigation penalty" provision of the LRAs and the balance of the LRAs, which bore directly on their fundamental purpose as load reduction agreements. In particular, the Court stated, "[b]ecause the 'litigation penalty' provisions of the LRAs, as amended by the 2004 Amendments, are sufficiently related to the 2000 REP Settlement Agreements, they *must be* revisited in light of our decision in *PGE*." *Id*. at 1155 (emphasis added). In contrast, the Court did not order BPA to revisit any other aspect of the LRAs. On the contrary, the Court identified various options available for BPA's consideration, stating that BPA:

> *could determine* that our prior opinions undermined the entire 2001 LRAs and, consequently, the 2004 Amendments modifying the LRAs are also void. Alternatively BPA *could determine* that our decisions invalidated the "litigation penalty" provisions of the LRAs, but that those provisions are tangential to the main agreement and severable. Finally, BPA *might* decide to honor the "litigation penalty" provision as amended by the 2004 Amendments, but decline to charge its preference customers the cost of paying the penalty. Because we cannot determine from the record what BPA intends to do – and BPA may have other options – we remand for further proceedings. Again, we express no judgment on the merits of BPA's options or on the legality of the "litigation penalty" itself.

Id. at 1155 (emphasis added). As such, the Court provided BPA considerable discretion to determine how to treat "the entire 2001 LRAs."[10]

At the outset, it is important to emphasize that BPA is required by statute to operate in a businesslike manner and that, since its inception, Congress declared that BPA's contracts are "binding in accordance with the terms thereof." 16 U.S.C. § 832d(a). Ultimately, BPA markets and purchases power through the negotiation and implementation of contracts with other utility companies and power marketers. This process is the cornerstone of BPA's power marketing business, which takes place in an environment where participants operate with an expectation that their contracts are binding and enforceable. Accordingly, BPA takes the sanctity of its contracts very seriously. In this instance, BPA does not believe that it is empowered to unilaterally declare the fully performed LRAs null and void unless presented with the most compelling reasons to take such drastic action.

In the Court's opinions, the Court did not hold that the LRAs were invalid and did not order BPA to make such a finding. On the contrary, the Court identified various options that would be available to BPA on remand. The Court opined that, on the one hand, BPA "could determine that our prior opinions undermined the entire 2001 LRAs," but, on the other hand, BPA "could determine that our decisions invalidated the 'litigation penalty' provisions of the LRAs but that those provisions are tangential to the main agreement and severable." The Court expressed no position on the merits or legality of BPA's various options.

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[10] In addition, although the "litigation penalty" provision of the LRAs was challenged in three related cases, all three cases were dismissed on jurisdictional grounds in unpublished memoranda opinions filed concurrently with *Snohomish*. *Public Utility District No. 1 of Snohomish County v. Bonneville Power Administration*, 250 Fed. Appx. 817 (9th Cir. 2007) (dismissed for failure to challenge a final action); *Public Utility District No. 1 of Snohomish County v. Bonneville Power Administration,* 250 Fed. Appx. 821 (9th Cir. 2007) (same); *Public Utility District No. 1 of Grays Harbor v. Bonneville Power Administration*, 250 Fed. Appx. 820 (9th Cir. 2007) (dismissed as moot).

B. The Applicability of Section 9(e)(5) of the NPA.

Significantly, no party has ever filed a challenge to the LRAs themselves. Although certain preference customers challenged the "litigation penalty" provision of the LRAs, the Court clearly distinguished between that provision and "the entire 2001 LRAs." Indeed, in *Snohomish*, the Court essentially determined the "litigation penalty" provision was not even part of the LRAs. Because the LRAs were never challenged, BPA believes they are no longer subject to judicial review and must be treated as valid and binding agreements.

Section 9(e)(5) of the Northwest Power Act contains a 90-day statute of limitations for challenges to final actions or the implementation of final actions taken by BPA. 16 U.S.C. § 839f(e)(5). If such challenges are not filed within the 90-day time frame, they are "barred." *Id.* There is no doubt that the LRAs were final actions subject to challenge by the filing of a timely petition for review. *Public Utility District No. 1 of Grays Harbor v. Bonneville Power Administration*, 250 Fed. Appx. 820 (9th Cir. 2007) ("*Grays Harbor*"). Nevertheless, no petitions, whether timely or untimely, were ever filed challenging the LRAs themselves.

Cowlitz contends that BPA, by raising the 90-day statute of limitations argument, "confuses a question of the jurisdiction of the Ninth Circuit made moot by *Grays Harbor* with the issues now before the agency." Cowlitz Br., WP-07-B-CO-01, at 54. However, BPA believes these two issues are directly related and, in the context of evaluating the issues now before BPA, the statute of limitations is an important consideration for at least three reasons.

First, because the 90-day period has run, BPA believes the LRAs must be treated as presumptively valid. Second, the statute of limitations was enacted for purposes of assuring timely and expeditious review of BPA's final actions. The Ninth Circuit has consistently adhered to this jurisdictional bar and specifically applied it to BPA's load reduction agreements. In *Bell,* the Ninth Circuit refused to review a challenge to a DSI load reduction agreement that was filed six months late because the Court found this was "far beyond the Northwest Power Act's ninety-day time limitation." *Bell,* 340 F.3d at 949. In the instant case, the 90-day period to challenge the LRAs expired nearly seven years ago. The purpose of the 90-day statute of limitations would be frustrated and undermined if BPA unilaterally declared the LRAs invalid seven years after they were executed and became final actions subject to review. Third, if BPA is to exercise sound business judgment as BPA is required to do, then BPA must be able to make important business decisions and move forward without fear that these decisions could be set aside years later, long after the 90-day clock has run.

In its Brief on Exceptions, Cowlitz contends that BPA's decision to treat the LRAs as valid and binding due to the ninety-day statute of limitations "is unsupportable, in light of controlling Ninth Circuit authority," citing *City of Santa Clara v. Andrus*, 572 F.2d 660 (9th Cir. (1978), *cert den*. 439 U.S. 859 (1978) ("*Santa Clara*"). Cowlitz Br. Ex.,WP-07-R-CO-01, at 36. In that case, the City of Santa Clara brought suit against the Bureau of Reclamation (Reclamation) challenging Reclamation's decisions to deny the City an allocation of firm power and instead sell power to Pacific Gas & Electric Company ("PG&E"), an investor-owned utility company. The City of Santa Clara alleged that Reclamation's decisions violated numerous rights, including

Santa Clara's preference rights. PG&E counterclaimed for funds held in escrow. In the context of reviewing PG&E's counterclaim, the Court stated that "past sales are void if unlawful, for administrative actions taken in violation of statutory authorization or requirement are of no effect." 572 F.2d at 677. Cowlitz seizes on this language to argue that, regardless of the 90-day statute of limitations in the NPA, the LRAs are void because, according to Cowlitz, the LRAs were executed in violation of BPA's statutory authority. Cowlitz Br. Ex.,WP-07-R-CO-01, at 37. BPA believes that Cowlitz reads too much into *Santa Clara*.

At the outset, there was no statutory provision at issue in *Santa Clara* analogous to section 9(e)(5) of the NPA. Specifically, the statutes under review in that case did not contain a statute of limitations that operated as a jurisdictional bar to preclude judicial review of final actions that are filed more than 90 days (or a similarly short time frame) after the final action was taken. It may well be that, if such a jurisdictional bar existed, the Court would have found past sales unreviewable. However, it is pure speculation to guess what action the Court may have taken if there was a statutory provision similar to section 9(e)(5) of the NPA. But, given the absence of an analogous jurisdictional bar, the Court's comment in *Santa Clara* about "past sales" has little probative value.

In addition, Cowlitz's argument begs the question because the language from *Santa Clara* cited by Cowlitz states that "past sales are void *if unlawful*." 572 F.2d at 677 (emphasis added). The very issue under consideration is *whether* the LRAs are unlawful. As explained, despite ample opportunity, the Court has not held that the LRAs are unlawful. It is notable that, although the Court issued a total of six opinions that directly or indirectly implicated aspects of the LRAs, the Court did not hold or suggest that the LRAs were unlawful. Indeed, because none of the parties to these six cases ever challenged either the validity of the LRAs themselves (other than the litigation penalty provision) or BPA's rate treatment of the LRAs, the Court had no reason to consider these issues.

Moreover, in *Santa Clara*, the Court merely articulated the general proposition that agency action taken in violation of statutory authority is void, and therefore past sales are also void if taken in violation of statutory authority. However, it is notable that the Court did not hold that the challenged power sales at issue in that case were void. On the contrary, the Court demonstrated a reluctance to make such a determination and instead preserved the viability of the contracts. In particular, the Court remanded aspects of the case to the district court, suggested various alternative remedies that were available to the district court, and stated that "what we suggest does not invalidate or violate either contract." 572 F.2d at 678.

Cowlitz further contends that section 9(e)(5) is not a "substantive" provision, and does not "validate ultra vires contracts" or "prevent BPA itself from refusing to perform a contract it subsequently realizes was beyond its authority even though no one challenged it in court …" Cowlitz, Br. Ex., WP-07-R-CO-01, at 38. However, BPA has not "subsequently realize[d]" that the LRAs were beyond BPA's statutory authority and neither BPA nor the Ninth Circuit has stated or indicated that the LRAs were ultra vires. As explained more fully below, BPA believes the LRAs are valid and binding agreements that, as described in *Snohomish*, were part of an "independent benefit or program," that is, BPA's Load Reduction Program.

C. The LRAs Are Part of an Independent Benefit or Program

Many of the arguments of Cowlitz and APAC regarding the alleged invalidity of the LRAs are based on their perception that the LRAs are essentially "fruit of the poisonous tree." Cowlitz Br., WP-07-B-CO-01, at 55; APAC Br., WP-07-B-AP-01, at 20, 23; Cowlitz Br. Ex., WP-07-R-CO-01, at 43. According to Cowlitz, the LRAs are not part of any "independent benefit or program" as described in *Snohomish* but rather are "part and parcel" of the same illegal act and the same illegal REP Settlement Agreement set aside in *PGE.* Cowlitz Br., WP-07-B-CO-01, at 54-55; APAC Br., WP-07-B-AP-01, at 23. For this reason, Cowlitz contends that *PGE* undermines the basis for the LRAs. Cowlitz Br., WP-07-B-CO-01, at 55. In its Brief on Exceptions, Cowlitz goes so far as to suggest that "'the entire agreement is part of an integrated scheme to contravene public policy' … Here the entire LRAs were direct responses to the 2000 REP Settlement Agreements and not independent of them." Cowlitz Br. Ex., WP-07-R-CO-01, at 47 (citations omitted). Similarly, Cowlitz contends that "[t]he LRAs, like the REP Settlement Agreements, are simply vehicles to establish REP benefits." *Id*., at 33.

These arguments mischaracterize the LRAs. The suggestion that the LRAs may have been part of a "scheme" to contravene public policy is completely unfounded and, as discussed below, the LRAs were not a direct response to the 2000 REP Settlement Agreements. Rather, they were a direct response to the 2001 power crisis as part of BPA's Load Reduction Program.

BPA has never denied that there is a nexus between the financial components of the LRAs and the 2000 REP Settlement Agreements. Indeed, Staff's testimony is in accord with the Court's finding that "[t]he LRAs eliminated BPA's obligation to deliver virtually all power to PacifiCorp and PSE for the FY 2002-2006 time period in exchange for cash payments." *Snohomish,* 340 F.3d at 1148. However, the LRAs are fundamentally different agreements than the 2000 REP Settlement Agreements. Contrary to the arguments of Cowlitz and APAC, the LRAs were not "part and parcel" of the 2000 REP Settlement Agreements. Rather, they were "part and parcel" of BPA's 2001 Load Reduction Program. The LRAs with Puget and PacifiCorp were two of the 71load reduction agreements that BPA executed with preference customers, IOUs, and DSIs for the sole reason of responding to the 2001 power crisis. These LRAs were an important part of BPA's effort to marshal all resources available to avoid a potentially catastrophic rate increase of 250 percent. At a time when the entire West Coast was paying exorbitant prices for electric power and the Pacific Southwest was experiencing rolling blackouts, BPA's Load Reduction Program was instrumental in keeping the lights on and the power flowing in the Pacific Northwest at manageable rates. *See*, *e.g*., *Morgan Stanley Capital Group v. Pub. Util. Dist. No. 1 of Snohomish County, Wash*., 128 S. Ct. 2733, 2743 (2008) (noting that while electricity had historically averaged approximately $24/MWh in the Pacific Northwest, prices on the California spot market peaked at $3,300/MWh during the energy crisis). It is for precisely this reason that the Ninth Circuit described BPA's Load Reduction Program as "an astounding success." *Bell*, 340 F.3d at 948.

From BPA's perspective, the LRAs with Puget and PacifiCorp were a critical component of BPA's Load Reduction Program. These LRAs represented a substantial contribution of low-cost power by the IOUs when BPA's customers, including its preference customers, needed it most. The success of the Load Reduction Program depended on a meaningful level of participation by customers from all BPA customer groups. The LRAs with PacifiCorp and Puget provided such participation for the IOUs. There is no doubt that all BPA customers, including preference customers, benefited substantially from the success of BPA's Load Reduction Program.

Despite the undeniable success of the Load Reduction Program, APAC, Cowlitz, and Canby argue that the LRAs with Puget and PacifiCorp did little more than allow BPA to purchase back power that BPA never should have sold these utilities in the first place. APAC Br., WP-07-B-AP-01, at 19; Cowlitz Br., WP-07-B-CO-01, at 54-55; Canby, Br. Ex., WP-07-R-CA-01, at 5-9. In its Brief on Exceptions, Cowlitz states that the load reduction effect of the agreements was simply removing the load that BPA unlawfully sold to the IOUs in the first place. Cowlitz Br. Ex., WP-07-R-CO-01, at 48. This argument, however, is inaccurate and misses the point. At the time the LRAs were executed, the 2000 REP Settlement Agreements were valid and binding agreements. BPA was responding to an unprecedented power crisis that was largely caused by drought and a dysfunctional market. Given the urgency of the power crisis, BPA took decisive action utilizing the tools available to BPA at the time. No one had any idea when the power crisis would end, how it would end, and what long-term consequences would follow. The important point is that, at the time they were executed, the LRAs with Puget and PacifiCorp were critical to the success of BPA's Load Reduction Program and helped extricate the Pacific Northwest from an enormously complex, difficult, and dire situation caused primarily by events outside of BPA's control. Thus, the efficacy of the LRAs in contributing to solving a critical power supply problem and stabilizing regional rates has never been subject to serious question. The widespread benefits provided by the Load Reduction Program offer the most likely explanation of why the LRAs with PacifiCorp and Puget were never challenged.

Similarly, Cowlitz argues in its Brief on Exceptions that BPA's "motive" for executing the LRAs is "irrelevant." Cowlitz Br. Ex., WP-07-R-CO-01, at 47. However, the issue of BPA's "motive" directly responds to the erroneous assertion that the LRAs were nothing other than a change in the form of consideration, from power to money, under the 2000 REP Settlement Agreements. *Id*. The genesis of the LRAs, as well as the purposes served by the LRAs, is critical to understanding that these agreements were a central element of BPA's Load Reduction Program and not simply a change in the form of consideration under the 2000 REP Settlement Agreements.

For these reasons, contrary to the arguments of Cowlitz and other preference customers, BPA believes the LRAs with Puget and PacifiCorp were very much a part of an "independent benefit or program" within the meaning of *Snohomish*. In *Snohomish*, the Court concluded that the "litigation penalty" provisions of the LRAs should be treated as amendments to the 2000 REP Settlement Agreements rather than as part of a separate agreement because "[t]he penalty is a direct response to the litigation over the 2000 REP Settlement Agreement and not an independent benefit or program." 506 F.3d at 1154. In contrast, the LRAs, with the exception of the "litigation penalty" provision, were not executed in response to the 2000 REP Settlement Agreements but rather were executed for the sole purpose of responding to the 2001 West Coast power crisis and were an integral component of BPA's larger Load Reduction Program. If there had not been a 2001 power crisis, there would have been no Load Reduction Program and no LRAs with PacifiCorp and Puget.

In these respects, the LRAs stand in stark contrast to the "litigation penalty" provision or the 2004 Amendments to the 2000 Settlement Agreements. Neither the litigation penalty provision nor the 2004 Amendments had any independent purpose apart from the 2000 REP Settlement Agreements.

This same logic applies to other contract provisions referenced by Cowlitz. In its Brief on Exceptions, Cowlitz accuses BPA of "selectively" applying the Court's opinions by treating some contract provisions as invalid, but not the LRAs. Cowlitz Br. Ex., WP-07-R-CO-01, at 43-45. As examples, Cowlitz cites BPA's treatment of the portion of Puget's 2001 Amended Settlement Agreement that pertains to the REP Settlement Agreements, BPA's treatment of a power sales contract attached as an exhibit to the 2000 REP Settlement Agreements, and BPA's treatment of certain conservation and renewable discount (C&RD) payments provided under the terms of the REP Settlement Agreements. *Id.* However, BPA believes the distinction between all of these contractual provisions and the LRAs is clear: BPA is treating these contractual provisions as invalid because they are akin to the litigation penalty provisions. That is, they are directly related to the REP Settlement Agreements and are not part of any independent benefit or program. Stated differently, these contract provisions have no purpose and provide no benefits apart from the REP Settlement Agreements. The same cannot be said of the LRAs, which were a central element of BPA's Load Reduction Program and contributed substantially to the success of that program. As such, BPA believes the LRAs are precisely the kind of "independent benefit or program" the Court referred to in *Snohomish.*

In addition, Cowlitz contends that the Court's reference to an "independent benefit or program" in *Snohomish* is merely "*dicta*" that should be given little weight. Cowlitz Br. Ex., WP-07-R-CO-01, at 45. BPA disagrees. This phrase was used by the Court as part of its rationale for carving out the litigation penalty provisions of the LRAs for separate treatment from the main text of the LRAs. 506 F.3d at 1154. Indeed, the Court used the phrase "independent benefits or program" in the context of a paragraph that the Court stated was expressly intended to provide "additional guidance to BPA." 506 F.3d at 1154.

Lastly, Cowlitz contends that the LRAs should be treated as invalid because they are allegedly supported by no consideration. Cowlitz Br. Ex., WP-07-R-CO-01, at 49-50. According to Cowlitz, there was no consideration because the IOUs had no lawful right to the power that they gave up for cash in the LRAs. *Id* at 49. Cowlitz contends that this circumstance distinguishes this case from *Bell*, where the DSIs gave up something that they unquestionably had a legal right to. *Id.* at 49-50.

In the LRAs, the IOUs arguably gave up much more than they received: the IOUs relinquished their rights to an extremely valuable supply of power during the midst of an unprecedented power crisis at a price that was below the prevailing market price for power. The benefits to BPA and its customers – especially preference customers – was that BPA could keep the lights on, maintain a reliable power supply, and do so at reasonable prices. It was due to this contribution by the IOUs, as well as similar contributions by the majority of BPA's other customers, that the Load Reduction Program was a success. Regardless of the source of the power, BPA and its customers clearly got the benefit of these contracts and they were supported by ample consideration.

For all these reasons, BPA believes the LRAs with PacifiCorp and Puget should continue to be treated as valid and binding agreements. The "litigation penalty" or reduction of risk payments will be treated as invalid payments in the same manner that the payments under the 2000 REP Settlement Agreements are treated.

Decision

For the reasons stated above, BPA will treat the LRAs as valid and binding agreements. BPA will treat the reduction of risk discount as invalid payments subject to repayment to BPA by Puget and PacifiCorp, and the amounts so recovered will be returned to preference customers in the same manner as payments under the 2000 REP Settlement Agreements.

8.3 Puget's LRA Superseded Its 2000 REP Settlement Agreement

Issue 1

Whether all of Puget's 2000 REP Settlement Agreement payments may be considered "protected" payments because the payments were made under the umbrella of Puget's unchallenged LRA, which superseded its 2000 REP Settlement Agreement.

Parties' Positions

Puget states that the assertion by an APAC witness that the LRAs "amended" the 2000 REP Settlement Agreements is incorrect with respect to Puget. IOU Br., WP-07-B-JP6-01, at 190-191. According to Puget, its 2001 Amended Settlement Agreement (Contract No. 01PB-10885) did not simply amend its 2000 REP Settlement Agreement, but "replaced and superseded PSE's 2000 REP Settlement Agreement in its entirety (prior to any payments thereunder)." *Id*. As a result, Puget contends that "all REP Settlement benefit payments for the period FY 2002 through BPA's suspension of payments in FY 2007 to PSE were pursuant to its" 2001 REP Amended Settlement Agreement and not pursuant to its 2000 REP Settlement Agreement. *Id*.

BPA Staff's Position

BPA Staff proposed to treat all benefits provided under the 2000 REP Settlement Agreements, including both payments and power delivered, as invalid. Marks, *et al.,* WP-07-E-BPA-62, at 2. However, in the process of calculating the Lookback Amounts for PacifiCorp and Puget, Staff proposed to treat payments under the LRAs with PacifiCorp and Puget as "protected" payments, meaning that the payments cannot be recovered in a Lookback Amount. *Id.* at 16. Staff did not address in testimony any legal issues associated with the unique circumstance presented by Puget's 2001 Amended Settlement Agreement, which supersedes in its entirety Puget's 2000 REP Settlement Agreement.

Evaluation of Positions

Puget argues its 2001 Amended Settlement Agreement did not simply amend its 2000 REP Settlement Agreement, but "replaced and superseded PSE's 2000 REP Settlement Agreement in its entirety (prior to any payments thereunder)." IOU Br., WP-07-B-JP6-01, at 190-191. As a result, Puget contends that all REP Settlement benefit payments to PSE for the period FY 2002 through suspension of payments in FY 2007 were pursuant to its 2001 REP Amended Settlement Agreement and not pursuant to its 2000 REP Settlement Agreement. *Id*. Puget argues the amounts subtracted from Puget's REP settlement benefits to determine a Lookback Amount must include all amounts paid under its LRA. *Id*.

Puget correctly states that its 2001 Amended Settlement Agreement with BPA "replaces and supersedes in entirety" Puget's 2000 REP Settlement Agreement. As a contract matter, Puget is also correct that Puget's 2001 Amended Settlement Agreement was the contractual vehicle used by BPA to provide Puget's 2000 REP Settlement Agreement benefits. However, BPA is not entirely clear from Puget's argument whether Puget is (1) simply trying to set the record straight and clarify that its 2001 Amended Settlement Agreement did not just amend its 2000 REP Settlement Agreement, but replaced and superseded its 2000 REP Settlement Agreement in its entirety, or (2) suggesting that, because its 2000 REP Settlement Agreement benefits were provided under the umbrella of its 2001 Amended Settlement Agreement, then all such payments are "protected" payments that must be excluded from Puget's Lookback Amount. Puget agreed with the summation of its argument as – if the load reduction agreements are valid, then *all of the settlement costs* for Puget are valid, and there is no Lookback. Tr. at 631. If such is Puget's position, then BPA strongly disagrees.

Puget's 2001 Amended Settlement Agreement serves dual purposes: it supersedes Puget's 2000 REP Settlement Agreement, and it addresses the rights and obligations of BPA and Puget with respect to Puget's agreement to reduce load under BPA's Load Reduction Program. Staff's proposal, in effect, severed Puget's 2001 Amended Settlement Agreement so that the portion of the agreement that pertains to Puget's 2000 REP settlement benefits is treated as invalid, which is precisely the treatment being afforded to the 2000 REP settlement benefits of all the other IOUs. At the same time, Staff proposed to treat the balance of Puget's 2001 Amended Settlement Agreement (excluding the reduction of risk or "litigation penalty" provision) as valid and binding, just as Staff proposed to treat PacifiCorp's LRA.

In *PGE*, the Court held that BPA's 2000 REP Settlement Agreements with the IOUs were invalid because BPA acted beyond the scope of its statutory authority. In *Golden NW*, the Court held that BPA improperly allocated costs of the invalid 2000 REP Settlement Agreements to preference customers' rates. The same logic applied by the Court in these cases applies with equal force to Puget's 2000 REP settlement benefits, regardless of whether the contractual mechanism used to provide those benefits was its 2001 Amended Settlement Agreement. Any interpretation that would continue to treat Puget's benefits under its 2000 REP Settlement Agreements, or the 2001 amendment, as valid directly conflicts with *PGE*.

In *Snohomish*, the Court found, in effect, that the provisions of the LRAs were severable and provided BPA guidance in determining whether a contract provision related to the 2000 REP Settlement Agreements should be treated as valid or invalid. In *Snohomish*, the Court found that the "litigation penalty" provisions of the LRAs were "not a part of a separate agreement" because they were "a direct response to the litigation over the 2000 REP Settlement Agreement and not an independent benefit or program." *Snohomish*, 506 F.3d at 1154. Further, the Court explained that, with respect to the 2004 Amendments to the 2000 REP Settlement Agreements, if the 2000 REP Settlement Agreements "undermined the basis" for the 2004 Amendments, then the amendments should be treated as invalid. *Snohomish*, 506 F.3d at 1154. In this case, there is no doubt that *PGE* undermined the basis for Puget obtaining any 2000 REP settlement benefits. BPA therefore finds that the provisions of Puget's 2001 Amended Settlement Agreement replacing the 2000 Settlement Agreement pertaining to the REP financial benefits are not tangential to the amended agreement and severable; rather they are directly related to the 2000 REP Settlement Agreements between PSE and BPA and not part of a separate agreement.

As noted, BPA believes the other provisions of Puget's 2001 Amended Settlement Agreement (other than the reduction of risk discount or "litigation penalty" provision) pertain to the central purpose of the agreement, which was to support BPA's Load Reduction Program. As BPA has explained, BPA believes its LRAs with PacifiCorp and Puget are part of "an independent benefit or program" within the meaning of Snohomish that remain valid and binding agreements. *Snohomish*, 506 F.3d at1154. As a result, BPA will treat the portion of Puget's 2001 Amended Settlement Agreement that pertains to its Load Reduction Agreement as BPA is treating its LRA with PacifiCorp. *See* Section 8.2.

Decision

All 2000 REP Settlement Agreement payments to Puget by BPA under the umbrella of Puget's 2001 Amended Settlement Agreement will be treated as invalid and subject to the Lookback analysis, whereas all load reduction payments under the 2001 Amended Settlement Agreement will be treated as LRA payments and "protected."

8.4 IOU Retention of Funds Under the 2000 REP Settlement Agreements

Issue 1

Whether BPA is prohibited from recovering funds paid to the IOUs under the 2000 REP Settlement Agreements because they contain an "invalidity" clause stating that IOUs are entitled to retain all funds received in the event a court determines the 2000 Settlement Agreements are invalid.

Parties' Positions

The OPUC contends that BPA's Lookback proposal is "prohibited" by the 2000 REP Settlement Agreements because these agreements contain an invalidity clause. OPUC Br., WP-07-B-PU-02, at 8-9. According to the OPUC, the invalidity clause allows the IOUs to retain all funds received from BPA under the 2000 REP Settlement Agreements in the event the Ninth Circuit determines that the agreements are "unlawful, void or unenforceable." *Id*. The IOUs raise the same argument and expand on this argument in their Brief on Exceptions. IOU Br., WP-07-B-JP6-01, at 177-179; IOU Br. Ex., WP-07-R-JP6-01, at 3-8. The OPUC states that, given the invalidity clause, BPA "will be found in breach of the 2000 REP Settlement Agreements and required to return any recovered Lookback Amounts to investor-owned utilities" if BPA goes through with the Lookback. OPUC Br., WP-07-B-PU-02, at 9.

BPA Staff's Position

BPA Staff did not address this issue in testimony because it is a legal issue.

Evaluation of Positions

The OPUC and the IOUs are correct that the 2000 REP Settlement Agreements contain an invalidity clause stating that, in the event the Ninth Circuit determines "that this Agreement … is unlawful, void, or unenforceable," then all monetary benefits provided to the IOU under the agreement "shall be retained" by the IOUs. Exhibit WP-07-E-JP6-15, at 17. The clause further states that this section "shall survive notwithstanding any determination that any other provision of this Agreement (or the exhibits) is unlawful, void, or unenforceable." *Id*. However, because the Court held that BPA acted beyond the scope of its statutory authority when it executed the 2000 REP Settlement Agreements and the Court did not carve out any exception with respect to the invalidity clause or any other clause, BPA believes the 2000 REP Settlement Agreements are invalid in their entirety. As a result, the invalidity clause is also invalid and cannot be used as a shield to prohibit BPA from recovering 2000 REP Settlement Agreement benefits from the IOUs through the Lookback proposal.

In their Brief on Exceptions, the IOUs, contend that "[t]he Ninth Circuit did not hold that the 2000 REP Settlement Agreements are invalid in their entirety," and that BPA "assumes, without adequate support" that the agreements are invalid. IOU Br. Ex., WP-07-R-JP6-01, at 4. However, as a general rule, if a contract is set aside because it is beyond the scope of an agency's statutory authority, then, unless the Court indicates otherwise, the contract is invalid, and no provision of the invalid contract can be enforced against the agency. "In general, a contract entered in violation of federal statutory or regulatory law is unenforceable… This is because 'one who has participated in an illegal act cannot be permitted to assert in a court of justice any right founded upon or growing out of the illegal transaction.'" *Resolution Trust Corp. v. Home Savings of America*, 946 F.2d 93, 96 (8th Cir. 1991). *See also Miller v. Rowland*, 999 F.2d 389, 392 (9th Cir. 1993) (citing well-established state law for the proposition that "[n]o contractual obligation may be enforced against a public agency unless it appears the agency was authorized by the Constitution or statute to incur the obligation; a contract entered into by a governmental entity without the requisite constitutional or statutory authority is void and unenforceable."); s*ee also*, Richard A. Lord, Williston on Contracts, 19:41 (4th ed. 1998) ("If a statute directly prohibits an agreement or sale, it is clear that the courts will not lend their aid to any attempt by the parties to enforce the agreement.").

In *PGE*, the Court found that the 2000 REP Settlement Agreements were invalid because BPA entered into the agreements without requisite statutory authority. Therefore, unless the Court indicates otherwise, no obligation that may have existed under the agreements, such as the invalidity clause, can be enforced against BPA.

In their Brief on Exceptions the IOUs argue that the invalidity clause, by its very language, was intended to be severable from the 2000 REP Settlement Agreement and survive even if the agreement was set aside. IOU Br. Ex., WP-07-R-JP6-01, at 6-7. However, given the nature of the Court's ruling in *PGE* and *Golden NW,* BPA does not believe the parties' contractual intent can prevail over the Court's express finding that, by executing the 2000 REP Settlement Agreements, BPA acted beyond the scope of its statutory authority. Indeed, the IOUs' arguments are based, in part, on minimizing the true nature of the Court's ruling. For instance, the IOUs state that "the Ninth Circuit in *Golden Northwest* held that BPA made a ratemaking error that resulted in overcharges to its preference customers." IOU Br. Ex., WP-07-R-JP6-01, at 7. However, the Court did not simply hold that BPA made a ratemaking error. The Court held that BPA acted beyond the scope of its statutory authority, which directly leads to BPA's conclusion that the agreements are invalid and unenforceable.

Notably, in *Snohomish*, the Court demonstrated that if it wants to carve out a contract provision from a BPA contract and treat that provision differently than other provisions of the contract, it knows how to do so. In that case, the Court effectively severed the "litigation penalty" provision of the LRAs with PacifiCorp and Puget from the balance of the LRAs to treat that provision as separate and distinct from all other provisions of the LRAs. *Snohomish*, 506 F.3d at 1154. The Court did nothing similar with respect to the invalidity clause or any other clause of the 2000 REP Settlement Agreements.

Lastly, to support the argument that the 2000 REP Settlement Agreements are not invalid in their entirety, the IOUs cite a passage from *Snohomish* stating that, on remand, "BPA might conclude that at least some of the contract provisions [of the 2000 REP Settlement Agreements] continue to be valid and enforceable." *Snohomish*, 501 F.ed at 1154 (emphasis added). However, this language is qualified by the phrase "subject to modifications to make them conform to our prior opinions and the requirements of the NWPA." *Id*. BPA believes that, even assuming *arguendo* that some isolated clause of the 2000 REP Settlement Agreements could be considered valid – which BPA does not believe to be the case - the invalidity clause could not survive this qualification. By its very nature, the invalidity clause conflicts with rather than conforms to the Court's opinions.

BPA previously explained regarding the nature and scope of the remand, BPA views the logic and language of the *PGE* and *Golden NW* opinions as the substantive equivalent of an instruction that BPA remedy what the Court itself describes as a "plain violation" of the law. The Court has clearly ruled in favor of BPA's preference customers and found that preference customers' rates were higher than they should have been because BPA unlawfully allocated the costs of the 2000 REP Settlement Agreements to their rates. BPA believes that allowing the IOUs to retain the funds they received under the 2000 REP Settlement Agreements, based solely on the invalidity clause, would undermine the Court's opinions. It would yield the incongruous result of having the Court declare the 2000 REP Settlement Agreements invalid while permitting the IOUs to use the same invalid agreements to retain the funds the Court said they were not entitled to receive. For reasons such as this, the courts "will not enforce an illegal contract where to do so would sanction the very type of bargain which a statute outlaws and [would] deprive the public of protections which the legislature has conferred." *De Vera v. Blaz*, 851 F.2d 294, 296-297 (9th Cir. 1988) (*citing United States v. Mississippi Valley Generating Co.,* 364 U.S. 520, 563 (1961)). BPA does not believe the Court's decisions can reasonably be interpreted to yield this result or deprive preference customers of an effective remedy.

Decision

The invalidity clause of the 2000 REP Settlement Agreements falls with the agreements in their entirety, and, therefore, does not prohibit BPA from recovering overpayments that BPA made to the IOUs under those agreements.

8.5 Rate Treatment of the PacifiCorp and Puget LRAs

Issue 1

Whether BPA should treat the payments made under the LRAs with PacifiCorp and Puget as "protected" payments that are excluded from the Lookback analysis and as costs that are properly allocated to preference customers' rates.

Parties' Positions

BPA's preference customers generally take the position that, regardless of whether BPA treats the LRAs as null and void, section 7(b)(2) of the Northwest Power Act prohibits BPA from allocating costs associated with the LRAs with PacifiCorp and Puget to preference customers' rates because these are costs of the 2000 REP Settlement Agreements. Tillamook Br., WP-07-B-JP24-01 at 13-15; Cowlitz Br., WP-07-B-CO-01, at 56-58; APAC Br., WP-07-B-AP-01, at 18-24; PPC Br., WP-07-B-JP25-01, at 38-40; WPAG Br., WP-07-B-WA-01, at 29-30. The joint brief filed by Tillamook and Central Lincoln ("Tillamook") addresses this issue most extensively and directly.

In contrast to these arguments, the IOUs contend that "[t]he validity of the 'LRAs' and payments thereunder were not timely challenged and cannot be included in any Lookback analysis." IOU Br., WP-07-B-JP6-01, at 11. CUB comments that "BPA's decision to honor the LRA payments (other than those made pursuant to the Risk Reduction Discount provision) made by BPA to PacifiCorp and Puget Sound Energy by excluding them from the Lookback calculation is consistent with the Ninth Circuit's rulings." CUB Br., WP-07-B-CU-01, at 16. WUTC and the IOUs are in accord. IOU Br., WP-07-B-JP6-01, at 11-13; WUTC Br., WP-07-B-WU-01, at 19-21.

<u>BPA Staff's Position</u>

In the WP-07 Supplemental Proposal, BPA Staff proposed to treat the LRAs as valid and binding contracts. 73 Fed. Reg. at 7,554 (Feb. 8, 2008). Staff proposed that the LRA payments to PacifiCorp and Puget would be treated as "protected" payments that are not subject to recovery as part of their Lookback Amounts and would continue to be allocated to preference customers' rates. Bliven*, et al.,* WP-07-E-BPA-52, at 19-20. Staff explained that the LRAs were contracts with PacifiCorp and Puget where BPA purchased power from the utilities as part of BPA's Load Reduction Program to limit BPA's exposure to volatile energy prices during the West Coast energy crisis of 2001. *Id*. at 9-10. Staff further explained that petitions to review the LRAs did not challenge final actions and that petitions that attempted to challenge only the reduction of risk provision of the LRAs, were dismissed as moot. Bliven, et al., WP-07-E-BPA-52, at 2-3.

<u>Evaluation of Positions</u>

BPA's preference customers contend that section 7(b)(2) of the Northwest Power Act prohibits BPA from allocating costs associated with the LRAs to preference customers' rates because these are costs of the 2000 REP Settlement Agreements. Tillamook Br., WP-07-B-JP24-01 at 13-15; Cowlitz Br., WP-07-B-CO-01, at 56-58; APAC Br., WP-07-B-AP-01, at 18-24; PPC Br., WP-07-B-JP25-01, at 38-40; WPAG Br., WP-07-B-WA-01, at 29-30. These parties continue to assert this position in their Briefs on Exceptions. Tillamook Br. Ex., WP-07-R-JP24-01; Cowlitz Br. Ex., WP-07-R-CO-01 at 42-43; APAC Br. Ex., WP-07-R-AP-01, at 5-6; WPAG Br. Ex., WP-07-R-WA-01, at 15-17; PPC Br. Ex., WP-07-R-PP-01, at 23.

BPA believes the arguments that BPA cannot allocate costs associated with the LRAs to preference customers' rates do not give adequate consideration to the 90-day statute of limitations in the Northwest Power Act and fail to address important differences between the LRAs and the 2000 REP Settlement Agreements, as well as important differences between BPA's rate treatment of the LRAs and BPA's rate treatment of the 2000 REP Settlement Agreements. In evaluating the parties' positions, it is valuable to address these issues in two parts: (1) whether BPA should treat payments to PacifiCorp and Puget under the LRAs as protected payments that these utilities are entitled to retain, and (2) if so, whether the Court's opinions prohibit BPA from including costs of the LRAs in preference customers' rates. In addition, because of the overlap between these issues and the discussion in section 8.2, above, regarding the validity of the LRAs, BPA hereby incorporates by reference that discussion into this issue.

A. PacifiCorp and Puget Should Retain the Financial Benefits of the LRAs

According to Tillamook, "[t]he question of whether the LRAs are lawful or unlawful has no relevance to the applicability of the Section 7(b)(2) rate ceiling" because "[t]he law dictates that the Section 7(b)(2) rate ceiling applies to all REP costs, even those lawfully incurred." Tillamook Br., WP-07-B-JP24-01, at 2. Tillamook argues that "[t]he bottom line is that if the preference customer rates have been increased to fund any form of REP benefits … then those rates violate Section 7(b)(2)." *Id.* at 11. Tillamook contends that "[Staff] has repeatedly and openly admitted throughout its testimony in this proceeding that the LRAs were merely one aspect of the total REP benefits allocated to PacifiCorp and Puget Sound Energy" and as such the LRAs "are subject to the same statutory rate ceiling as any other REP Settlement Agreement costs." *Id.* at 12-13. Cowlitz, APAC, PPC, and WPAG raise substantially similar arguments in their Initial Briefs as well as in their Briefs on Exceptions. Cowlitz Br., WP-07-B-CO-01, at 58; APAC Br., WP-07-B-AP-01, at 18-24; PPC Br., WP-07-B-JP25-01, at 38-40; WPAG Br., WP-07-B-WA-01, at 29-30; Tillamook Br. Ex., WP-07-R-JP24-01; Cowlitz Br. Ex., WP-07-R-CO-01, at 42-43; APAC Br. Ex.,WP-07-R-AP-01, at 5-6; WPAG Br. Ex., WP-07-R-WA-01, at 15-17; PPC Br. Ex., WP-07-R-PP-01, at 23.

Tillamook recognizes that "BPA may choose to continue to honor the validity of its LRAs," and if BPA does, "there would be no reason for BPA to recover such payments from PacifiCorp and Puget Sound Energy through its Lookback Amount." Tillamook Br., WP-07-B-JP24-01, at 16. In such a case, Tillamook states that these IOUs "would be entitled to retain the benefit of these agreements." *Id.* However, according to Tillamook, "[w]hat the [Northwest Power Act] categorically prohibits BPA from doing … is recovering or retaining any portion of the costs of the LRAs from its preference customers." *Id.*

With respect to the 90-day statute of limitations, Tillamook acknowledges that "there were no timely appeals filed with respect to the LRAs." *Id.* at 4. However, Tillamook cites *Blachly-Lane Electric Cooperative Ass'n. v. U.S. Dept. of Energy*, 79 Fed. Appx. 975 (9th Cir. 2003) ("*Blachly-Lane*"), for the proposition that "BPA's ratemaking treatment of the LRAs through this proceeding is not time-barred even though BPA's original decision to execute the LRAs may be." *Id.* at 17. In its Brief on Exceptions, Cowlitz cites *Blachly-Lane* for a similar proposition, but adds that "the issue in this case is how much REP benefits BPA may recover in rates to preference customers, and that question turns in part on whether the LRAs were lawful, not on whether they were timely challenged." Cowlitz Br. Ex., WP-07-R-CO-01, at 39.

At the outset, it is important to note that the Court's opinions do not address the issues of the validity of the LRAs themselves or the appropriate rate treatment of the LRAs. Similarly, neither the LRAs themselves nor BPA's rate determinations under the LRAs have been specifically remanded to BPA. Although the Court stated that, on remand, "BPA could determine that our prior opinions undermined the entire 2001 LRAs," the Court also noted that "BPA may have other options" and expressed "no judgment on the merits of BPA's options." *Snohomish*, 506 F.3d at 1155. As explained in section 8.2 above, regarding the validity of the LRAs, BPA believes the Court's remand provides BPA considerable discretion to determine the appropriate treatment of the LRAs.

BPA does not agree with Tillamook that "the question of whether the LRAs are lawful or unlawful has no relevance to the applicability of the Section 7(b)(2) rate ceiling." Tillamook Br., WP-07-B-JP24-01, at 2. In *Golden NW*, the Court held that BPA improperly allocated costs of the 2000 REP Settlement Agreements to preference customers' rates *after* the Court held in *PGE* that the agreements themselves were invalid. Indeed, in *Golden NW*, the Court stated that "[o]ur holding in *Portland General Electric* is dispositive." *Golden NW*, 501 F.3d at 1048. Therefore, BPA believes the validity of the underlying contracts is far from irrelevant and is an important consideration in determining the propriety of the rate treatment of the LRAs. Indeed, Cowlitz appears to agree with BPA on this point, stating that the issue of the appropriate rate treatment of the LRAs "turns in part on whether the LRAs were lawful." Cowlitz Br. Ex., WP-07-R-CO-01, at 39.

In the instant case, the validity of the LRAs bears directly on the question of whether the payments to PacifiCorp and Puget under the LRAs should continue to be treated as "protected." The reason is that if the LRAs are treated as valid contracts, then it necessarily follows that PacifiCorp and Puget have the right to retain the payments they received under those agreements. If the LRAs are treated as invalid, then such payments are more likely subject to refund.

As explained in section 8.2, BPA has decided that the LRAs should be treated as valid and binding agreements. In the LRAs, PacifiCorp and Puget agreed to forgo all power deliveries they were entitled to receive for FY 2002-2006 and, in exchange, they accepted financial payments from BPA that were less than the fair market value of the power they gave up. These agreements have now been fully performed, and all of BPA's customers, including preference customers, received substantial benefits from these agreements because, as previously explained, the LRAs contributed substantially to reducing a BPA rate increase from 250 percent to 46 percent.

BPA believes that attempting to recover these payments from PacifiCorp and Puget would deprive these IOUs of the benefit of their bargain, arguably placing BPA in breach of contract and running afoul of BPA's statutory obligations to treat its contracts as "binding in accordance with their terms." 16 U.S.C. § 832d(a). Therefore, because BPA has decided the LRAs are valid and binding contracts, BPA should treat the payments to PacifiCorp and Puget under the LRAs as "protected" payments that these utilities are entitled to retain.

It is worth noting that Tillamook appears to agree with BPA on this point. Tillamook states that "BPA may choose to continue to honor the validity of its LRAs" and if BPA does, "there would be no reason for BPA to recover such payments from PacifiCorp and Puget Sound Energy through its Lookback Amount." Tillamook Br., WP-07-B-JP24-01, at 16. In such a case, Tillamook states that these IOUs "would be entitled to retain the benefit of these agreements." *Id.*

B. BPA's Rate Treatment of the LRAs Further Demonstrates That They Were Part of an Independent Benefit or Program That Was Never Challenged

1. The Applicability of Section 9(e)(5) of the NPA

Tillamook argues that the Northwest Power Act "categorically prohibits" BPA from "recovering or retaining any portion of the costs of the LRAs from its preference customers." Tillamook Br., WP-07-B-JP24-01, at 16. This conclusion stems from the premise of Tillamook's argument that "the LRA payments were REP benefits," and BPA cannot allocate any REP costs to preference customers' rates. *Id*. at 11-12; Tillamook Br. Ex., WP-07-R-JP24-01, at 3. WPAG and PPC, in their Briefs on Exceptions, contend that BPA, by treating the costs of the LRAs as "protected" payments and allocating such costs to preference customers' rates, is repeating the same mistakes the Court found unlawful in *GNA*. WPAG Br. Ex., WP-07-R-WA-01, at 17; PPC Br. Ex., WP-07-R-PP-01, at 23. However, before turning to the merits of these arguments, a threshold issue that pertains to jurisdiction must be addressed: no petitions for review were ever filed challenging either the LRAs themselves or BPA's decision to allocate the costs of the LRAs to preference customers' rates. Because BPA's decision to allocate the costs of the LRAs to preference customers' rates was made in the context of BPA's WP-02 rate proceeding, the 90-day statute of limitations to challenge BPA's rate treatment of the LRAs has long since expired.

Section 9(e)(5) of the Northwest Power Act contains a 90-day statute of limitations to challenge final actions or the implementation of final actions taken by BPA. 16 U.S.C. § 839f(e)(5). If such challenges are not filed within the 90-day time frame, they are "barred." *Id.* As explained in section 8.2, above, although the LRAs were final actions subject to challenge by the filing of a timely petition for review, no such petitions were ever filed. *Public Utility District No. 1 of Grays Harbor, Wash. v. Bonneville Power Admin.*, 250 Fed. Appx. 820 (9th Cir. 2007). Indeed, Tillamook concedes that "there were no timely appeals filed with respect to the LRAs." Tillamook Br., WP-07-B-JP24-01, at 4.

Tillamook attempts to distinguish between challenges to BPA's contract decisions and challenges to BPA's rate decisions, arguing "the fact that the LRA contracts themselves may not be challenged does not insulate BPA from judicial scrutiny of its rate-making treatment of them." *Id*. at 17. In support of this proposition, Tillamook cites *Blachly-Lane.* Cowlitz, APAC and WPAG raise similar arguments. Cowlitz Br., WP-07-B-CO-01, at 56-57; APAC Br., WP-07-B-AP-01, at 24; WPAG Br. Ex., WP-07-R-WA-01, at 15-16; Cowlitz Br. Ex., WP-07-R-CO-01 at 39. Although Tillamook acknowledges that no timely petitions for review were ever filed challenging the LRAs themselves, Tillamook fails to acknowledge that no timely petitions for review were ever filed challenging BPA's rate treatment of the LRAs as well. BPA believes that its rate treatment of the LRAs is insulated from judicial scrutiny for the same reasons and to the same extent that the LRAs themselves are insulated from judicial scrutiny.

For this reason, BPA believes *Blachly-Lane* is inapposite. Regardless of whether a party challenges a BPA contract determination or a BPA rate determination, a petition for review must be filed within 90 days of the date of the final action. In this case, no timely petitions for review were ever filed challenging either the LRAs themselves or BPA's rate treatment of the LRAs. Tillamook acknowledges that "[a]s with the REP Settlement Agreements, BPA charged these costs [of the LRAs] to its preference customers through its FY 2002-2006 rates," which were under review in *Golden NW*. *Id.* at 4. Given that BPA's rate decisions with respect to BPA's FY 2002-2006 wholesale power rates became a final action subject to review on October 17, 2003, and none of the numerous petitions for review filed in that case challenged BPA's rate treatment of the LRAs, the 90-day statute of limitations has run, and judicial review of these rate determinations is barred. 16 U.S.C. § 839f(e)(5). *Golden NW*, 501 F.3d at 1043.

In their Briefs on Exceptions, numerous preference customers disagree with BPA's position regarding the application of the 90-day statute of limitations. Cowlitz contends that "[t]here can be no question that challenges to the WP-02 rates were timely filed and are still pending and that the statute of limitations on the WP-07 rates has not run." Cowlitz Br. Ex., WP-07-R-CO-01 at 39. Tillamook, APAC and WPAG are generally in accord. Tillamook Br. Ex., WP-07-R-JP24-01, at 7; APAC Br. Ex., WP-07-R-AP-01, at 5-6; WPAG Br. Ex., WP-07-R-WA-01, at 15-17.

BPA does not agree with these arguments. Although BPA believes it has considerable discretion to fashion a remedy under the remand order, BPA's discretion is not boundless. BPA does not believe it has the latitude to breathe new life into either contract challenges that are time-barred or challenges to rate matters that were based on those contracts and never raised. BPA believes the remand cannot be used as a vehicle for parties to resurrect arguments they should reasonably have raised, but chose not to. If such arguments could be presented anew, then the 90-day jurisdictional bar would, for all intents and purposes, be eviscerated. In BPA's opinion, those BPA decisions that were challenged by the parties as part of their initial challenge to BPA's WP-02 power rates (including BPA's supplemental power rates) and that are implicated by the remand order are subject to reconsideration under the remand, as are all issues that were covered by the now-invalidated settlement agreements. However, BPA believes that those issues that were never raised, and reasonably should have been raised, are time barred.

The failure of preference customers to challenge both the LRAs themselves and BPA's rate treatment of the LRAs in the WP-02 rate proceeding stands in stark contrast to their actions with respect to the 2000 REP Settlement Agreements. In *PGE*, preference customers filed timely petitions for review challenging the 2000 REP Settlement Agreements, and in *Golden NW*, preference customers filed timely petitions for review challenging BPA's rate treatment of the 2000 REP Settlement Agreements. In contrast, no petitions for review were filed challenging the LRAs themselves or BPA's rate treatment of the LRAs. The most likely reason no petitions were filed is that, at the time, preference customers generally supported the LRAs due to the substantial rate benefits they received from these agreements. However, regardless of the reason the bottom line is the same: because the LRAs themselves, and BPA's rate decisions respecting the LRAs, were not challenged on a timely basis, such challenges are barred, and the LRAs and BPA's rate decisions respecting the LRAs should be treated as presumptively valid.

The IOUs concur with BPA's position and contend that "[t]he validity of the 'LRAs' and payments thereunder were not timely challenged and cannot be included in any Lookback analysis." IOU Br., WP-07-B-JP6-01, at 11. CUB comments that "[Staff's proposal] to honor the LRA payments (other than those made pursuant to the Risk Reduction Discount provision) made by BPA to PacifiCorp and Puget Sound Energy by excluding them from the Lookback calculation is consistent with the Ninth Circuit's rulings." CUB Br., WP-07-B-CU-01, at 16. WUTC and the IOUs are in accord. IOU Br., WP-07-B-JP6-01, at 11-13; WUTC Br., WP-07-B-WU-01, at 19-21.

The IOUs assert that "no party filed a timely petition for review of the 2001 LRAs," and the Ninth Circuit dismissed an untimely challenge to the LRAs for lack of jurisdiction in *Snohomish*. IOU Br., WP-07B-JP6-01, at 12. Therefore, the IOUs contend that "the propriety of the LRAs aside from any reduction of risk discount provision was not remanded to BPA and is not properly before BPA in this or any other proceeding." *Id.* at 13. The IOUs, CUB, and WUTC agree that it is fully consistent with *Snohomish* to recognize the continued validity of the LRAs separate and apart from the reduction of risk discount provision. CUB Br., WP-07-B-CU-01, at 15-16; WUTC Br., WP-07-B-WU-01, at 19-21. WUTC contends that BPA should "continue to honor these contracts" and that "BPA's treatment of the LRAs rests on firm legal grounds." WUTC Br., WP-07-B-WU-01, at 20.

2. BPA's Rate Treatment of the LRAs.

The failure of preference customers to challenge both the LRAs and BPA's rate determinations with respect to the LRAs in the WP-02 rate proceeding (as well as in *PGE* and *GNW*) is significant not only from a jurisdictional perspective, but also from a substantive perspective. The preference customers' arguments to exclude LRA costs from their rates focus predominantly on the financial nexus between the LRAs and the 2000 REP Settlement Agreements – a nexus BPA does not deny. However, preference customers' arguments take that nexus too far and disregard the substantial differences between the 2000 REP Settlement Agreements and the LRAs, and in particular, the differences between BPA's rate treatment of the 2000 REP Settlement Agreements and BPA's rate treatment of the LRAs. As explained below, these differences are important because they further demonstrate why the LRAs are part of an independent benefit or program within the meaning of *Snohomish*.

For ratemaking purposes, the LRAs were not treated the same as the 2000 REP Settlement Agreements. Rather, because the LRAs were part of BPA's Load Reduction Program, they were treated in the same fashion as all other BPA load reduction agreements (*e.g.,* those with the DSIs and preference customers) as well as all other BPA augmentation purchases to meet load under the Load Reduction Program. Whereas BPA allocated the costs of the 2000 REP Settlement Agreements to preference customers' rates through the application of section 7(g) of the Northwest Power Act, the costs of LRAs with PacifiCorp and Puget were augmentation expenses that were recovered through the Load-Based Cost Recovery Adjustment Clause "LB CRAC).

In *Golden NW*, the Court rejected BPA's classification of the 2000 REP Settlement Agreements as an ordinary cost of doing business that could be recovered under section 7(g). *Golden NW*, 501 F.3d at 1048. However, the rate mechanisms used by BPA to recover and allocate costs under the LB CRAC were significantly different than the rate mechanisms used by BPA to allocate and recover costs of the 2000 REP Settlement Agreements under section 7(g). These differences stem from the purposes the LB CRAC was intended to serve.

The LB CRAC was developed in the context of BPA's WP-02 Supplemental Rate Proposal as a risk mitigation measure to respond to the need to acquire additional power for system augmentation when BPA load was increasing and power prices were escalating. In BPA's WP-02 Supplemental ROD, BPA explained why its supplemental rate proposal was necessary:

> By August 2000, however, it was clear that extraordinary changes were occurring in the wholesale electricity market, which threatened to overwhelm the cost recovery capability of BPA's initial rate proposal. The Supplemental Proposal has been designed to recover the incremental costs and to mitigate the incremental risks brought about by the upheaval in the west coast electricity market, while leaving intact the May Proposal and its ability to recover the costs BPA was facing at the time the May Proposal was developed.

2002 Supplemental Record of Decision, WP-02-A-09, at 2·5.

BPA addressed this cost recovery problem by amending the risk mitigation tools contained in BPA's WP-02 Final Proposal and developing a three-component CRAC. *Id.* at 2·6. *See also Industrial Customers of NW Utilities v. Bonneville Power Admin.*, 408 F.3d 638, 642 (9th Cir. 2005) (discussing each of the three CRACs). The three-component CRAC is comprised of the Load-Based (LB) CRAC, the Financial-Based (FB) CRAC, and the Safety Net (SN) CRAC. BPA's customers, including preference customers, generally supported BPA's adoption of the three CRACs because they enabled BPA to keep its base rates lower while providing BPA the ability to recover costs in a relatively expeditious fashion should any of the events contemplated by the CRACs transpire.

The LB CRAC provides BPA the necessary tools to recover increased costs that result from augmenting the system with power purchases to meet increased load. 2002 Supplemental Record of Decision, WP-02-A-09, at 2·6; 4·2. There was never any doubt that the LB CRAC would be used to recover "buy-down" costs incurred under BPA's Load Reduction Program. In the Supplemental ROD, BPA stated that the amount of load augmentation BPA would need to acquire may ultimately be reduced by buying down loads, "in which case the costs of the buy-downs will be collected through the LB CRAC…" *Id*. at 2·6. The LB CRAC was incorporated into BPA's Supplemental General Rate Schedule Provisions (GRSPs) and contained a detailed formula and set of procedures to be followed to establish costs to be recovered under the LB CRAC. 2002 Rate Schedules and GRSPs, WP-02-A-09, Appendix, at 3. One component of the LB CRAC formula included the "BUYDOWN," which was defined as "the costs that BPA incurs to reduce or eliminate its contractual obligations to deliver firm power to regional customers…" *Id*. at 3, 9.

The costs incurred under the LB CRAC were recovered through a percentage adjustment to base rates in the form of a surcharge. To determine the actual LB CRAC adjustment, the LB CRAC was subject to recalculation every six months. *Id*. at 9. BPA conducted workshops with customers in a public process to establish the LB CRAC percentages that applied to each six-month period. *Id*. at 9. Documents developed and distributed during the course of LB CRAC workshops identified the costs of all load reduction agreements under BPA's Load Reduction Program as being recovered through the LB CRAC. *See* http://www.bpa.gov/Power/psp/rates/implementation/LB_CRAC_Final_Results_Revision2.pdf.

Notably, none of the rate procedures or formulas described above with respect to the allocation and recovery of costs under the LB CRAC have corollaries under section 7(g) of the Northwest Power Act. On the contrary, all of these procedures and formulas were unique to the LB CRAC and reflected material differences between BPA's rate treatment of the LRAs under the LB CRAC, and BPA's rate treatment of the 2000 REP Settlement Agreements under section 7(g) of the Act. Because neither the LRAs themselves nor BPA's rate decisions under the LRAs were challenged, none of these differences were addressed in *PGE* and *Golden NW*. Nevertheless, due to these differences, it may well be that the Court's rationale in *PGE* and *Golden NW* with respect to the allocation of costs to preference customers' rates under sections 7(g) and 7(b)(2) of the Act would not apply with equal force to BPA's allocation of augmentation expenses to preference customers' rates under the LRAs and LB CRAC.

Cowlitz, in its Brief on Exceptions, argues that the fact that the costs of the LRAs were recovered through the application of the LB CRAC rather than through section 7(g) of the NPA, is "irrelevant" because this is just a rate design issue. Cowlitz Br. Ex., WP-07-R-CO-01 at 42. WPAG concurs. WPAG Br. Ex., WP-07-R-WA-01, at 15-17. However, the vast majority of arguments against BPA allocating costs of the LRAs to preference customers' rates are based on the premise that costs incurred under the LRAs are nothing more than costs of the REP Settlement Agreements. As demonstrated, that premise is not accurate. Although LRA costs may be related to and derive from REP Settlement Agreement costs, they are nonetheless augmentation expenses that, for ratemaking purposes, were not treated as costs of the REP Settlement Agreements under section 7(g) of the NPA. Rather, they were treated the same as all other augmentation expenses under BPA's Load Reduction Program in the LB CRAC. As a result, BPA's allocation of costs of the LRAs through the LB CRAC is significantly different than BPA's allocation of costs in the 2000 REP Settlement Agreements under section 7(g) of the NPA.

Moreover, as explained in section 8.2, above, BPA believes the LRAs with PacifiCorp and Puget, as an integral component of BPA's Load Reduction Program, were part of an "independent benefit or program" within the meaning of *Snohomish*. BPA's rate treatment of the LRAs and BPA's decision to treat the LRAs in precisely the same manner as BPA's rate treatment of all other load reduction agreements and augmentation purchases through the LB CRAC further solidifies this conclusion.

Tillamook, in its Brief on Exceptions, contends that BPA's arguments regarding the LRAs are based on attempts by BPA to "disavow the LRAs as a component off [sic] the REP benefits," are "directly contradicted by numerous other statements made by BPA concerning the LRA payments," and is a "sudden reversal" of BPA's position. Tillamook Br. Ex., WP-07-R-JP24-01, at 4-5. BPA believes Tillamook either misunderstands or mischaracterizes BPA's position. To be clear, BPA does not disavow any statements made in testimony and does not believe its position is either a reversal or a contradiction of prior statements, positions or testimony. On the contrary, BPA has expressly stated that it recognizes and does not deny the nexus between the financial component of the LRAs and the 2000 REP Settlement Agreements. However, what

BPA does not agree with is parties' arguments that the LRAs and 2000 REP Settlement Agreements are, for all intents and purposes, one and the same.

For instance, Tillamook states that "BPA has conceded that the LRA payments were *nothing more* than a form of REP benefit paid to PacifiCorp and Puget Sound Energy." Tillamook Br. Ex., WP-07-R-JP24-01, at 3, 5 (emphasis added). This statement is inaccurate. As BPA has explained, the LRAs are much more than "a form of REP benefit" because they were part and parcel of a much broader program, that is, the Load Reduction Program, and were treated as such for all purposes, including ratemaking purposes. This is not a matter of BPA disavowing anything, but rather accurately describing the nature of the LRAs and putting these agreements in their proper perspective.

Similarly, Tillamook argues that BPA's position in the Draft ROD on its rate treatment of the LRAs is a "post-hoc rationalization." Tillamook Br. Ex., WP-07-R-JP24-01, at 3, 5. However, there is nothing "post-hoc" about BPA explaining the basis for its disagreements with positions taken by the parties in their Initial Briefs. In the Draft ROD, BPA responded to arguments raised in the parties' Initial Briefs with citations to the record. As noted, many of the parties' briefs readily acknowledge the similarities between the LRAs and the 2000 REP Settlement Agreements but ignore the substantial differences between these agreements. It is incumbent on BPA in the Draft ROD, as well as Final ROD, to set forth BPA's reasons and rationale for accepting or rejecting arguments raised in the parties' briefs, and to explain BPA's rationale for taking a particular course of action.

Lastly, BPA believes it is important to keep the scope of BPA's Lookback analysis and the Court's remand in perspective. In *PGE* and *Golden NW*, the Court set aside the 2000 REP Settlement Agreements and BPA's allocation of the costs of the 2000 REP Settlement Agreements to preference customers' rates. The Court then remanded BPA's WP-02 rates to BPA "to set rates in accordance with this opinion." *Golden NW*, 501 F.3d at 1053. In *Snohomish,* the Court identified various options available to BPA on remand without expressing any opinion on the merits of these options. 506 F.3d at 1155. BPA determined that, through the Lookback analysis, BPA would attempt to remedy the injury sustained by preference customers that resulted from the invalidated agreements.

However, BPA does not believe the Court's opinions call for BPA to take the next step and unilaterally declare the LRAs invalid or, if not expressly declaring them invalid, treat them as invalid by setting aside BPA's rate determinations under the LRAs. As explained previously, although preference customers had multiple opportunities to file petitions for review challenging the LRAs themselves or BPA's rate determinations under the LRAs, they chose not to. Regardless of their reasons, BPA believes it has no authority to unravel, seven years after-the-fact, the substantial benefits all of BPA's customers, including preference customers, received under BPA's Load Reduction Program in response to the 2001 West Coast energy crisis. In the absence of clear and express directives from the Court, BPA will treat the LRAs with Puget and PacifiCorp as valid and binding agreements, exclude the costs of the LRAs from the Lookback Amounts, and not reverse the allocation of the costs of the LRAs to preference customers' rates under the LB CRAC.

Decision

BPA will exclude costs of the LRAs from the Lookback Amounts and not reverse the allocation of the costs of the LRAs to preference customers' rates.

8.6 Inclusion of Simplified CRAC in Post-Processor

Issue 1

Whether BPA's proposal to apply a Cost Recovery Adjustment Clause (CRAC) to the PF Exchange rate to establish the reconstructed REP benefits is arbitrary.

Parties' Positions

CUB argues that BPA should consider all of the consequences and not pick and choose which consequences to recognize when conducting the Lookback analysis. CUB Br., WP-07-B-CU-01, at 10. CUB concludes that the Lookback is not an accurate reflection of the benefits the IOUs would have received in the absence of the REP Settlement Agreements. *Id*. CUB argues that BPA should not have used actual revenues, net secondary revenues, and other revenue credits to establish the simplified CRAC in the Post-Processor model. *Id*. at 11. Furthermore, CUB states that BPA lacks the authority to apply this simplified CRAC now since it is not certain BPA would have applied CRACs on a going-forward basis. *Id*.

BPA Staff's Position

BPA Staff considers it reasonable and appropriate to calculate a CRAC to apply to the PF Exchange rate to establish the reconstructed REP benefits in the absence of the REP Settlement Agreements. Ingram, *et al.*, WP-07-E-BPA-58, at 15. Staff considers it appropriate to use actual revenues, net secondary revenues, and other revenue credits to establish the CRAC to apply to the PF Exchange rate in the Lookback analysis for purposes of establishing the REP benefits in the absence of the REP settlements. *Id.* at 16-18.

Evaluation of Positions

The overriding purpose of the Lookback analysis is to respond to the Court's rulings by calculating the overcharges to the COUs resulting from the invalid REP Settlement Agreements. Bliven, *et al.*, WP-07-E-BPA-52, at 18. In order to accomplish this purpose, and assuming that the IOUs would have signed RPSAs in the absence of the REP Settlement Agreements, BPA needs to establish the REP benefits that the IOUs would have then received. *Id*. at 11-12. A key component of the calculation of these "reconstructed benefits" is the PF Exchange rate, as well as any CRACs that would have applied to them. Burns, *et al.*, WP-07-E-BPA-53, at 2.

CUB first argues that BPA must consider all consequences of not settling the REP, and not just the ones it chooses. CUB Br., WP-07-B-CU-01, at 10. CUB, however, fails to explain what consequences Staff purposely has left out. In fact, BPA took the Ninth Circuit's remand to mean that it needed to establish the PF Exchange rate for FY 2002-2006 and to use that PF Exchange rate, the ASCs, and the exchange loads of the IOUs in order to establish the REP benefits they would have received in the absence of the REP Settlement Agreements. Burns, *et al.*, WP-07-E-BPA-53, at 2; Ingram, *et al.*, WP-07-E-BPA-58, at 18. This reconstructed PF Exchange rate is a critical component to determining the amount of REP settlement costs improperly included in preference customer rates.

CUB notes that BPA assumed that actual revenues, secondary revenues, and other revenue credits would be the same under the Lookback as actually occurred. CUB Br., WP-07-B-CU-01, at 11. Thus, the only revenues BPA is changing in the Lookback analysis are the revenues from the Lookback rates. *Id*. CUB argues that BPA's assumption is not realistic and that assuming that changes in price will affect changes in other variables, such as demand and revenue, in some circumstances but not in others is arbitrary. *Id*. Without further information from CUB, BPA does not understand what changes in other variables CUB considers appropriate that BPA has missed.

CUB concludes that it is not certain that BPA would have run the CRACs on a going-forward basis had the REP Settlement Agreements not occurred. *Id*. Therefore, CUB argues that BPA lacks the authority to run CRACs now when rerunning the rate case. *Id*.

CUB misconstrues Staff's approach. Staff's approach requires that the PF Exchange rate and associated CRAC reflect only those costs and revenues that would have changed in the absence of the REP Settlement Agreements. Ingram, *et al.*, WP-07-E-BPA-58, at 16-17. Staff did not propose the CRAC as a risk mitigation tool that would have been included in rates instead of the three CRACs that were actually used. Staff did not propose that the way the CRAC was used would have been the way a CRAC would have played out under actual circumstances. Rather, Staff proposed the single, simplified CRAC as a method to filter out unintended cost and revenue changes that were unrelated to the REP settlements.

CUB argues that BPA's use of the actual net secondary revenues, the actual surplus contract revenues, and the actual other revenue credits that were actually collected in the FY 2002-2006 time period is unrealistic. CUB Br., WP-07-B-CU-01, at 11.

However, CUB provides no suggestion as to how BPA could have made a more realistic estimate of the actual revenues received other than what BPA did, which was to use the actual revenues it received to establish each year's CRAC in the absence of the REP settlements. BPA fails to understand how CUB can believe that the "real" revenues collected over the FY 2002-2006 time period can be deemed "unrealistic." The revenues in question are tied in large part to actual weather and market conditions. The historical FY 2002-2006 weather and market conditions would not have likely changed if BPA conducted a traditional REP rather than the REP settlement. Therefore, BPA's assumption that revenues tied to the historical weather and market conditions would not change is reasonable.

Staff reasonably assumed that net secondary revenues and other revenue credits would have been the same in the absence of the REP settlements as actually occurred with the settlements. Therefore, the only revenues that should be allowed to change in the Lookback analysis would be the revenues from Lookback rates. Ingram, *et al.*, WP-07-E-BPA-58, at 16. Therefore, it is reasonable that if the Lookback rates themselves are insufficient to recover the actual rate period costs, BPA would have utilized a CRAC mechanism to avoid a revenue over or underrecovery. *Id.*

The Post-Processor model computes annual revenue targets for FY 2002-2008 by replacing the costs of the REP settlements with the costs of the traditional REP as the only change to actual revenues. *Id.* at 15. The model then determines if the Lookback rates would have recovered the adjusted revenue targets. *Id*. If, in any year, the revenues under Lookback rates are not equal to the adjusted revenue target, the model will calculate an annual CRAC that is sized to adjust for the difference. *Id*. The annual CRAC adjusts the annual revenue recovery by increasing or decreasing both the PF Preference and PF Exchange rates, thereby changing the PF Preference revenue and changing the net cost of the REP. The sum of the changed revenues and the changed net REP costs equals the annual revenue target. *Id*.

What CUB's argument misses is that the Lookback analysis is quantifying the amount of REP settlement benefits improperly included in rates to preference customers. The Post-Processor CRAC is an important component of the determination. If the CRAC is removed from the determination, then other elements will be included in the determination of the overcharges to preference customers. As CUB rightly points out, there are many effects that occur once rates are established, some caused by the rates themselves. Changing weather and streamflow conditions have a large impact on BPA's revenues, as do market prices for secondary sales. Forecast error is a normal part of ratemaking. But all rates bear a proportionate share of forecast error when setting forward-looking rates. In this proceeding, BPA is calculating the overcharges to preference customers by isolating the effects of the REP settlements. The Post-Processor CRAC is a necessary element to screen out unintended cost and revenue changes that are unrelated to the REP settlements. Without this step, the Lookback Amounts may reflect other factors, such as the difference between actual costs and forecast costs used to set rates.

Decision

BPA properly calculated the Lookback Amounts. In that process, it properly applied a simplified CRAC to a reconstituted PF Exchange rate to establish reconstructed REP benefits in the absence of the REP Settlement Agreements. It is not necessary to determine if this is the kind of CRAC that BPA would have adopted in the absence of REP settlements.

Issue 2

Whether the value of the firm power sold to PGE at the Residential Load (RL) rate during FY 2002-2006 should be established based on the benefits paid to PGE consumers, as established by PGE in consultation with the OPUC.

Parties' Positions

When calculating the REP settlement benefits paid to PGE for FY 2002-2006, the OPUC argues that BPA should value the firm power sold to PGE at the RL rate based on the cost of the power to BPA. OPUC Br., WP-07-PU-B-02, at 14. In particular, the OPUC notes that using BPA's average cost of augmentation, as proposed by BPA Staff in rebuttal testimony, would be a reasonable approach. *Id.* PGE supports Staff's rebuttal proposal to use the average cost of augmentation if BPA rejects the IOUs' positions on the Lookback in general. IOU Br., WP-07-B-JP6-01, at 159.

BPA Staff's Position

BPA Staff first proposed to value the RL sale to PGE based on the value that PGE and the OPUC ascribed to the sale for the purpose of determining the REP credit to place on residential and small farm consumer bills. Marks, *et al.,* WP-07-E-BPA-62, at 4. In rebuttal testimony, in response to the OPUC's direct case, Staff proposed to value the RL sale to PGE for FY 2002-2006 at BPA's average cost of augmentation. Forman, *et al.,* WP-07-E-BPA-76, at 50. Staff took this position because it best captured the cost of the RL sale that was included in the PF Preference rates for FY 2002-2006 for this component of the REP settlement benefits paid to PGE. *Id.* BPA staff also expressed a willingness to consider other valuations. Forman, *et al.,* WP-07-E-BPA-76, at 49.

Evaluation of Positions

The REP Settlement Agreements signed by the region's six IOUs implemented the Power Subscription Strategy and ROD and included two components: a 1,000 aMW power sale and 900 aMW of financial benefits. Burns, *et al*., WP-07-E-BPA-53, at 4. The power sold to the IOUs under the REP Settlement Agreements was charged at BPA's RL rate. PGE was the only IOU that opted to retain the power sale portion of its REP Settlement Agreement as an actual delivery of power. PGE purchased 232 aMW in FY 2002 and 258 aMW annually for FY 2003-2006. Marks, *et al.*, WP-07-E-BPA-62, at 3. Two other IOUs sold their RL power back to BPA through Load Reduction Agreements (Bliven, *et al.*, WP-07-E-BPA-52, at 10), while the other three IOUs monetized their part of the 1,000 aMW power sale at the beginning of FY 2002 pursuant to an option in the agreement.

At the time BPA signed the REP Settlement Agreements, and in conjunction with the signing of the Subscription contracts by the public utilities, BPA found itself in the midst of the West Coast energy crisis, a very volatile and complex time. Burns, *et al*., WP-07-E-BPA-53, at 4. During this time, BPA's total load-serving obligation ended up more than 3,000 aMW above the level of the firm output of the FCRPS. Bliven, *et al*., WP-07-E-BPA-52, at 9. As a result, BPA bought down some loads and also made a number of market purchases. These load buy-downs and purchases in combination are referred to as augmentation.

In order to complete its multi-step approach to calculating PGE's Lookback Amount for FY 2002-2006, BPA needed to establish the value of the power it sold to PGE at the RL rate. Marks, *et al.*, WP-07-E-BPA-62, at 4. Different valuation methods have been proposed and debated in the different phases of this Supplemental proceeding.

Staff first proposed a valuation of the firm power sold to PGE at the RL rate based on the formula that PGE used when monetizing the power it received from BPA into a REP credit on the bills of its residential and small farm customers. Marks, *et al.,* WP-07-E-BPA-62, at 4. This approach seemed reasonable because it measured the actual REP settlement benefits that PGE's residential and small farm customers received, which is an important component of the determination of any overpayments. *Id.* Also, PGE's valuation of the RL sale was an amount certified by PGE in its certification statements. *Id.* Staff considered this valuation methodology to be reasonable because, ultimately, any overpayments received by the residential and small farm customers would also be recovered from them. *Id.*

In its direct case, the OPUC had objected to this valuation method because the benefit that PGE passed to its residential and small farm ratepayers was not necessarily connected or related to the amount that was recovered from preference customers through the PF Preference rate. Hellman and McGovern, WP-07-E-PU-01, at 11. Therefore, the amount paid to PGE consumers is not relevant to calculating any overcharges to the COUs. *Id*. The OPUC then proposed a mark-to-market approach in its testimony that was based on the monthly Mid-C prices for FY 2002-2006. *Id.*

Staff granted that the OPUC had a fair point, and presented three alternative methods for valuing the RL sale: (1) BPA's approach from its initial testimony; (2) the OPUC's mark-to-market approach; and (3) a new, third approach based on BPA's average cost of augmentation for FY 2002-2006. Forman, *et al.,* WP-07-E-BPA-76, at 51. Staff indicated that all three of these approaches had merit, and they would be reviewed by the Administrator before making a decision. *Id.* at 50.

The OPUC states its support for the methodology that Staff presented in rebuttal testimony that valued the PGE RL sale using BPA's average cost of augmentation for FY 2002-06. OPUC Br., WP-07-B-PU-02, at 14. PGE also supports BPA's use of the average cost of augmentation, assuming *arguendo* that BPA must do a Lookback at all. IOU Br., WP-07-B-JP6-01, at 159.

BPA recognizes that each of the three approaches noted in the Staff rebuttal testimony has merit. Staff committed to reviewing the proposed methods before making a recommendation to the Administrator. Forman, *et al.,* WP-07-E-BPA-76, at 50. Given that BPA's paramount goal in this rate proceeding is to establish the overcharges to the COUs (Bliven, *et al.,* WP-07-E-BPA-52, at 18), the most appropriate approach to use is the one that best quantifies the cost of the RL sale that was charged through the PF-02 Preference rates paid by the COUs, including the various CRACs.

BPA finds that the mark-to-market approach for valuing the RL sale as proposed by the OPUC (Hellman and McGovern, WP-07-E-PU-01, at 11), best captures the cost of the RL power sale included in the PF-02 Preference rates. Had BPA not needed to serve the RL power sale, it would have made fewer market purchases at the margin in the same amounts as the RL sale, or would have sold more at market prices; either way, the logic holds for using a mark-to-market approach.

BPA has decided not to use the average cost of augmentation because it would result in an underestimate of the value and a comparable underestimate of PGE's Lookback Amount. The average cost of augmentation accounts for all of BPA's augmentation purchases at all prices and is, by definition, less than the marginal purchase. Removing the RL sale from BPA's obligation to serve would not reduce BPA's costs "on average" – it would reduce BPA's market purchases on the margin. If it were no longer served, the marginal purchase at market would be the cost that no longer would have been recovered through the PF-02 Preference rates.

Furthermore, it is the overcharges in the PF-02 Preference rates that BPA is quantifying through the comparison of REP settlement benefits paid with reconstructed REP benefits calculated in the absence of the REP settlements. Bliven, *et al.,* WP-07-E-BPA-52, at 12, 18. It is reasonable to use a mark-to-market approach to valuing the RL power sale to PGE because BPA is measuring the impact on the rates in the absence of the REP settlements, which means in the absence of this one particular power sale. That is, BPA would have avoided a marginal market purchase if it had not needed to serve the RL sale to PGE. This value is best represented by the monthly Mid-C prices, which is the valuation methodology first proposed by the OPUC in its direct case. Hellman and McGovern, WP-07-E-PU-01, at 11.

The market valuation approach has two other benefits as well. It is an objective approach to valuing the PGE power sale. Attempts to assign specific BPA purchases to the PGE power sale relegates BPA into second-guessing which purchases were for which purpose. Does PGE get the first purchase? Or the most expensive purchase? The market valuation approach avoids those pitfalls by assigning the power a marginal value. In addition, it is unclear whether Staff's rebuttal proposal properly accounted for the costs of power buybacks, such as the LRAs with Puget Sound Energy and PacifiCorp. The power buyback costs were appropriately recognized as a form of augmentation; in fact, the costs of the buybacks were recovered through the LB CRAC, the cost recovery mechanism employed to recover the costs of augmentation in excess of amounts included in base rates. While the power buybacks greatly relieved BPA's need to purchase power, the buyback costs may not have been properly included in Staff's average cost of augmentation. Excluding the cost of buybacks may understate the true cost of BPA's acquisitions to meet it load obligations. The market valuation approach avoids arguments about whether or not Staff properly included buyback costs in the average cost of augmentation.

Decision

BPA will value the sale to PGE at the RL rate in FY 2002-2006 using a mark-to-market valuation approach that is based on monthly spot prices at Mid-C.

8.7 Treatment of Costs of Power Sales under the 2000 REP Settlement Agreements

Issue 1

Whether power sales to the IOUs that occurred under the 2000 REP Settlement Agreements should be treated as part of the REP settlement benefits.

Parties' Positions

The WUTC argues that WPAG erred in calculating the amount of 2000 REP Settlement Agreement costs that BPA allocated to preference customers' rates; specifically, those connected with the sale of power to the IOUs at the RL rate. WUTC Br., WP-07-B-WU-01, at 14. The IOUs, in their Brief on Exceptions, states that the RL rate was not challenged in the Ninth Circuit opinions, and BPA should not consider the RL power sales agreements invalid simply because they were attached to the 2000 REP Settlement Agreements. IOU Br. Ex., at 9, WP-07-R-JP6-1.

BPA Staff's Position

For purposes of the Lookback analysis, BPA Staff has included the value of both the power sales and monetary benefits provided under the 2000 REP Settlement Agreements in the total REP settlement benefits received by the IOUs. Marks, *et al.*, WP-07-E-BPA-62, at 2.

Evaluation of Positions

The WUTC argues that WPAG erred in calculating the amount of 2000 REP Settlement Agreement costs that BPA allocated to preference customers' rates; specifically, those connected with the sale of power to the IOUs at the RL rate. WUTC Br., WP-07-B-WU-01, at 14. According to the WUTC, WPAG improperly claims that BPA allocated approximately $143 million in annual REP Settlement Agreement costs to the preference customers' PF rate because "roughly $73 million of the Settlement's economic benefit to the IOUs came, not from residential exchange benefits, but from power sales entered into in connection with the Settlement Agreements that were not deemed to be error by the Ninth Circuit." *Id*. WUTC claims that these power sales were implemented through block power sales at a rate that recovered "essentially all of its cost." *Id*.

BPA does not agree with WPAG's claim that the proper measure of REP Settlement benefits in FY 2002-2006 is only $143 million per year. Rather, Staff appropriately started with an accounting of all of the REP settlement benefits actually paid to the IOUs, which includes the eventual costs of the RL sales to the IOUs. Marks, *et al.*, WP-07-E-BPA-62, at 2. As noted elsewhere, only PGE took delivery of its portion of the 1,000 aMW of RL sales for the entire five years. Other utilities either signed LRAs, or converted their portion of the 1,000 aMW to financial payments. Staff's proposal included the costs of the PGE portion of the power sales referenced by WUTC in the total REP settlement benefits, and also included the financial benefits of the converted power sales. Marks, *et al.,* WP-07-E-BPA-62, at 2.

As stated in Staff's testimony, the settlement benefits provided to the IOUs included a power sale component and a monetary benefit component. *Id*. The power sales occurred under BPA's "RL" Agreement, which was executed for the sole purpose of providing the IOUs their benefits under the 2000 REP Settlement Agreement. BPA believes it is largely immaterial that the Court did not separately address this power sales component of the 2000 REP settlement benefits. As BPA has explained in Chapter 2, the Court in *PGE* ruled that the 2000 REP Settlement Agreements were invalid in their entirety. Therefore, BPA believes that the power sales that occurred under the 2000 REP Settlement Agreements are within the scope of the Court's opinion and should be treated as invalid in BPA's Lookback analysis.

WUTC's argument raises the question of the treatment of the WP-02 forecast of REP settlement costs as claimed by WPAG. This question is addressed in Chapter 2.

Lastly, the IOUs, in their Brief on Exceptions takes issue with BPA's position in the Draft ROD that the RL agreements should be treated as invalid. According to the IOUs, BPA's position "ignores" the IOUs' argument that "the RL rate applicable to sales under those agreements was a cost-based rate and recovered all or virtually all of BPA's costs for providing the power for those sales." IOU Br. Ex., at 9, WP-07-R-JP6-1. The IOUs conclude that, because BPA did not project any under-recovery in the WP-02 rates from the RL sales, "there is no rational basis for including such sales in BPA's Lookback analysis." *Id*.

The IOUs are correct in that the PF, RL, IP, and NR rates in WP-02 were established as cost-based rates and that there was no *forecasted* under recovery of costs in WP-02. However, the Lookback analysis is designed to revisit the FY 2002-06 rates assuming there were no IOU REP Settlement monetary benefits or the sale of actual power to the IOUs under the RL rate. Therefore, the net cost of those actual sales to the IOUs is a cost of the IOU REP Settlements that was borne by the PF Preference class.

In the WP-02 rate case, the posted rates were set to recover all of the forecast power costs, including all forecast system augmentation costs. The forecast of system augmentation costs was determined by, among other things, the load/resource balance in each year, including the forecast RL loads. Without those RL loads, the load/resource balance in each year would have been different and the cost of system augmentation would also have been different. In standard BPA ratemaking, system augmentation is defined as an FBS replacement, and BPA does not assign specific FBS resources to specific customer loads. So, while technically the initial WP-02 rates were projected to recover FBS costs in WP-02, had the RL load not existed, the FBS costs would have been lower due to less system augmentation. If BPA had assumed that the cost of system augmentation purchased in the market is higher than the average cost of other FBS resources, all rates served by the FBS would be lower if less of this expensive resource was needed. Conversely, because the RL load existed in WP-02, more system augmentation was needed and all rates served with FBS resources, mainly the PF Preference rate, were higher.

The Lookback Post-Processor model calculates what the CRACed rates would have been in a world that had the REP been implemented through the traditional REP rather than the IOU REP Settlement Agreements. The Post-Processor puts the RL sale to PGE at the margin and determines the cost difference with and without that load to determine the net cost of the RL sale. The net cost is then added to the actual monetary benefits paid out in FY2002-06 to get a total cost of the IOU REP Settlement to the PF Preference customer class.

Because the PF Preference rate in WP-02 would have arguably been lower without the RL loads, it is appropriate to include the cost of serving the RL loads in the Lookback analysis.

Decision

BPA will not exclude the power sales component of the 2000 REP Settlement Agreements in the determination of REP settlement benefits received by the IOUs.

8.8 Treatment of the C&RD and CRC in Determining Lookback Amounts

Issue 1

Whether the payments made to the IOUs pursuant to the Conservation and Renewable Discount (C&RD) during FY 2002-2006 and the Conservation Rate Credit (CRC) in FY 2007-2008 should be counted as REP settlement benefits for the purpose of calculating each utility's Lookback Amount.

Parties' Positions

The OPUC argues BPA should exclude the payments made to the IOUs under the C&RD and the CRC from the calculation of each utility's REP settlement benefits for the purpose of the Lookback analysis because BPA relied on the resulting conservation acquired by the IOUs to meet BPA's conservation targets. OPUC Br., WP-07-B-PU-02, at 15. The OPUC argues that it is inequitable for BPA to require IOUs to return the monies associated with the C&RD by including these amounts in the utilities' Lookback Amounts, but retain the benefit that BPA obtained from these payments. *Id.*

The IOUs also oppose the inclusion of payments under the C&RD and the CRC as REP settlement benefits for the same reasons cited by the OPUC, as well as for the fact that these payments were not included in the REP credits that the residential and small farm customers received on their bills. IOU Br., WP-07-B-JP6-01, at 192; IOU Br. Ex., WP-07-R-JP6-01, at 11.

BPA Staff's Position

BPA Staff proposes that the C&RD and CRC monies be included in the total REP settlement benefits paid, or that would have been paid, to the IOUs. Marks, *et al.,* WP-07-E-BPA-62, at 3. Staff considers this as appropriate for two reasons. First, while it is true that BPA counted the conservation acquired via the C&RD toward its conservation target for FY 2002-2006, the conservation target would have been achieved without the conservation acquired by the IOUs. Forman, *et al.,* WP-07-E-BPA-76, at 76. Second, it is apparent from the 2002 Rate Schedules and 2002 General Rate Schedule Provisions that, had there been a functioning REP instead of the REP Settlement Agreements, the IOUs would not have received C&RD or CRC payments because the PF Exchange rate was not eligible for those adjustments. *Id.* at 77.

Evaluation of Positions

The C&RD, and its successor, the CRC, are line item reductions in the monthly power bills of public utility customers purchasing firm power from BPA to serve their retail loads. Administrator's Final Record of Decision, WP-02-A-02, at 10-92. By accepting the credit, customers agree to expend the credit amount on various conservation measures and renewable resource activities. The credit is intended to achieve cost-effective energy savings that will reduce BPA's firm power supply obligation that would otherwise be met through physical generation. In addition, under the terms of the REP Settlement Agreements, BPA provided funds to the IOUs to apply toward their conservation and renewable activities under the C&RD/ CRC.

The OPUC and the IOUs present several reasonable perspectives on the issue of whether the payments made to the IOUs through the C&RD and the CRC should be included as REP settlement benefits, thus affecting the calculation of each utility's Lookback Amount. These programs, as well as several other conservation programs that BPA developed in collaboration with its public utility customers, were developed for the purpose of promoting conservation and renewable resources in the region. Supporting the development of conservation and renewables has been an important component of BPA's mission since the passage of the Northwest Power Act. In FY 2001, the Northwest Power and Conservation Council (NPCC) established a target for BPA of 220 aMW for the accomplishment of conservation in FY 2002-2006. Forman, *et al.,* WP-07-E-BPA-76, at 75.

In the Lookback analysis, Staff proposed to reconstruct a reasonable "what if" world based on the best information available at the time regarding what would have happened if the REP Settlement Agreements had not been signed. Bliven, *et al.,* WP-07-E-BPA-52, at 12. What BPA would have offered to the IOUs in the absence of the REP settlements regarding the C&RD program is the question that must be answered in order to decide whether the payments made through the C&RD program or the CRC should be included as REP settlement benefits.

By accepting the credit, customers agreed to expend the credit amounts on various conservation measures and/or apply them to renewable resource activities. The credit is intended to achieve cost-effective energy savings that will reduce BPA's firm power supply obligation that would otherwise be met through physical generation. Under the terms of the REP Settlement Agreements, BPA provided funds to the IOUs to apply toward their conservation and renewable activities. Unlike the public utility customers, the monies provided to the IOUs did not achieve conservation that reduced a BPA load-serving obligation since there was none under the REP Settlement Agreements.

In the Supplemental Proposal, Staff proposed that the payments made to the IOUs pursuant to the C&RD and the CRC be included in calculations of the REP settlement benefits paid to the region's six IOUs. Marks, *et al.,* WP-07-E-BPA-62, at 15. The OPUC considers this treatment to be inequitable because BPA is both including these monies in the Lookback analysis, making them subject to repayment by the IOUs, as well as claiming that the conservation and renewables acquired by the IOUs helped BPA meet its conservation targets specified by the Northwest Power and Conservation Council. OPUC Br., WP-07-B-PU-02, at 15 and IOU Br., WP-07-B-JP6-01, at 154. While it is true that BPA counted the conservation acquisitions funded by the IOUs through the C&RD and the CRC toward the Council's conservation targets, Staff did not find this argument persuasive. Forman, *et al.,* WP-07-E-BPA-76, at 75-78. As explained below, BPA would have met its conservation target without the conservation acquired by the IOUs. *Id.* at 76. In addition, these payments were a byproduct of the REP Settlement Agreements, and, as demonstrated by the WP-02 and WP-07 Rate Schedules and General Rate Schedule Provisions (GRSPs), the C&RD and the CRC would not have been available to the IOUs had BPA been operating a traditional REP. *Id*. at 78.

The Council's target for BPA of 220 aMW for FY 2002-2006 was for conservation acquisitions only and did not include renewable resources. *Id*. In addition, there were several conservation programs BPA sponsored in order to meet this target. *Id*. at 76. They included conservation augmentation and market transformation as well as the C&RD. *Id*. Contrary to the OPUC's contention that "BPA planned on those [IOU] savings," BPA did not forecast specific IOU savings. There is no evidence in the record as to how the conservation achievement of individual utilities resulting from the C&RD would be combined to meet the Council's target. Administrator's Final Record of Decision, WP-02-A-02, at 10-100.

BPA's records indicate that 244 aMW of conservation were acquired by BPA during FY 2001-2006 through the C&RD, which was allowed to start in late FY 2001 due to the West Coast energy crisis. *Id*. The IOUs' efforts were responsible for approximately 17 aMW of that total, and therefore the target of 220 aMW would have been met by BPA's activities even without the efforts funded by the C&RD in the IOUs' service territories. *Id*. The OPUC argues against this point because of BPA's statement on cross-examination that BPA would perhaps not have known that it did not need the 17 aMW of conservation acquired in the IOUs' service territories to meet the Council's target. OPUC Br., WP-07-B-PU-02, at 16. However, as Staff stated in its rebuttal testimony, there is no evidence that BPA found, or that the OPUC could provide, that showed that BPA would have increased its efforts through its other programs to make up for the conservation that would not have been acquired from the IOUs. Forman, *et al.,* WP-07-E-BPA-76, at 76. Lastly, the target was set independent of the assessment of C&RD, so it is unlikely that the target would have changed due to the activity of such a small component of the overall program. *Id.*

The OPUC next argues that it is irrelevant that the majority of the C&RD payments were for conservation measures in the residential sector because BPA has the independent authority to offer the C&RD program distinct from the REP. OPUC Br., WP-07-B-PU-02, at 16. BPA, however, suggests that the C&RD monies, as well as the CRC payments, are a proxy for REP settlement benefits and therefore are subject to the Lookback analysis. Forman, *et al.,* WP-07-E-BPA-76, at 76. BPA determined the IOUs' C&RD and CRC benefit amounts by using the payments provided pursuant to the REP Settlements. While BPA does have the ability to offer the C&RD program outside of the REP, the fact that BPA's GRSPs for FY 2002-2006 and for FY 2007-2009 do not show C&RD or CRC to be applicable to the PF Exchange rate indicates that BPA was unwilling to offer these rate discounts independent of the REP Settlement Agreements. *Id.* at 77. In addition, there is no evidence that BPA would have increased its spending on conservation at the expense of COUs paying the PF-02 Preference rates in order to make up for conservation acquired by the IOUs. *Id.* at 76. Lastly, the target would not have changed in the absence of the REP settlements because it was established in a manner independent of the C&RD activity of the IOUs. *Id.* at 77.

The OPUC argues that it is unfair to subject the C&RD program monies to the Lookback analysis because BPA's public utility customers continue to benefit from lower exchange loads that result from this program. OPUC Br., WP-07-B-PU-02, at 16. BPA is not persuaded by this argument. Notwithstanding the results of conservation activities funded by the monies provided to the IOUs under the C&RD and the CRC, such as the possibility of lower exchange load, the C&RD program would not have been available in a world without the REP Settlement Agreements. The conservation remains regardless of whether or not the monies should be returned to the preference customers. *Id.* at 76. Likewise, that same conservation continues to benefit each IOU in its individual utility load-serving capacity notwithstanding the outcome of this rate proceeding.

In their brief, the IOUs also argue these payments should not be included in the REP settlement benefit calculations because they were not captured in the bill credits of the residential and small farm ratepayers. IOU Br., WP-07-B-JP6-01, at 155. This has no import in the Lookback analysis. What is important in the calculation of the Lookback Amounts is determining the overcharges in a reasonable and equitable manner. Forman, *et al.,* WP-07-E-BPA-52, at 55.

In their Brief on Exceptions, the IOUs argue, assuming *arguendo*, that if BPA does include C&RD and CRC payments in determining any Lookback Amounts, the reconstructed REP benefits used in BPA's Lookback analysis should be increased by applying the C&RD and CRC to the PF Exchange rate. IOU Br. Ex., WP-07-R-JP6-01, at 11. They contend that in the absence of the REP settlements it is reasonable to assume that the C&RD and CRC would apply to the PF Exchange rate, just as it applied to the RL rate used in the REP settlements. *Id*. BPA is not persuaded by the IOU's contention since, without the REP settlement, the C&RD and CRC would not have been available to the IOUs, and those costs would not have been in the PF Preference rates; therefore, the monies provided to the IOUs under the C&RD and the CRC should be included in the Lookback Amounts. These payments were a byproduct of the REP Settlement Agreements, and, as demonstrated by the WP-02 and WP-07 Rate Schedules and

General Rate Schedule Provisions (GRSPs), the C&RD and the CRC would not have been available to the IOUs had BPA been operating a traditional REP. *Id*. at 78. The GRSPs show that the C&RD and CRC were only available to customers purchasing power under the PF, NR, and RL rates, and not the PF Exchange rate. Therefore, BPA will not reconstruct REP benefits with a PF Exchange rate that is lower by the C&RD and CRC.

Finally, the OPUC notes that the germane consideration is that BPA received a benefit in return for the payments in terms of a contribution to the Council's target and, because of this consideration, BPA should not decide that these payments must be paid back. OPUC Br., WP-07-B-PU-02, at 17. As stated above, BPA does not find this argument persuasive, nor does it agree with the OPUC's mischaracterization of how BPA's conservation target was met. BPA demonstrates above that, notwithstanding the IOUs' conservation achievements, BPA met its conservation target. Indeed, for the specific purpose of the Lookback analysis, it is indisputable that the IOUs would not have been eligible for these credits had there been a functioning REP in place of the REP settlement.

Therefore, in spite of the plausible arguments to the contrary, on balance, the overriding argument is that BPA would not have offered the C&RD or the CRC to the IOUs under an REP, in the absence of the REP settlements. The payments made through the C&RD and CRC would not have existed but for the REP Settlement Agreements, and therefore should be included as settlement benefits subject to the Lookback.

Decision

BPA will include the payments made to the IOUs pursuant to the C&RD and the CRC as part of the total REP settlement benefits paid, or that would have been paid, to the IOUs during FY 2002-2008 for the purpose of calculating their Lookback Amounts. BPA will not apply the C&RD or the CRC to the reconstructed PF Exchange rate for the purposes of calculating the reconstructed REP benefits.

8.9 Inclusion of the "Lesser Than" Rule

Issue 1

Whether BPA should adopt the "lesser than" rule when calculating each IOU's annual and total Lookback Amounts.

Parties' Positions

The OPUC argues that BPA should reject the "lesser than" rule because it is arbitrary and capricious. OPUC Br., WP-07-B-PU-01, at 17.

CUB argues the "lesser than" rule caps the utility's benefit for its customers at the settlement level. CUB Br., WP-07-B-CU-01, at 12-13. CUB states this increases the utility's Lookback Amount and, in effect, overcompensates the COUs for any "overpayment." *Id*.

The IOUs object to the use of the "lesser than" rule when calculating the Lookback Amounts because it fails to accomplish BPA's stated goal of determining the amount preference customers were "overcharged," lacks evidentiary support, and results in contradictory outcomes that are arbitrary and capricious. IOU Br., WP-07-B-JP6-01, at 140-141.

<u>BPA Staff's Position</u>

BPA Staff supports the use of the "lesser than" rule, as articulated in the policy testimony. Bliven, *et al*., WP-07-E-BPA-52, at 18-19. This rule has the effect of ensuring that the Lookback Analysis calculates only what the COUs were overcharged without any effects from the possibility that an IOU might have been eligible for more REP benefits than it received via the REP settlements. Forman, *et al*., WP-07-E-BPA-76, at 53-55. This rule therefore caps the amount that an IOU would have otherwise received in the absence of the REP settlements at the lesser of the settlement benefits received, or that would have been received, and the reconstructed REP benefits. Bliven, *et al*., WP-07-E-BPA-52, at 19.

<u>Evaluation of Positions</u>

BPA established the so-called "lesser than" rule in order to fulfill the goal of the Lookback analysis, which is to determine the magnitude of REP settlement costs that were improperly included in the PF Preference rates for FY 2002-2008, and to return those amounts to the COUs. Forman, *et al.,* WP-07-E-BPA-76, at 53. BPA approached its analysis with the limited purpose of addressing only the harm imposed on the COUs, and not with the purpose of making the IOUs whole for what might have happened in the past. *Id*. at 54. BPA's narrow focus is predicated on its reading of the direction from the Court's decisions. *Id*. at 53.

In general, the "lesser than" rule limited the amount of reconstructed REP benefits BPA would credit to the IOUs for FY 2002-2008 when calculating their respective Lookback Amounts. Forman, *et al.*, WP-07-E-BPA-76, at 53. The limit is based on the REP settlement benefits the respective IOUs received in a given year. *Id.* For example, if an IOU received $30 million in REP settlement payments in FY 2002, but the reconstructed REP benefits are $50 million under BPA's Lookback approach, the IOU would have a zero Lookback Amount for that year. *Id.* The "lesser than" rule thus limited an IOU's reconstructed benefits to the lesser of the REP settlement benefits that an IOU received in any given year or the reconstructed REP benefits.

The OPUC argues that such a narrow reading of the Court's opinion is too one-sided, and that the Court's ruling in *Golden NW* can reasonably be read to require that BPA correct the errors identified in that opinion, and in *PGE,* only on a prospective basis. OPUC Br., WP-07-B-PU-02, at 18. The OPUC continues to assert that there is just no reasonably consistent interpretation of BPA's approach to the Lookback that causes it to stop short of including undercharges to offset overcharges. *Id.* at 19.

The IOUs similarly argue and explain that the "lesser than" rule fails to accomplish BPA's stated goal of determining the amount preference customers were "overcharged," lacks evidentiary support, and results in contradictory outcomes that are arbitrary and capricious. IOU Br., WP-07-B-JP6-01, at 141. The IOUs encourage BPA to discard this rule when calculating Lookback Amounts. *Id*. The IOUs outline two examples in their brief that illustrate the impacts of the "lesser than" rule in two sets of circumstances, showing that the resulting Lookback Amount in one example and no Lookback Amount in the other illustrate an improper outcome. *Id*. at 142-143. They claim that such an outcome is counter to BPA's proposed goal to calculate the overcharges to the COUs because in these two examples, the rate effects are the same but the Lookback Amounts are different. *Id.* The IOUs further argue that BPA's proposal to disregard any undercharges when calculating Lookback Amounts is not required by the rulings from the Ninth Circuit in *Golden NW*. *Id.* at 144. The IOUs state that the Ninth Circuit's direction to BPA was to "set rates in accordance with this opinion." *Golden NW*, 501 F.3d at 1053.

CUB argues that Staff's proposal fails to accept that, had the IOUs executed a RPSA instead of settling in 2001 (a core assumption of the Lookback), the IOUs would have taken the full value of the REP for their customers. CUB Br., WP-07-B-CU-01, at 13. Had any IOU refused the value of the REP, the utility's regulator would have found the action imprudent. *Id*. If BPA's Lookback assumes that an IOU signed an RPSA, it must assume that the IOU takes the value of the RPSA. *Id*. (CUB's brief referred to the Settlement Agreement, which does not make sense in CUB's argument; BPA assumes that CUB meant to refer to the RPSA, the contract implementing the traditional REP.) CUB asserts that BPA's position on this issue is inconsistent with its own rate case assumptions and is irrational. *Id*. Instead, CUB urges BPA to take a consistent position by netting-out, from the Lookback Amount, the amounts when the reconstructed Residential Exchange was more than the settlement value. *Id*.

Staff disputed these arguments, claiming the Court did not order the IOUs to be made whole as they had chosen the REP over the REP settlements in 2000. Forman, *et al*., WP-07-E-BPA-76, at 53-54.

BPA finds these arguments presented by the IOUs, OPUC, and CUB persuasive and, upon further consideration, will revise the way the "lesser than" rule is used. BPA agrees that it is reasonable to have symmetry in the way the reconstructed REP benefits are applied to determine the Lookback Amounts. One of the foundational assumptions Staff followed when constructing the Lookback is that the IOUs would have signed RPSAs instead of the REP Settlement Agreements. *See* Bliven, *et al.*, WP-07-E-BPA-52, at 16; Forman, *et al.*, WP-07-E-BPA-76, at 45-46. The IOUs have demonstrated that just because one utility would receive more under the REP than under the REP settlements, it does not mean that the COUs were necessarily overcharged. IOU Br., WP-07-B-JP6-01, at 142-143. As CUB noted, there is no "cap" on the amount of REP benefits that would have been paid under these agreements. CUB Br., WP-07-B-CU-01, at 13. BPA agrees that it is not reasonable to assume that the IOUs would have signed RPSAs on the one hand, and at the same time assume for purposes of calculating the Lookback Amounts that the reconstructed REP benefits would be limited to the REP Settlement Agreements on a yearly basis. BPA concurs that a more logically consistent approach is to credit against the Lookback Amount the entirety of the reconstructed REP benefits. In addition, BPA finds that netting all REP benefits is more accurate because it better reflects the costs of the REP that would have been included in the COUs' rates. Had RPSAs been in place, the COUs' rates would have recovered the full amount of reconstructed REP benefits, not just the amounts under the REP Settlement Agreements. Thus, BPA will credit the full amount of reconstructed REP benefits against the REP settlement costs to determine an IOU's Lookback Amount.

The OPUC makes an additional argument that BPA does not find persuasive. As an alternative to the "lesser than" rule, the OPUC suggests that BPA abandon its year-by-year calculations and instead make calculations of the overcharges on a rate period basis. OPUC Br., WP-07-B-PU-02, at 19. The OPUC specifically suggests that BPA compare the total REP settlement benefits for the years of each rate period and subtract the REP benefits the utility would have received in the same period. *Id*. This approach would produce very similar results to BPA's approach, absent the "lesser than" rule, with one exception. The protection of the LRA payments continues to require a year-by-year calculation of the annual Lookback Amount, even absent the "lesser than" rule. Marks, *et al*., WP-07-E-BPA-62, at 17.

Finally, the OPUC states that the Administrator should also ensure that the IOUs' Lookback Amounts do not include REP Settlement Agreement amounts allocated to rates other than the PF Preference rate. OPUC Br., WP-07-B-PU-02, at 19.

The Court's remand in *Golden NW* is not limited to the PF Preference rates. *Golden NW*, 501 F.3d at 1053. Rather, it speaks to rates; that is, all rates. In *PGE*, the Court ruled that any implementation of the REP must conform to sections 5(c) and 7(b) of the Northwest Power Act. *PGE*, 501 F.3d at 1036-37. Thus, BPA must examine the REP settlement costs in light of what section 7(b) would allow in all rates, not just in the PF Preference rates, thereby allowing higher settlement costs to persist in other rates. In this fashion, the Lookback Amounts account for the properly constructed overcharges to the COUs.

While BPA is proposing to eliminate the "lesser than" rule in most respects, BPA intends to apply the "lesser than" rule in one instance: the total Lookback Amount for FY 2002-2008 for any IOU cannot be less than zero. In other words, if the sum of the annual Lookback Amounts is negative, BPA will not make additional payments to the IOUs to make up the difference. BPA believes that in this narrow instance it is reasonable to apply the fundamental principle behind the "lesser than" rule, which is to provide no more REP benefits to the IOUs than they would have received under the REP Settlement Agreements. Forman, *et al.*, WP-07-E-BPA-76, at 53-54. Applying the "lesser than" rule here makes sense because it is fundamentally unreasonable to require the COUs to incur even greater costs due to reconstructed REP benefits than those already paid in the PF-02 and PF-07 power rates. Furthermore, BPA believes that paying the IOUs additional benefits under these circumstances would be an impermissible result in light of the *PGE* and *Golden NW* decisions.

The IOUs raise a number of other arguments in support of their position to eliminate the "lesser than" rule. As discussed above, BPA has already agreed to modify the "lesser than" rule to accommodate most of the concerns raised by the parties. BPA finds the additional arguments proffered by the IOUs for eliminating the "lesser than" rule unpersuasive. For example, the IOUs argue that the fact that the Load-Based Cost Recovery Adjustment Clause (LB CRAC) was applied twice a year rather than once a year indicates again that the "lesser than" rule is arbitrary and capricious. IOU Br., WP-07-B-JP6-01, at 145. In fact, the application of the LB CRAC twice a year has no bearing on the choice to apply the "lesser than" rule annually. Rather, Staff argued that the Lookback Amount for each IOU should be calculated on an annual basis because that approach best mimicked what would have happened in a world that included a fully functioning REP. Forman, *et al.,* WP-07-E-BPA-76, at 82. The reconstructed REP benefits would be the same whether they resulted from two six-month calculations or one annual calculation using the same CRACs, exchange loads, and PF Exchange rate. Nonetheless, because BPA is proposing to modify the application of the "lesser than" rule as described above, BPA finds the additional arguments raised by the IOUs to be moot, and will not address them further.

Decision

BPA will not use the "lesser than" rule when calculating each IOU's annual Lookback Amount. However, the aggregate Lookback Amount for any IOU for the entire FY 2002-2008 period cannot be less than zero.

Issue 2

Whether the "lesser than" rule should apply to utilities with "deemer" balances.

Parties' Positions

The OPUC argues that there is no rational explanation for BPA's decision to apply the "lesser than" rule to utilities without deemer balances, but not apply the rule to utilities with deemer balances. OPUC Br., WP-07-B-PU-01, at 19.

BPA Staff's Position

BPA Staff proposed to apply the "lesser than" rule after the "deemer" rule when applying reconstructed REP benefits to then-existing deemer balances. Marks, *et al*., WP-07-E-BPA-62, at 13. In this manner, the treatment of deemer balances was in line with the terms and conditions of the RPSAs offered to the IOUs in 2000. *Id.* Staff considered the RPSA to be the primary consideration prior to imposing any additional rules dictated by the Lookback analysis.

Evaluation of Positions

As presented in the previous issue discussion in this section, BPA is proposing to modify the use of the "lesser than" rule. As a result, this issue is moot.

Decision

BPA is proposing to modify the "lesser than" rule in the Lookback analysis. The modified "lesser than" rule does not result in disparate treatment among the IOUs, whether there is a deemer balance or not.

8.10 Interest on Lookback Amounts

8.10.1 Interest on Lookback Amount FY 2002-2008

Issue 1

Whether BPA should use an inflation-based rate to calculate interest on the total Lookback Amount for FY 2002-2008.

Parties' Positions

APAC and Cowlitz take issue with BPA's use of the average annual rate of inflation to escalate the 2002 through 2008 nominal Lookback Amounts into current dollars. APAC argues BPA should use a three-month Treasury Bill rate. APAC Br., WP-07-B-AP-01, at 16. Cowlitz, on the other hand, suggests using a five-year T-Bill rate. Cowlitz Br., WP-07-B-CO-01, at 74. They argue that using an inflation rate does not adequately compensate the COUs for the time value of the amounts they were overcharged. *Id.*

The IOUs argue that no adjustment for the time value of money is justified. IOUs Br., WP-07-B-JP6-01, at 175-176. The IPUC similarly argues that no interest be applied to the Lookback Amount. IPUC Br. Ex., WP-07-R-ID-01, at 15.

BPA Staff's Position

The proper interest rate to apply to the Lookback period (FY 2002-2008) is an inflationary rate. This rate is the most reasonable because it preserves the purchasing power of the Lookback Amounts for the COUs without unduly penalizing the IOUs for performing their obligations under the REP Settlement Agreements. Marks, *et al.*, WP-07-E-BPA-62, at 9; Forman, *et al.*, WP-07-E-BPA-76, at 89-90.

Evaluation of Positions

The total Lookback Amounts were initially calculated in nominal dollars. Marks, *et al.*, WP-07-E-BPA-62, at 9. BPA, however, recognized that up to seven years has transpired since the original payments were made under the REP Settlement Agreements. To account for the passage of time, BPA used the Gross Domestic Product (GDP) deflator available from the U.S. Department of Commerce to adjust the total Lookback Amount for inflation. *Id.* at 9-10*; see also* Lookback Study, WP-07-E-BPA-44, at 194.

APAC and Cowlitz both claim that BPA's use of inflation is inadequate. APAC Br., WP-07-B-AP-01, at 15-17; Cowlitz Br., WP-07-B-CO-01, at 74-75. APAC argues that it is a well-founded principle of law that adequate interest rates are absolutely necessary to assure that the reimbursements made to the victims of the illegal overcharges fully compensate them for all risks, including the passage of time. APAC Br., WP-07-B-AP-01, at 15. APAC claims that BPA's proposal fails to meet this standard because it uses an inflation rate, which does not adequately compensate the COUs for their damages. *Id.* A more adequate rate, according to APAC, is one that recognizes the "risks underlying cash flows." *Id.* APAC contends this rate would be the three-month T-Bills for each fiscal year. *Id.* Cowlitz recommends that BPA use either a five-year T-Bill rate or BPA's annual borrowing rate to pay on amounts refunded to preference customers. Cowlitz Br., WP-07-B-CO-01, at 74.

BPA recognizes various approaches to calculating interest for the FY 2002-2008 period exist. However, BPA's proposal to use an inflation rate for the FY 2002-2008 period was influenced by the unique set of circumstances which created the present situation. Forman, *et al.*, WP-07-E-BPA-76, at 89. In deciding to use an inflation-based rate for the FY 2002-2008 period, BPA considered several factors.

First, BPA considered whether it had any *legal* obligation to provide interest to the COUs. APAC argues it is a "principle of law" that adequate interest rates are absolutely necessary to assure that the reimbursements to the harmed parties fully compensate them for their damages. APAC Br., WP-07-B-AP-01, at 15. This argument, however, hinges on whether the party on whom interest is being assessed has *any* legal obligation to provide interest. BPA has determined that it has no such duty in the present case. The general rule is that a party cannot recover interest against the government absent an express waiver of sovereign immunity. *See Library of Congress v. Shaw*, 478 U.S. 310, 314, 106 S. Ct. 2957, 92 L. Ed.2d 250 (1986), *superseded by statute as recognized in Jones v. Washington Metro. Area Transit Auth*., 205 F.3d 428, 434 n. 7 (D.C. Cir. 2000). This "no-interest" rule applies even where there is a significant delay between the accrual of the original claim and the actual entering of a judgment for damages. *Id*. As such, the government is required only to pay damages in "nominal dollars," not "real dollars." *See Sandstrom v. Principi*, 358 F.3d 1376, 1377 (Fed. Cir. 2004). This rule can only be varied if the government agreed to pay interest in a contract or if a statute expressly waives the government's immunity to pay interest. *Id*. at 317. In the present case, BPA is unaware of any statute or contract that would direct BPA to pay interest on the overcharges. *See* Forman, *et al.,* WP-07-E-BPA-76, at 90.

Notwithstanding the absence of the specific statutory or contractual basis for interest, BPA believes that some amount of interest is appropriate in the present proceeding. *See* Forman, *et al.,* WP-07-E-BPA-76, at 89-90. In determining what the appropriate rate should be, BPA recognizes that "[i]nterest is not recovered according to a rigid theory of compensation for money withheld, but is given in response to considerations of fairness." *Board of Commr's of Jackson Cty. v. United States*, 308 U.S. 343, 352 (1939). In addition, agencies have "wide discretion in granting interest on awards and may grant interest at rates above or below prevailing rates." *See Farmers Export Co. v. United States,* 758 F.2d 733, 738 (D.C. Cir. 1985).

Consistent with these principles, the record evidence in this proceeding strongly supports Staff's proposal to use a rate based on inflation. First, the IOUs operated under the REP Settlement Agreements for almost seven years before the agreements were found unlawful. *See* Forman, *et al.,* WP-07-E-BPA-76, at 89. Neither BPA nor the IOUs could have foreseen how long it would take for the challenges to the REP Settlement Agreements to be ultimately decided. *Id.* During this period, both parties met their respective obligations in the agreements in the good faith belief that the payments were appropriate. *Id.* BPA does not consider it either fair or reasonable to penalize the IOUs now, seven years after the fact, for complying with the contract by charging them a market-based interest rate for any overpayments. *Id.*

Second, BPA does not believe it reasonable to charge a market-based interest rate before the amount of the overpayment is known. *Id.* It is one thing to require a party to return an overpayment, with full interest, where the party knew or reasonably could have known it was being overpaid. *Id.* at 89-90. In these instances, the recipient of the payment is culpable because it had a duty to notify the payer of the overpayment. *Id.* at 90. It is quite another thing, though, where, as here, the existence of an overpayment and the amount of the overpayment are unknown and in this instance will not be known until BPA completes a massive administrative proceeding. *Id.* In these instances, the policy rationale for requiring a party to pay a market-based interest rate is not present. *Id.* This is particularly the case where, as here, the IOUs will not know how much they were overpaid until BPA issues the final Record of Decision.

This is not to say, though, that the COUs should receive no interest for FY 2002-2008. *Id.* As already noted, BPA proposes to adjust the overcharges to the COUs to reflect the passage of time after the Lookback Amounts have been determined. *Id.* In considering what interest rate to propose, BPA considered it a reasonable policy position to choose a rate that preserves the value of the refund amount through the FY 2002-2008 period. *Id.* In the absence of specific direction in an applicable statute or contract, BPA believes that an inflation rate is appropriate because it preserves (rather than enhances) the value of the COUs' refund amounts until it is finally determined. *Id.* This approach ensures that the value of the COUs' refund is not degraded by inflationary pressures, but does so in a neutral non-prejudicial fashion that recognizes the special circumstances that led to the present overpayments. *Id.*

APAC argues that applying a higher interest rate would not penalize the IOUs for complying with their obligations under the REP settlements because the IOUs and BPA were well aware that the REP settlements were the subject of a pending legal challenge by various parties and that it was possible that the settlements would be invalidated. APAC Br., WP-07-B-AP-01, at 16. APAC's argument is not persuasive. As BPA noted above, interest is most appropriate when parties knew or should have known that they were being overpaid. Forman, *et al*., WP-07-E-BPA-76, at 89-90. In the present case, the IOUs had no way of knowing during the FY 2002-2008 period whether they were being overpaid, and BPA is only now making that determination. *Id.* BPA does not consider it fair or reasonable to assess a market-interest rate against a party, such as an IOU, unless the amount of overpayment is known in the first instance. *Id.* That amount will not be known until the close of this proceeding. As such, BPA believes it more reasonable and equitable to only preserve the purchasing power of the Lookback Amounts until they are established.

Also, as a matter of policy, APAC's proposal is unreasonable. BPA is statutorily directed to operate in a "businesslike manner." 16 U.SC. § 839f(a). Businesses enter contracts assuming they will be implemented in accordance with their terms until and unless an intervening force requires one of the parties to stop performing. BPA's ability to operate in this manner, however, would be seriously undermined if parties to BPA contracts would be penalized by high interest rates if the underlying contract is later found to be invalid. Every contractor with BPA would have to seriously consider whether to continue to perform a contract with BPA in the event the underlying contract is challenged by a lawsuit.

APAC also argues that although the precise amount of total overcharges has yet to be finally determined by BPA, sufficient information existed during the time, and exists now, to measure the scope of damages the IOUs faced. APAC Br., WP-07-B-AP-01, at 16. APAC states that this is the case because the IOUs knew both the amount of benefits that they were receiving under the REP settlements as well as the PF Exchange rate under which BPA was prepared to make traditional REP benefits available to the IOUs in absence of the REP Settlements. *Id.* at 16-17. APAC is mistaken. The *forecast* of REP costs in the WP-02 rate case is not the appropriate amount of REP benefits to compare against the REP Settlement Agreement benefit levels. Forman, *et al.*, WP-07-E-BPA-76, at 13-14. These forecasts were based on projections and assumptions that were subsequently undermined by the 2000 West Coast energy crisis. Burns, *et al.*, WP-07-E-BPA-53, at 5-7. Further, the forecasted REP costs do not set a "limit" on the amount of REP benefits that may have been provided during the FY 2002-2008 period (and therefore collected from COUs). Forman, *et al.*, WP-07-E-BPA-76, at 13-14. Finally, BPA did not have the utilities' ASCs for the FY 2002-2008 period. Manary, *et al.*, WP-07-E-BPA-61, at 2. These filings are absolutely essential for estimating the amount of REP benefits the IOUs would have received. *Id*. Without making the adjustments described above and estimating the IOUs' ASCs for the FY 2002-2008 period, there would have been no way for either BPA or the IOUs to even guess whether the REP Settlements were inappropriately high. APAC is, therefore, flatly wrong in suggesting the amount of overpayments the IOUs received could have been determined on the bare WP-02 record prior to this proceeding.

Cowlitz argues that BPA's proposed rate is "a zero real rate" rate that penalizes the preference customers. Cowlitz Br., WP-07-B-CO-01, at 75. Cowlitz claims that if BPA brings suit against the IOUs to recover the illegal payments, it would be entitled to 9% prejudgment interest. ORS 82.010(2)(c). *Id.* Cowlitz states BPA offers no valid reason the aggrieved preference customers should get less. *Id.* Cowlitz is incorrect. As already noted above, BPA *is not* legally obligated to give Cowlitz or the preference customers *any* interest on the Lookback Amount. In this instance, BPA is on firm legal grounds to propose the COUs receive only the "nominal" value of the Lookback Amount. *See Sandstrom v. Principi*, 358 F.3d 1376, 1377 (Fed. Cir. 2004). Nevertheless, BPA chose as a matter of policy to provide some time value of money to the COUs. Forman, *et al.*, WP-07-E-BPA-76, at 89-90. After considering the unique circumstances of this case, BPA believes that, as a policy matter, inflation is a reasonable interest rate for the Lookback Amount. *Id.* This results in an interest rate that ranges from 2.1% to

3.2%, which adds *tens of millions* to the total Lookback Amount. *See* Lookback Study Documentation, WP-07-FS-BPA-08, at Table 15.9. The COUs are not, therefore, being "penalized" by BPA's proposal. Cowlitz's citation to an Oregon State prejudgment interest statute does not change this calculus. What interest rate BPA *may* be able to obtain from the IOUs through litigation is not informative of what interest rate BPA is *legally* obligated to *pay* to the COUs. BPA has distinct legal relationships with both the IOUs and the COUs. What interest rate BPA must pay the COUs is determined by federal law and any applicable contracts, not an Oregon State statute.

The IOUs argue that, to the extent BPA imposes its Lookback remedy, BPA cannot and should not include any interest or time value of money adjustment on any Lookback remedy. IOU Br., WP-07-B-JP6, at 175. As an initial matter, the IOUs note that the opinion from the Ninth Circuit instructs BPA "to set rates in accordance with th[e] opinion." *Id.* The IOUs argue that the opinion does not instruct BPA to order refunds or to calculate any amount of interest or time value of money adjustment. *Id.* Therefore, the calculation and imposition of interest or time value of money adjustment (as well as the imposition of any form of Lookback remedy) is outside the scope of relief granted by the Ninth Circuit, and all actions in this proceeding should be prospective in nature only. *Id.*

BPA is not persuaded by the IOUs' arguments. The IOUs claim, incorrectly, that the Court's opinion prohibits BPA from considering interest in the Lookback Amount. BPA already discussed at length in Chapter 2 its position on the scope of the remand. As noted in that section, the law allows agencies the ability to implement judicial reversals. *See Natural Gas Clearinghouse v. FERC,* 965 F.2d 1066, 1073 (D.C. Cir. 1992). A judicial reversal of an agency order that has been in effect "at times results in the return of benefits received under the upset administrative order." *United Gas. Imp. Co. v. Callery Properties, Inc.,* 382 U.S. 223, 230-31 (1965). When determining what amount to refund to customers harmed by the administrative order, the Supreme Court has recognized that adding interest on refunds is "not an inappropriate means of preventing unjust enrichment." *Id.* Similarly, it is appropriate for BPA in this proceeding to determine what amount of interest is reasonable on the Lookback Amount to prevent the "unjust enrichment" of the IOUs. BPA recognizes that the IOUs as entities have not received the specific economic benefits of the REP Settlement Agreements. IOU Br., WP-07-B-JP6, at 176. Rather, these amounts have been passed on directly to the residential and small farm customers of the IOUs. *Id.* BPA considered this unique circumstance in its proposal, and it was another factor in favor of using an inflation-based rate rather than a market-based interest rate for the Lookback period. As explained in Staff's testimony, "this approach ensures that the value of the COU's refund is not degraded by inflationary pressures, but does so in a neutral non-prejudicial fashion that recognizes the special circumstances that led to the present overpayments." Forman, *et al.*, WP-07-E-BPA-76, at 90.

The IOUs also point out that interest is not recovered through a particular theory, but through considerations of fairness. IOU Br., WP-07-B-JP6, at 176. The IOUs contend that principles of fairness in this case strongly support applying no interest. *Id.* Specifically, the IOUs note that the "ratemaking errors" were made by BPA, no stay was sought, and any Lookback remedy would inherently rely on speculation in the face of great uncertainty. *Id.* For these reasons the

IOUs conclude it would be unfair and inequitable to permit BPA to calculate and impose interest or time value of money adjustment on any Lookback remedy amounts. *Id.* The selection of any particular interest rate or time value of money adjustment rate would, under these circumstances, necessarily be arbitrary and capricious. *Id.*

As noted above, BPA is taking into account the unique circumstances of the present proceeding, and agrees that principles such as fundamental fairness and good faith are important considerations. *See* Forman, *et al.*, WP-07-E-BPA-76, at 89-90. As explained above, however, these factors strongly favor BPA's proposal. The IOUs point out that BPA made the "ratemaking errors" that caused the current remand. IOU Br., WP-07-B-JP6, at 176. This point is only relevant to the extent that it is another factor BPA must take into account when fashioning a remedy to respond to the remand. The fact that BPA bears some responsibility for the legal error committed does not dissolve BPA's duty to redress the harm caused by that legal error. The Court determined that BPA's actions were unlawful, and the COUs were in turn harmed by the REP Settlement Agreements. To respond to the remand, BPA believes it is reasonable and appropriate to develop a remedy that includes some amount of interest to account for the passage of time. Staff proposed an approach that preserves the value of the COUs' refund amounts until they are finally determined. Forman, *et al.*, WP-07-E-BPA-76, at 90. This approach ensures that the value of the COUs' refunds is not degraded by inflation. *Id.* At the same time, though, BPA recognizes that because of the facts of this particular case, a market-based rate would not be appropriate. Therefore, since return of Lookback Amounts to COUs begins in FY 2009, BPA proposes to adjust nominal Lookback Amounts to FY 2009 dollars using the GDP implicit price deflator.

The IPUC in its Brief on Exceptions argues that since the time period for paying the Lookback Amount is being changed from 20 years to seven, there is no longer a need to adjust the Lookback Amounts for inflation. IPUC Br. Ex., WP-07-R-ID-01, at 15. This argument, however, is not persuasive because BPA's decision to adjust the Lookback Amounts for inflation for the FY 2002-2008 period has nothing to do with the length of the repayment period. The Lookback Amounts were adjusted to FY 2009 dollars to reflect the time that has *already passed.* The inflation adjustment was made because BPA recognized that without it, inflationary pressures alone would have degraded the value of the refunds to the COUs. The fact that BPA is now proposing to change the repayment period from 20 years to seven does not affect in any respect BPA's decision to protect the value of the Lookback Amounts from inflation. The IPUC's argument is therefore misplaced.

The IPUC also argues in its Brief on Exceptions that BPA should use the interest that it earns on its reserves to provide the interest on the Lookback Amounts. IPUC Br. Ex., WP-07-R-ID-01, at 15. As discussed in Section 9.3.3, Issue 2, using any part of reserves to pay the Lookback Amount, even the interest, is self-defeating because it effectively results in the COUs paying for their own refund. For this reason, BPA rejects the IPUC's suggestion.

Decision

BPA will use inflation-based rates to adjust nominal Lookback Amounts to FY 2009 dollars.

8.10.2 Interest on Lookback Amount Post-FY 2009

Issue 1

Whether BPA's proposal to apply an interest rate equal to the 20-year Treasury Bill rate to the outstanding balance of Lookback Amounts for the post-2009 period is reasonable.

Parties' Positions

APAC challenges BPA's initial proposal to use a 20-year T-Bill rate of 5.03%. APAC Br., WP-07-B-AP-01, at 15-18. APAC claims that due to the risk that there will not be sufficient REP benefits over 20 years to fully repay the Lookback Amounts, the customers of the COUs are in the same risk position as equity owners of a modern integrated electric utility, and should therefore receive an equity rate of return. Their estimate of such a return ranged from 7.5% to 11.5%. *Id.; see also* Villadsen and Wolverton, WP-07-E-AP-2-CC1, at 18-19.

Cowlitz argues that if BPA retains its long-term repayment plan, a higher interest rate would be appropriate. Cowlitz points to the Oregon State statutory rate of 9% as an example. Cowlitz Br., WP-07-B-CO-01, at 74-75.

To the extent that interest is found to apply, the OPUC supports BPA's proposal. OPUC Br., WP-07-B-PU-2, at 31.

The IOUs argue that no adjustment for the time value of money is justified. IOUs' Br., WP-07-B-JP6-01, at 175-176.

The IPUC argues that BPA should use an inflationary rate for FY 2009 and beyond, and urges BPA to use the interest on its reserves to pay the interest on the Lookback Amount. IPUC Br. Ex., WP-07-R-ID-01, at 15.

BPA Staff's Position

BPA Staff originally proposed that a 20-year Treasury Bill rate be the applicable rate on any outstanding Lookback Amounts for the period post-2009. Marks, *et al.*, WP-07-E-BPA-62, at 17-18. This rate is a neutral rate that neither advantages nor disadvantages the IOUs or the COUs. *Id.*

Evaluation of Positions

In its initial proposal, BPA proposed that the Lookback Amounts, once determined, should accrue interest on a going-forward basis. Marks, *et al.*, WP-07-E-BPA-62, at 17-18. BPA proposed using a 5.03% rate, which is the average daily 20-year Treasury Bill rate for the period starting October 1, 2001, and ending September 30, 2007. *Id.* This rate was chosen because it is a neutral rate of interest that does not advantage or disadvantage either the COUs or the IOUs. *Id.* It also reflects the potential Lookback Amount amortization period of up to 20 years. Forman, *et al.*, WP-07-E-BPA-76, at 91. In rebuttal testimony, BPA Staff noted that it would consider other alternatives and consider parties' arguments concerning using a risk-adjusted rate of interest. *Id.* at 94. BPA Staff also noted that they would consider this issue and make a proposal to the Administrator based on the complete record of this proceeding. *Id.*

The OPUC states that, to the extent an interest rate is applied to Lookback Amounts, it supports BPA's proposal. OPUC Br., WP-07-B-PU-2, at 31. The OPUC notes that it recommended a similar interest rate. *Id.* The OPUC noted that BPA's recommendation of 5.03% is based on the daily average of 20-year T-Bill rates starting with October 1, 2001 and going through September 30, 2007. *Id.* The OPUC's recommendation of 4.0% is based on the methodology used by the OPUC to establish the interest rate applicable to customer deposits held by regulated utilities in Oregon. *Id.* The OPUC agrees with the reasoning underlying BPA's proposal to use the daily average of 20-year T-Bill rates to determine the applicable interest rate, and supports the interest rate proposed by BPA. *Id.*

APAC argues that BPA's proposal fails to provide for adequate interest for the post-2008 period. APAC Br., WP-07-B-AP-1, at 17; APAC Br. Ex., WP-07-R-AP-01, at 3-4. APAC relies on testimony proffered by its witnesses, Dr. Villadsen and Mr. Wolverton, which explains that because of the repayment risks that Preference Customers face under BPA's proposal, BPA's Preference Customers are more akin to "equity holders" than "debt holders," and therefore should receive an equity-based rate of return. APAC Br., WP-07-B-AP-01, at 17*, citing* V Villadsen and Wolverton, WP-07-E-AP-2, at 11-14. APAC acknowledges that BPA is a "unique entity" and that there is no "perfect sample of companies" from publicly traded companies with which to compare. *Id.* Nevertheless, APAC recommends that BPA adopt a "carrying charge" reflective of an integrated utility as a benchmark establishing the lower bound of the numerical value of the carrying charge. *Id.*

BPA does not agree with APAC's assessment of the risk profile of the COUs'. As BPA Staff pointed out in their rebuttal testimony, COUs are fundamentally not in the same position as equity shareholders of a publicly traded company. Forman, *et al.*, WP-07-E-BPA-76, at 92-93. Equity owners of a privately held company, by the very definition of the term, have made monetary investments in a company, and these investments depend on two aspects of equity ownership to generate a return: (1) appreciation of their stock's value through increasing share price; and (2) a cash return in the form of a cash dividend distribution from that company. *Id.* at 93. Neither one of these aspects applies to the COUs. *Id.* First, BPA is part of the United States government, and as such has no stock to sell to the COUs to make them equity investors. *Id.* Therefore, comparing the COU's return risk profile to that of an equity investor's return is inapposite. *Id.* The second aspect is possibly more relevant to the instant case. *Id.* BPA infers that the comparison APAC is attempting to make between COUs and equity shareholders is with the dividend payout shareholders may receive from time to time. *Id.* In theory, equity holders must wait until the company has paid all of its operating expenses and debt service costs to get a dividend distribution. This concept of equity holders being last in line, however, is inapplicable to the COUs. *Id.* Unlike equity shareholders, the COUs are *not last* in line to get their payment;

rather they are *first* in line. *Id.* In BPA's rebuttal testimony, Staff explained that the COUs were in a priority position because they will receive the Lookback Amounts through a reduction in future rates. *Id.* In the Draft Record of Decision, BPA agreed with the position that the Lookback Amounts should go to the parties that were overcharged. *See* Chapter 9. The Lookback Amount credit will not be embedded in the COUs' rates generally, but as credits on individual customers' bills. *Id.* This adjustment, however, will not change the COUs' position. BPA will still establish its rates assuming that credits will be made to the COUs, thereby retaining the priority positioning of the COUs for receiving the Lookback Amount refunds. In either case, APAC's contention that the COUs' position is analogous to that of equity shareholders, who bear substantial risk of no return, is inapposite.

APAC and Cowlitz both argue that there is some risk that the COUs will not completely recover the overcharges due to the uncertain level of post-2009 REP payments. APAC Br., WP-07-B-AP-01, at 17; APAC Br. Ex., WP-07-R-AP-01, at 3-4; Cowlitz Br., WP-07-B-CO-01, at 74-75. Cowlitz claims that this risk justifies using a higher interest rate, such as the Oregon State statutory rate of 9%. BPA already explained above the reason that this Oregon statutory rate is inapplicable to the present case. But even if it was applicable, it is not reasonable to use on a going-forward basis. BPA concurs that it cannot guarantee that the repayments from the IOUs will be made in the time allotted. Forman, *et al.*, WP-07-E-BPA-76, at 94. It is because of this potential risk that BPA decided to use a more robust interest rate in the going-forward period than the interest rate used for the Lookback period (2002-2008), where BPA escalated the total Lookback Amount for inflation, which ranged from 1.56% to 3.39%. *Id.* at 85. From FY 2009 and onward, BPA Staff proposed in the Supplemental Proposal to accrue interest on unamortized Lookback Amounts using a T-Bill interest rate, which corresponded to the period estimated to be needed to amortize all Lookback Amounts (with the exception of Idaho Power). Marks, *et al.*, WP-07-E-BPA-62, at 17-18. BPA believes using the T-Bill interest rate corresponding to the expected term of repayment of the Lookback Amounts appropriately compensates the COUs for the delay in returning the Lookback Amount over BPA's proposed payment term.

In this Record of Decision, the Administrator adopted a method for recovering and returning the Lookback Amounts that was different than Staff's original proposal. *See* Section 9.3.3. Amongst other differences, the Administrator decided to change the goal of returning the repayment from up to 20 years to seven. To be consistent, BPA will also change the T-Bill rate used to calculate the interest applicable to the IOUs' Lookback Amounts to correspond to the expected term of repayment. This will be an IOU-by-IOU determination. Thus, if an IOU's Lookback Amount will be totally repaid in seven years, the seven-year T-Bill will be used to calculate interest. If an IOU's Lookback Amount will be repaid in a longer period, then a T-Bill interest rate matching the longer repayment period will be used. This approach is consistent with BPA's previous proposal to match the T-Bill interest rate with the expected repayment period. *See* Chapter 15, Lookback Study, WP-07-FS-BPA-08.

The IOUs argue again that BPA should not impose any interest on the Lookback Amounts. IOU Br., WP-07-B-JP6-01, at 175. BPA has already addressed the substantive issues the IOUs raised on this issue in the discussion on the preceding issue.

The IPUC requests BPA to use an inflation based rate for FY 2009 and beyond. IPUC Br. Ex., WP-07-R-ID-01, at 15. BPA notes here, though, that imposing a higher interest rate from FY 2009 and forward is appropriate because the IOUs will know the amount of the overpayment. While as a practical matter BPA recognizes that it would be highly unlikely for the IOUs to decide to make a lump sum payment of their Lookback Amounts, the IOUs could avoid accruing interest by voluntarily making such payment, or by returning the Lookback Amount in fewer years. This option was not available to the IOUs during the FY 2002-2008 period because BPA had to reconstruct several elements of the WP-02 and WP-07 cases, as well as calculate backcast ASCs, to determine the amount of overcharges. Once the total Lookback Amount becomes known, though, it is reasonable to require the IOUs to pay a higher interest rate to preserve its value. By using the T-Bill rate, and not a higher market-based rate, BPA is still giving weight to the circumstances which led to the overpayments. Nevertheless, to keep BPA (and in turn the COUs) whole for the overcharges, once known, the most reasonable course is to apply a more robust rate of interest to preserve the value of the Lookback Amounts over time.

The IPUC also requests BPA to use the interest it earns on its reserves to pay the interest on the Lookback Amounts. IPUC Br. Ex., WP-07-R-ID-01, at 15. As discussed in the previous issue, using interest from reserves to pay the Lookback Amount is self-defeating because it effectively results in the COUs paying for their own refund. For this reason, BPA rejects the IPUC's suggestion.

Decision

BPA will use the T-Bill rate to assess interest on post-FY 2009 unamortized Lookback Amounts. The rate for each IOU will be the T-Bill rate corresponding to the number of years that BPA expects it will take for an IOU to return its Lookback Amount. Reserves will not be used to pay the Lookback Amounts.

8.11 Issues Associated with Deemer Balances

Issue 1

Whether deemer balances should be considered in this Lookback.

Parties' Positions

The IPUC asserts that the deemer mechanism is not authorized by the Northwest Power Act, and should not be considered in this proceeding. IPUC Br., WP-07-B-ID-01, at 14. The IPUC also takes issue with certain BPA's characterizations made in the Draft ROD. IPUC Br. Ex., WP-07-R-ID-01, at 10-11.

The WUTC and IOUs[11] contend BPA should make no assumptions about any alleged deemer balances in this proceeding for purposes of the Lookback calculations. WUTC Br., WP-07-B-WU-01, at 24; IOU Br., WP-07-B-JP6-01, at 184. Idaho Power argues that BPA should assume that no deemer balances exist in the Lookback analysis because the balances are subject to dispute for several reasons. IPC Br. Ex., WP-07-R-IP-V1, at 2.

WPAG supports BPA's proposal to consider deemer issues in the Lookback calculation. WPAG Br., WP-07-B-WA-01, at 38.

BPA Staff's Position

BPA Staff proposed that determination of the amount of REP benefits that would have been provided to an IOU in the absence of the REP Settlement Agreements must account for any existing deemer balance. Bliven, *et al.*, WP-07-E-BPA-52, at 18. In calculating a Lookback Amount for an IOU with a deemer balance, reconstructed REP benefits are first applied to reduce a utility's deemer balance each year until the deemer balance is exhausted. Marks, *et al.*, WP-07-E-BPA-62, at 13. Once the balance reaches zero, Staff then proposes to compare each deemer utility's reconstructed REP benefits to its REP settlement benefits to calculate annual Lookback Amounts. *Id.*

Evaluation of Positions

BPA's response to the Court's rulings includes a determination of the amount COUs were overcharged due to the REP Settlement Agreements, referred to as the Lookback Amount. Marks, *et al.,* WP-07-E-BPA-62, at 9. This total Lookback Amount is composed of six separate Lookback Amounts, one for each IOU. *Id.* One component of the calculation of Lookback Amounts is the determination of the amount of REP benefits each IOU would have received in the absence of the REP Settlement Agreements, called "reconstructed REP benefits." Bliven, *et al.*, WP-07-E-BPA-52, at 12.

Deemer balances are a remnant of BPA's implementation of 1981 RPSAs with exchanging utilities. Boling, *et al.,* WP-07-E-BPA-57, at 3. Staff's proposal regarding deemer balances is to assume that any deemer balances that existed as of October 1, 2001 should be treated in a manner that is consistent with their historical treatment. Bliven, *et al.,* WP-07-E-BPA-52, at 18.

As stated in the 1981 RPSAs, when a utility's ASC was less than the PF Exchange rate, the utility could elect to "deem" its ASC equal to the PF Exchange rate. Boling, *et al.*, WP-07-E-BPA-57, at 3. By doing so, it avoided making actual monetary payments to BPA. *Id.* The amount that the utility would otherwise have paid BPA was tracked in a "deemer account." *Id.* At such time as the utility's ASC became higher than BPA's PF Exchange rate, benefits that would otherwise have been paid to the utility would be first credited against the negative

[11] Avista and Idaho Power sponsored the portion of the IOUs' brief that opposed BPA's treatment of the deemer balances in the Lookback. Unless otherwise noted, BPA's reference to the "IOUs" in this section refers to Avista and Idaho Power.

"deemer balance." *Id.* Only after positive REP benefits had completely offset the "negative balance," or the "negative balance" had been bought down by the deeming utility, would the utility again receive actual monetary REP payments. *Id.* The 1981 RPSAs provided that "[u]pon termination of this agreement, any debit balance in such separate account shall not be a cash obligation of the Utility, but shall be carried forward to apply to any subsequent exchange by the Utility for the Jurisdiction under any new or succeeding agreement." *Id.* Consequently, the deemer balances that a utility accrued under the 1981 RPSA would need to be satisfied under future RPSAs with BPA before the utility would receive REP payments. Idaho Power, NorthWestern, and Avista all had deemer balances as of October 1, 2001. *Id.*

In determining "reconstructed REP benefits," and consequently Lookback Amounts, BPA assumes that it would have had an operational REP for both the WP-02 and WP-07 rate periods. Bliven, *et al.*, WP-07-E-BPA-52, at 14. Five IOUs filed letters of intent with BPA to participate in the REP prior to the WP-02 rate proceeding. *Id.* Had BPA and the IOUs not signed the REP Settlement Agreements, these five utilities would have signed RPSAs with BPA, and thereby would have received REP benefits during FY 2002-2008 consistent with the terms and conditions of those RPSAs. *Id.* The sixth utility, Idaho Power, is assumed not to participate in the REP due to its large deemer balance and relatively low ASC. *Id.*

WPAG supports BPA's proposal to consider deemer issues in the Lookback calculations. A deemer obligation survives the termination of the initial 1981 RPSA and is applicable whenever an IOU with a deemer balance executes a replacement RPSA. WPAG Br., WP-07-B-WA-01, at 37. WPAG notes that since the inception of the REP, over $4.0 billion has been collected from the customers of preference utilities and paid to the customers of IOUs. *Id.* As part of this bargain, the IOUs agreed by contract to reimburse amounts by which their ASCs fell below the applicable PF Exchange rate by forgoing REP payments until any such balance is brought to zero. *Id.* This contractual repayment commitment survived the termination of the initial RPSA, and is applicable whenever an IOU with a deemer balance executes a replacement RPSA. *Id.* The contractual liability to bring to zero any deemer balances is a natural consequence of BPA's "what if" approach to determining the amount of the illegal overcharges imposed on the preference customers. *Id*. at 38. Since BPA's approach includes the calculation of payments to the IOUs under RPSAs they are assumed to sign in the absence of the Settlement Agreements, it must include the reimbursement to BPA of any outstanding deemer balances. *Id.* The position advanced by some of the IOUs and the IPUC on deemer balances has no basis in logic or in the law and should not be adopted. *Id.*

The IPUC, WUTC, and the IOUs generally opposed BPA's proposed treatment of the deemer balances in the Lookback. IPUC Br., WP-07-B-ID-01, at 14; WUTC Br., WP-07-B-WU-01, at 24; IOU Br., WP-07-B-JP6-01, at 184. Before addressing the specific arguments of these parties, BPA must emphasize here that it is *not* finally determining the validity or invalidity of the deemer balances in this proceeding. Forman, *et al.,* WP-07-E-BPA-76, at 67. BPA is only proposing an assumption as to the deemer balances for purposes of calculating the Lookback Amounts. This assumption, however, will not finally resolve either BPA's or the deeming utilities' rights. As Staff noted in the hearing phase of this case:

> BPA … is not resolving the deemer account balances as part of this proceeding. Our assumptions about the deemer balances are made only for purposes of this Supplemental Proceeding and, in particular, the calculation of the Lookback Amount. Also, we agree that the deemer balances are contract issues to be resolved by the contract parties as part of the implementation of the REP. The reflection of assumed deemer balances in this proceeding is not intended to constitute a final determination of such balances by BPA. We agree that the Ninth Circuit did not have the 1981 RPSAs or other agreements involving deemer balances before it when deciding the *PGE* and *Golden NW* cases. Nevertheless, deemer balances are an aspect of the REP and thus, in reviewing the implementation of the REP in the absence of the REP settlements, we cannot ignore them and must make some assumptions regarding the deemer balances for ratemaking purposes.

Id. BPA's responses to the parties' arguments in this section must be viewed in light of this qualification. The analysis below demonstrates that BPA's deemer balance *assumptions* are reasonable. It is not intended to be a final adjudication or decision on the deeming utilities' rights or obligations.

The IPUC argues that there is no statutory authorization for BPA to utilize the deemer mechanism or engage in deemer accounting. IPUC Br., WP-07-B-ID-01, at 14. According to the IPUC, the Northwest Power Act contemplates that BPA and the IOUs would exchange when an IOU's ASC was <u>above</u> BPA's cost, and there is nothing in the Northwest Power Act or its legislative history that suggests that the exchange benefits should flow in the <u>opposite direction</u>, from the three IOUs to BPA. *Id*.

This argument is not persuasive. The IPUC's assertions that BPA should ignore the deemer issues in its Lookback calculations are directly at odds with the facts surrounding the implementation of the REP since its inception in 1981. While the Northwest Power Act does not expressly call out a deemer mechanism, it also does not prohibit one. In the absence of express statutory guidance on this issue, or a court order voiding the deemer provisions, BPA finds it reasonable to assume that the deemer provisions are a valid and binding obligation of the IOUs.

Further, the IPUC's argument is even more unconvincing when considered in light of the historical operation of the exchange program. The deemer mechanism has been a component of the REP since the creation of the RPSAs in 1981. At that time all of the IOUs, including Avista and Idaho Power, signed without protest the 1981 RPSAs, which contained deemer provisions. During the term of the 1981 RPSAs, no party (including the IPUC) brought any legal challenges against the deemer provisions on the grounds that they were not authorized by the Northwest Power Act. This point must be emphasized. If the framers of the Northwest Power Act never intended the REP to result in payments from the IOUs to BPA, then it follows that the IOUs and state regulatory bodies would have vigorously opposed including the deemer mechanism in the 1981 RPSA. The facts show, however, that no such challenge was made.

Moreover, in 1987 and 1988, BPA executed RPSA Suspension Agreements with Avista and Idaho Power, respectively. Westerfield, WP-07-E-ID-2, at 7. Both agreements addressed deemer balances outstanding as of specific dates, the interest rate applicable to deemer balances, and whether interest would be compound or simple. *See* WP-07-E-ID-2-AT6 and WP-07-E-ID-2-AT7. At the time the Suspension Agreements were entered into, no party raised any objection or legal challenge to the deemer approach in general or to the specific treatment specified in the Suspension Agreements on the grounds that these provisions were not authorized by the Northwest Power Act. Later, Idaho Power and Avista terminated their respective 1981 RPSAs in 1993. The record in this proceeding addresses at considerable length the circumstances surrounding the 1993 termination of the 1981 RPSAs and the deemer issues. *See* Westerfield, WP-07-E-ID-02, at 9-11. BPA reviewed this documentation and once again found no indication that parties in 1993 considered the deemer provisions counter to the Northwest Power Act.

Also, in 2000, BPA conducted a formal public comment process on the proposed 2000 RPSAs that would have provided REP benefits in the absence of Settlement Agreements. This process concluded with a ROD entitled "Residential Purchase and Sale Agreements with Pacific Northwest Investor-Owned Utilities" (2000 RPSA ROD) dated October 4, 2000. Pages 41 through 56 of the 2000 RPSA ROD address deemer issues in the context of REP benefits under the 2000 RPSAs. Despite opposition to the deemer provision, including a statement by Avista that "there is no mention of a deemer account in the Northwest Power Act," BPA retained the provision in the final agreement. 2000 RPSA ROD at 52. BPA's decision to retain the deemer in the 2000 RPSA was never challenged.

In view of the above record evidence, BPA cannot agree in this proceeding that the deemer mechanism is now contrary to the Northwest Power Act. In effect, the IPUC requests BPA to adopt an assumption that would invalidate a contractual mechanism that has been in effect for over 20 years. BPA can find no basis in the record of this proceeding, the Northwest Power Act, or any other law or policy that would require BPA to make this unreasonable assumption. The IPUC's position must be rejected.

The IPUC notes that negative deemer balances are extremely detrimental to IOU ratepayers, especially to the more than 400,000 eligible customers of Idaho. IPUC Br., WP-07-B-ID-01, at 14. The IPUC also notes that the deemer account has merely accrued interest since FY 1985. *Id.* BPA acknowledges that deemer balances have an impact on the amount of REP benefits available to Idaho Power's residential customers. BPA further concurs that much of the deemer balance that exists today is a result of interest that has accrued since 1988. However, these observations are not relevant considerations for determining the Lookback calculations in this proceeding. In its Lookback determination, BPA assumes that Idaho Power would not have signed an RPSA in 2000. Bliven, *et al.*, WP-07-E-BPA-52, at 14. BPA's Lookback calculations indicate that Idaho Power has zero "reconstructed REP benefits" over FY 2002-2008. *See* FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 191-192. Therefore, Idaho Power's Lookback Amount as calculated in this proceeding is the same under BPA's deemer assumptions as it would be if BPA assumed Idaho Power had zero deemer balance as of October 2001.

Furthermore, as addressed earlier, BPA is not resolving the deemer issues as part of this proceeding. Instead, BPA is making assumptions for purposes of calculating the Lookback Amounts. Forman, *et al.,* WP-07-E-BPA-76, at 67. Idaho Power's Lookback Amount is the same regardless of the deemer assumptions BPA makes. *Id.* Given that BPA is not asserting that the assumptions made in this proceeding resolve deemer issues or constitute a final determination of the deemer obligations, BPA believes that it is not necessary to address specific deemer issues in order to establish reasonable Lookback Amounts.

The WUTC contends that BPA should not resolve the deemer issue in this proceeding because such issues are contract matters that were not before the Court; the Court did not require BPA to resolve them; a rate case is not the forum for resolving these issues; and the record is insufficient for BPA to resolve them in any event. WUTC Br., WP-07-B-WU-01, at 26. The IOUs make similar arguments, stating that the deemer balances are the result of bilateral contracts between BPA and the IOUs. IOU Br., WP-07-B-JP6-01, at 184. The IOUs contend BPA asserts without explanation that an underlying assumption is that a "deemer" balance must be repaid before exchanging utilities are eligible for payments through a RPSA. IOU Br., WP-07-B-JP6-01, at 183. The IOUs state that BPA has acknowledged (*see, e.g.,* Forman, *et al.*, WP-07-E-BPA-76, at page 67, lines 15-21, and page 74, lines 3-4) – and Avista and Idaho Power agree – that the deemer accounts, and any issues and disputes regarding such deemer accounts, are beyond the scope of this section 7(i) rate proceeding and, therefore, issues regarding the purported deemer accounts are not properly addressed in this proceeding. *Id.* at 184.

BPA agrees with the WUTC that deemer balances were not before the Ninth Circuit, and the deemer issue is not an issue the Court remanded to BPA to resolve. Nevertheless, BPA believes it is necessary to take into account the deemer balances to properly calculate the REP benefits the IOUs would have received during the Lookback period. Under the traditional implementation of the REP, a utility must exhaust its deemer balance before receiving positive REP benefits. Forman, *et al.*, WP-07-E-BPA-76, at 66. In the absence of the REP Settlement Agreements, BPA would have continued this historical practice and required the IOUs to extinguish their deemer balances before receiving positive REP payments. *Id.* It follows that when calculating what amount of REP benefits each utility would have received under a functioning REP, deemer balances must be paid off before positive benefits could flow to the utilities. *Id.* Absent this assumption, the utilities with deemer balances could receive REP benefits when they should have received nothing. *Id.* BPA believes that this result would be contrary to the Court's direction in *Golden NW.*

The WUTC and IOUs both argue that the deemer issues are contract issues that should not be "resolved" in this proceeding. As noted above, BPA is not finally resolving the specific contractual disputes related to the deemer provisions. Rather, BPA fully anticipates that there will be other opportunities to discuss the merits of parties' arguments through negotiations, other processes, or litigation. However, the deemer balances, even assumed amounts, must be accounted for in the Lookback calculation to ensure that the results of this proceeding reasonably reflect what the REP benefit payments to the IOUs would have been without the REP Settlement Agreements. Consistent with BPA's position that the decisions in this proceeding do not constitute final determinations of disputed deemer issues, if deemer issues are settled or otherwise determined subsequent to this proceeding, BPA will reflect the resolution of issues in the respective IOUs' Lookback Amounts. Forman, *et al*., WP-07-E-BPA-76, at 74.

The IOUs request BPA to ignore the deemer balances for purposes of this proceeding because of contractual disputes regarding BPA's implementation of the deemer provisions. IOU Br., WP-07-B-JP6-01, at 183. While BPA acknowledges the IOUs dispute certain aspects of the deemer provision, BPA does not agree that these disputes require BPA to assume no deemer balances exist. The primary deemer question in this proceeding is whether or not it is logical and appropriate to calculate a Lookback Amount without considering the effect of the deemer balance. Ultimately, rate case assumptions must be driven by the known facts. On the one side are arguments about the validity of the underlying deemer obligations. Forman, *et al.*, WP-07-E-BPA-76, at 73. On the other side is the fact that the 1981 RPSAs, which the IOUs signed, included language requiring that deemer balances be paid off before utilities could receive positive REP benefits; the fact that the administration of the REP, including the subsequent suspensions and terminations of the Avista and Idaho Power 1981 RPSAs, reflected this requirement; the fact that the utilities accrued deemer balances; the fact that evidence indicates those deemer balances existed at the beginning of the Lookback period, although they are disputed; and the fact that BPA's prototype RPSA that was offered in 2000 contained the requirement that the deemer balances be paid off before receiving positive benefits. *Id*. In consideration of this strong evidentiary foundation, BPA does not believe it reasonable to simply assume away the deemer balances for purposes of the Lookback calculations.

Even if BPA could assume that the deemer balances would have been resolved prior to the Lookback Period, BPA cannot determine with any degree of certainty what resolution would have occurred. BPA is unaware of any serious negotiations regarding the deemer balances prior to the signing the 2000 REP Settlement Agreements. Consequently, there is no evidence regarding what the specifics of that resolution might have been. Further, there is no evidence or rationale for assuming that NorthWestern or Avista would have refused to enter into the 2000 RPSAs absent resolution of the deemer issues. To the contrary, the likelihood that outstanding deemer balances as asserted by BPA would be reduced or eliminated during the term of the RPSAs, and that REP benefits would have been provided to NorthWestern's and Avista's eligible consumers once deemer balances were extinguished, supports the assumption that these utilities would have signed RPSAs in 2000 even though the agreements contained deemer provisions objected to by the companies.

In its Brief on Exceptions, the IPUC objects to BPA's reference to the "2000 RPSA" in the Draft Record of Decision, claiming that the 2000 RPSA is "irrelevant" to BPA's decision. IPUC Br. Ex., WP-07-R-ID-01, at 10-11. This is incorrect. While BPA has assumed Idaho Power would not have signed an RPSA for the FY 2002-2008 period, BPA has assumed that both Avista Corp and Northwestern would have. Bliven, *et al*., WP-07-E-BPA-52, at 14. Under the terms of the 2000 RPSA, these utilities' deemer balances would have been subject to simple interest for the FY 2002-2008 period. *See* 2000 RPSA Draft Prototype section 12, WP-07-E-JP6-17. Consequently, BPA assumed that Avista's and Northwestern's deemer balances would have accrued simple interest during the Lookback period pursuant to the terms of the 2000 RPSA. Thus, BPA's reference to the 2000 RPSA in this Record of Decision is proper.

The IPUC also argues that although BPA insists that it is only making "assumptions" about the deemers, its calculation concerning the deemer offset has monetary consequences to Avista and Northwestern, as well as for Idaho Power in FY 2002. IPUC Br. Ex., WP-07-R-ID-01, at 11-12. The IPUC asserts that these actions constitute final decisions. *Id.* The mere possibility that BPA might discuss the merits of the deemer issues in future "negotiations, other processes or litigation" does not transform BPA's final ratemaking decisions in this proceeding to non-final decisions. *Id.* IPUC states they stands ready to engage in serious negotiations regarding deemer issues, although they note these issues have remained unresolved for more than two decades. The public interest requires that the deemer issues finally be resolved. IPUC, Br. Ex., WP-07-R-ID-01, at 11-12.

BPA and the exchanging utilities previously reached agreement on the amount of the deemer account balances and the applicable interest. Those agreements were not challenged. Nonetheless, concerns have been subsequently raised about the equities and legality of the amount and interest. BPA concurs that resolving these deemer balance concerns is important. However, BPA does not agree that by making an assumption in this case as to the amount of deemer balances for Idaho Power, Avista, and Northwestern, it is making another final decision as to those balances. BPA has made it plainly clear that the deemer balance numbers are only *assumptions.* Forman, *et al.,* WP-07-E-BPA-76, at 67. As with any assumption, events after the fact may prove that the assumption is inaccurate. If subsequent to the rate case a settlement is reached on the deemer balances, or a court finally determines BPA and the deeming utilities' respective rights, then BPA intends to make appropriate adjustment to the Lookback Amounts. *Id.* at 68. Either way, BPA's assumptions in this case as to the amount of the deemer balances is not dispositive, and will not preclude the deeming utilities or BPA from pursuing this issue in other forums after the issuance of this Record of Decision.

Idaho Power argues in its Brief on Exceptions that the relevance of BPA's analysis of deemer issues is more than outweighed by the prejudice to Idaho Power resulting from the discussion of the deemer issue appearing in the Draft ROD. IPC Br. Ex., WP-07-R-IP-V1, at 2. Idaho Power argues that the Administrator, or his designee, will ultimately have to review all the evidence and relevant law to determine the government's position with respect to resolving deemer balances in another forum. *Id.* Idaho Power claims that it is unfair and a denial of its due process rights for BPA to predict for ratemaking purposes the outcome of a contract dispute, which is yet to be fully and fairly considered by the Administrator, and then use that prediction to design rates to the disadvantage of Idaho Power and its eligible customers. *Id.*

BPA is puzzled by this argument. Despite BPA's repeated entreaties that the deemer issues are not being finally resolved in this case and will be resolved in other forums, Idaho Power and the IPUC have persisted in raising numerous policy, contractual, statutory, and now constitutional arguments to oppose BPA's deemer assumptions. BPA, in turn, must respond to these arguments to show that its decision to account for the deemer balance (in full recognition that it is disputed) in the Lookback is reasonable. If Idaho Power does not want the Record of Decision to discuss the deemer balance issue at length, then it should accept BPA's statement that the deemer issue is not being resolved in this case, and limit the issues it raises in its briefs. BPA's assumptions in this case are not finally determining BPA's or Idaho Power's rights.

Idaho Power argues that one example of the alleged prejudicial analysis contained in the Draft ROD is BPA's assertion that it is not bound by a Department of Energy regulation establishing a ten-year limitation upon exercising a right of administrative offset. IPC Br. Ex., WP-07-R-IP-V1, at 2-3. This is a clear mischaracterization of BPA's argument. As explained below in the discussion of Issue 5, BPA is *not* saying it is not "bound" by the 10 C.F.R. § 1015.203(a)(4); rather, BPA is merely noting that Idaho Power is *wrong* in arguing that this regulation *prohibits* BPA from collecting the deemer balances. If the regulation were to apply, which it does not, then BPA would be precluded from using the *administrative* setoff features of the Debt Collection Act. The case law is clear, though, that the ten-year limitation in the DCA in no way impact BPA's other rights under the common law to collect outstanding debts. Idaho Power's argument is clearly wrong. *See supra* Chapter 8.11, Issue 5.

Idaho Power then asks rhetorically why BPA would choose to ignore the policy represented by 10 C.F.R. § 1015.203(a)(4), and claim a largely unrestricted common law right to offset deemer balances, when the Draft ROD, in effect, admits that BPA cannot articulate its reasoning for key components of the deemer calculation because of the passage of time. IPC Br. Ex., WP-07-R-IP-V1, at 2-3. Idaho Power then argues BPA has sound reasons for finding that deemer balances have been discharged by the passage of time. *Id.* This argument, however, is in direct conflict with Idaho Power's previous argument that "it is unfair and a denial of [Idaho Power's] due process rights for BPA to predict for ratemaking purposes the outcome of a contract dispute." *Id.* at 2. Here, Idaho Power would have BPA make the prediction that the deemer balances are extinguished due to the application of the ten-year limitation in the DCA regulation. To make this prediction, though, BPA would have to assume that its right of setoff had accrued (despite the clear language in the contract to the contrary) that it was on notice of such right (despite the fact that there have been no REP benefits in the past fifteen years) and that BPA was incapable, unable, or unwilling to use its common law right to set off the deemer balances. BPA does not believe adopting these predictions is any more reasonable than BPA's proposal, which relies upon the current *status quo ante* – that is, the deemer balances exist, but are subject to dispute.

Finally, Idaho Power argues that BPA's decisions in this case will insure that Idaho Power's residential and small farm customers will not receive REP benefits for many decades, if ever. IPC Br. Ex., WP-07-R-IP-V1, at 2-3. BPA should find for purposes of this rate case that the methods for determining deemer balances cannot be adequately authenticated or explained, and claims for deemer balances are barred by the passage of time. *Id.* Alternatively, the Administrator need not and should not make any assumptions at all about deemer balances in this case. *Id.*

Idaho Power is mistaken. Whether BPA assumes Idaho Power has a deemer balance has no final effect on Idaho Power's ultimate Lookback Amount. As described earlier, Idaho Power's ASC is well below BPA's PF Exchange rate for most of the FY 2002-2008 period, and as such, Idaho Power is entitled to no REP benefits for this period. *See* 2007 Supplemental Wholesale Power

Rate Case Final Proposal Lookback Study, WP-07-FS-BPA-08, Chapter 14. Consequently, Idaho Power is incorrect that taking into account its deemer balance has any affect on its total Lookback Amounts. However, deemer balances do play a role in calculating Avista's and Northwestern's Lookback Amounts. To be consistent for all deeming utilities, BPA assumed for purposes of this case that Idaho Power also had a deemer balance. In the final analysis of this case, BPA assumes that Idaho Power would not be participating in the REP for either the Lookback period (FY 2002-2008) or for the future rate period (FY 2009). *Id.* at Chapter 15.3.2. As such, what amount of deemer balance Idaho Power has or may have had during the Lookback Period is a moot issue. In consideration of some of the concerns that Idaho Power has expressed above, BPA will remove any references to the alleged numerical value of Idaho Power's deemer balance in the final studies. This should alleviate Idaho Power's concern that its deemer balance is being decided in this case.

The most reasonable assumption for purposes of this proceeding is that BPA would have required the IOUs to extinguish their deemer balances before receiving REP benefit payments during the Lookback period. Consequently, it is proper for BPA to account for the deemer balances when calculating the IOUs' Lookback Amounts.

Decision

BPA will reflect the deemer balances as of October 1, 2001 and the provisions of the 2000 RPSAs in the calculation of the IOUs' Lookback Amounts and FY 2009 rates. These assumptions are for rate setting purposes and do not constitute final determinations of the deemer balances, including for purposes of RPSAs that may be entered into for FY 2009 and beyond.

Issue 2

Whether there is financial risk of revenue under-recovery if BPA adopts its assumptions regarding deemer balances when calculating Lookback Amounts and FY 2009 power rates.

Parties' Positions

The IOUs contend that there is financial risk of revenue underrecovery if BPA adopts its deemer assumptions. IOU Br., WP-07-B-JP6-01, at 185.

BPA Staff's Position

BPA Staff argued that the most appropriate approach is to use available REP records to estimate deemer balances and to reflect such balances in the Lookback calculations and determination of FY 2009 rates. Forman, *et al.,* WP-07-E-BPA-76, at 75.

Evaluation of Positions

Staff acknowledge that resolution of deemer disputes through litigation or settlement would occur outside of a rate proceeding and that deemer balances affect the level of REP benefits paid. Forman, *et al.*, WP-07-E-BPA-76, at 75. An assumption of significant deemer balances would understate REP benefits to be paid if such balances were eventually found invalid, and an assumption of no deemer balances would overstate REP benefits paid if such balances were subsequently affirmed. *Id.* The most appropriate assumption at this time is for BPA to use the REP records to estimate deemer balances and to reflect such balances in the Supplemental Proposal. *Id.*

The IOUs argue BPA's proposal is financially risky because if it is subsequently determined that deemer balances are not legally binding or were improperly calculated, BPA will have improperly offset REP benefits that accrue under future RPSAs. IOU Br., WP-07-B-JP6-01, at 185. These offsets may have to be subsequently reversed, resulting in BPA undercollecting its revenue requirement. *Id.*

BPA disagrees. If an assumed deemer balance was subsequently determined to have been too large, then REP benefits would have been underpaid, and BPA would presumably owe some additional amount to the IOUs. Conversely, if an assumed deemer balance was subsequently determined to have been too small, then REP benefits would have been overpaid, and the overpayments presumably would need to be recovered. In the latter instance, BPA and the deemer utilities will likely again be in the unfortunate position of recovering excess REP benefits provided to end consumers and facing some of the same issues argued at length in this proceeding.

The IOUs' argument is founded on the simple observation that if some assumption BPA makes in setting rates turns out to have understated actual costs, then BPA will have understated and presumably undercollected its "true" revenue requirement (costs). This issue, however, is not unique to the deemer balances. All of BPA's cost assumptions are based on forecasts. As with any forecast, the actual cost BPA experiences may be higher or lower than anticipated. The mere fact that actual costs may differ from a forecast, however, does not automatically mean BPA's rates will underrecover its costs. Indeed, BPA has risk mitigation measures built into its rates to recover unanticipated cost increases. Additionally, variations in costs are often offset by other factors, such as lower costs in one category or higher revenues than forecast in another. In any case, BPA's rates are designed to deal with these unavoidable variations through the application of reserves, rate mitigation measures, and cost recovery mechanisms. Consequently, the financial risk to BPA in making an assumption regarding the deemer balance is insignificant.

More specifically, whether BPA would have undercollected its REP costs as a result of the deemer balance is a function of three things: (1) when the determination is made that the deemer balances used to set rates were not valid or excessive; (2) whether or not the magnitude of the overstatement of deemer balances resulted in an underpayment of REP benefits during the rate period or simply a smaller unamortized deemer balance; and (3) if REP benefits were underpaid, whether BPA cures the underpayments of REP benefits during the rate period or in a subsequent rate period.

If the magnitude of the overstatement of deemer balances results in a smaller unamortized deemer balance, but no underpayment of REP benefits, then there is no cost underrecovery. If a determination is made near the end of a rate period, but prior to the determination of rates for the subsequent rate period, and REP benefits were underpaid, but the cure of the underpayment occurs in the subsequent rate period, then there is no cost underrecovery because rates applicable when the additional payments are made will have been set including the costs of the cure. While there may be circumstances when the underrecovery postulated by the IOUs would occur, there are also circumstances where little or no underrecovery occurs even if a determination is made that deemer balances used to set rates were excessive.

Finally, even if it is ultimately determined that BPA's deemer balance assumptions are completely invalid, the impact of such a decision in the overall context of BPA's FY 2009 generation revenue requirement is minor. BPA's Supplemental Proposal indicated a FY 2009 total generation revenue requirement of $2.408 billion. *See* Supplemental Revenue Requirement Study, WP-07-E-BPA-46, at 51. Assuming a final determination that Avista, Idaho Power, and NorthWestern had no deemer obligations whatsoever as of October 1, 2001, Avista and NorthWestern would have no Lookback Amounts. *See* FY 2002-2008 Lookback Study Documentation WP-07-E-BPA-44A, Table 15.3, at 1041. Therefore $4.5 million and $1.2 million that would have gone toward Avista's and NorthWestern's Lookback Amounts in FY 2009 would instead be paid to them. *See* FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 205. An assumption of no deemer obligation means that Idaho Power would have been paid $7.7 million in FY 2009 rather than zero. *Id*. In total, therefore, an assumption of no deemer obligations would result in an increase in FY 2009 costs of only $13.4 million. This translates into a revenue underrecovery of 0.6 percent if the full amount of the error was returned to the utilities in FY 2009. BPA does not believe it is appropriate to assume no deemer obligations or some reduced obligations in setting FY 2009 rates because of the worst-case possibility of a 0.6 percent revenue under-recovery.

Decision

The risk to BPA of underrecovering its costs because of an incorrect deemer balance assumption is not significant enough to require BPA to assume no deemer balances exist when calculating Lookback Amounts.

Issue 3

Whether BPA's calculation of deemer balances is arbitrary and discriminatory and not supported by the evidence.

Parties' Positions

The IPUC asserts that BPA's use of different methods to calculate interest on deemer balances (*i.e.*, simple versus compound) is arbitrary and discriminatory. IPUC Br., WP-07-B-ID-01, at 17. The IOUs also assert that there is no logical explanation or legal justification for using compound interest for Idaho Power and simple interest for Avista. IOU Br., WP-07-B-JP6-01, at 188. The IPUC also asserts that the evidence does not support BPA's calculation of deemer balances. IPUC Br., WP-07-B-ID-01, at 18. The IOUs assert that BPA relies solely on the Suspension Agreements from the late 1980s and fails to verify or substantiate the assumed deemer balances. IOU Br., WP-07-B-JP6-01, at 186. They also argue that BPA largely disregarded the 1981 RPSAs, which specified simple interest and the use of BPA's Treasury borrowing rate in calculating interest. *Id.* at 187.

BPA Staff's Position

Staff derived the deemer balances and the applicable interest rates from the Suspension Agreements signed by Avista and Idaho Power. Forman, *et al.,* WP-07-E-BPA-76, at 73. Staff believes that using the information from these agreements, which were signed by Avista and Idaho Power, is reasonable and sufficient for determining the deemer assumptions to be used in this proceeding. *Id.*

Evaluation of Positions

BPA based its assumption of deemer amounts on the terms of agreements that Avista and Idaho Power signed in 1987 and 1988. Forman, *et al.,* WP-07-E-BPA-76, at 73. In 1987 and 1988, BPA executed RPSA Suspension Agreements with Avista and Idaho Power, respectively. Westerfield, WP-07-E-ID-2, at 7. Both agreements addressed deemer balances outstanding as of specific dates, the interest rate applicable to deemer balances, and whether interest would be compound or simple. Idaho Power's Suspension Agreement provided as follows:

> The parties agree that Idaho Power's accrued deemer balance as provided in section 10 of the RPSA is $52,903,825.00, including interest, as of July 31, 1988. … From and after August 1, 1988, … [the deemer account balance] shall accrue interest, which shall **compound quarterly**, at an average prime rate for each calendar quarter, which shall be the arithmetic mean, to the nearest one-hundredth of 1 percent, of the prime rate values published in the Federal Reserve Bulletin, or in the Federal Reserve's "Selected Interest Rates" …

Westerfield, WP-07-E-ID-2-AT6, at 4 (emphasis added). After the suspension agreements were terminated in 1993, the Vice President and General Counsel of Idaho Power followed up with a letter to BPA noting that:

> the Company agrees that the Company's deemer account balances accrued as of September 30, 1993, for each of its exchange jurisdictions shall continue to accrue interest, said interest to be **compounded quarterly**, at an average prime rate for

> each calendar quarter, which shall be the arithmetic mean, to the nearest one-hundredth of one (1) percent …

Westerfield, WP-07-E-ID-2-AT9 (emphasis added).

Avista's Suspension Agreement similarly notes the outstanding deemer balance and the method for calculating applicable interest:

> The parties agree that the WWP's[12] accrued deemer account as provided in section 10 of the RPSA is $27,336,185, including interest, as of 2400 hours, June 30, 1987 … From and after October 1, 1987, … [the deemer account balance] shall accrue interest, which **shall not be compounded**, at an average prime rate for each calendar quarter, which shall be the arithmetic mean, to the nearest one-hundredth of one percent, of the prime rate value published in the Federal Reserve Bulletin, or in the Federal Reserve's "Selected Interest Rates" …

Westerfield, WP-07-E-ID-2-AT7, at 3-4 (emphasis added).

As these agreements make clear, Idaho Power's deemer balance was subject to compound interest, and Avista's deemer balance was subject to simple interest. Staff used these documents to determine deemer balance assumptions for both Avista and Idaho Power for purposes of the Lookback calculations.

The IPUC argues that the use of two different interest rates (*i.e.*, simple versus compound) for similarly situated utilities is arbitrary and discriminatory. IPUC Br., WP-07-B-ID-01, at 17. The IPUC claims there is no evidence in the record, and BPA has offered no explanation, for why Avista agreed to apply simple interest to its deemer balance, and Idaho Power agreed to apply compound interest to its deemer balance. *Id.* The IPUC notes that besides this difference in interest, all other aspects of the two companies' Suspension Agreements are identical. *Id.* The IPUC claims that the fact that these agreements include different interest rates "is clearly unreasonable and arbitrary." *Id.* The IOUs make similar arguments. IOU Br., WP-07-B-JP6-01, at 188. They note that BPA's decision to use the interest rates identified in the Suspension Agreements continues the discriminatory treatment that occurred originally when representatives of Avista and Idaho Power signed these agreements. The IOUs further claim that BPA has failed to provide a rationale as to why Avista and Idaho Power accepted different interest rates in their respective Suspension Agreements. *Id.* The IOUs conclude that because such discrimination lacks a rationale, the interest rates and the deemer balances that result from them are arbitrary and capricious and should not be assumed in this proceeding. *Id.*

Contrary to the IPUC and IOUs' assertions, the basis for using different interest rates for deemer balance assumptions in this proceeding is not arbitrary. The interest assumptions used to calculate the deemer balances are derived directly from the agreements executed by

[12] The suspension agreement was executed by representatives of Washington Water Power Company, the predecessor to Avista Corp.

representatives of both Avista and Idaho Power. In these agreements, it is clear that Avista and Idaho Power agreed to the existing deemer balances and the means of calculating interest. In view of these facts, BPA does not believe it is arbitrary to base its deemer balance assumptions on terms and conditions that were signed by Idaho Power and Avista.

The IPUC and the IOUs also assert that the use of different interest methodologies is discriminatory, capricious and unreasonable. BPA finds these arguments unconvincing. First, as a general matter, BPA is unaware of any law or rule that would require it to offer the same terms and conditions to every party that it negotiates with. BPA's statutory directives are clear that the Administrator has broad discretion to enter into agreements and contracts "upon such terms and conditions and in such manner as he may deem necessary." 16 U.S.C. § 832a(f). Here, BPA apparently believed that Idaho Power's Suspension Agreement should include compounding interest, and Avista's Suspension Agreement should include simple interest. By choosing to negotiate different interest provisions in these agreements, BPA has not violated any rule of law.

Furthermore, it is flatly unreasonable for the IPUC and the IOUs now, 20 years after these agreements were signed, to demand an explanation from BPA as to why these differences in the interest rates exist. This request *might* have been reasonable in 1988, when the memories of the representatives who negotiated the agreements were fresh and any documentation still available. Making such a request *20 years* later, however, after memories have faded and documents have been lost or destroyed, is patently absurd. Moreover, the IPUC and the IOUs should not be requesting *BPA* to explain its actions, but should direct their inquiries to the representatives from Avista and Idaho Power who originally agreed to these terms. BPA would suggest the parties begin with the author of Idaho Power's September 28, 1993, letter to BPA, which stated in no uncertain terms that:

> [Idaho Power] agrees that the [Idaho Power's] deemer account balances accrued as of September 30, 1993, for each of its exchange jurisdictions shall continue to accrue interest, said interest to be **compounded quarterly** …

Westerfield, WP-07-E-ID-2-AT9 (emphasis added). In short, BPA has not acted arbitrarily, discriminatorily, or unreasonably in not explaining the basis for terms in 20-year-old agreements that were negotiated with representatives from Avista and Idaho Power.

In response to this argument, Idaho Power assets in its Brief on Exceptions that nothing in the record indicates that the affected utilities even knew when they executed their suspension agreements nearly twenty years ago that BPA was requiring different interest rates of different companies, and it is therefore questionable whether the companies would have known of the discrimination in time to protest it. IPC Br. Ex., WP-07-R-IP-V1, at 4. Again, this argument fails because it relies on Idaho Power's erroneous assumption that BPA has a duty to inform all parties at all times of the terms and conditions of contracts that BPA has signed. Furthermore, BPA finds it difficult to fathom that Idaho Power would have had no knowledge of Avista's Suspension Agreement, particularly since both Avista and Idaho Power would likely have needed to receive approval from the IPUC to agree to suspend their respective 1981 RPSAs. Idaho Power has also presented no evidence on this record indicating that it was "surprised by" or "uninformed of" the terms of Avista's Suspension Agreement. Even if Idaho Power did not have knowledge of the terms of the agreement, it could have requested the Suspension Agreement under the Freedom of Information Act from BPA at any time. In any case, for purposes of this proceeding, what Idaho Power executives knew and when they knew it is irrelevant to whether the deemer balances should be accounted for in BPA's analysis.

Idaho Power also disputes BPA's assertion that the record supports an inference that documents signed over nearly twenty years ago memorialize truly "voluntary and mutual bargains." IPC Br. Ex., WP-07-R-IP-V1, at 4. Instead, Idaho Power claims it is more reasonable to infer that BPA, as a contracting party with all the exchanging utilities (and therefore privy to information about the negotiations with individual utilities that other utilities would not have shared), and as the rule-maker of the Average System Cost methodology, had superior bargaining power that could induce affected utilities to agree to language requested by BPA. *Id.* Supporting this inference is the fact that a BPA attorney authored the interest rate language that appeared in a document signed by an Idaho Power representative requesting termination of the exchange agreement.

As noted above, specific deemer issues are not being resolved in this case. Consequently, in response to Idaho Power's comment, BPA has removed references to "voluntarily" from this document to avoid making this an issue in this case. However, by removing this word from the discussion above, BPA is in no way granting Idaho Power's statement that BPA has superior bargaining power. Far from it, BPA notes that there is very little evidence on the record that would support Idaho Power's assertion. For example, the Suspension Agreement itself does not state that it is being executed under protest. Furthermore, the September 28, 1993, letter from Idaho Power that agreed to pay BPA compound interest was signed by Idaho Power's "Vice President, General Counsel, and Secretary" – a person BPA would presume would know how to respond in the event the government was attempting to gain terms under duress. Based on these facts alone, there is no apparent basis to assume that BPA had superior bargaining power. Nevertheless, this is a factual question that must be addressed in another forum, and is not relevant to the current case. BPA has removed references to the term "voluntarily" from the Final ROD.

In its Brief on Exceptions, Idaho Power also argues that it is not "absurd" to require BPA to articulate a "legally sustainable commercial reason" for continuing to insist on the application of alleged "discriminatory" interest rates in calculating deemer balances that will be used as a basis for designing rates in this case. IPC Br. Ex., WP-07-R-IP-V1, at 5. Idaho Power claims that nothing in the Northwest Power Act or its legislative history supports any inference that Congress intended the REP program to generate substantial net revenues from utilities to BPA. *Id.* Idaho Power concludes that BPA simply does not have, and is unable to articulate, a statutory duty or "legitimate commercial reason" to maximize interest rates on deemer balances in order to diminish future REP benefits to future residential and small farm customers of selected utilities. *Id.*

Idaho Power's arguments are not relevant to this case. BPA does not believe that by negotiating compound interest terms in Idaho Power's Suspension Agreement that BPA achieved "substantial net revenues from" Idaho Power. Rather, BPA was following its statutory mandate to operate in accordance with "sound business principles." Any normal business would naturally want favorable terms and conditions when it came to negotiating the treatment of interest on an outstanding balance. Requesting that interest be *compounded* is simply an industry standard way of calculating interest. In this regard, there is nothing inherently diabolical in BPA wanting compound interest from Idaho Power. Idaho Power's specific policy concerns about BPA's past decision are not issues to be resolved in this case.

Idaho Power's second argument is also not relevant. Idaho Power declares that BPA must articulate a "legally sustainable commercial reason" for wanting compound interest from Idaho Power and simple interest from Avista. As explained above, it is normal industry practice and common sense to want compound interest for an outstanding balance. The fact that Avista was able to receive simple interest is immaterial. The give and take of Avista's negotiation obviously led the parties to agree to simple interest. Whether that term came at the expense of some other term in the Suspension Agreement cannot be determined on the existing record.

Even assuming *arguendo* that the "discriminatory" standard advocated by the IOUs and IPUC has merit, which it does not, the record evidence in this case would strongly support applying *compound interest* to the deemer balances of both Avista and Idaho Power. As noted above, BPA's assumption that compound interest is applicable to Idaho Power's deemer balance is based on clear language in Idaho Power's Suspension Agreement and September 28, 1993 termination notice letter to BPA. *See* Westerfield, WP-07-E-ID-2-AT9. Less clear is what method of interest would apply to Avista's outstanding deemer balance. Evidence supplied by the IPUC shows that the September 29, 1993 termination notice letter from Avista (then Washington Water Power) provided notice of termination with no reference to deemer balances, interest rate or whether interest would be simple or compound. *See* Westerfield, WP-07-E-ID-2-AT8. After receiving Avista's letter, BPA responded in a missive dated October 19, 1993, as follows:

> BPA accepts the termination subject to the following conditions … The Company's deemer account balances accrued as of September 30, 1993, for each of its exchange jurisdictions shall continue to accrue interest, which shall be compounded quarterly …
>
> Termination of the [Avista's] RPSA in accordance with the above-stated conditions is agreed by BPA to meet the requirements of the Company's RPSA for termination and to satisfy the Company's obligations under paragraphs 4 and 6 of the Suspension Agreement concerning effective revocation of the Suspension Agreement. Termination of the Company's RPSA without the above-stated conditions is unacceptable to BPA as not meeting the requirements of the Company's RPSA and Suspension Agreement.

Westerfield, WP-07-E-ID-2-AT11, at 1.

Given these facts, BPA could reasonably assume that compound interest was intended to apply to *both* Avista's and Idaho Power's deemer balances from 1993 to the present. While Avista did not directly acknowledge or concur with BPA's termination conditions, there is equally no evidence that Avista timely objected to the specific conditions stated in BPA's 1993 letter. Avista's actions appear, in fact, to show agreement with BPA's conditions because it proceeded to file notices of termination of the RPSA with FERC in letters in September and October of 1993, with FERC granting Avista's request in December of 1993. *See* Westerfield, WP-07-E-ID-2-AT14. Consequently, BPA *could* assume for purposes of this proceeding that Avista's silence and subsequent termination constituted agreement with BPA's conditions, and thereby assume compound interest applies to Avista's deemer balance. This would eliminate the alleged "discriminatory" treatment of interest between Idaho Power and Avista that the IPUC and the IOUs are concerned about.

BPA, however, decided not to adopt this proposal because the record evidence on this issue is unclear. Five years following the 1993 termination of the RPSA, Avista filed a letter with BPA that stated that it did not agree with BPA's position that deemer balances resulting from the changed 1984 Average System Cost Methodology could be carried over to a new contract. *See* Westerfield, WP-07-E-ID-2-AT15. The 1998 letter from Avista is silent with regard to the applicable interest rate and whether interest would be simple or compound. *Id.* Because BPA never received clear assent from Avista to the terms of the October 19, 1993 letter, it could be argued that compounding of interest would not apply to Avista's deemer balance. Since the record evidence on this subject is unsettled, BPA proposes to adopt a conservative assumption for purposes of this rate proceeding, and assume that simple interest would continue to apply to Avista's deemer balance. In adopting this position, BPA is not waiving its right to assert later in other forums that Avista's deemer balance is subject to compound interest. As stated above, these issues will not be resolved in this proceeding. Based on these considerations, BPA concludes that an appropriate assumption regarding deemer interest for this proceeding is one based on the agreement signed by BPA and Avista, the Suspension Agreement; namely, simple interest for Avista.

In its Brief on Exceptions, the IPUC argues that BPA must remove the foregoing analysis because it is unreasonable to even state that compound interest was intended to apply to Avista after 1993. The IPUC claims there is a lack of substantial evidence in the record to support this assumption. IPUC Br. Ex., WP-07-R-ID-01, at 13. The IPUC mischaracterizes BPA's position. As noted above, BPA was responding to the IOU's and IPUC's arguments that BPA should assume that Idaho Power and Avista should have received comparable interest rate treatment. In response, BPA noted that there is evidence on the record that could support a position that Avista could be charged compound interest, thereby eliminating the disparity. But, as noted in the above paragraph, BPA did not believe that assumption would have been reasonable for purposes of this proceeding because of the lack of record evidence that establishes Avista's agreement to those terms. The IPUC takes issue with BPA's characterization that it would be "reasonable" to assume that Avista could be charged compound. *Id.* Since BPA is *not* assuming that Avista would be charged compound interest, but simple interest, the IPUC's points are moot, and BPA will not respond further to those arguments here.

Notwithstanding this evidence, the IOUs and IPUC appear to request BPA to assume simple interest would apply to both agreements. IOU Br., WP-07-B-JP6-01, at 188; IPUC Br., WP-07-B-ID-01, at 17. BPA does not agree this is a reasonable assumption because it requires BPA to disregard the clear language in a signed agreement that states without question that compound interest would apply to Idaho Power's deemer balance. BPA is statutorily mandated to implement its valid contracts "in accordance with the terms thereof[.]" 16 U.S.C. § 832d(a). Assuming away the interest provisions of the Suspension Agreements and the letters from Idaho Power ignores this statutory directive. Furthermore, even if BPA made such an assumption, it would not change Idaho Power's Lookback Amount determined in this proceeding. Assuming simple interest for Idaho Power would not resolve the disputed deemer issues and does not get to the core of the problem facing the IPUC and Idaho Power; namely, that Idaho Power still has a substantial deemer balance by BPA's calculation. Given all of these considerations, BPA concludes that for purposes of this proceeding, the most reasonable and straightforward assumption is to assume the interest calculations as stated in the IOUs' respective Suspension Agreements. In the case of Idaho Power, this is compound interest.

The IOUs state that BPA relies solely upon the Suspension Agreements from the late 1980s for determining the principal amount of deemer balances. (Hearing Transcript at page 90, line 23 through page 91, line 6.) IOU Br., WP-07-B-JP6-01, at 186. The IOUs assert that BPA produced no records to verify or substantiate those balances, or the appropriateness of relying on these documents. *Id.* The IOUs assert that absent an audit or accounting trail upon which to verify deemer balances contained in the Suspension Agreements, it is imprudent and arbitrary and capricious to assume that the suspension agreements correctly reflect the actual deemer balances. *Id.* The IPUC similarly notes that BPA is unable to explain how Idaho Power's deemer balance grew from slightly over $8 million as of May 31, 1985 to over $58 million as of January 1987. IPUC Br., WP-07-B-ID-01, at 18, 19.

The IPUC's and the IOUs' arguments reflect the fact that the accumulation of deemer balances stems from data and terms extant two decades or more in the past. Unfortunately, BPA had neither the time nor the staff resources to reconstruct the historical origins of the deemer balances. The absence of this analysis, however, does not detract from the deemer assumptions BPA is proposing in this case. As noted above, Staff *started* with the deemer balances that were *identified* in the Suspension Agreements. *See* Westerfield, WP-07-E-ID-2-AT7, at 3-4; WP-07-E-ID-2-AT6 at 4. The plain language of these agreements states clearly and unambiguously that the parties agreed to the specified deemer balances as of specified dates and agreed to other information needed to objectively determine deemer balances from the dates of the agreements to the present. *See* WP-07-E-ID-2-AT6 and WP-07-E-ID-2-AT7. Neither the IPUC nor the IOUs have provided any evidence contemporaneous with the Suspension Agreements or with the subsequent 1993 termination letters indicating that they believed different deemer balances, different interest rates, or different methods of computing interest should be used. Under these circumstances, BPA finds that is reasonable to base the deemer assumptions in this case upon the deemer balances in the Suspension Agreements.

Furthermore, while the IPUC and the IOUs decry the lack of BPA evidence on the record to support the calculation of the deemer balances *prior* to the Suspension Agreements, they provide no evidence from their own records or systems of accounts that call into question or otherwise refute BPA's assumed deemer balances. Instead, they assert that because BPA has not provided an audit or accounting trail to substantiate documents Avista and Idaho Power signed in 1987 and 1988, it is imprudent to assume these signed agreements reflect the actual deemer balances and method for determining interest. This argument is unpersuasive. The language in the Suspension Agreements does not state that the balances are "estimates" or "subject to change." Rather, the agreements state that the deemer balance for Idaho Power "is" $52,903,825, and the deemer balance for Avista "is" $27,336,185. *See* Westerfield, WP-07-E-ID-2-AT7, at 3-4; WP-07-E-ID-2-AT6 at 4. It defies common sense and logic to suggest that the parties would have agreed to these very specific numbers in the absence of a detailed accounting. Moreover, BPA cannot believe that sophisticated business entities like Avista and Idaho Power would agree in writing to tens of millions of dollars in deemer obligations without conducting a modicum of due diligence to check the accuracy of these balances. For these reasons, BPA can find no basis for ignoring the deemer balances that Avista and Idaho Power signed in the Suspension Agreements. BPA's reliance on these balances is therefore reasonable.

In its Brief on Exceptions, the IPUC claims that BPA has overstated the validity of the calculations in the Suspension Agreement signed by Avista and Idaho Power. The IPUC asserts that the Suspension Agreement, when read in its entirety, show that the "parties agreed to disagree on the deemer balances." IPUC Br. Ex., WP-07-R-ID-01, at 12-13. The IPUC complains that BPA "failed to acknowledge that neither party - both BPA and Avista/Idaho Power - consented to the manner in which the amounts were calculated." *Id.* The IPUC claims that this alleged dispute undercut BPA's unconditioned reliance on the specified deemer amounts. *Id.*

The IPUC's arguments are seriously misleading and contradict the very language that it cites in its brief. The IPUC points to contractual language in the Suspension Agreements which states as follows:

> Notwithstanding the parties' agreement to the aforementioned deemer account balances, which is a compromise neither party, by entering into this Suspension Agreement shall be deemed to have in any way approved, accepted, or consented to the facts, principal methods, or theories employed by either party in arriving at the stated balances for each jurisdiction of the deemer account as of July 31, 1988.

Westerfield, WP-07-E-ID-2-AT7 and AT7, at § 4.

The IPUC alleges that this contractual language demonstrates that "the parties agreed to disagree on the deemer balances." IPUC Br. Ex., WP-07-R-ID-01, at 12-13. This is reading of the contractual language is not persuasive. The first ten words of this provision state that the parties have agreed to the deemer balances: "Notwithstanding the parties' *agreement to the aforementioned deemer account balances* …" *Id.* (emphasis added). It would not make sense to read these words to mean the parties intend to "agree to disagree on the deemer balances." Thus, contrary to the IPUC's statements, the language in the Suspension Agreements does not clearly state that the deemer balances are subject to dispute. BPA's reliance on the Suspension Agreement is therefore reasonable.

The IPUC apparently recognizes that its initial statement is overreaching, and immediately follows up in its brief with the important qualification that what was *actually* unresolved by the parties was "that neither party - both BPA and Avista/Idaho Power - consented to the *manner in which the amounts were calculated*." IPUC Br. Ex., WP-07-R-ID-01, at 12-13 (emphasis added). On this point, the IPUC is correct. The language in the contract is clear that the methods used to calculate the deemer balances were not agreed to: "neither party, by entering into this Suspension Agreement shall be deemed to have in any way approved, accepted, or consented to the facts, principal methods, or theories employed by either party in arriving at the stated balances." As this language indicates, the reservation was made to the "facts, principal methods, or theories" that were *used* to calculate the deemer balances. The balances themselves were *not* subject to dispute, but were in fact the result of a "compromise." BPA has relied on these "compromised" numbers for its deemer assumptions in the Lookback analysis. The IPUC's assertion that this language "undercuts" BPA's reliance on the Suspension Agreements is unpersuasive, and must be rejected.

The IPUC asserts that although the 1981 RPSAs provided that interest on the deemer balances would accrue at the Treasury rate, BPA utilized the prime rate to calculate the quarterly interest on the deemer balances <u>before</u> the effective date of Idaho Power's Suspension Agreement, August 1, 1988. *Compare* WP-07-E-ID-2-AT6 with WP-07-E-ID-4, p. 1, 10, 19. IPUC Br., WP-07-B-ID-01, at 19. The IPUC claims the same error applies to the calculation of Avista's deemer balance. *Compare* WP-07-E-ID-2-AT7 with WP-07-E-ID-5, p. 1, 8. *Id.* at 20. The IPUC is mistaken. The IPUC is referring to spreadsheets provided by BPA that take the deemer balances, interest rate, and interest methodologies specified in the Suspension Agreements and calculate the deemer balances over time. Interest at the prime rate is applied beginning August 1, 1988 for Idaho Power and October 1, 1987 for Avista, both consistent with the effective dates of the respective Suspension Agreements. The IPUC's assertion that BPA utilizes the prime rate to calculate the quarterly interest on the deemer balances before the effective date of the respective Suspension Agreements is therefore incorrect.

In fact, BPA used data on the prime rate for months prior to the effective dates of the Agreements to calculate the applicable interest rate for the period beginning October 1, 1987 for Avista and August 1, 1988 for Idaho Power. These prior months' prime rate data are needed because the Suspension Agreements specify that the applicable rate "shall be the arithmetic mean, to the nearest one-hundredth of 1 percent, of the prime rate values published in the *Federal Reserve Bulletin*, or in the Federal Reserve's 'Selected Interest Rates' (Statistical Release G. 13), for the fourth, third, and second months preceding the first month of the calendar quarter." *See* WP-07-E-ID-2-AT6, at 4 and WP-07-E-ID-2-AT7, at 4. The IPUC misinterprets the inclusion of prior months' prime rate data that are needed to calculate the applicable interest rate specified in the Suspension Agreements as the application of the prime rate prior to the effective date.

Idaho Power also argues that it is "elementary" that the Constitution does not permit arbitrary classifications by the federal government. IPC Br. Ex., WP-07-R-IP-V1, at 5. Idaho Power then claims that BPA is creating classifications by imposing substantially different interest rates which will have the effect of disabling hundreds of thousands of eligible residents in southern Idaho and eastern Oregon from being treated equally with customers of other investor owned utilities elsewhere in the Northwest. *Id.* This argument is without merit. BPA has not created a "classification" by negotiating different interest terms in Idaho Power's and Avista's contracts. BPA has not stated that as a rule or regulation it will in all instances require Idaho Power to pay compound interest, and all other utilities simple interest. The reason compound interest ended up in Idaho Power's contract and not in Avista's was because of the particular negotiations between the parties. Again, this forum is not the place to determine all of the facts that occurred in those negotiations. In any case, BPA has not violated any Constitutional principle by agreeing to different interest rate terms in Idaho Power's or Avista's contracts.

Idaho Power argues that the 1981 RPSA established the deemer accounts and recited that interest rates applicable to such balances were set forth in the 1981 Average System Cost methodology. IPC Br. Ex., WP-07-R-IP-V1, at 6. Idaho Power then argues that this rate of interest charged to Bonneville by the U.S. Treasury applied to deemer balances, unless another interest rate was ordered by the Joint State Board, the FERC, or a reviewing court. *Id.* Idaho Power contends that BPA failed to obtain any order of the Joint State Board, the FERC, or a reviewing court authorizing or ratifying BPA's decision to require higher and more onerous interest rates than the Treasury Rate, or to impose different interest rates on similarly situated utilities under the 1981 ASCM. *Id.*

This argument is unconvincing because the 1981 ASCM was subsequently superseded by the ***1984 ASCM***, which did not have this provision. Moreover, even if the 1984 ASCM did have such a provision, Idaho Power subsequently agreed to a different interest provision in the Suspension Agreement.

Anticipating BPA's above response, Idaho Power argues that even if BPA is correct, an interest rate established or approved by the Joint State Board, FERC, or a reviewing court presumably represents a "clearly established and non-discriminatory standard" for determining the interest rate applicable to deemer balances. IPC Br. Ex., WP-07-R-IP-V1, at 7. Idaho Power assets BPA's departure from this standard (or some other "legally based standard") for purposes of this case is arbitrary and illegal. *Id.* This argument attacks BPA's business and policy decision to adopt different interest rates in the Suspension Agreements, which is not subject to the review of either a Joint State Board or FERC. To the extent that BPA's decision to use different interest rates was reviewable under the Northwest Power Act by a Court, the deadline for filing such a petition has long since passed.

The IPUC notes that Idaho Power sold its Nevada service area to an Idaho electric co-operative in 2001. WP-07-E-ID-01-CC1, at 13, lines 17-21; WP-07-E-ID-01-AT2. It concludes that it is inappropriate to collect the Nevada deemer balance of $2.9 million from the remaining Idaho Power customers in Idaho and Oregon. IPUC Br., WP-07-B-ID-01, at 19.

BPA agrees with the equity issue raised by the IPUC. BPA will therefore remove the portion of Idaho Power's deemer balance associated with its Nevada service area for purposes of this proceeding.

Decision

BPA is not making final decisions with respect to deemer balances in this proceeding. BPA's decision to rely upon the balances as stated in Idaho Power's and Avista's Suspension Agreement as the basis for the deemer balance assumptions is not arbitrary or capricious. BPA will exclude the portion of Idaho Power's deemer balance associated with its Nevada service area from Idaho Power's deemer balance for purposes of this proceeding.

Issue 4

Whether the fact that BPA has not recorded deemer balances in its financial books means that BPA cannot reflect deemer balances in its determination of Lookback Amounts and FY 2009 rates.

Parties' Positions

The IPUC argues that because BPA has not recorded the deemer balances in its financial books, BPA cannot now include these "off the books" amounts in the Lookback Analysis and, thus, in rates. IPUC Br., WP-07-B-ID-01, at 19.

BPA Staff's Position

How BPA or the IOUs "book" the deemer account balances has no bearing on whether they are legitimate obligations. Forman, *et al.,* WP-07-E-BPA-76, at 69. Regardless of whether or how the deemer balances are booked, they are a legitimate consideration for BPA in its Lookback analysis. *Id.* at 70.

Evaluation of Positions

The IPUC argues that BPA's failure to record the deemer balances in its financial records is contrary to generally accepted accounting principles as well as ratemaking principles. IPUC Br., WP-07-B-ID-01, at 21. Neither generally accepted accounting principles, nor FERC's Uniform System of Accounts, nor DOE's accounting order RA 6120.2 sanctions "off the books" accounting for transactions. *Id.* Therefore, BPA cannot now propose to include these "off the books" amounts in the Lookback Analysis and, thus, in rates in violation of accounting and ratemaking principles. *Id.*

BPA does not find the IPUC arguments convincing. How BPA or the IOUs "book" the deemer account balances has no bearing on whether they are legitimate obligations. Forman, *et al.,* WP-07-E-BPA-76, at 69. As the IPUC notes, BPA views the REP as a resource transaction (meaning an actual sale and purchase of power) rather than an accounting (meaning a strictly financial payment) transaction. *Id.* at 70. As such, BPA has no call on the deemer balances unless the resource transaction takes place. *Id.* If the REP were an accounting transaction, BPA could seek repayment from the IOUs whether or not they participated in the REP. *Id.* Implicit in this treatment is the recognition that the only avenue BPA has to recover deemer balances is through the reduction of future REP benefits. *Id.*

The IPUC argues that BPA's failure to reflect the deemer obligations on its books means that BPA cannot include these "off the books" amounts in the Lookback analysis. The IPUC claims that in a state regulatory context, BPA's treatment of the deemer balances would not be allowed. While BPA is not fully current with the status of IOU retail rates, BPA knows of at least two instances that contradict this premise, one within the state of Idaho. Forman, *et al.,* WP-07-E-BPA-76, at 70. First, the pass-through of REP benefits is not reflected on the books of a number of IOUs, including Idaho Power and Avista. *Id.* at 71. In these instances, the REP components of the utilities' rates are off-book transactions. *Id.* This appears to be true for four of the six IOUs. *Id.* A second example is in the state of Oregon, where the Public Purposes Charge is charged to retail customers, but not, to our knowledge, included on the books of Portland General Electric, PacifiCorp, or Idaho Power. *Id.*

IPUC also argues that section 10 of the 1981 RPSAs specifies that BPA "shall debit to a separate account the net exchange payment to Bonneville." WP-07-E-JP21-01/2/3, § 10. The IPUC claims that the plain meaning of "separate account" is an account contained in BPA's financial books and records, not an account kept somewhere else. IPUC Br., WP-07-B-ID-01, at 21. This argument is simply not relevant. The phrase "separate account" could mean many things, including a separate bank account or a separate account at BPA. Either way, the clear import of this language is to maintain the "non-cash" nature of the deemer balances by not commingling it with other cash payments BPA may be making to the IOUs. If the deemer balances were commingled in such accounts, it is possible that BPA's billing system could "net" the deemer balances against such payments. This "netting" would have the effect of changing the deemer balances into cash payments to BPA. To avoid this, BPA is obligated to segregate the deemer balances into an account that is separate from other accounts the IOUs may have with BPA. How BPA displays this separate account on its books is, consequently, irrelevant to the term "separate account."

Finally, even assuming that this is not the clear intent of the term "separate account," BPA finds that its accounting treatment of the deemer balances has no bearing on the validity of the IOUs' deemer obligations. As noted above, the IOUs themselves, and their regulators in some instances, do not maintain entries on their books for the Residential Exchange Benefits. BPA's obligation to pay the REP benefits under an RPSA, however, is no less legally binding. BPA sees no reason why a different standard would apply to the deemer balances. Furthermore, it is irrelevant whether BPA for *accounting purposes* treats the deemer balances as line items on its books. The determining factor for whether an outstanding debt is legitimate or not is the *terms of the contract*, not the accounting treatment the party gives the obligation. The IPUC's arguments must be rejected.

Decision

The deemer balances are a legitimate consideration for BPA in its Lookback analysis regardless of how the deemer balances are booked or treated for accounting purposes.

Issue 5

Whether regulation bars BPA from collecting deemer balances.

Parties' Positions

The IPUC asserts that collection of deemer amounts is barred by regulation promulgated under the authority of the Debt Collection Act (DCA). IPUC Br., WP-07-B-ID-01, at 15. The IOUs assert that BPA's proposed offset of assumed deemer balances is barred by a Department of Energy regulation prohibiting use of administrative offsets against obligations older than ten (10) years. IOU Br., WP-07-B-JP6-01, at 189.

BPA Staff's Position

This issue did not arise in this proceeding prior to the Initial Briefs and is purely a legal issue. BPA Staff has taken no position on this issue.

Evaluation of Positions

The IPUC and the IOUs argue that even if the deemer balances were valid obligations, it is unreasonable to assume they still exist because of an administrative regulation which limits BPA's ability to administratively offset obligations older than 10 years. IPUC Br., WP-07-B-ID-01, at 15-16; IOU Br., WP-07-B-JP6-01, at 189-190.

As already noted, this rate proceeding is not the forum to address all of the legal arguments related to the deemer balances. However, to demonstrate that BPA's deemer assumptions are reasonable for purposes of this proceeding, BPA makes the following observations.

First, the administrative offset regulation cited by the parties applies only to claims and debts that are "due" an agency. *See* 10 C.F.R. § 1015.102(a). Until the debt becomes "due," application of the administrative offset provisions of the DCA is not appropriate. Consequently, there is an argument that in the context of the deemer balances, Avista's and Idaho Power's debts have yet to become "due." Under the terms of the 1981 RPSAs, the deemer balances are "not a cash obligation of the Utility" but shall be "carried forward to apply to any subsequent exchange by the Utility for the Jurisdiction under any new or succeeding agreement." 1981 RPSA between BPA and Idaho Power Company, WP-07-E-JP21-01, at 6. In other words, under the terms of the contract, BPA can only apply the deemer balances against REP benefits that Avista and Idaho Power are entitled to under an RPSA. The deemer balances will become "due" once Avista and Idaho Power become eligible for future REP benefits. However, Avista and Idaho Power have not received REP benefits under an RPSA since the mid-1980s. Since Avista and Idaho Power have not been entitled to any REP funds, BPA has had no right to set off any outstanding deemer balances. In light of this unique treatment of deemer balances, BPA believes that it is likely that the 10-year statute of limitations noted by the IPUC and the IOUs is not implicated in the present case.

Second, BPA also notes that the 10-year statute of limitations in the DCA would generally begin to run only when the government's claim against the debtor "accrues." *See* 10 C.F.R. § 1015.203(a)(4). A claim "accrues" once the government knows or should have reasonably known of material facts that would have given rise to the right to collect such debt. *Id.; see also Kinsey v. United States*, 852 F.2d 556, 557 (Fed. Cir. 1988). Here again, BPA believes that there may be an argument that BPA's claim to the deemer balances has not yet accrued. As just noted, BPA's right to collect the deemer balances is directly tied to the REP payments the IOUs are to receive under an RPSA. The IOUs have not received any REP benefits under an RPSA since the 1980s. As such, BPA believes that a reasonable argument could be made that a claim against the IOUs for the deemer balance has not accrued because the facts necessary to give rise to BPA's claim – the presence of REP payments otherwise owing to the IOUs – has not existed for the past 20 years. This argument, if successful, would mean that BPA's claim would not be barred by the DCA's 10-year statute of limitations.

Finally, even if the DCA's limitation period were implicated in this case, BPA observes it may still have a right to recover the deemer balances against future REP benefits. The courts have consistently stated that the administrative offset provisions of the DCA do not limit an agency's ability to recover debts under the common law. *See Cecile Industries, Inc., v. United States,* 995 F.2d 1052, 1056 (Fed. Cir. 1993). Rather, the provisions of the DCA are a last resort that the agency may turn to when other forms of collection have failed. *Id.* at 1055. As such, agencies still retain their common-law rights to recover obligations owed to the government, including the right of setoff. *Id.* at 1056. As the court in *Cecile Industries* noted:

> Before the enactment of the DCA, the Government possessed a common law right to offset contractual rights against contractual payments. In sum, the administrative offset provision of the DCA extended this collection procedure to debts other than the purely contractual debts at issue in this case. Nowhere does the language, context, or enactment history of the DCA suggest restriction or replacement of doctrines permitting contractual offsets.

Id. Thus, it could be argued that BPA's right to recover the deemer balances under the common law is not displaced by the limitations in the Debt Collection Act. Furthermore, the government's right to set off a debt is generally not subject to a statute of limitations. *See Thomas v. Bennett,* 856 F.2d 1165, 1169 (8th Cir. 1988); *United States v. Sather,* 191 F. Supp.2d 1146, 1153-54 (D. S.D. 2001). Thus, even if BPA were precluded by the 10-year statute of limitations from using the administrative setoff provisions of the Debt Collection Act, BPA may still have rights under the common law to recover the deemer balances against future REP benefits.

BPA notes that it has provided the above analysis in response to the particular claims raised by the IOUs and IPUC. It was provided to make clear that BPA's decision to assume the deemer balances exist in the Lookback is reasonable. This analysis, however, is not intended to definitively resolve any claims regarding the statute of limitations issues noted by the IOUs and IPUC, nor any other issues regarding the deemer balance. BPA fully recognizes that the above analysis is not without question, and that there are counterarguments and positions to the above discussion. These issues, as noted before, must be resolved in another forum. BPA notes again that it remains open to settling the deemer issues with the deemer utilities.

Decision

Whether the deemer balances are barred by DOE regulations cannot be finally determined in this rate proceeding. BPA, however, has properly assumed for purposes of calculating the Lookback Amounts that the deemer balances are valid obligations.

Issue 6

Whether BPA has inconsistently applied the 1984 ASCM by not accounting for a deemer balance for PacifiCorp.

Parties' Positions

Cowlitz contends that BPA has acted contrary to the 1984 ASCM by not taking into account a potential "deemer" balance for PacifiCorp. Cowlitz Br., WP-07-B-CO-01, at 64. Cowlitz also notes that if BPA assumes PacifiCorp signed an RPSA, BPA must assume that PacifiCorp would have accrued a deemer balance. *Id.* Cowlitz also argues that BPA has adopted special rules that are not consistent with the 1984 ASCM that avoid accruing a deemer balance for PacifiCorp. *Id.* Cowlitz concludes that BPA could avoid these special rules if it adopted WPAG's minimalist approach. *Id.*

PacifiCorp supports BPA's proposal not to account for a deemer balance in the Lookback. IOU Br., WP-07-B-JP6-01, at 183, n. 74. PacifiCorp notes that it did not actually sign an RPSA during the period, has never had a deemer balance, and supports BPA's proposal not to accrue such a balance. *Id.*

BPA Staff's Position

Staff believes it is reasonable to assume that PacifiCorp would have waited to sign an RPSA until such time as it was clear that its residential customers would have received positive REP benefits. Forman, *et al.,* WP-07-E-BPA-76, at 80-81. Further, as a matter of policy, Staff does not believe it necessary to recover from PacifiCorp not only the payments that were made under the REP Settlement Agreements, but also payments associated with a non-existent deemer balance to make the COUs whole. *Id.*

Evaluation of Positions

Generally speaking, BPA calculated Lookback Amounts by comparing the amounts by which REP settlement benefits provided to each IOU exceeded the REP benefits that would have been due each IOU during the FY 2002-2008 period in the absence of the settlements. Marks, *et al.,* WP-07-E-BPA-62, at 9. The difference between these two amounts, as modified by the rules described in BPA's testimony, represents the REP benefits BPA should not have included in COUs' rates, and therefore must return to the COUs. *Id.* At an informal rate case workshop, participants identified a possible issue regarding BPA's modeling of PacifiCorp's Lookback Amount. *Id.* at 14. Specifically, it was noted that PacifiCorp's REP benefits in some years were zero. Participants asked if BPA assumed PacifiCorp accumulated deemer amounts in those years. *Id.* Following the workshop, BPA confirmed it did not assume PacifiCorp accumulated deemer amounts in years when REP benefits were zero. *Id.*

PacifiCorp supported BPA's proposal to assume no PacifiCorp deemer balance for the Lookback period. IOU Br., WP-07-E-B-JP6-01, at 183, n. 74. PacifiCorp points out that (1) it does not have, and has never had, a deemer balance; (2) it did not have a contract during the REP settlement period by which a deemer balance could have been created, and it is unreasonable to assume PacifiCorp would have executed an RPSA if doing so would have put it into deemer status; and (3) PacifiCorp supports BPA's position that no deemer balance should accrue for PacifiCorp. *Id., citing* Forman, *et al.,* WP-07-E-BPA-76, at 80-81.

PacifiCorp identifies a clear factual difference between its circumstance and those of Avista, Idaho Power, and NorthWestern. The latter three utilities accrued deemer obligations under the 1981 RPSAs. PacifiCorp did not. The deemer balances that a utility accrued under the 1981 RPSA would need to be satisfied under future RPSAs before the utility would receive REP payments. Boling, *et al.*, WP-07-E-BPA-57, at 3. For the three utilities that had deemer balances from the 1981 RPSAs, BPA's Lookback approach recognizes and reflects these balances for the reasons discussed above. BPA's approach does not create a deemer obligation for these utilities where none existed, but rather reduces or eliminates the assumed deemer obligations for two of the three utilities. Therefore, BPA does not believe it is reasonable or necessary in its response to the Court's opinions in *Golden NW* to create a deemer balance where none existed.

Cowlitz argues in its brief that to the extent that BPA calculates individual ASCs, it should do so consistent with the 1984 ASCM in effect during the Lookback period. Cowlitz asserts, "BPA failed to treat PacifiCorp's deemer balances in accordance with the 1984 ASCM, and adopted a 'lesser than' limitation on benefits – the less of the 'reconstructed' benefit value or the amount paid under the REP settlements – that also does not comply with the 1984 ASCM." Cowlitz Br., WP-07-B-CO-1, at 64, *citing* Schoenbeck and Beck, WP-07-E-JP17-01-CC1, at 39.

Cowlitz misunderstands the interplay between the 1984 ASCM and the RPSA deemer provisions. Cowlitz claims several times in its brief that BPA must take into account a deemer balance for PacifiCorp to be "consistent" with the 1984 ASCM. Cowlitz Br., WP-07-B-CO-01, at 64. Cowlitz is incorrect, however, in suggesting that BPA's treatment of the deemer balances has anything to do with the 1984 ASCM. The deemer concept is a contract term that comes from the RPSA the IOUs signed in 1981, *not* the 1984 ASCM. Boling, *et al.,* WP-07-E-BPA-57, at 3. Under the 1981 RPSA, when a utility's ASC was less than the PF Exchange rate, the utility could elect to deem its ASC equal to the PF Exchange rate. *Id.* By doing so, the utility avoided making actual monetary payments to BPA. *Id.* The ASCM, by contrast, establishes the methodology BPA uses to determine the average cost of resources for a utility requesting an exchange of power under section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c)(7). There is nothing in the 1984 ASCM describing what BPA must do in the event a utility's ASC is *below* the PF Exchange rate. Indeed, the 1984 ASCM does not even mention the word "deemer." Deemer balances are a contractually created mechanism that has its origins only in the deemer provisions included in the 1981 RPSA. Consequently, contrary to Cowlitz's arguments, whether BPA imputes a deemer balance to PacifiCorp in the Lookback for the FY 2002-2008 period has nothing to do with BPA's compliance with the 1984 ASCM.

Cowlitz complains that BPA announced a special rule for PacifiCorp, suggesting that its participation would have been delayed until FY 2004 to avoid the deemer problem. Cowlitz Br., WP-07-B-CO-01, at 64, *citing* Forman, *et al.,* WP-07-E-BPA-76, at 81. Cowlitz states that BPA does not and cannot explain how this special PacifiCorp rule is consistent with the 1984 ASCM or the offered RPSAs. Cowlitz Br., WP-07-B-CO-01, at 64.

As explained above, Cowlitz's association of the deemer balance and the 1984 ASCM is incorrect. The 1984 ASCM did not address how BPA was to approach situations where the utility's ASC was *below* the PF Exchange rate. Thus, BPA is not in violation of the 1984 ASCM by not accounting for deemer balances. Regarding Cowlitz's second argument, the RPSAs offered in 2000 included a deemer-like provision that would have required exchanging utilities to net or set off positive REP benefits they received against any negative REP payments they would have owed under the terms of the agreement. *See* 2000 RPSA Draft Prototype section 12, WP-07-E-JP6-17. Thus, at first blush, Cowlitz appears to make a fair point that BPA should assume PacifiCorp would have accrued a deemer balance if BPA is also going to assume PacifiCorp would have signed an RPSA. Cowlitz's position begins to break down, however, when viewed in light of the full record. As BPA Staff noted in its rebuttal testimony, PacifiCorp's ASCs would have been below BPA's PF Exchange rate (thereby putting them in "deemer" status) beginning in FY 2002-2003, and again in FY 2007. Forman, *et al.,* WP-07-E-BPA-76, at 80. Fiscal year 2002 would have been the first year of the RPSA. Thus, Cowlitz would have BPA assume that PacifiCorp would have signed an RPSA *even though* signing would have immediately put PacifiCorp into deemer status.

It is illogical to assume that a sophisticated entity such as PacifiCorp would have executed an RPSA if doing so meant that the utility immediately would enter deemer status, thus accruing a negative balance. *Id.* at 81. An exchanging utility rationally would begin the exchange transaction only in circumstances where the utility knew, or at least believed it highly likely, it would receive positive REP benefits. *Id.* A more rational assumption is to assume that PacifiCorp would have waited until at least FY 2004 to enter the REP. *Id.* Indeed, nothing would have prevented PacifiCorp from waiting until FY 2004 to sign an RPSA. Section 5(c) of the Northwest Power Act states that "[w]henever a Pacific Northwest electric utility offers to sell

… the Administrator shall acquire …" such power from the utility at its ASC. 16 U.S.C. § 839c(c)(1). If PacifiCorp had requested an RPSA from BPA in FY 2004, based on this statutory language, it appears that BPA could not have refused to provide such service. Thus, BPA believes it is reasonable to assume that PacifiCorp would *not* have accrued a deemer balance for FY 2002-2003. *Id.*

Also, as a policy matter, BPA does not agree that adding a deemer balance to PacifiCorp's Lookback obligation is necessary to remedy the harm to the COUs. The key responsibility BPA has in this case is to answer the fairly narrow question of whether the COUs paid too much in their rates for the FY 2002-2008 period due to the REP Settlement Agreements and, if they did, to calculate the amount the COUs were overcharged. Forman, *et al.,* WP-07-E-BPA-76, at 54. In answering this question, BPA does not think it necessary to add a deemer balance on top of a total Lookback obligation; such would overstate PacifiCorp's actual cost contribution to the COUs' rates. *Id.* at 81. Under BPA's proposal, PacifiCorp's Lookback Amount is equal to its total REP settlement payments for the FY 2002-2008 period. *Id.* If BPA adds a deemer balance on top of this, PacifiCorp would return not only the overpayments it actually received, but also payments it did not receive. *Id.* Stated another way, BPA would be refunding to COUs not only the REP costs that were inappropriately collected in rates, but also additional amounts of REP costs that were *never* collected in rates. This result is contrary to BPA's stated goal of recovering from the IOUs the overpayments that were included in the COUs' rates. *Id.*

Cowlitz argues that with respect to the "lesser than" rule, Staff claims that a special rule is justified because "we are not establishing rates for the FY 2002-2008 period," citing Forman, *et al.,* WP-07-E-BPA-76, at 64; but, Cowlitz claims, at least for FY 2002-2006, that is what *Golden NW* requires BPA to do. Cowlitz Br., WP-07-B-CO-01, at 64-65. Cowlitz then claims that BPA "ironically" explains that application of the Lookback approach to PacifiCorp, modified as Cowlitz and Clark suggest to be consistent with the 1984 ASCM policy concerning deemer balances, would produce the result that "PacifiCorp would return not only the overpayments it actually received, but also payments it did not receive." *Id., citing* Forman, *et al.,* WP-07-E-BPA-76, at 81. Cowlitz asserts that this outcome underscores the virtues of a more minimalist approach, where the IOUs simply pay back the benefits, and BPA refunds the overcharges. *Id.*

Cowlitz's arguments are unpersuasive. First, BPA has addressed what it believes its duties are to respond to the Court's remand in *Golden NW*. *See* Chapter 2. Second, Cowlitz misunderstands and mischaracterizes the 1984 ASCM and the RPSAs by claiming that there is a link between the 1984 ASCM "policy" and BPA's treatment of deemer accounts. As explained above, there is no such link, because the 1984 ASCM only calculates a utility's ASC and does not address what BPA or the exchanging utility must do if the resulting ASC is below BPA's PF Exchange rate. The "deemer" concept is a provision of the RPSA. Finally, BPA has explained the pitfalls and shortcomings of the "minimalist" approach advocated by Cowlitz. *See* Chapter 2. This approach violates the historical implementation of the REP, is inconsistent with the plain language of the Northwest Power Act, and would produce inaccurate REP benefit levels.

Decision

BPA will not assume PacifiCorp accrued a deemer balance during the Lookback Period. It is reasonable to assume PacifiCorp would have waited until it was assured or very likely to receive REP benefits before executing an RPSA. As a policy matter, it is not necessary to add a deemer balance on top of a Lookback Amount because it would overstate PacifiCorp's actual cost contribution to the COUs' rates. The 1984 ASCM is not relevant to the issue of whether BPA has appropriately treated the deemer issue for PacifiCorp.

Issue 7

Whether BPA should have assumed that Idaho Power would have received $9.574 million in reconstructed REP benefits to pay against its deemer balance in FY 2002.

Parties' Positions

The IPUC and Idaho Power contend that BPA should assume that Idaho Power would have received positive REP benefits in FY 2002. IPUC Br. Ex., WP-07-R-ID-01, at 10. This assumption would reduce Idaho Power's deemer balance by $9.574 million.

BPA Staff's Position

This issue was raised by the IPUC and Idaho Power for the first time in their Briefs on Exceptions. Idaho Power is assumed to not enter the REP for the entire FY 2002-2008 period. Bliven, *et al.,* WP-07-E-BPA-52, at 14. This assumption is reasonable because if BPA assumed that Idaho Power would have executed an RPSA, BPA would also have to assume Idaho Power would have accumulated an additional $200 million in deemer balances. *Id.* Staff did not believe Idaho Power would have executed an RPSA under these circumstances. *Id.*

Evaluation of Positions

The IPUC notes that in FY 2002 of the Lookback, Idaho Power would have received $9.574 million in REP benefits. IPUC Br. Ex., WP-07-R-ID-01, at 10. The IPUC argues that it is error for BPA to assert in the Draft ROD that "calculations indicate that Idaho Power has zero reconstructed REP benefits for FY 2002-2008." *Id.*

In response, BPA notes that Idaho Power was assumed to be entitled to zero reconstructed REP benefits because BPA assumed for purposes of the Lookback that Idaho Power would not have signed an RPSA. Bliven, *et al.,* WP-07-E-BPA-52, at 14. This assumption was in place throughout this case, and no evidence had been presented on the record to dispute this assumption.

The IPUC argues for the first time in its Brief on Exceptions that BPA should credit to Idaho Power's deemer balance the $9.574 million that Idaho Power would have received had it executed an RPSA. IPUC Br. Ex., WP-07-R-ID-01, at 10. The IPUC argues that this is reasonable because none of the six IOUs signed a RPSA in 2000 because they all (including Idaho Power) executed REP Settlement Agreements. *Id.* The IPUC also says this is consistent with BPA's policy guidance to staff and the Draft ROD that states "reconstructed REP benefits are first applied to reduce a utility's deemer balance each year until the deemer balance is exhausted." *Id.*

Idaho Power raises a similar concern. IPC Br. Ex., WP-07-R-IP-V1, at 7-8. It argues that it is not disputed that during 2002 Idaho Power's average system cost would have exceeded BPA's priority firm exchange rate. *Id.* Any benefits that would have been generated by Idaho Power's participation in an exchange arrangement during 2002 are simply ignored by the Draft ROD. *Id.* Therefore, Idaho Power argues BPA's selective choice of assumptions on this issue not only preserves, but, in effect, increases the assumed financial burden on Idaho Power and its customers to be discharged, before they can receive benefits under an REP program. This combination of assumptions and analysis is allegedly arbitrary and discriminatory as applied to Idaho Power. *Id.* Idaho Power argues that it is reasonable to assume that any positive benefits that would have accrued in 2002 would have been applied to reduce Idaho Power deemer balances, and the ROD should not assume otherwise. *Id.*

These suggestions are misguided. In order for BPA to reduce Idaho Power's deemer balance by the $9.574 million in reconstructed REP benefits, BPA would also have to assume that Idaho Power would have signed an RPSA. Under the 2000 RPSA, if a utility's ASC fell below BPA's PF Exchange rate, the utility would have been required to accrue a deemer balance. *See* 2000 RPSA Draft Prototype section 12, WP-07-E-JP6-17. While Idaho Power's ASC was above the PF Exchange rate for FY 2002, its ASC was well below the PF Exchange rate for the remaining years of the rate period (*i.e.,* FY 2003-2008). *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.3.6 and 9.2.9. As such, if BPA assumed Idaho Power had signed an RPSA, Idaho Power's deemer balance would have *grown* by $200 million, which is obviously contrary to what the IPUC and Idaho Power advocate for in this case. Under these circumstances, BPA does not believe that a sophisticated utility such as Idaho Power would agree to incur $200 million in additional deemer balances just to receive an initial REP payment of $9.574 million. BPA's decision to assume that Idaho Power would not have signed an RPSA for the FY 2002-2006 period is reasonable.

The IPUC also mischaracterizes BPA's policy guidance to staff. The guidance to staff that the IPUC quotes was obviously intended to apply to those utilities that BPA assumed would be receiving REP benefits. Marks, *et al.,* WP-07-E-BPA-62, at 7. BPA assumed throughout this case that Idaho Power would not be one of those utilities. *Id*. Again, no evidence was presented on the record to rebut this assumption. If BPA were to adjust downward Idaho Power's deemer balance for the benefits it would have received in FY 2002, as advocated by the IPUC, then BPA would also have to adjust it upward to reflect the fact that Idaho Power's ASC is below the PF Exchange rate in the FY 2003-2006. As noted above, it is not reasonable assume that Idaho Power would have incurred $200 million in deemer balance in order to receive only $9.574 million in FY 2002. BPA's position is reasonable.

Finally, assuming Idaho Power's deemer balance would have been reduced by $9.574 million would have had no effect on the end results of this proceeding. Idaho Power's Lookback Amount is equal to its total REP Settlement Agreements benefits. Lookback Study, WP-07-FS-BPA-08, section 15.2.1.3.3. BPA's assumptions regarding the deemer balances are not final and dispositive determinations, so assuming that Idaho Power's deemer balance would have been reduced by $9.574 million for purposes of this proceeding is of no consequence.

Decision

BPA properly assumed that Idaho Power would not have received $9.574 million in reconstructed REP benefits to pay against its deemer balance in FY 2002.

8.12 The Lookback and Fish and Wildlife Costs

Issue 1

Whether BPA "undercharged" or "underprojected" fish and wildlife costs in the 2002 Rate Case such that BPA must, in the Lookback analysis, increase projected fish and wildlife costs and then set off any "undercharges" to preference customers against any "overcharges" resulting from forecast REP Settlement costs allocated to the PF Preference rate in the WP-02 Rate Case.

Parties' Positions

The IOUs assert BPA's fish and wildlife cost projections for WP-02 rates were too low and that there should have been additional or increased projections of fish and wildlife costs for the PF Preference Rate for FY 2002-2006. IOU Br., WP-07-B-JP6-01, at 18, 177-179; *but see* oral argument (the IOUs were not arguing for BPA to include greater fish and wildlife costs in the rates, Tr. at 772). The IOUs assert that with increased projections of fish and wildlife costs used in the Lookback analysis, there should be resulting "undercharges" to preference customers that would then be set off against any "overcharges" resulting from forecast REP Settlement costs allocated to the PF Preference rate in the WP-02 case. IOU Br., WP-07-B-JP6-01, at 182. The IOUs recommend that BPA use a portion of BPA's Starting Financial Reserves Available for Risk to promptly resolve any net "overcharges" to preference customers after subtracting projected fish and wildlife cost "undercharges." *Id.* at 18-21, 183.

BPA Staff's Position

Staff stated there were no "undercharges" to BPA's fish and wildlife cost estimates for the FY2002-2006 period; BPA was able to recover the costs of its fish and wildlife commitments during that time despite the problems identified by the Ninth Circuit regarding BPA's fish and wildlife cost estimates. Bliven, *et al*., WP-07-E-BPA-52, at 12. Staff has addressed the Court's concerns about the process BPA uses in developing fish and wildlife costs projections on a going-forward basis; BPA used a different approach to estimate fish and wildlife costs and address risks in the WP-07 rate case and this Supplemental proceeding. Lefler, *et al.*, WP-07-E-BPA-63, at 8. Having met its fish and wildlife cost commitments for the 2002 rate period, BPA sees no purpose in redoing the fish and wildlife cost projections in the Lookback. Bliven, *et al.*, WP-07-E-BPA-52, at 12. Further, were BPA to alter its Lookback analysis by increasing its forecast of fish and wildlife costs, it would not likely have the benefit to the IOUs that the IOUs suggest.

Evaluation of Positions

The IOUs assert BPA's fish and wildlife cost projections for WP-02 rates were too low and that there should have been additional or increased projections of fish and wildlife costs for the PF Preference Rate for FY 2002-2006. IOU Br., WP-07-B-JP6-01, at 18, 177-179; *but see* oral argument (the IOUs were not arguing for BPA to include greater fish and wildlife costs in the rates, Tr. at 772).

The IOUs start from a premise that the Ninth Circuit Court of Appeals ruled in *Golden NW* that BPA's fish and wildlife cost projections for the 2002 rate case were "too low." IOU Br., WP-07-B-JP6-01, at 18. In forums external to the WP-02 rate proceeding, BPA had developed 13 alternatives (with associated estimated costs) for carrying out its fish and wildlife obligations in advance of the WP-02 rate case. Lefler, *et al.*, WP-07-E-BPA-87, at 11. BPA did not alter the alternatives or the equal weighting of them in risk analyses in any significant way over the three years from the time of the development of those alternatives to the final Supplemental ROD in 2001. Tribal parties to that case (and ultimately the *Golden NW* litigation) asserted there was additional information that suggested BPA was significantly underestimating its fish and wildlife costs. While the Court did express a belief that the fish and wildlife projections were too low, *Golden NW,* 501 F.3d at 1052, the Court's actual holding was that BPA's failure to reassess its fish and wildlife costs in light of the evidence meant the agency was arbitrary and capricious. The Court focused on process concerns: that the adherence to outdated information, *Id.* at 1051, and discounting or ignoring crucial facts presented to BPA, were inappropriate, *id.* at 1053.

Despite the infirmities identified by the Court, however, BPA was able to recover the costs of its fish and wildlife commitments during the FY 2002-2006 period. Bliven, *et al*., WP-07-E-BPA-52, at 12. The IOUs assert this conclusion is "speculative" because BPA is not able to calculate how much of any particular BPA cost any particular customer pays. IOU Br., WP-07-B-JP6-01, at 20, fn. 10. The IOU argument is inapposite. An inability to apportion each particular fish and wildlife cost BPA has to each individual customer does not mean BPA did not pay that fish and wildlife cost.

The IOUs argue that just because BPA was able to "cover the costs of its fish and wildlife commitments or make its Treasury Payment," that does not mean BPA's projections of fish and wildlife costs in rates were appropriate. IOU Br., WP-07-B-JP6-01, at 20 (footnote omitted). While the projections may have been developed in a flawed way, this does not translate into a requirement that BPA reforecast the costs in order to confirm that BPA could, indeed, pay its commitments. The purpose of forecasting fish and wildlife costs is to ensure sufficient cost recovery to meet spending commitments. If the spending commitments were met, then the cost projections were "appropriate" even if reached via a flawed approach.

Nonetheless, the IOUs essentially argue that because BPA is doing a Lookback, it must, in that Lookback, adjust fish and wildlife cost projections. IOU Br., WP-07-B-JP6-01, at 182. The IOUs appear to believe that redoing fish and wildlife cost estimates is necessary because it will result in a potential benefit to them, although they provide no testimony or other evidence in support of this assertion.

Even assuming *arguendo* that BPA were to do new cost projections for fish and wildlife for FY 2002-2006 for the Lookback, and even assuming those cost projections were higher (whether by increasing the range of 13 alternatives or altering the weighting of them from equal to a greater likelihood of the more costly alternatives), this does not result in benefits to the IOUs.

The IOUs have assumed a simplistic formula: if "overcharges" to COUs are smaller because of increased fish and wildlife cost projections, then IOU "overpayments" must also be smaller, and therefore there will be more for the IOUs and less for the COUs than Staff has proposed in the Lookback. The possibility of "overcharges" stemming from fish and wildlife forecasts requires the consideration of two kinds of Lookbacks, one for REP issues and one for fish and wildlife issues, and requires that the impact on COUs and IOUs be tracked very carefully. Unlike REP issues, where an overcharge to COUs must equal the undercharge (or overpayment) to the IOUs, there is no reason to suppose that undercharges to COUs would be equal in size to an overcharge to the IOUs, or vice versa. In fact, the formula would look more like this:

- Assuming *arguendo* a fish and wildlife (F&W) undercharge, this results in PF rates (*all* PF rates) being too low. This would result in a net "F&W undercharge" which would = COU F&W undercharge + IOU F&W undercharge.

To address this in a Lookback-type solution then:

- F&W Lookback = COU F&W Lookback (negative to COUs) + IOU F&W Lookback (negative to IOUs)

The constructed "net" Lookbacks would then be:

- Net COU Lookback = REP Lookback (positive) + COU F&W Lookback (negative)
- Net IOU Lookback = REP Lookback (negative) + IOU F&W Lookback (negative)

Thus, while the total amount of a fish and wildlife "undercharge" is not identified, it would have increased the PF rate and therefore increased the PF Exchange rate, which would in turn decrease the amount of REP benefits in the reconstruction, and finally would increase, not decrease, the size of the IOU Lookback obligation overall. Thus, there could not be a "net overcharge" to the IOUs.

Even if the IOUs were correct in their assumptions about "undercharges" and "overcharges," a Lookback approach to fish and wildlife cost projection errors identified by the Court in *Golden NW* is not warranted. BPA was able to fund its fish and wildlife commitments in the FY 2002-2006 period, so reassessing those costs now would serve no purpose. Indeed, in order to recalculate its FY 2002-2006 fish and wildlife projections, BPA would need to revisit fish and wildlife costs that are now themselves quite outdated (*e.g.*, seeking to reassess the costs of the 2000 FCRPS BiOp, even though that BiOp has been replaced by two subsequent BiOps), contrary to the guidance from the Court in *Golden NW*.

Moreover, the IOUs' argument could be taken to imply that BPA must add funding to its current fish and wildlife commitments. Otherwise, under the IOUs' approach, BPA would be increasing fish and wildlife projections for the FY 2002-2006 period when BPA had already funded its costs during that period. In effect, BPA would be projecting additional fish and wildlife costs that it didn't need at the time to meet its funding commitments, and so presumably such collection would need to be applied to current spending. Thus, the IOUs appear to be asserting BPA should have spent more on fish and wildlife during the FY 2002-2006 period despite their denial, Tr. at 772. What BPA decides to spend on fish and wildlife (as distinct from what it projects it will need to spend), and whether or not that spending is adequate as a matter of law, are not matters determined in rate proceedings. Such determinations are made in forums and through processes external to the rate case, such as in response to recommendations for fish and wildlife projects from the Northwest Power and Conservation Council under the Northwest Power Act, or in response to requirements of a Biological Opinion to BPA on Endangered Species Act responsibilities issued by NOAA Fisheries. Lefler, *et al.*, WP-07-E-BPA-63, at 13-14. This is one reason why BPA excludes such matters from the scope of its rate proceedings in the first instance. *See* BPA Notice of Proposed Wholesale Power Rates for this Supplemental proceeding, 73 Fed. Reg. 7539, at 7543, February 8, 2008.

Instead, BPA is focusing on addressing the Court's concerns as to fish and wildlife on a forward-looking basis. BPA explained how, unlike its fish and wildlife cost projections for the WP-02 case, forecasting of fish and wildlife spending in the WP-07 case was confirmed very close in time to the final rate proposal, using the most up-to-date information possible, with intensive public review. Lefler, *et al.*, WP-07-E-BPA-63, at 8. In addition, BPA is treating uncertainty about future fish and wildlife costs differently in both the WP-07 and this Supplemental proceeding as compared to the WP-02 case. Instead of establishing a range of alternative fish and wildlife costs weighted equally, BPA developed up-to-date actual forecasts of costs, vetted in public processes, then added special risk-mitigation tools addressed to specific fish and wildlife cost uncertainties. *Id.* at 9-10. BPA also detailed the steps it was taking to address the Court's direction that BPA is required to develop "a realistic projection of fish and wildlife costs that accurately reflected the information available at the time the rates were set and the cost recovery mechanisms adopted." *Golden NW,* 501 F.3d at 1053. BPA took steps to ensure that the most recent events affecting BPA's forecasting of fish and wildlife costs, including execution of long-term agreements with states and tribes about fish and wildlife spending, as well as the expected costs of implementing the new FCRPS Biological Opinion, were reflected. Lefler, *et al.*, WP-07-E-BPA-63, at 10-11.

Decision

The projections of costs and the actual costs of fish and wildlife for the FY 2002-2006 were established in non-rate-case forums, and all such costs were recovered by BPA in that rate period. Having recovered all its fish and wildlife costs for FY 2002-2006, BPA would have no purpose in doing new forecasts for the FY 2002-2006 period. Even if BPA were to alter the Lookback (designed for addressing REP issues only) as IOUs propose, by increasing the forecast of fish and wildlife costs for the FY 2002-2006 period, it would likely increase, rather than decrease, the Lookback Amounts for which the IOUs would be responsible. BPA's approach to addressing fish and wildlife concerns identified in Golden NW *on a forward-looking basis rather than as part of the REP Lookback is a reasonable response.*

9.0 LOOKBACK RECOVERY AND RETURN

9.1 Introduction

Once the Lookback Amounts are established as described in Chapter 8, an approach must be developed for recovering these amounts from the IOUs and returning them to the COUs. The policy guidance for Staff's proposed approach to recovering the Lookback Amounts from the IOUs and returning them to the COUs is described in Bliven, *et al.*, WP-07-E-BPA-52, at 11-25, and further explained in Forman, *et al.*, WP-07-E-BPA-76, at 95-125.

As proposed in Bliven, *et al.*, WP-07-E-BPA-52, at 21-22, BPA seeks to recover and return the Lookback Amounts in a manner that balances the impact on the IOUs' residential and small farm customers with the need to provide a full and timely remedy to COUs for the overcharges they incurred. BPA's goal is to provide a reasonable level of lawful REP benefits to the residential and small farm consumers of the IOUs as well as a reasonable assurance that the unlawful amounts related to the REP settlements will be repaid in a reasonably short time. *Id*. As described in this chapter, BPA's approach includes a combination of immediate cash payments to the COUs and credits on future COU power bills funded by future reductions in IOU REP benefit payments. This chapter also addresses the Definitive Benefit Amounts, Definitive Payment Amounts and the individual COU percentages of the Definitive Payment Amounts needed to administer interim agreements that BPA and utilities executed in March 2008.

9.2 Overall Approach

Issue 1

Whether BPA's Lookback must achieve intergenerational equity or adhere strictly to a matching principle that generally states that customers receiving a refund of an unlawfully charged rate, insofar as possible, should be the same customers that paid the unlawful rate in the past.

Parties' Positions

Certain parties have argued that Staff's Lookback proposal is flawed because it does not achieve intergeneration equity or fails to adequately accommodate the matching principle. APAC Br., WP-07-B-AP-01, at 12; WUTC Br., WP-07-B-WU-01, at 8.

BPA Staff's Position

BPA Staff recognized that REP benefits go to the residential consumers of the IOUs. Forman, *et al.*, WP-07-E-BPA-76, at 100. Staff understands that future consumers whose REP payments would be reduced are not necessarily the exact same consumers as those who received the past REP settlement benefits. *Id*. Staff proposed a longer period of time to recover overpayments and return them to COUs in order to minimize the effects on current residential customers. *Id*. at 100-101. However, Staff notes that BPA's business relationship is with BPA's customers, the IOUs, not with the end-use consumers of the IOUs. *Id*. at 101. Ultimately, it will be up to the

IOUs and the state commissions to decide how to spread the REP benefits to residential customers in the future. *Id*.

Evaluation of Positions

The Federal Energy Regulatory Commission follows a "general ratemaking principle" of "matching," by which ratepayers are charged with the costs of producing the service they receive. 61 F.E.R.C. at 62,214. A related principle is "intergenerational equity." The State of Vermont Public Utility Board offers the following definition:

> Intergenerational equity is a long-standing ratemaking doctrine which refers to the matching of the timing of ratepayers' payments for utility services with the benefits from those services. To achieve this, the doctrine can require spreading the costs of a utility investment across different "generations" of ratepayers. For example, many types of utility plant provide service to ratepayers for decades. It would be inequitable for the ratepayers at the time the plant was built to pay for the entire cost of that plant. Instead, all ratepayers who receive the benefit of that plant throughout the decades should share in paying for the plant.

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Given the importance of BPA's cost recovery requirements, it is unclear the extent to which these principles apply to BPA's ratemaking activities. Moreover, since BPA's sales are at the wholesale level, it is not clear to whom these principles should be applied given that BPA has no direct relationship with retail consumers. Nonetheless, there is no question that, to the extent that they promote equity and economic efficiency, it is not improper that these concepts receive consideration by the Administrator pursuant to his obligation to set rates consistent with sound business principles.

In this instance, it appears to BPA that the issue of intergenerational equity is a challenge that would be impossible to fully satisfy, especially given the limited tools at BPA's disposal. In this proceeding, BPA has embraced the concept that an error was committed and needs to be rectified. This includes identifying and correcting past overpayments of REP settlement benefits and past overcharges in the PF Preference rates. However, BPA's contracts are with utilities: the IOUs that pass REP or REP settlement benefits on to their residential and small farm consumers and the COUs that pass the costs of providing those benefits on to their consumers. From the standpoint of BPA's relationship with its wholesale customers, BPA believes that any inconsistencies with the matching principle and the principle of intergenerational equity are, at most, *de minimis*. BPA will likely be selling to the same utilities, or their successors in interest, for generations to come.

However, as already noted, BPA does not have a direct business relationship with the retail consumers that ultimately received the overpayments from the REP settlements or with the retail consumers of the COUs who ultimately paid the excess costs. How to best achieve intergenerational equity with respect to retail consumers is probably best left to those who directly provide them with electric service. The retail utility's consumers are constantly changing. For example, homeowners move in or move out of different utility service territories, and some businesses start up while others shut down, so correcting for overpayments of benefits or overcharges in rates at the utility level will, if reflected in retail rates, certainly create some new inequities, as noted by CUB. Jenks, WP-07-E-CU-01, at 15.

Correcting the past error through BPA's wholesale relationships with the IOUs and COUs will mean some consumers who are new to a service territory will be asked to repay benefits they did not receive, while others will receive a repayment of costs they did not pay. BPA believes the "rough justice" accomplished under this approach, while imperfect, is better than the alternative of no justice at all. Yet, as described later in this chapter, the impact on non-participants in the original error in the WP-02 rates identified by the Court has influenced BPA's perspective regarding how repayment should be accomplished.

APAC argues that consumers have a strong equitable interest in receiving prompt payment of refunds when such refunds are found to be due. APAC Br., WP-07-B-AP-01, at 12, *citing Public Srv. Comm'n v. FPC*, 543 F.2d 757, 811 (D.C. Cir. 1974). APAC also submits that the 20-year payback period proposed by Staff violates another general ratemaking rule known as the matching principle: customers being refunded an unlawfully charged rate *insofar as possible* should be the same customers that paid the unlawful rate in the past. APAC Br., WP-07-B-AP-01, at 13 (emphasis added). APAC offers two reasons why Staff's proposal does not comport with the matching principle. First, the 20-year payment period is too long. *Id*. at 14. Second, the Lookback proposal does not make repayments to preference customers in proportion to their original overcharges. *Id*. at 15.

The WUTC also raises the intergenerational equity issue by stating that "one consequence of a retrospective remedy could be to force some future consumers of exchanging utilities to forgo a portion of the exchange benefits to which they are entitled to remedy past benefits they did not receive, in order to compensate some future customers of preference agencies" who did not pay for past benefits and who may not realize any future benefit. WUTC Br., WP-07-B-WU-01, at 8-9, *citing* OPUC Br., WP-07-E-PU-01, at 3.

BPA's customers are wholesale purchasers of power, such as public body, cooperative, and investor-owned utilities. BPA does not enter into contracts for sales of power directly with the retail consumers of its utility customers. However, BPA also recognizes, as APAC relates, the appropriateness of structuring repayments in order to ensure, to the extent possible, that the parties who bore the ultimate burden of the overcharges are the ones who should receive compensation. APAC Br., WP-07-B-AP-01, at 14, *citing* Tr. at 112.

BPA has tried to treat its customers equitably, "insofar as possible." However, the concept advocated by APAC and WUTC creates an expectation of perfect parity among all retail consumers. BPA does not believe that it is obliged to create such a utopian construct with regard to the retail consumers of BPA's wholesale utility customers, nor does it believe that such an ideal is achievable in the final analysis. As the D.C. Circuit has noted:

> In matters of prospective and retroactive effect, there are large questions of equity and public interest – both for agencies and for courts. While full refund under an

invalid order is a sound basis rule, it may be offset, at least in part, by the lack of a mechanism to restore the full status quo ante.

Consumer Federation of America et al., v. Federal Power Commission, 515 F.2d 347 (D.C. Cir. 1975). Similarly, achievement of intergenerational equity and adherence to the matching principle are worthwhile goals, but other important considerations, whether equitable, legal, or otherwise, sometimes stand in the way of achieving the result that may be desired by some. In this instance, BPA has crafted a remedy through modifications to Staff's Lookback proposal, described later in this chapter, which strikes a reasonable balance among the interested parties without hampering BPA's governmental and business interests, while taking into account other relevant considerations, including the matching principle and intergenerational equity.

Decision

While BPA is not required to achieve intergenerational equity or to strictly adhere to a matching principle in its Lookback approach, it has given these doctrines due consideration "insofar as possible."

9.3 Recovery of Overpayments to the IOUs and Return of Overcharges to the COUs

9.3.1 Recovery from the IOUs

Issue 1

Whether BPA has the statutory authority to reduce future REP benefits to recover the Lookback Amounts.

Parties' Positions

The OPUC argues that BPA does not have the statutory authority to change REP benefits so that they do not reflect the full level of benefits authorized under the Northwest Power Act. OPUC Br., WP-07-B-PU-02, at 2.

CUB contends that BPA's proposal to reduce the level of future REP benefits as a means of recovering past overpayments violates the Northwest Power Act, which states that BPA must pass on all such benefits to the qualifying utility. CUB Br., WP-07-B-CU-01, at 2. CUB claims that such an approach increases rate disparity by effectively raising the rates of IOU consumers relative to the rates of preference customer consumers, thus penalizing the class of people that Congress intended the REP to benefit. *Id*. at 3-4.

The WUTC argues that reducing future REP benefits paid in order to recover the Lookback Amount from each IOU violates the requirement in the Northwest Power Act that REP benefits be passed through to qualifying ratepayers. WUTC Br., WP-07-B-WU-01, at 7.

The IOUs further argue that BPA should not use its asserted right of setoff when collecting the Lookback Amounts. IOU Br. Ex., WP-07-R-JP6-01, at 13-14. Instead, the IOUs argue that BPA should leave the issue of what amount of REP benefits to apply to Lookback Amounts as a ratemaking matter addressed in a section 7(i) proceeding. *Id.*

BPA Staff's Position

BPA Staff supported the approach of reducing future payments of REP benefits as the most reasonable approach to recovery of the Lookback Amount from each IOU, given the fact that such overpayments had already been passed through to the residential and small farm consumers of the IOUs. Marks, *et al.*, WP-07-E-BPA-62, at 18.

Evaluation of Positions

The OPUC, CUB, and the WUTC raise concerns that Staff's Lookback proposal violates the application of section 5(c) of the Northwest Power Act. CUB argues that BPA lacks the authority to withhold money BPA is obligated to pass on to residential and small farm consumers under section 5(c). CUB Br., WP-07-B-CU-01, at 2. CUB notes that the Northwest Power Act requires BPA to pass through the benefits of the REP directly to IOUs' residential and small farm consumers. *Id*. CUB claims that withholding REP benefits through the Lookback is akin to permitting BPA to exchange something less than an equivalent amount of power, which the Northwest Power Act does not allow. *Id*. at 3. The OPUC similarly argues that BPA cannot "ignore" the mandates of section 5(c) by providing a level of REP benefits lower than required under the Act. OPUC Br., WP-07-PU-02, at 2.

BPA is not persuaded by the arguments raised by CUB and the OPUC. Contrary to the arguments raised by the parties, Staff's proposal is consistent with section 5(c). Section 5(c) requires the Administrator to "acquire by purchase" whenever requested by a Pacific Northwest electric utility an amount of power equal to the residential load of the exchanging utility. 16 U.S.C. § 839c(c)(1). The price BPA pays for such power is the "average system cost" of the requesting utility, which is determined according to a methodology developed by the Administrator. *Id*., § 839c(c)(7). These provisions of the Act are being implemented fully under BPA's Lookback approach. In accordance with section 5(c)(1), BPA will offer an RPSA to the IOUs to begin exchanging with BPA as of October 1, 2008. Consistent with sections 5(c)(1) and 5(c)(7), BPA will calculate the exchanging utility's ASC pursuant to BPA's 2008 Average System Cost Methodology. BPA will then determine the utility's REP benefit amount by comparing the utility's ASC with BPA's PF Exchange rate, multiplying the difference by the utility's residential load. Thus, contrary to the claims of CUB and the OPUC, BPA will be determining REP benefits following all of the statutory mandates in section 5(c).

After these requirements are satisfied, BPA will then apply a portion of the lawful REP benefits to each IOU's outstanding Lookback Amount. CUB and the OPUC contend that BPA does not have statutory authority to make such reductions to account for past overpayments, and that by making this adjustment, BPA is effectively exchanging less than the equivalent amount of power, as required by the Act. CUB Br., WP-07-B-CU-01, at 2-3; OPUC Br., WP-07-PU-02, at 2. These arguments are unfounded. First, as just described, BPA will be calculating the IOU's

REP benefits consistent with section 5(c). This means that the exchanging utility's *entire* eligible load will be considered when determining the amount of REP benefits. CUB's assertion that BPA is proposing to make REP payments to the IOUs using less than the full amount of exchangeable load is, therefore, incorrect.

Second, BPA is not exceeding its authority by reducing the REP payments to satisfy previous overpayments. Section 5(c) describes the Administrator's general obligation to enter into the exchange program and the criteria for establishing an exchanging utility's ASC. 16 U.S.C. § 839c(c)(1). This provision says nothing about whether BPA is precluded from retaining future REP benefits to satisfy past REP overpayments. In this respect, BPA's approach is conceptually similar to a surcharge on the PF Exchange rate. Such a surcharge would represent the kind of cost that section 7(g) of the Northwest Power Act covers. 16 U.S.C. § 839e(g). Such costs (or credits) are to be "equitably allocate[d] to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act…" *Id*. In this case, the allocation is equitable because it follows the accepted ratemaking principle of cost causation, and it recognizes that under the Northwest Power Act, REP benefits are unique to each exchanging utility, based on its ASC.

Additionally, the courts have long recognized that the government may use the common law to set off debts and payments. *See U.S. v. Munsey Trust Co.*, 332 U.S. 234, 239 (1947); *Dunn & Black, P.S. v. U.S.*, 492 F.3d 1084, 1092, n. 10 (9th Cir. 2007). The authority to set off debts extends between separate contracts which the debtor may have with the government. *See Cecile Industries, Inc. v. Cheney*, 995 F.2d 1052, 1054 (Fed. Cir.1993). As such, in the absence of explicit statutory guidance, an agency may use its authority under the common law right of setoff to collect overpayments. *See Applied Companies v. U.S.*, 144 F.3d 1470, 1476 (Fed. Cir. 1998). Staff proposes to set off the overpayment made in one contract (the REP Settlement Agreement) with the future payments due and owing from another contract (RPSA). As the above cases make clear, this approach is squarely allowed by the law. Consequently, the assertion by CUB and the OPUC that BPA is prohibited by the Northwest Power Act from reducing future REP benefits must be rejected.

In their Brief on Exceptions, the IOUs comment that BPA should not use an "asserted" right of set off under common law, but rather, should make any such adjustment as a ratemaking adjustment. IOU Br. Ex., WP-07-R-JP6-01, at 13-14. The IOUs argue that any BPA decision to exercise any asserted common law set off rights is beyond the scope of this section 7(i) ratemaking proceeding, and that a decision to use a set off under common law is not an appropriate remedy under the present circumstances because the REP settlement payments were required by statute to be, and were, passed through by the Pacific Northwest IOUs to their residential and small farm consumers. *Id.*

BPA disagrees with the IOUs' characterization of BPA's common law set off right as "asserted". The law is clear that government agencies retain their common law rights, including the right of setoff, unless a statute *expressly* states otherwise. *See U.S. v. Munsey Trust Co.*, 332 U.S. 234, 239 (1947); *Dunn & Black, P.S. v. U.S.*, 492 F.3d 1084, 1092, fn. 10 (9th Cir. 2007). Nevertheless, BPA clarifies that it is not proposing to use its authority under the common law in a manner separate from its rate proceeding. As noted above, BPA's proposal is to determine in each rate proceeding the appropriate reduction to REP benefits to apply against the IOUs' respective Lookback Amounts. It is immaterial for purposes of this proceeding to determine whether this action is an exercise of BPA's authority just under the Northwest Power Act or under both it and the common law. As stated above, BPA has the authority under both to make the adjustment. The key point is that BPA will be deciding the amount of the reduction in a section 7(i) proceeding and will apply such reduction only to the REP benefits. This clarification should address the IOUs' concern.

CUB and the WUTC also note that section 5(c)(3) of the Northwest Power Act requires BPA to pass through all of the benefits of the REP to residential consumers of an exchanging utility. CUB Br., WP-07-B-CU-01, at 2; WUTC Br., WP-07-B-WU-01, at 7. They argue that Staff's proposal to reduce future REP payments is inconsistent with this direction. *Id*.

BPA disagrees. Section 5(c)(3) describes the obligation of the *IOUs* to pass through the benefits of the REP to their residential consumers. 16 U.S.C. § 839c(c)(3). It does not speak to the present case where a past overpayment has been made. As such, BPA may use its rights under the common law or the Northwest Power Act to recover these overpayments. Moreover, any REP benefits that are actually paid to the IOUs after application of the Lookback Amount will be subject to section 5(c)(3). The RPSAs that will be offered to the IOUs will contain a provision that states clearly that all REP payments that are actually made to the IOUs must be passed on to the residential and small farm consumers of the utility. Staff's proposal is therefore consistent with section 5(c)(3).

CUB also argues that reducing future REP benefits in order to recover the Lookback Amounts violates the "spirit" of the Northwest Power Act. CUB Br., WP-07-B-CU-01, at 3. CUB notes that the REP was the mechanism Congress chose to reduce the disparity in rates between preference and non-preference customers by giving the IOUs' residential and small farm consumers access to BPA's cheaper power. *Id*. CUB contends that if BPA proceeds with the Lookback, that disparity will increase where BPA is effectively taking money due current residential and small farm consumers and giving that money to BPA's preference customers in the form of lower rates over the next 20 years. *Id*.

BPA does not disagree that its proposal will have an impact on the residential and small farm consumers of the IOUs. This impact, however, is unavoidable. As a consequence of the Court's decision in *Golden NW*, it is now the case that the retail consumers of the region's IOUs received benefits over FY 2002-2007 they were not entitled to. They had greater access to the benefits of the Federal hydro system than Congress intended. These overpayments must be returned. In recognition of these unique circumstances, Staff has taken great care in developing the Lookback approach to balance the past receipt of those overpayments by IOUs and the determination of the amount of REP benefits that need to be recovered by BPA. To implement this recovery, Staff proposed a reduction, or set off, of future REP benefit amounts. *See* Marks, *et al.*, WP-07-E-BPA-62, at 18. The fact that REP benefits go to the residential consumers of the IOUs was paramount in the construction of the Lookback proposal. Forman, *et al.*, WP-07-E-BPA-76, at 100. BPA recognizes that the IOUs did not keep the monies paid under the REP settlements, but passed them on to residential consumers. *Id*. For this reason, Staff structured the recovery of the Lookback Amounts through a reduction of future REP benefits paid, rather than seek repayment directly from the IOUs. *Id*. Given that the IOUs do not have the monies paid under the REP settlements, it is reasonable to reduce future REP benefits to recover the Lookback Amounts from those who generally received the overpayments. *Id*.

BPA recognizes that future consumers whose REP payments are reduced in order to return the Lookback Amounts are not necessarily the exact same consumers as those who received the past REP settlement benefits. Forman, *et al.*, WP-07-E-BPA-76, at 100-101. However, reducing future REP payments over a period of time was one of the few mechanisms available that could return overcharges to the COUs while minimizing the effects on current IOU residential consumers. *Id*. Some parties in this proceeding suggested that BPA request a lump sum payment for the Lookback Amounts from the IOUs in order to minimize the so-called mismatch between those who received the overpayments and those who will receive reduced REP benefits paid as BPA recovers the Lookback Amounts. This position would make sense if the REP Settlement funds were available to be refunded. However, all of the payments made to the IOUs have been passed on to their residential and small farm consumers. There is, therefore, no ready pool of money held by the IOUs that BPA could reasonably claim to provide the lump -sum payment. Forman, *et al.,* WP-07-E-BPA-76, at 103. Consequently, Staff rejected a lump -sum approach because it would require costly and contentious litigation with the IOUs, with an uncertain outcome. *Id*. In addition, requiring a lump sum payment would not only zero out the REP benefits to the IOUs and their residential consumers; it would likely result in some form of rate surcharge borne by the residential and small farm consumers. Staff's proposal, which simply reduces future REP benefits, avoids this problem as well as the possibility of additional rate increases to the IOUs' residential consumers, and is therefore reasonable.

Finally, BPA recognizes that its approach to recovering the Lookback will have an impact on the rate differences between the IOUs and COUs. While unfortunate, BPA does not believe that concerns over rate disparity between IOUs and COUs can be a basis for ignoring the remand from the Court. As noted earlier, BPA's approach balances the objective of returning the Lookback Amounts to the COUs within a reasonable time while maintaining some level of lawful REP benefits. BPA does not believe it reasonable to upset this balance by not recovering the Lookback Amount based on concerns of rate disparity. Furthermore, as noted later, even under BPA's approach, residential customers of IOUs may still receive some relief under the REP, which should alleviate some of the rate disparity noted by CUB. For these reasons, BPA's proposal is reasonable.

<u>Decision</u>

BPA's approach for recovering the Lookback Amounts from the IOUs is lawful. The Northwest Power Act does not prohibit BPA from recovering past overpayments of REP settlement benefits from future REP benefits. In addition, BPA has rights under the common-law right to set off claims against the IOUs. Finally, BPA appropriately considered the impact of its approach on the residential consumers of the IOUs.

<u>Issue 2</u>

Whether BPA should recover the Lookback Amount in proportion to the REP settlement benefits paid to the IOUs.

<u>Parties' Positions</u>

The WUTC argues that recovering a Lookback Amount of $246 million is best accomplished by recovering such amounts in proportion to the REP settlement benefits paid to each IOU. WUTC Br., WP-07-B-WU-01, at 12.

<u>BPA Staff's Position</u>

BPA Staff's proposal defines the Lookback Amount for each IOU as the difference between the total REP settlement benefits paid, or that would have been paid, to each IOU and the reconstructed REP benefits each IOU would have received absent the settlements, after certain additional considerations. Bliven, *et al.*, WP-07-E-BPA-52, at 11-12.

<u>Evaluation of Positions</u>

The WUTC's proposal cannot be reconciled with BPA's overall approach to the Lookback analysis, which is predicated on the comparison of the REP settlement benefits received to the reconstructed REP benefits. Forman, *et al.*, WP-07-E-BPA-76, at 122-123. The reconstructed benefits are grounded in the Northwest Power Act, section 5(c), whereas the WUTC's approach is grounded in the REP Settlement Agreements that the Ninth Circuit found did not meet the requirements of section 5(c). As such, BPA must calculate the individual IOU ASCs to fulfill the primary objective of this proceeding; namely, to determine what the REP benefits would have been had the REP Settlement Agreements not been executed. *Id.* at 44. In order to accomplish this objective, BPA must have all of the relevant data, especially the ASCs of the individual utilities. *Id.* Without these data, BPA would have no way of knowing if, or by how much, it overcharged the COUs. *Id.* Apportioning liability among the IOUs based on their respective shares of REP settlement benefits would not assist in answering this question. *Id.* The proportion of REP settlement benefits an IOU received may not have any specific relationship to the REP benefits that such utility would have received in the absence of the REP settlements. *Id.*

The WUTC proposal also ignores the fact that the LRAs are treated as valid agreements in this analysis, and thus "protected" from the Lookback analysis. *Id.*; *see also* Chapter 8. If BPA were to allocate the recovery of the total Lookback Amount based on the amount of REP settlement benefits received, there would be no relationship between that amount and what the utility would have otherwise been due had it signed an RPSA instead of a settlement agreement. The result of such an approach would be that residential and small farm consumers who received high benefits through the REP settlement, and who otherwise were due relatively high REP benefits, would retain very few of the REP benefits to which they would have had a claim in the absence of the REP settlements. This is an illogical result.

Finally, the WUTC proposal would shift the repayment obligations of some IOU consumers to the consumers of other IOUs. Those consumers that received smaller settlement benefits compared to lawful REP benefits would end up repaying the excess settlement benefits received by other consumers that received larger settlement benefits compared to lawful REP benefits. This shifting of repayment responsibility, if not illegal, would certainly not be fair.

Decision

BPA will not recover the Lookback Amounts in proportion to the REP settlement benefits paid to each of the IOUs. Lookback Amounts will be determined by comparing each IOU's REP settlement benefits to that IOU's lawful REP benefits, subject to certain other considerations.

Issue 3

Whether the Lookback Amount of an IOU should be reduced to the extent that the IOU loses residential or small farm load to another service provider.

Parties' Positions

The IOUs argue that the Lookback Amount of any investor-owned utility should be reduced to the extent that such utility loses residential or small farm load to another service provider. IOU Br. Ex., WP-07-R-JP6-01, at 13.

BPA Staff's Position

This is a new issue not raised before the Briefs on Exceptions. BPA Staff took no position on this issue.

Evaluation of Positions

The IOUs note that an IOU could lose residential load to another utility due to annexation and, unless the Lookback Amount for the utility is reduced to reflect the lost load, the remaining residential and small farm customers of the utility would unfairly bear Lookback Amounts attributable to the lost load. IOU Br. Ex., WP-07-R-JP6-01, at 12. The IOUs argue that it would be fundamentally unfair, and arbitrary and capricious, to require the remaining customers of an investor-owned utility that loses load to a different service provider to bear the portion of the Lookback Amount attributable to the lost load. *Id*. The IOUs draw a comparison to what they view as a similar fundamental equity issue. They cite BPA's Draft Record of Decision where BPA agreed to remove the portion of Idaho Power's deemer balance associated with its Nevada service area that was sold to an Idaho electric co-operative in 2001. *Id*.

The IOUs raise a new issue that BPA has not previously addressed in this proceeding. On the one hand, the IOUs appear to raise a legitimate concern. To the extent an IOU loses residential and small farm load, it will qualify for fewer REP benefits, assuming all else equal. If the utility's Lookback Amount is not reduced to reflect the lost load or some other adjustment is not made, it would appear that the remaining residential and small farm consumers would "bear the portion of the Lookback Amount attributable to the lost load," an outcome that raises equity issues. Reducing the utility's Lookback Amount would address the arguable inequity otherwise falling on the IOUs' remaining residential and small farm consumers. However, this reduction would come at the expense of the COUs that would no longer get the return of this portion of the Lookback Amount. Arguably, it is the IOU residential and small farm consumers that are no longer served by the utility that should bear their fair share of the return of the Lookback Amount. Whether this is the appropriate outcome and, if so, how it could equitably and practically be achieved is unclear.

Because this issue was not raised until the Briefs on Exceptions, the record in this proceeding does not provide sufficient basis for BPA to decide this issue. In addition, BPA believes that the likelihood of material IOU residential and small farm load loss to a different service provider in the next year is low given the actions that generally must be taken and the lead times involved. Therefore, BPA believes this issue should be addressed in a subsequent proceeding, such as the upcoming WP-10 rate proceeding. Doing so will allow BPA Staff and the Parties to establish a record on which BPA can make a fully informed decision. Delaying the decision until a subsequent proceeding, such as the conclusion of the WP-10 proceeding, would not appear to cause sufficient harm to warrant a decision now based only on the arguments provided in the IOUs' Briefs on Exceptions.

Decision

BPA will address the load loss issue raised by the IOUs in a subsequent proceeding, thereby giving parties the opportunity to establish a sound record for deciding this issue.

9.3.2 Certainty and Priority of Repayment

Issue 1

Whether Staff's proposal to recover the overpayments to the IOUs and return them to the COUs provides sufficient certainty of repayment to the COUs.

Parties' Positions

The WUTC argues that a payback period of up to 20 years aggravates the problem of intergenerational transfers and raises additional issues regarding carrying charges and interest rates. WUTC Br., WP-07-B-WU-01, at 12-13.

APAC, WPAG, PPC, and Cowlitz argue that there is far too much uncertainty in Staff's proposal for return of the overcharges to the COUs in 20 years or less. APAC Br., WP-07-B-AP-01, at 8-15; APAC Br. Ex., WP-07-R-AP-01, at 3; WPAG Br., WP-07-WA-01, at 33-34; WPAG Br. Ex., WP-07-R-WA-01, at 37-38; PPC Br., WP-07-B-JP25-01 at 40; Cowlitz Br., WP-07-B-CO-01, at 72-73; Cowlitz Br. Ex., WP-07-R-CO-01, at 50-51.

WPAG and Cowlitz argue that it is imperative that BPA assure repayment to the COUs of the full amount of overcharges within a time frame that matches, or does not exceed, the seven years that overcharges were in place. WPAG Br., WP-07-WA-01, at 34; Cowlitz Br., WP-07-B-CO-01, at 73. PPC argues that if the Administrator cannot provide this certainty, then the amounts wrongfully collected should be returned over a much shorter period that is more analogous to the period over which they were collected. PPC Br., WP-07-B-JP25-01, at 40.

Noting that BPA's revised approach to recover the overpayments in seven years, as well as to return the overpayments to the customers who paid them, responds "positively to preference customers' complaints," Cowlitz argues that BPA's revised approach is still inadequate. Cowlitz Br. Ex., WP-07-R-CO-01, at 50. Cowlitz reiterates its objections to BPA's plan to reduce prospective REP benefits as the source of funds to return to the COUs, while also assuring that an IOU's benefits would not be reduced below 50 percent of the REP benefits due. *Id*. Cowlitz argues that these changes still pose "serious problems," and encourages BPA to take the additional steps for the recovery of the Lookback Amounts from the IOUs Cowlitz presented in its initial brief. *Id*. at 50-51. Cowlitz asserts that changes are essential given that, under certain assumptions, the Lookback Amounts could be substantially larger. *Id*. at 51.

In their Brief on Exceptions, the IOUs argue that BPA's revised proposal violates the goals outlined by Staff in BPA's initial proposal. IOU Br. Ex., WP-07-R-JP6-01, at 15-16. The IOUs claim that BPA's revised proposal results in an unreasonable reduction in REP benefits, and is arbitrary and capricious. *Id.* The IOUs also argue that BPA should recover the Lookback Amounts over the 20-year term of the Regional Dialogue contracts. *Id.* at 16.

<u>BPA Staff's Position</u>

Based on the policy direction provided in Bliven, *et al.*, WP-07-E-BPA-52, at 21-22, BPA Staff proposed to return the Lookback Amount to the COUs over 20 years or less, beginning in FY 2009. Bliven, *et al.*, WP-07-E-BPA-52, at 21-22; Marks, *et al.*, WP-07-E-BPA-62, at 18. Future amounts to be applied against each IOU's Lookback Amount would be decided in each future rate period and recovered from future IOU REP benefits. Bliven, *et al.*, WP-07-E-BPA-52, at 18, 21. These amounts would then be returned to the COUs through the resulting lower PF Preference rates. *Id*.

<u>Evaluation of Positions</u>

A. Staff's Supplemental Proposal

Staff had seven key objectives when constructing its approach to recovering and returning Lookback Amounts. First, the approach must be consistent with law and consistent with the Court's rulings. Bliven, *et al.*, WP-07-E-BPA-52, at 21. Second, the approach must be reasonable given the circumstances. *Id*. Third, the approach should, to the extent possible, recover the Lookback Amounts from the IOUs and return them to the COUs over a reasonable period of time. *Id*. Fourth, timely recovery of Lookback Amounts should also allow a reasonable level of REP benefits to residential and small farm consumers of the IOUs if, in fact, such benefits are owed. *Id*. Fifth, the approach should reflect the fact that key factors impacting future REP benefits, including IOU and BPA costs, load growth, regulatory and environmental policies, and other factors, cannot be forecast with precision. *Id*. Sixth, stability and predictability of REP benefits to IOUs and of REP costs borne by COUs is a laudable and appropriate policy objective, but this objective should be pursued in light of the uncertainties and practical limitations noted previously. *Id*. Seventh, the approach should, to the extent possible, reflect the perspectives and input of BPA's customers and other regional stakeholders. *Id*. at 21-22.

With these objectives in mind, Staff proposed to return the overcharges to the COUs as follows:

- BPA would provide the COUs with up-front cash payments of the difference between REP settlement benefits collected in rates and the amounts of reconstructed REP benefits the IOUs would have received;

- The remaining overcharges would be returned to all of the COUs through future rate reductions;

- The rate reductions would be funded by reduced payments of future REP benefits to the IOUs in an amount determined by the Administrator in each rate case;

- BPA would reduce future REP benefits with the objective of returning the remaining Lookback Amounts to the COUs within 20 years or less; and

- For FY 2009, Staff proposed to limit the REP benefits to $202.3 million, using the excess above this amount ($38.7 million) as a setoff to the Lookback Amount.

While Staff considered this approach as one viable method of returning the Lookback Amounts, it was not the only means of meeting the objectives described above. Staff welcomed other approaches to its proposal, and encouraged the parties to present other alternatives. Bliven, *et al.*, WP-07-E-BPA-52, at 26.

B. Parties' Positions and BPA's Revised Approach

The WUTC, APAC, WPAG, Cowlitz, and PPC all charge that the 20-year term for repayment is too long and must be modified. *Id*. WUTC Br., WP-07-B-WU-01, at 12-13; APAC Br., WP-07-B-AP-01, at 5-15; WPAG Br., WP-07-B-WA-01, at 33-34; Cowlitz Br., WP-07-CO-01, at 71-78; PPC Br., WP-07-B-JP25-01, at 40-41. APAC, WPAG, Cowlitz, and the PPC also claim that BPA's proposal provides virtually no certainty to the COUs that the Lookback Amounts will ever be repaid in full. APAC Br., WP-07-B-AP-01, at 5-15; WPAG Br., WP-07-B-WA-01, at 33-34; Cowlitz Br., WP-07-CO-01, at 71-78; PPC Br., WP-07-B-JP25-01, at 40-41; Cowlitz Br. Ex., WP-07-R-CO-01, at 50-51. As an alternative, several parties recommend that the time period for returning the Lookback Amounts be no greater than the period for which the REP Settlement Agreement payments were originally made; that is, seven years. WPAG Br., WP-07-B-WA-01, at 34; APAC Br., WP-07-B-AP-01, at 11-12. APAC also commented that BPA should adjust its proposal so that payments would be made to preference customers in proportion to their original overcharges. APAC Br., WP-07-B-AP-01, at 14-15.

The parties generally encouraged BPA to consider these and other revisions that accelerate both the amounts and timing for returning the Lookback Amounts to the COUs. In its Brief on Exceptions, Cowlitz stated that BPA should recover promptly the Lookback Amounts from the IOUs using the steps outlined by Cowlitz in its initial brief. Cowlitz Br. Ex., WP-07-R-CO-01, at 51.

After reviewing the arguments and concerns of the parties in this proceeding, BPA concurs that certain revisions to Staff's proposed approach to returning the overcharges are warranted. In response to the parties' arguments, BPA adopts the following approach for return of the IOUs' overcharges:

- BPA will return the FY 2007-2008 overcharges by providing the COUs with up-front cash payments from funds collected in rates but not paid to the IOUs for FY 2007-2008. BPA has advanced $170.9 million of this amount already to those COUs that signed Standstill and Interim Relief Payments Agreements. *See* Section 9.6 below;

- BPA will return the FY 2002-2007 overcharges to the COUs that paid the PF-02 preference rates through *individual bill credits*;

- These bill credits will be funded by reducing future REP benefits owed to the IOUs by an amount determined by the Administrator in each rate case;

- BPA will reduce future REP benefits with the objective of returning the remaining Lookback Amounts to the COUs within seven years (by the end of FY 2015); *provided*, *however*, for FY 2009 the amount of REP benefits provided to any IOU will not fall below 50 percent of the REP benefit amount otherwise due. The 50 percent limitation will be subject to reconsideration in future rate proceedings;

- For FY 2008, as explained in Section 9.6 below, BPA will apply a portion of REP benefits due to the IOUs to their Lookback Amounts;

- For FY 2009, BPA will establish a fixed amount of REP benefits due to apply to the IOUs' Lookback Amounts and send these funds to the COUs as credits on their power bills;

- Finally, BPA is open to alternative payment arrangements with the IOUs for recovery of their Lookback Amounts in less than seven years.

As discussed in detail in Section 9.5, BPA will return the Lookback Amounts to the COUs who paid the PF-02 Preference rates through a credit on their power bills rather than through a lower PF rate. This adjustment should ensure that Lookback Amounts are returned to the COUs that were injured by the overcharges.

BPA will also change the goal of returning the Lookback Amounts from 20 years or less to seven years. The seven-year goal reflects BPA's objective of returning the Lookback Amounts to the

COUs in the same amount of time during which the overcharges were incurred and responds to arguments made by several parties. WPAG Br., WP-07-WA-01, at 34; Cowlitz Br., WP-07-B-CO-01, at 73; APAC Br., WP-07-B-AP-01, at 12. BPA, however, believes that a minimal amount of lawfully due REP benefits should be provided to residential customers of the IOUs. For FY 2009, BPA believes that all IOUs should receive at least 50 percent of their lawfully due REP benefits. However, BPA notes that this is not a long-term commitment to delivering at least 50 percent of the REP benefits otherwise due an IOU. Rather, BPA could set REP benefits paid to less than 50 percent in future rate cases should it be necessary in order to accelerate the recovery of a utility's Lookback Amount.

Cowlitz objects to the 50 percent limit because it says that, as a result, PacifiCorp and Puget would not repay their Lookback obligation within the seven years. Cowlitz Br. Ex., WP-07-R-CO-01, at 50. Cowlitz further comments that apparently "BPA has no intention of recovering the excess payments to Idaho Power." *Id*. at 51. First, Cowlitz errs in claiming that Puget would not repay its Lookback within the seven-year goal. Under BPA's simplifying assumption of no change in REP benefits over time, Puget would most definitely repay its Lookback obligation. BPA believes that Cowlitz was perhaps referring to Avista , which under the same simple assumption of no change in REP benefits, would not repay its Lookback obligation until 2018. PacifiCorp, under the same assumption, would complete its repayment in 2020.

Cowlitz misconstrues BPA's decision. The seven-year repayment timeframe is a goal. In each subsequent rate proceeding, the Administrator will assess progress toward that goal, and potentially could relax the 50 percent lower limit in order to accelerate repayment of a particular IOU's Lookback Amount.

In addition, Avista had an outstanding deemer balance at the beginning of this rate proceeding. That balance is in dispute, and could be settled or resolved through litigation. Should that occur, as described in Section 8.11, BPA would recalculate Avista's Lookback Amount. It is unlikely that this recalculation would result in a larger Lookback Amount. Therefore, should settlement of Avista's deemer obligation occur, its likely that its Lookback obligation would be reduced, and repayment would occur more quickly.

Taken together, BPA believes this revised approach meets the objectives described in Bliven, *et al.*, WP-07-E-BPA-52, at 21-22, in a manner superior to Staff's proposal. As a general matter, it increases the pace of the return of the Lookback Amounts to the COUs. It does so by increasing the Lookback Amount returned to the COUs in FY 2009; returns a larger portion of the total Lookback Amounts to the COUs within seven years; and ensures that the overcharges are returned to the affected COUs. In addition to returning the Lookback Amounts to the COUs more quickly, this approach also has the added benefit of potentially continuing a minimal level of lawfully determined REP payments to the residential consumers of the IOUs. This overall approach allows BPA to meet its overarching policy objectives of returning the Lookback Amounts to the COUs in a reasonable time, while providing some level of lawfully determined REP benefits to the residential and small farm consumers of the IOUs.

The above described revisions also address concerns raised by the parties. By shortening the time period for repayment from 20 years to seven, BPA has addressed the primary timing concerns of Cowlitz, WPAG, PPC, and APAC. Also, by increasing the Lookback Amounts to be recovered and returned each year of the seven-year period, and targeting these refunds to the specific customer that were overcharged, BPA has mitigated the alleged "matching" problem noted by APAC. Further, reducing the time horizon for returning the Lookback Amounts will increase the amount of refunds to be distributed in each year, thereby reducing the intergenerational inequities identified by a number of parties. For these reasons, BPA finds this approach a more reasonable method to returning the Lookback Amounts.

C. Response to Parties' Other Arguments

While BPA believes the revised approach should address most of the concerns raised by the parties, BPA recognizes that certain issues will remain outstanding even after these adjustments are made. BPA addresses these latter issues below.

Cowlitz, WPAG, APAC, and PPC argue that BPA must provide "certainty" in the repayment of the Lookback Amounts to the COUs. Cowlitz Br., WP-07-B-CO-01, at 72-73; WPAG Br., WP-07-B-WA-01, at 33-34; APAC Br., WP-07-B-AP-01, at 11-12; PPC Br., WP-07-B-JP25-01, at 40. Cowlitz further argues that such repayment should also be prompt. Cowlitz Br. Ex., WP-07-R-CO-01, at 50-51. As discussed above, BPA believes its revised proposal includes sufficient features to ensure that the repayment of the Lookback Amount will occur over a reasonable period of time. These features include, for FY 2009, the decision to reduce REP benefits by no more than 50 percent to recover the Lookback Amounts from the IOUs. The Administrator will assess the progress toward repaying the Lookback Amounts within each rate proceeding. Forman, *et al.*, WP-07-E-BPA-76, at 120. If it is determined that the objective of returning the Lookback Amounts is not on track, the Administrator may decrease the level of REP benefits paid to the IOUs. Furthermore, the time horizon for returning the Lookback Amount is significantly less. Rather than a 20-year time horizon, BPA is proposing a seven-year time horizon. As discussed above, this change should result in a larger portion of the Lookback Amounts being returned to the COUs within a shorter period of time. Finally, BPA notes that it is providing a significant amount of up-front cash payments to the COUs. For one, BPA will return all of the overcharges for FY 2007-2008 to the COUs. Marks, *et al.*, WP-07-E-BPA-62, at 22-24; Forman, *et al.*, WP-07-E-BPA-76, at 107. These adjustments should mitigate the concerns with providing "certainty" in the repayment of the Lookback Amounts.

In its Brief on Exceptions, PPC concurs that BPA's revised proposal is reasonable, stating that BPA's decision to shorten the payment horizon to seven years "helps give greater certainty of recovery" of the Lookback Amounts to the COUs. PPC Br. Ex., WP-07-R-PP-01, at 24.

Cowlitz and WPAG argue that BPA should make a binding commitment to return the Lookback Amount in at most seven years. Cowlitz Br., WP-07-B-CO-01, at 72-73; WPAG Br., WP-07-B-WA-01, at 33-34. APAC similarly argues that the seven-year repayment period is only acceptable if it can assure payment within that time. APAC Br. Ex., WP-07-R-AP-01, at 3. This proposal must be rejected because it is self-defeating. BPA believes that the most appropriate approach is one that ties the return of funds to COU with the recovery of funds from the IOUs. While BPA has a reasonable degree of confidence that most, if not all, of the Lookback should be repaid within seven years, BPA cannot ensure that the future level of REP benefits will support a seven-year payback. If BPA commits to return the Lookback Amounts in seven years, but has not recovered the funds from the IOUs, BPA would be left in the position of paying Lookback Amounts to the COUs from financial reserves. As noted in Section 9.5, BPA would have to replenish these reserves through future rate increases to the COUs, which has the perverse effect of the COUs paying for their own refund. For this reason, then, BPA will not commit to an absolute seven-year repayment period.

WPAG, PPC, and APAC also argue that there is no guarantee after this proceeding that BPA will continue to reduce future REP benefits to return the Lookback Amounts. WPAG Br., WP-07-B-WA-01, at 33; PPC Br., WP-07-B-JP25-01, at 41; APAC Br., WP-07-B-AP-01, at 7-8; APAC, Br. Ex., WP-07-R-AP-01, at 3. These parties express concern that the Administrator will eliminate all future refunds of the Lookback Amount. BPA disagrees. First, BPA's approach is not without guidelines. As noted already, BPA has established a goal of returning the Lookback Amounts within seven years. This is a significantly shorter period than Staff proposed.

Second, even if BPA were to consider adopting a different payment approach in a subsequent rate proceeding, the COUs would have ample opportunity to challenge BPA's actions. BPA has stated that it intends to determine the reduction in REP benefits in each subsequent rate case. Forman, *et al.*, WP-07-E-BPA-76, at 109. In this context, there may be legitimate reasons to consider a different approach for recovering the Lookback Amounts that could either accelerate or decelerate the pace of repayment. Thus, it is correct that BPA will have some discretion in future rate proceedings to adjust the Lookback recovery terms to account for the circumstances of each case. However, this does not mean that the Administrator will have unbridled discretion. As with any issue presented in a rate proceeding, parties such as WPAG, PPC, Cowlitz, and APAC will be afforded an opportunity to bring evidence and arguments before the Administrator regarding BPA's proposals. If these parties believe BPA is departing from the policy goals and objectives described in this case, they can make arguments to that effect in the rate proceeding. BPA will ultimately respond to these arguments in its final decisions, and will be sustained only if supported by substantial evidence. In short, BPA's future discretion to return the Lookback Amounts is not without limits. It will be guided by the policy decisions made in this proceeding and subject to the evidentiary and legal requirements of a section 7(i) proceeding. Consequently, the argument by WPAG, PPC, and APAC that BPA's proposal is faulty because it only assures payment for FY 2009 is not persuasive.

Though noting BPA's revised approach is a "positive proposal," WPAG still maintains in its Brief on Exceptions that BPA's proposal is deficient in three areas. WPAG Br Ex., WP-07-R-WA-01, at 37-38. First, WPAG notes that the amount of the IOU repayment obligation is woefully understated due to BPA's failure to respond properly to the remand order in the *GNA* decision. WPAG Br. Ex., WP-07-R-WA-01, at 38. This observation, however, has nothing to do with whether or not BPA's proposal for returning the Lookback Amounts is reasonable. BPA has explained its rationale for calculating Lookback Amounts throughout this Record of Decision. WPAG obviously disagrees with BPA's decisions. Simply because WPAG believes that a larger Lookback Amount is due does not automatically mean BPA's method of returning the Lookback Amounts is defective. Thus, this first alleged "defect" is irrelevant.

Second, WPAG claims that even though BPA is increasing the amount of up-front cash payments and is shortening the time period for returning the Lookback Amounts, BPA's revised proposal is still defective because BPA could change its proposal in subsequent rate proceedings. WPAG Br. Ex., WP-07-R-WA-01, at 38. As discussed above, BPA's ability to change its proposal is not without limits. BPA will still have to establish its rationale for changing any feature of its approach in a rate proceeding. WPAG and other parties will continue to have opportunities to challenge BPA's decisions and present evidence in support of retaining the original proposal.

Third, WPAG asserts the shorter repayment period has come at the "the cost of a permanent three-fold increase in the REP costs preference customers will have to shoulder long after the seven-year repayment period has ended." WPAG Br. Ex., WP-07-R-WA-01, at 38. Again, this observation says nothing about whether BPA's method of returning the Lookback Amounts is defective. This comment is aimed at BPA's decisions with respect to the FY 2009 rate case assumptions. BPA explains in detail in later chapters its basis for the decisions that affect FY 2009 rates and REP benefit levels. As explained thoroughly in those sections, BPA's decisions are based on the law and the facts presented in this proceeding and are not connected to BPA's decision to increase or decrease the repayment period. WPAG's assertion that BPA's decision to shorten the period for returning the Lookback Amounts comes at the cost of higher future REP benefits is without merit.

APAC and Cowlitz object to BPA's approach of relying on future REP benefits as the source of funds for the Lookback Amounts. APAC Br., WP-07-B-AP-01, at 8-9; APAC, Br. Ex., WP-07-R-AP-01, at 3; Cowlitz Br. Ex., WP-07-R-CO-01, at 50. APAC contends that REP payments are volatile and can change as a result of either the section 7(b)(2) rate test or the filed ASCs of the IOUs. *Id*. Cowlitz contends this approach "poses serious problems," but does not clearly articulate such problems, other than by saying that the Lookback Amount could be much larger, and the future REP benefits much smaller, under a different set of decisions than those made by BPA. *Id*. at 51. BPA concurs that the level of REP benefits is likely to change in each rate proceeding. Forman, *et al.*, WP-07-E-BPA-76, at 119. The fact that this volatility exists, however, does not mean that BPA's approach is faulty. At this time, BPA believes with reasonable certainty that repayment of the Lookback Amounts will occur (with the exception of Idaho Power) in seven years, while also maintaining some level of REP benefits paid in those years. Further, in each rate case the Administrator will assess the likelihood of returning the Lookback Amounts in seven years. If, as APAC suggests, the level of REP benefits diminishes significantly as a result of the application of section 7(b)(2) or because of changes in the utility's ASCs, the Administrator has the responsibility to make adjustments to the schedule of payments for the remaining Lookback Amounts.

Cowlitz's observation that the Lookback Amounts or future REP benefits could be much larger has no bearing on whether or not BPA's approach for returning the Lookback Amounts is reasonable. BPA has explained throughout this Record of Decision its rationale for calculating Lookback Amounts and future REP benefits. Cowlitz obviously disagrees with several of BPA's decisions, and BPA has responded to Cowlitz's arguments elsewhere in this document in the appropriate chapters. BPA explains in detail in later chapters its basis for the decisions that affect FY 2009 REP benefit levels. As explained thoroughly in those sections, BPA's decisions are based on the law and the facts presented in this proceeding. It is not appropriate to reiterate those numerous debates here. It is sufficient to say that BPA's revised approach to recover the Lookback Amounts from the IOUs and return them to the COUs is reasonable and responsive to parties' arguments.

APAC also states that if ASCs do not remain high enough to result in a level of REP benefits that is sufficiently above the intended REP payout, then no repayment can take place under BPA's approach. APAC Br., WP-07-B-AP-01, at 8-9. APAC is mistaken. BPA is not committing to provide a rigid dollar limit on the amount of REP benefits to the IOUs. Forman, *et al.*, WP-07-E-BPA-76, at 120. Furthermore, BPA's modified approach as described above allows the Administrator to adjust the level of refunds to correspond with the objective of returning the Lookback Amounts within seven years. The Administrator may determine in a subsequent rate proceeding that an IOU's REP benefits should be reduced below 50 percent in order to ensure recovery of the Lookback Amount in seven years. The amount of refunds provided in any one year, consequently, will not be only the amount that is in "excess" of any amount BPA is proposing to provide in FY 2009.

APAC argues BPA is committing to pay the IOUs' REP benefits "first" and then using any excess funds for reducing the Lookback Amounts. APAC Br., WP-07-B-AP-01, at 7-8. According to APAC, this alleged treatment places the COUs in the same risky position as equity shareholders. *Id*. at 10. APAC asserts that this result is unreasonable, and that for reasons of both law and equity, the more appropriate result would be to prioritize repayment of preference customers ahead of exchange benefits. *Id*. APAC's objections are mistaken. As noted above, BPA is not creating a certain minimum amount of REP benefits paid to the IOUs for future rate periods. Rather, BPA's objective is to repay the Lookback Amounts in seven years, depending upon the particular circumstances of each rate proceeding. If it becomes apparent that the Lookback Amounts will not be paid off within seven years, BPA has the ability to reduce further the REP benefits paid to the IOUs to ensure repayment.

Next, APAC argues that BPA's approach violates the principle that refunds be directed at those harmed by the overcharges, otherwise known as the "matching principle." APAC Br., WP-07-B-AP-01, at 13. BPA has already addressed this issue earlier in this chapter. Nevertheless, BPA notes further here that reducing the target date for refunds from 20 years to seven years mitigates the "matching" concerns raised by APAC. Furthermore, while seven years may not constitute an "immediate" return of the overcharges, it is far more immediate than 20 years, and it has the advantage of matching the time period of the original offending overcharges.

In its Brief on Exceptions, APAC argues that the COUs will be justly repaid if the payments are made "quickly," "repaid to the customers that overpaid them" and include a "reasonable interest rate." APAC Br. Ex., WP-07-R-AP-01, at 3. APAC claims that BPA's revised approach still does not meet these objectives. *Id.* APAC is incorrect. While BPA does not grant that these objectives are the only considerations in this case, the revised proposal squarely meets APAC's criteria. First, BPA's proposal has been modified to "quicken" the repayment from up to a 20-year term, as originally proposed, to a goal of repaying the COUs in seven years. This is the same time period over which the overcharges were incurred, and was advocated by several parties, including APAC. APAC Br., WP-07-B-AP-01, at 11-12. BPA's revised approach, therefore, meets APAC's first objective. Second, BPA has revised its proposal to ensure that the COUs who paid the unlawful rates receive the credits from refunds. This adjustment addresses APAC's second objective. Third, BPA is proposing to apply interest to the outstanding Lookback Amount balance. As discussed in Section 8.10.2, BPA will apply a Treasury Bill rate of interest. For the reasons discussed in that section, a Treasury Bill rate appropriately preserves the value of the Lookback Amounts for the COUs. In short, BPA's revised approach meets the three objectives outlined by APAC in its brief. APAC's claim that BPA's proposal does not accomplish these objectives is simply wrong.

In its Brief on Exceptions, APAC also asks for a clarification of BPA's proposal to return the Lookback Amounts to the customers that were overcharged. APAC Br. Ex., WP-07-R-AP-01, at 4. Specifically, APAC requests that BPA explain what would happen if the amount of the credit is greater than the amount of the current monthly bill. *Id.* APAC suggests that in such case, the customer should receive a cash payment of the balance from BPA. *Id.* BPA agrees with APAC's request. If the amount of credit is greater than the amount of the current monthly bill, then BPA will disburse the amount BPA owes the customer through an Electronic Funds Transfer (EFT) (or other means in the rare instance that EFT is not possible). The disbursement will be made based on BPA's then-current billing procedures for issuance of "credit bills."

Cowlitz notes that the Supreme Court has opined that "where refunds are found due," it is the duty of the rate-setting agency "to direct their payment at the earliest possible moment consistent with due process." Cowlitz Br., WP-07-B-CO-01, at 72-73, *citing United Gas*, 382 U.S. at 230. As described above, BPA's revised approach meets this objective because it proposes to return the Lookback Amounts to the COUs in seven years.

Cowlitz also objects to BPA's approach of reducing future REP benefits as the source of funds for the Lookback Amounts. Cowlitz Br., WP-07-B-CO-01, at 73-74; Cowlitz Br. Ex., WP-07-R-CO-01, at 50. Instead, Cowlitz argues that BPA should bring legal action against the IOUs to ensure that the full Lookback Amount payments can be recovered. Cowlitz Br., WP-07-B-CO-01, at 73-74. As support, Cowlitz cites to BPA's general obligation to recover claims and debts promptly. *Id.*; *see also* 31 C.F.R. § 901.1(a). Cowlitz reiterates its support for such actions in its Brief on Exceptions. Cowlitz Br. Ex., WP-07-R-CO-01, at 51.

BPA's revised approach meets this obligation because BPA will have recovered most, if not all, of the Lookback Amounts within seven years (not accounting for Idaho Power). Thus, BPA's revised approach is "promptly" returning the overpayments to BPA. Furthermore, the regulations that Cowlitz cites are clear that BPA has discretion to adopt any number of ways of recovering debts from a party. *See* 31 C.F.R. § 900.1(c) ("[A]gencies are not limited to the remedies contained in parts 900-904 of this chapter and are encouraged to use all authorized remedies… The regulations in this chapter are not intended to impair agencies' common law rights to collect debts.") Here, BPA has determined that best way of recovering the Lookback Amounts from the IOUs is to set off future REP benefits. BPA considers this approach more reasonable, practical, and effective than initiating claims against the IOUs in court. Cowlitz fails to cite to any case or law that would require BPA to adopt one collection effort over another. In this instance, for the reasons described earlier, reducing future REP benefits is the most reasonable approach.

Cowlitz argues that BPA's approach does not address the issue of Idaho Power, which under BPA's own assumptions is unlikely to be entitled to any future REP benefits. Cowlitz Br., WP-07-B-CO-01, at 77-78; Cowlitz Br. Ex., WP-07-R-CO-01, at 50-51. Cowlitz argues that no sound business reason can possibly be advanced for failing to collect funds due and owing to BPA, a failure patently inconsistent with BPA's duties under the cited statutes. Cowlitz Br., WP-07-B-CO-01, at 77-78. Cowlitz misstates BPA's approach. BPA is not allowing Idaho Power to retain its REP Settlement Agreement benefits without consequence. Rather, under BPA's simplified projections, Idaho Power does not repay its Lookback Amount within 20 years in part due to its significant deemer balance that is presently in dispute. Forman, *et al.*, WP-07-E-BPA-76, at 117-118. If an agreement is reached regarding the deemer balance, Idaho Power may at some future date qualify for REP benefits. *Id*. at 118. In such case, BPA will reduce Idaho Power's REP benefits in order to recover its Lookback Amounts. Thus, contrary to Cowlitz's statement, BPA is not ignoring Idaho Power's outstanding Lookback Amount. In any event, BPA is open to settlement discussions with Idaho Power regarding its deemer balance.

In their Brief on Exceptions, the IOUs claim that BPA's revised approach for the recovery of Lookback Amounts fails to meet all seven stated objectives in Bliven, *et al.,* WP-07-E-BPA-52, at 21-22. IOU Br. Ex., WP-07-R-JP6-01, at 15-16. The IOUs claim that the revised proposal does not permit a reasonable timeframe for recovery of Lookback Amounts, does not permit a reasonable level of benefits for residential and small farm customers of the Pacific Northwest IOUs, and does not promote stability and predictability. *Id.*

The IOUs' criticism is misplaced. The revised approach meets all of BPA's identified objectives in a manner superior to BPA's original proposal. First, as described in Section 9.3.1, BPA has the legal authority to recover the Lookback Amounts from the IOUs through reduced REP payments. Thus, BPA's first objective is still being met.

Second, BPA's revised approach still accounts for the unique circumstances that led to the overpayments. Instead of requiring the IOUs to make cash payments up-front, BPA has a goal of reducing future REP benefits for a period of seven years in order to return the overcharges to the COUs. This meets BPA's second objective to develop a reasonable approach, given the circumstances.

Third, the revised approach allows for a reasonable timeframe for recovery of the Lookback Amounts. To be clear, BPA is not setting a hard and fast rule that within seven years all of the Lookback Amounts will be returned. Rather, BPA is revising its goal of returning the Lookback Amounts from up to twenty years to seven. As noted above, the goal of returning the Lookback within seven years may change as a result of the particular circumstances and evidence presented in a future rate case. For now, though, BPA notes that its decision to adopt the seven-year goal is heavily influenced by the arguments of APAC, WPAG, and Cowlitz that persuasively note that the return of the Lookback Amounts should correspond as closely as possible to the period over which the overcharges occurred. BPA believes that this approach makes sense. Additionally, this approach is reasonable because it shortens the time period that REP benefits are likely to be reduced for the IOUs and quickens the return of the refunds to the COUs. BPA also found persuasive the arguments by some parties that a payout stretched to as many as 20 years was too long a period for returning the refunds to the COUs. Finally, while not dispositive, the shorter time period mitigates the intergeneration equity issues raised by several parties. APAC Br., WP-07-B-AP-01, at 12; WUTC Br., WP-07-B-WU-01, at 8. For these reasons, changing the time period for payment from up to 20 years to seven years meets BPA's objective of recovering the Lookback Amounts within a reasonable amount of time.

Fourth, the revised approach allows for the IOUs to receive a reasonable level of benefits to pass on to their residential and small farm consumers. It must be noted that even under the initial proposal BPA never guaranteed that the IOUs would be entitled to a reasonable level of benefits. Rather, BPA's stated goal was to allow for a reasonable amount REP benefits "if, in fact, such benefits are owed." Bliven, *et al*., WP-07-E-BPA-52, at 21. BPA stated that it would determine the level of REP benefits to apply against the Lookback in each rate proceeding. Marks, *et al*., WP-07-E-BPA-62, at 18. Thus, the IOUs' REP benefits could have been completely eliminated in order to pay back the Lookback Amounts under BPA's initial proposal. It would be up to the IOUs and other parties to debate in subsequent rate cases the meaning of a "reasonable" amount of REP benefits. BPA has decided to continue determining the amount of future reductions in each IOU's REP benefits within a section 7(i) proceeding. Consequently, the IOUs will continue to retain the right to argue in BPA rate proceedings for a reasonable level of REP benefits.

On this point, BPA also notes that, for FY 2009, BPA is proposing to apply a 50% limit on the amount of REP benefits used to reduce the Lookback. While this limit only applies for FY 2009, it is further evidence that BPA's proposal does not arbitrarily eliminate the REP benefits due the IOUs' residential customers. Thus, BPA's revised approach does not violate the objective to allow for a reasonable level of REP benefits, if such REP benefits are owed.

Fifth, shortening the time period for repayment also is more consistent with BPA's fifth objective, which states "the approach should reflect the fact that key factors impacting future REP benefits, including IOU and BPA costs, load growth, regulatory and environmental policies and other factors cannot be forecast with precision." Bliven, *et al.,* WP-07-E-BPA-52, at 21. Since the amount of future REP benefits applied to the Lookback Amounts is to be determined in future rate cases, each Administrator has the flexibility to match the repayment amount to the then-current level of REP benefits, while also accomplishing the seven year goal of a full recovery, where possible.

Sixth, the revised approach promotes the objective of stability and predictability of REP benefits and their costs, as borne by COUs. The seven-year payment objective shortens the time period to amortize the Lookback Amounts. This shortened period increases stability in the amount of Lookback that is applied in each rate case. REP benefits are determined by a number of factors that can and will change over time, and these changes will be captured in future rate cases. These factors are likely to change more over a longer time horizon than a shorter one because the longer the horizon, the more opportunity for changes in factors such as loads, resource additions and so forth. As such, any predictions of REP benefits in a future decade (as under the previous proposal) are by their nature more speculative and uncertain than predictions of what the level of REP benefits will be in just seven years. All else equal, the chances that the Lookback Amounts will be amortized in a more stable and predictable fashion is therefore greater in the revised approach. This predictability should, in turn, translate into more stability for the IOUs when they set rates with their respective commissions. BPA's revised approach, therefore, satisfies this objective very well.

Seventh, BPA's revised approach reflects the perspectives and input of parties. As described above, BPA received a substantial amount of input from parties in this proceeding on the proposed payback period. Though the parties presented varying viewpoints, there was general support among preference customers that the repayment term should correspond to the period over which the overcharges were incurred. BPA considered these positions and agrees that returning the Lookback Amounts in seven years, where possible, is reasonable and fair.

In short, BPA's revised approach meets the seven objectives outlined by Staff in its initial proposal. The IOUs' argument that BPA has failed to meet these criteria, therefore, must be rejected. One final point must be made on this topic. Under *both* the revised and original approach, any outstanding Lookback Amounts would earn interest. A segment of the IOUs has argued vehemently in this proceeding about the alleged inequities of the deemer balance. *See* IPUC Br., WP-07-B-ID-01, at 14; IOU Br., WP-07-B-JP6-01, at 184. These parties argue that a significant portion of the existing deemer balance is a result of interest that has accrued over the past 20 years, and that current customers should not be burdened with these obligations today. *See* Westerfield, WP-07-E-ID-1, at 18-19; IPUC Br., WP-07-B-ID-01, at 16-17. While BPA does not intend to address the merits of these arguments in this case, BPA is acutely aware that similar arguments may be made in yet another 20 years regarding the Lookback Amounts. By shortening the time period for repayment of the Lookback Amounts, the potential for the Lookback Amounts to grow quickly due to accumulating interest, thereby inappropriately burdening future generations of ratepayers, is greatly diminished. BPA's revised approach is therefore reasonable.

The IOUs claim in general that BPA's revised approach inappropriately diminishes the amount of REP benefits available for Pacific Northwest IOUs' residential and small farm customers during the recovery period and, therefore, is fundamentally unfair and inequitable. IOU Br. Ex., WP-07-R-JP6-01, at 16. The IOUs assert that the revised approach would unreasonably, and arbitrarily and capriciously, affect the REP benefit payments for customers of Pacific Northwest IOUs. *Id.* BPA disagrees that its revised approach inappropriately diminishes the level of REP benefits due the IOUs' residential customers. Regardless of whether BPA had adopted the revised approach or retained its original approach, the IOUs' REP benefits would have been reduced to recover the Lookback Amounts. Thus, the fact that BPA's revised proposal "impacts" the REP benefits that the IOUs' residential customers receive does not make BPA's proposal arbitrary or capricious. Moreover, as noted above, the level of REP benefits used to apply against the Lookback Amount will be determined in each rate proceeding. In this case, BPA has determined that a 50 percent rule should apply, and has proposed to allow the IOUs to retain no less than 50 percent of the REP benefits. The IOUs have not objected to this feature of the revised approach. This rule could be applied in a similar way in a future rate case, depending on the record, and whether an IOU would likely pay off its Lookback Amounts in seven years. BPA's decision to allow these issues to be addressed in future rate proceedings is not in any way arbitrary or capricious.

The IOUs argue that to ameliorate the impact on residential and small farm customers, BPA should recover Lookback Amounts over a period equal to the duration of the new Regional Dialogue contracts (*i.e.,* 20 years) and fund the difference in cash flows with BPA's financial reserves. IOU Br. Ex., WP-07-R-JP6-01, at 16. This suggestion is misguided. BPA has *never* proposed that the term of the repayment of the Lookback Amount be coterminous with the Regional Dialogue contracts. BPA's original proposal provided that the term of repayment could be "twenty-years *or less.*" Bliven, *et al*., WP-07-E-BPA-52, at 21, emphasis added. Under BPA's rough calculations, it was expected that certain IOUs would pay off their Lookback Amounts sooner than others, with the 20 year mark being the end of the repayment spectrum. *See* FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 207. BPA can find no basis in the record for moving now to the fixed term of the 20-year Regional Dialogue contracts as the basis for the repayment period for the Lookback Amounts. Moreover, the IOUs provide no rationale in their brief as to why connecting the term of the Regional Dialogue contracts with the term for repaying the Lookback Amounts is reasonable. Consequently, the IOUs' request that BPA fix the term of repayment to 20 years is rejected.

The IOUs also suggest that BPA use it reserves to fund part of the Lookback Amounts. As discussed in Section 9.3.3, Issue 2, using reserves to pay the Lookback Amounts to the COUs is self-defeating because it causes the COUs' rates to subsequently increase. Under this approach, the COUs are, in effect, paying for their own refunds. BPA rejects this approach in Section 9.3.3., and rejects it here as well.

<u>Decision</u>

BPA adopts the revised approach described above for recovering the overpayments to the IOUs and returning them to the COUs. The revised approach provides adequate certainty and addresses the primary concerns raised by the parties with respect to the return of the overcharges by focusing on returning the overcharges in seven years, where possible. The revised approach also achieves BPA's stated objectives of returning the Lookback Amounts within a reasonable time to the COUs, while allowing for a reasonable level of REP benefits. Finally, BPA clarifies that if the amount of bill credit exceeds the amount of the current monthly bill, then BPA will disburse the amount BPA owes the customer through an Electronic Funds Transfer (EFT) payment or other means in the rare instance that EFT is not possible.

<u>Issue 2</u>

Whether BPA's approach of providing some level of legally justifiable REP benefits to the IOUs for their residential consumers is improper.

<u>Parties' Positions</u>

APAC argues that Staff's proposal to recover and return the Lookback Amounts inappropriately puts payment of REP benefits to the IOUs before BPA's responsibility to return the overcharges to the COUs. APAC Br., WP-07-B-AP-01, at 10.

BPA Staff's Position

BPA Staff's proposal to recover the Lookback Amounts through a reduction of future REP benefits over 20 years or less does not represent an improper priority of payments. Forman, *et al.*, WP-07-E-BPA-76, at 112. Rather, this approach to recovery of the Lookback Amounts represents a flexible approach that can respond to an uncertain future and maintain a reasonable balance between the competing goals of returning the overcharges to the COUs in a reasonable time frame and maintaining a reasonable level of REP benefits for the residential and small farm consumers of the region's IOUs. Forman, *et al.*, WP-07-E-BPA-76, at 119.

Evaluation of Positions

APAC claims that the alleged uncertainty around the future repayment of overcharges to the COUs stems from the fact that Staff's proposal includes an inappropriate priority of payment. APAC Br., WP-07-B-AP-01, at 10. According to APAC, this improper priority occurs because Staff proposes to maintain a stream of REP benefits paid to the IOUs, which will be passed on to their residential and small farm consumers prior to returning the full Lookback Amount to the COUs. *Id*. APAC argues that BPA should provide no REP benefits to the IOUs' residential and small farm consumers until the Lookback Amounts are recovered and returned to the COUs. *Id*.

While BPA understands the concerns APAC raises, BPA does not agree that eliminating all REP benefits to return the Lookback Amounts is reasonable. First, BPA must correct an error in APAC's characterization of Staff's proposal. APAC incorrectly states that Staff's proposal is to provide "the repayment of Preference Customer overcharges contingent on first providing the IOUs with some 'reasonable level' of REP benefits." APAC Br., WP-07-B-AP-01, at 10. This was not Staff's proposal. Rather, Staff's proposal was to balance several objectives, as articulated in Bliven, *et al.*, WP-07-E-BPA-52, at 21-22, while also committing to recover and return as much of the Lookback Amounts as possible within 20 years or less (now seven years). Forman, *et al.*, WP-07-E-BPA-76, at 115.

Indeed, it is one of BPA's key priorities to adopt a construct that will return the Lookback Amounts to the COUs in a reasonable amount of time through reductions in future REP benefits. *Id*. at 112. As noted earlier, BPA has considered and accepted APAC's concerns that the time horizon for these payments in Staff's proposal was too broad, and modified BPA's approach to return the Lookback Amounts within seven years, provided that the REP benefits for any one IOU are not reduced below 50 percent for FY 2009. This adjustment to a seven year repayment period is evidence of BPA's commitment to returning the Lookback Amounts to the COUs.

Second, as a matter of equity, BPA believes that it is appropriate to provide some level of legally determined REP benefits to the residential consumers of the IOUs. BPA recognizes that the COUs have been overcharged for REP benefits and now must receive refunds. As Staff has stated throughout this proceeding, BPA is committed to returning those funds to the COUs within a reasonable time. Bliven, *et al.*, WP-07-E-BPA-52, at 21. Returning these funds to the COUs is crucial to responding to the Court's remand in *Golden NW* and to the general policy of undoing the harm caused by BPA's legal error. However, BPA must balance its responsibility to return these funds against its statutory duty to implement the Residential Exchange Program. There can be little dispute that the REP is a key feature of the Northwest Power Act. It is the only means by which residential consumers of the IOUs receive a benefit from the federally owned and operated hydroelectric dams. Congress bestowed upon the Administrator the duty to implement the REP in accordance with the provisions of the Northwest Power Act, including specifically sections 5(c) and 7(b)(2). 16 U.S.C. §§ 839c(c), 839e(b)(2). As noted by the Court in *PGE*, for the past seven years BPA has failed to implement these provisions, thereby thwarting Congress's intent with the REP. *PGE*, 501 F.3d 1009, 1036-37 (9th Cir. 2007). To remedy this harm, BPA does not believe it reasonable or necessary to go to the other extreme and effectively eliminate the REP for the next seven years or more.

Further, BPA believes it has latitude under the law to fashion a remedy that cures the harm to the COUs without abandoning its statutory duty to implement the REP. For this, BPA draws upon the well-founded principle of law that when fashioning a remedy, an agency may weigh consequences and balance interests to achieve a result that is both fair and equitable. *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 160 (D.C. Cir. 1967); *see also Consumer Federation of America et al., v. Federal Power Commission*, 515 F.2d 347, 359 (D.C. Cir. 1975) (in matters of prospective and retroactive effect, there are large questions of equity and public interest, both for agencies and for courts). In the instant case, BPA's approach properly balances the interest of the COUs and the residential consumers of the IOUs. On the one side, BPA's approach returns a significant amount of funds to the COUs within a short period of time. First, BPA's approach offers short-term relief in the form of immediate cash payments to the COUs for the return of the FY 2007-2008 overcharges. *See* Section 9.6. BPA's approach also provides long-term relief in the form of future credits on COUs' power bills to return overcharges that are recovered from the IOUs through reduced REP benefits. BPA believes these features of its recovery approach adequately address its duty to return the Lookback Amounts to the COUs within a reasonable time period.

On the other side, BPA's approach allows for some amount of REP benefits to the residential consumers of the IOUs in accordance with the Northwest Power Act. This potential minimal payment of lawful REP benefits mitigates the impact to the current residential consumers of the IOUs who may or may not have received the benefits of the REP Settlement Agreements. This approach also recognizes equity in that it is not the fault of the current residential and small farm consumers that BPA and their serving utilities entered into now-invalid agreements. Taking these considerations together, BPA finds that this approach strikes the proper balance between its duty to return overcharges to the harmed COUs and its duty to implement the REP in accordance with the Northwest Power Act and fundamental principles of fairness and equity.

Decision

BPA's approach of providing some level of legally justifiable REP benefits to the IOUs for their residential consumers is not improper. Rather, the approach for recovery and return of Lookback Amounts presents a reasonable balance between the interests of the COUs and the residential consumers of the IOUs and does not represent an improper priority of payments.

9.3.3 Method of Returning Lookback Amounts to COUs

Issue 1

Whether BPA should return the FY 2002-2006 overcharges to the COUs to all preference customers through a reduction in future PF Preference rates.

Parties' Positions

APAC favors a targeted return of the FY 2002-2006 overcharges to the COUs in proportion to their original overcharges. APAC Br., WP-07-B-01, at 14-15. APAC proposed that such a return can be accomplished by calculating each utility's percentages of actual preference loads for FY 2002-2007 as a basis for establishing each COU's proportion of the overcharges to be returned. Wolverton, WP-07-E-AP-01, at 86.

Cowlitz favors an approach that ensures that the overcollected funds are returned to those COUs that made the overpayments, rather than to preference customers whose rates for purchases from BPA may have been unaffected by the REP settlement costs. Cowlitz Br., WP-07-B-CO-01, at 75. Cowlitz proposes that the return of overcharges should be targeted to those customers that were harmed by BPA's rate treatment of the REP settlements. *Id.* at 76.

In contrast, Central Lincoln objects to the APAC proposal and supports Staff's original proposal. Central Lincoln Br., WP-07-B-CL-01, at 5-10.

The OPUC argues that BPA would violate the Northwest Power Act by reducing future PF Preference rates to return an overcharge because, by definition, such a rate would not recover BPA's costs properly. OPUC Br., WP-07-B-PU-02, at 2-3.

BPA Staff's Position

BPA Staff proposed that the return of the overcharges captured in the Lookback Amount for FY 2002-2006 would be most simply accomplished through reductions in the FY 2009 and future PF Preference rates. Marks, *et al.*, WP-07-E-BPA-62, at 22. Staff expressed a willingness to consider alternative approaches. Bliven, *et al.*, WP-07-E-BPA-52, at 11. In rebuttal, Staff proposed an alternative that targeted the return of Lookback Amounts to those customers who paid the overcharges in the PF-02 rates as represented by each COU's share of total PF Preference rate revenues collected during the Lookback period. Forman, *et al.*, WP-07-E-BPA-76, at 125.

Evaluation of Positions

Staff indicated that the simplest approach to returning the overcharges for FY 2002-2007 to the COUs would be through future reductions in the PF Preference rates for both Slice and non-Slice customers beginning in FY 2009. Marks, *et al.*, WP-07-E-BPA-62, at 22. Using this approach, COUs would pay lower rates than they otherwise would face, reflecting the return of the

Lookback Amounts. There would be no distinction between those COUs who paid the PF-02 rates and those that pay the PF-07R rate and subsequent PF rates.

APAC suggested a targeted return of the Lookback Amount to the COUs in proportion to their original overcharges. APAC Br., WP-07-B-01, at 15. APAC proposed that such a return can be accomplished by calculating each utility's percentage of total actual PF rate loads for FY 2002-2007 as a basis for establishing each COU's proportion of the overcharges to be returned. Wolverton, WP-07-E-AP-01, at 86.

Central Lincoln supports Staff's original proposal and objects to the APAC proposal. Central Lincoln Br., WP-07-B-CL-01, at 5-10. First, Central Lincoln claims that APAC mischaracterizes pre-Subscription contracts and that no evidence exists to support the contention that overpayments to the IOUs were covered by the various cost recovery adjustment mechanisms. *Id*. at 5-6. Second, Central Lincoln argues that APAC's proposal is unlawful because it would require BPA to establish two PF Preference rates, which would be a violation of the Northwest Power Act. *Id*. at 6-7. Third, Central Lincoln states that if BPA were to implement APAC's proposed methodology, BPA would be in breach of Central Lincoln's pre-Subscription and Subscription contracts, which would expose BPA to additional prolonged litigation. *Id*. at 7-8. Finally, Central Lincoln claims that APAC's proposal is not consistent with BPA policy direction, as it would place an unreasonable administrative burden on BPA. *Id*. at 8-10.

APAC pointed out that Staff's proposal did not return the Lookback Amount to those customers that suffered the harm created by the inclusion of the REP settlement costs in the PF-02 rates. Wolverton, WP-07-E-AP-01, at 86. APAC's alternative approach would create a total amount owed to each COU that paid the PF-02 rate based on each customer's annual percentage of BPA's total preference customer load. *Id*.

On rebuttal, Staff proposed a variation to the approach that APAC suggested; instead of calculating amounts owed to each COU based on loads, the return of the Lookback Amounts could be based on each COU's percentage share of total PF-02 revenues paid during the FY 2002-2006 period. Forman, *et al.*, WP-07-E-BPA-76, at 125-126. Staff testified that this approach would more equitably return the Lookback Amount for the following reasons. First, the return would be targeted to those COUs who paid the PF-02 rates, thus excluding the purchases COUs made through pre-Subscription contracts that were at rates that did not include and recover the REP settlement costs. Second, using revenues instead of loads as a basis for establishing each COU's proportional share of the total Lookback Amount would be more equitable. *Id.* Using loads would not capture the fact that each utility "experiences" a different average rate from BPA based on its unique load shape and applicable monthly rates as well as any application of the Low Density Discount. BPA Staff noted that returning FY 2002-2006 overcharges to COUs based on revenues would be consistent with Staff's proposal for returning FY 2007-2008 overcharges. *Id.*

In Section 9.6, BPA addresses one issue raised regarding how FY 2007-2008 overcharges to Slice customers should be returned. BPA Staff believes that the arguments, evaluation, and decision regarding this matter apply equally to the return of FY 2001-2006 overcharges to Slice customers. Therefore BPA will adopt the same approach for determining the allocation of FY 2002-2006 overcharges among Slice customers that it adopts for the FY 2007-2008 period. Specifically, returns will be based on customers' Slice percentages rather that on the customers' shares of Slice PF revenues. BPA will ensure that Slice customers do not receive any additional payments for the return of Lookback Amounts for FY 2002-2006 through the Slice True-Up process.

Cowlitz asserted that it would not be fair to return Lookback monies to the pre-Subscription customers that did not pay the PF-02 rates in FY 2002-2006 because they were unaffected by the payments under the invalid REP settlements. Cowlitz Br., WP-07-B-CO-01, at 75-76. On rebuttal, Staff stated a similar desire to mitigate where practicable the return of overcharges to COUs that did not actually pay the overcharges. Forman, *et al.*, WP-07-E-BPA-76, at 124.

BPA is not persuaded by Central Lincoln's arguments. Central Lincoln's first argument that APAC has mischaracterized pre-Subscription contracts is flawed. As Central Lincoln admits, "the price term of [Central Lincoln's] pre-Subscription contract was fixed," while COUs exposed to the PF-02 rate were subject to the various cost recovery adjustment mechanisms that occurred during the FY 2002-2006 rate period. Central Lincoln Br., WP-07-B-CL-01, at 6. As stated above, if a COU was not subject to the inclusion of REP settlement costs in its rates, then it should not be allowed to enjoy the return of overcharges through its future rate.

BPA reads Central Lincoln's second and third arguments, *id*. at 6-8, as based on a misperception that APAC's proposed methodology would require BPA to develop two PF Preference rates; *i.e.*, one for pre-Subscription customers and one for those who purchased power under the PF-02 rates. Implementation of APAC's proposal does not require two PF Preference rates. Instead, return of the Lookback Amount would be a line item credit on each COU's power bill determined by the amount of the total credit and each COU's share of total PF-02 revenues. Whether one characterizes this as a rate, it is fully consistent with section 7. BPA is authorized to establish a rate or rates of general application under section 7(b)(1). The Slice and non-Slice rates are an example of this. In this case, section 7(g) is also appropriately brought into play as well. As indicated earlier, in the context of setting off each IOU's future REP benefits (which may be thought of as tantamount to surcharging the PF Exchange rate), it is equitable to allocate the credit from the recovery of the Lookback Amounts via REP benefit offsets to those who overpaid the cost in the first instance. This is fully consistent with the traditional ratemaking principle of cost causation, which in this instance might be more aptly referred to as credit causation.

Similarly, Central Lincoln's breach of contract claim relies on contract provisions that guarantee Central Lincoln the lowest PF rates through FY 2011. Central Lincoln Br., WP-07-B-CL-01, at 7-8. Implementing APAC's proposal and returning the Lookback Amount as a line item credit on each COU's power bill ensures that there is only one lowest PF Preference rate available to all preference customers.

Finally, Central Lincoln's claim that APAC's proposal is unreasonable because "it would create an administrative nightmare for BPA" reflects the Staff's concern that APAC's proposal "would involve considerable administrative work." *Id*. at 9; Forman, *et al.*, WP-07-E-BPA-76, at 124.

While APAC's proposal would require a significant amount of work on the front end to compile historical data and establish the COU-specific accounts, once this is done, the administrative burden should be minimal as compared to the benefit of ensuring that the return of overcollected funds goes to those COUs that made the overpayments.

The OPUC's contention that BPA would violate the Northwest Power Act by reducing future PF rates to return an overcharge because such a rate would not recover BPA's costs misconstrues Staff's original proposal. OPUC Br., WP-07-B-PU-02, at 2-3. To the contrary, Staff's proposal covers both sides of the coin, so to speak, such that cost recovery is occurring appropriately. Marks, *et al.*, WP-07-E-BPA-62, at 18-22. In Staff's Supplemental Proposal, future PF rates are reduced by exactly the same amount by which REP costs are reduced. *Id*. Thus, cost recovery would occur appropriately. Similarly, if BPA returns the Lookback Amount for any fiscal year to individual COUs as a line item credit on their power bills, BPA's power rates would be set to fully recover its costs. Under this approach, PF Preference rates would be established based on the lawful amount of IOU REP benefits. BPA would then withhold a portion of the REP benefits payments to IOUs, and return this withheld amount to COUs as a line item credit on eligible COU power bills.

Decision

For purchases at the PF-02 non-Slice rate, BPA will return the FY 2002-2006 overcharges based on a customer's share of total non-Slice PF-02 revenue. This amount will be returned as a credit on the COU's BPA power bill. For purchases at the PF-02 Slice rate, BPA will return the FY 2002-2006 overcharges based on a customer's Slice percentages. This amount will be returned as a credit on the COU's BPA power bill.

Issue 2

Whether BPA should use its reserves to fund the return of the overcharges to the COUs.

Parties' Positions

The WUTC suggests that BPA should use its reserves to speed up the repayment of the Lookback Amounts and thus mitigate the intergenerational issues presented by a 20-year repayment plan. WUTC Br., WP-07-B-WU-01, at 13.

The IOUs, assuming *arguendo* that a Lookback Amount exists, also suggest that payments from BPA's financial reserves available for risk offers an expedient method for returning the overcharges to the COUs. IOU Br., WP-07-B-JP6-01, at 182-183; IOU Br. Ex., WP-07-R-JP6-01, at 14-15.

Cowlitz suggests that "industry practice" would require prompt, lump sum recovery from the IOUs and a lump sum return to the COUs, perhaps from reserves. Cowlitz Br., WP-07-B-CO-01, at 73. APAC similarly argues that a lump sum payment would be "just and reasonable." APAC Br. Ex., WP-07-R-AP-01, at 3.

BPA Staff's Position

BPA Staff opposes using financial reserves as a source of funds for returning the Lookback Amounts to the COUs because it would result in future rate increases to the COUs, thereby effectively making the COUs pay for their own refund. Forman, *et al.*, WP-07-E-BPA-76, at 104-105, 108.

Evaluation of Positions

Several parties suggested that BPA should use its reserves to speed up the return of Lookback Amounts to the COUs by providing lump sum payments. WUTC Br., WP-07-B-WU-01, at 13; IOU Br., WP-07-B-JP6-01, at 182-183; IOU Br. Ex., WP-07-R-JP6-01, at 14-15; Cowlitz Br., WP-07-B-CO-01, at 73; APAC Br. Ex., WP-07-R-AP-01, at 3. Parties' proposals to provide refunds from BPA's reserves available for risk are not well grounded. BPA is an entity of the United States government and is required by statute to set rates to recover all of its costs. *See* 16 U.S.C. § 839e(a)(1). All costs (regardless of their source) must eventually be included and recovered through the cost-based rates charged to BPA's regional firm power customers, including preference customers. In general, if BPA were to make payments to the COUs from reserves available for risk, BPA would likely need to subsequently *increase* the COUs' rates to replenish such reserves, all else being equal. Bliven, *et al.*, WP-07-E-BPA-52, at 22; Forman *et al.*, WP-07-E-BPA-76, at 104-105. Payments out of reserves would likely result in higher rates to the COUs because the remaining reserves for risk would probably be too low to support BPA's Treasury Payment Probability (TPP) standard. Thus, Planned Net Revenues for Risk (PNRR) would need to be added to the revenue requirement, and the PF Preference rate would increase. The end result is that the use of reserves to pay Lookback Amounts would result in the COUs effectively paying for their own remedy through higher future rates, all else being equal.

Another complication of using reserves involves the Slice rate. Slice rates do not include PNRR, so distributions from reserves for risk as a form of lump sum Lookback compensation would need to be restricted to non-Slice rates. However, that would not be equitable to the non-Slice customers because the Slice customers would receive these lump sum payments. As a result, Slice customers should also cover any cost resulting from such a use of reserves. In that case, a very complicated system would have to be created to track how much future PNRR was required by the funding of Lookback Amounts from reserves so that the Slice customers could be charged appropriately.

Given these facts and complications, repayment of the full amount of COU overcharges in a lump sum payment as suggested by the IOUs, Cowlitz, and the WUTC would not be reasonable because the COUs would effectively be paying for their own remedy through future rate increases. Forman *et al.*, WP-07-E-BPA-76, at 107. BPA finds this result unreasonable and fundamentally inconsistent with the objective of returning the overcharges to the affected COUs.

It is true that Staff is proposing to return the overcharges for FY 2007-2008 in lump sum payments from reserves. Marks, *et al.*, WP-07-E-BPA-62, at 22-23. However, these payments are not from reserves available for risk. Normandeau, *et al.*, WP-07-E-BPA-73, at 5-6. The overcharges for FY 2007-2008 returned to the COUs in lump sums through the Interim Agreements and/or payments at the conclusion of the WP-07 Supplemental rate proceeding are funded by monies collected in rates subsequent to the Court's rulings in May 2007 when payments to the IOUs were suspended. Marks, *et al.*, WP-07-E-BPA-52, at 22-23. Any lump sum payments in amounts above these "surplus" funds would have the result already described of raising COUs' future rates, all else being equal. Bliven, *et al.*, WP-07-E-BPA-52, at 22.

The WUTC states that if BPA were to contribute a "significant portion of the total remedy from its reserves, preference agency rates could be lowered more quickly, and the 'remedy' period for the IOUs could be shortened, perhaps even to the 7 years recommended by APAC and Cowlitz/Clark." WUTC Br., WP-07-B-WU-01, at 13. BPA appreciates the WUTC's efforts to find ways to accelerate the return of overcharges to the COUs, but unfortunately, as described above, this approach would result in the COUs paying for their own refund. Forman, *et al.*, WP-07-E-BPQ-76, at 107.

Cowlitz suggests that Staff's proposal violates "industry practice," and that such standard practice requires that BPA recover the overpayments in lump sums from the IOUs and return them to the COUs, also in lump sums. Cowlitz Br., WP-07-B-CO-01, at 73. BPA finds this argument unpersuasive. Cowlitz's brief does not articulate what "industry" is being referred to or what the referred-to "practice" might be. Cowlitz cites to testimony proffered by a WPAG witness, but that testimony is equally opaque on the alleged industry practice to be relied upon. *See* Grinberg, *et al.*, WP-07-E-WA-05, at 54. Without a specific description of the alleged industry and an explanation of how BPA's current position is relevant to that industry practice, BPA cannot agree that "industry practice" is a legitimate basis for departing from BPA's proposal.

Furthermore, BPA's proposal to recover the Lookback Amounts through a reduction of future REP benefits is itself an accepted "industry practice" for recovering the Lookback Amounts. As noted earlier, BPA possess the same self-help rights of recovery through setoff as any other creditor. *See United States v. Munsey Trust Co.*, 332 U.S. 234, 239 (1947); *Hilburn v. Butz*, 463 F.2d 1207 (5th Cir. 1972), *cert. denied*, 410 U.S. 942 (1973). The government on numerous occasions has used the practice of setting off an alleged outstanding debt against payments due a party. *See Applied Companies v. U.S.*, 144 F.3d 1470 (Fed. Cir. 1998); *Boers v. United States*, 44 Fed. Cl. 725 (1999); *United States v. Maxwell*, 157 F.3d 1099 (7th Cir. 1998). Although BPA does not intend to exercise this authority outside of the context of a section 7(i) rate proceeding, as discussed in Section 9.3.2, reducing future payments to a party to recover past overpayment to the same party is an accepted "government practice" of recovering an outstanding debt.

Cowlitz also reminds BPA of its commitment to consider the possibility of charging the IOUs for any necessary increases in Planned Net Revenues for Risk created by lump sum payments to the COUs from reserves. Cowlitz Br., WP-07-B-CO-01, at 74. BPA has considered this approach and finds it impractical. A number of factors must be considered. Forman, *et al.*, WP-07-E-BPA-76, at 108. For one, BPA finds it will be extremely difficult to develop and implement special tracking and separation of such dollars. For example, BPA would need to impute which portion of the PNRR required in the next rate period would be required as mitigation for BPA's "normal" risks and which portion would be required to replace a payment from reserves of the overcharges to the COUs. Such a system is fraught with complications and potential debate in subsequent rate cases. In view of these complications, Staff believes a more straightforward approach to recover the Lookback Amounts, such as reducing payments of future REP benefits, is the better choice in the present proceeding.

Cowlitz also notes that BPA possesses the same self-help right of recovery through set off as any other creditor, and as such, suggests that BPA withhold other payments being made to the IOUs to speed up the recovery of Lookback Amounts. Cowlitz Br., WP-07-B-CO-01, at 74. BPA does not believe it prudent to commit to reduce any other payments to the IOUs for several reasons. First, as a policy matter, BPA believes it is inconsistent with fundamental principles of fairness and reason to reduce non-REP payments as a way to recover past REP overpayments. The IOUs did not use the payments made under the REP Settlement Agreements for their business operations but passed them directly through to their residential consumers. The residential customers of the IOUs, consequently, were the direct beneficiaries of the REP Settlement Agreements. Under these circumstances, BPA does not think it reasonable to recover the overpayments through agreements that have nothing to do with the REP, thereby implicating a different set of IOU consumers.

Second, Cowlitz's suggestion is also unreasonable because it would put in jeopardy the contracts from which BPA is withholding payments, and thereby undermine BPA's ability to operate in a businesslike manner. Cowlitz correctly notes that Congress directed BPA to operate consistent with "sound business principles." 16 U.S.C. §§ 825s, 838g, 839(a)(1). This command requires BPA to consider the potential business consequences of taking certain actions. In the present case, BPA foresees at least two serious problems with a policy that requires BPA to withhold payments from the IOUs on contracts unrelated to the REP to recover the Lookback. To begin with, BPA's ability to enter into new agreements and arrangements with the IOUs would be compromised. The IOUs would justifiably be cautious of entering any new arrangements with BPA because they would have no way of knowing whether BPA would claim a right to withhold payments under the new agreements to recover the Lookback Amounts. This result would seriously undermine BPA's ability to operate in a businesslike fashion.

Furthermore, if BPA were to reduce future non-REP payments as a form of Lookback recovery, the IOUs might have a claim for initiating litigation against BPA for breach of contract. Such litigation could, in turn, threaten the continued viability of other non-REP agreements, which could cause BPA to lose potential lucrative arrangements. This litigation would also be a huge administrative burden on BPA, and would put BPA in the untenable position of defending in court not only the Lookback calculations, but also the right to recover the Lookback through the setoff mechanism under these non-REP related agreements. BPA does not believe it either reasonable or necessary to incur this inordinate amount of legal and business risk to recover the Lookback Amounts if another viable alternative is available. As described above, Staff's proposal to reduce future REP benefits is such an alternative. While not without risk, reducing future REP benefits contains BPA's exposure to the specific transactions related to the REP, thereby leaving undisrupted BPA's other business dealings with the IOUs.

Decision

BPA will not make lump sum payments to the COUs out of its reserves available for risk as a means of returning the Lookback Amounts. Lump sum payments will be made only with respect to the return of overcharges for FY 2007-2008, as defined in the Standstill and Interim Rate Relief Agreements and this ROD for those who did not sign such an agreement.

9.4 FY 2007-2008 Interim Agreements and the Definitive Payment ROD

9.4.1 Introduction

The following sections address elements of the recovery and return of Lookback Amounts specific to FY 2007-2008. BPA's approach includes elements specific to agreements that were offered to all eligible IOUs and COUs in late February 2008, referred to herein as Interim Agreements. The distribution of funds to customers that did not sign Interim Agreements is also addressed. The Interim Agreements provided "interim" REP benefits to IOUs for their residential and small farm consumers as well as interim payments to COUs toward the return of a portion of the overcharges due to the REP settlement agreements collected in the PF-07 power rates. *See* Bonneville Power Administration's Response to Comments Regarding Interim Agreements With Investor-Owned Utility and Preference Customers (Feb. 21, 2008), at 5, www.bpa.gov/power/pl/regionaldialogue/implementation/documents ("BPA Response to Comments"). These interim payments are subject to a true-up to the final determinations made in this proceeding. *Id*. at 4-6. The Interim Agreements refer to a Definitive Payment ROD as the basis for implementing the true-up provisions of the agreements. *See* IOU Interim Agreement at § 2(f)-(h); COU Interim Agreement at § 2(h), at www.bpa.gov/power/pl/regionaldialogue/implementation/documents. The Administrator's Final Record of Decision for the 2007 Supplemental Wholesale Power Rate Case constitutes the Definitive Payment ROD for purposes of the Interim Agreements.

9.4.2 Background

On December 17, 2007, BPA released two sets of draft prototype Interim Agreement contracts for public comment. BPA Response to Comments, at 4-5. BPA requested that comments be provided no later than January 7, 2008. *Id*. The contracts intended to be executed by BPA and IOUs that would have otherwise qualified for the REP are entitled "Residential Exchange Interim Relief and Standstill Agreements." The contracts intended to be executed by BPA and the COUs are entitled "Standstill and Interim Relief Payment Agreements."

On February 22, 2008, BPA released a document that responded to comments received on the draft agreements and also released final prototype IOU and COU Interim Agreements reflecting BPA's decisions. *Id.* Shortly thereafter, BPA offered Interim Agreements to five qualifying IOUs and 127 COUs. Four IOUs and 100 COUs executed Interim Agreements. Avista, NorthWestern, PGE, and PSE signed IOU Interim Agreements. PacifiCorp chose not to execute an agreement. Idaho Power did not qualify and was not offered an agreement. BPA disbursed interim payments to the parties on April 2, 2008.

The Interim Agreements state that the final determinations of the amounts to be paid to IOUs and COUs will be established in a Definitive Payment ROD. *See* IOU Interim Agreement at § 2(f)-(h); COU Interim Agreement at § 2(h), available at www.bpa.gov/power/pl/regionaldialogue/implementation/documents. These finally determined amounts are defined as Definitive Benefit Amounts and Definitive Payment Amount for the IOUs and COUs, respectively. *Id*. The Definitive Benefit Amounts are specific amounts for each IOU for FY 2008. *Id*. The Definitive Payment Amount is the total amount of COU overcharges for the FY 2007-2008 period for all COUs. *Id*. The COU Interim Agreements also state that the Definitive Payment ROD will establish individual COU percentages of the Definitive Payment Amount that will be used to calculate Customer Payment Amounts as defined in the Interim Agreement. *Id*. All benefits and payments provided to the IOUs and COUs under the Interim Agreements have now been superseded by the level of benefits determined in this Final WP-07 Supplemental Rates ROD (which also constitutes the Definitive Payment ROD under the Interim Agreements).

9.4.3 Definitive Benefit Amounts for IOUs

The Definitive Benefit Amounts for the IOUs are the REP benefit payments the IOUs will receive for FY 2008. The Definitive Benefit Amounts, as determined by the Administrator, are calculated in three steps. First, BPA determines the reconstructed REP benefits that the IOU would have received in FY 2008. Second, BPA subtracts from the reconstructed REP benefits any outstanding deemer balances that the IOU may have had with BPA. Third, BPA subtracts an additional amount from the remaining reconstructed REP benefits to apply toward the IOU's outstanding Lookback Amount. After making this final adjustment, the resulting amount is the Definitive Benefit Amount for each IOU.

The three components that determine the Definitive Benefit Amounts are established consistent with the various Lookback decisions described in this ROD. The calculations of the Definitive Benefit Amounts are documented in the FY 2002-2008 Lookback Study and Final FY 2002-2008 Lookback Study Documentation. *See* FY 2002-2008 Lookback Study, WP-07-FS-08 and FY 2002-2008 Lookback Documentation, WP-07-FS-08A. Table 1 summarizes the calculation of the Definitive Benefit Amount for each IOU.

PacifiCorp and Idaho Power did not sign Interim Agreements. In the WP-07 Supplemental Proposal, BPA staff proposed that, after adjusting for any deemer balances, the full amount of reconstructed REP benefits for FY 2008 for IOUs that did not sign Interim Agreements would be applied to those utilities' Lookback Amounts. *See* FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 202. Parties did not address this proposal in testimony or briefs. Therefore, any REP benefits that Idaho Power or PacifiCorp were entitled to for FY 2008 will be applied to their Lookback Amounts and returned to COUs.

For Avista, all reconstructed REP benefits for FY 2008 are applied to its existing deemer balance.

For Northwestern, PGE and PSE, BPA applied an amount of FY 2008 reconstructed REP benefits to these utilities' respective Lookback Amounts such that total REP benefits paid to all IOUs in FY 2008 are comparable to the benefits to be paid to all IOUs in FY 2009.

Table 1
Definitive Benefit Amounts
$ millions

Customer	FY 2008 Reconstructed REP Benefits	FY 2008 Deemer Adjustment	FY 2008 Benefits Applied to Lookback Amounts	Definitive Benefit Amount
Avista	33.516	33.516	0	0
Idaho Power	0	0	0	0
NorthWestern	14.099	0	0	14.099
PacifiCorp	6.937	0	6.937	0
Portland General Electric	82.029	0	26.822	55.207
Puget Sound Energy	164.474	0	53.780	110.694

9.4.4 Return of FY 2007-2008 Overcharges to COUs, Definitive Payment Amount, COU Percentages, and COUs That Did Not Sign Interim Agreements

In the WP-07 Supplemental Proposal, Staff proposed that FY 2007-2008 overcharges to the COUs (Definitive Payment Amounts) be returned as lump sum payments to the COUs. Marks, *et al.*, WP-07-E-BPA-62, at 22. The Definitive Payment Amount would be divided into a non-Slice Definitive Payment Amount and a Slice Definitive Payment Amount by applying the respective non-Slice and Slice percentages of 77.3722 percent and 22.6278 percent, respectively. FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 210. Individual COU percentages of the non-Slice and Slice Definitive Payment Amounts are then calculated based on each COU's share of total PF-07 revenues paid in FY 2007. Marks, *et al.*, WP-07-E-BPA-62, at 23.

With the exception of the Slice percentage issue discussed below, no party filed testimony or otherwise raised issues regarding BPA's WP-07 Supplemental Proposal. Therefore, BPA will return FY 2007-2008 overcharges to COUs as Staff proposed, except as modified below.

For COUs that signed Interim Agreements, the terms and conditions of the agreements address how the customer percentages and Definitive Payment Amounts will be used to true up differences between customer Definitive Payment Amounts and amounts provided under the Interim Agreements.

9.4.5 Definitive Payment Amount

The Definitive Payment Amount and associated non-Slice and Slice Definitive Payment Amounts will be described and documented in the Final FY 2002-2008 Lookback Study and Final FY 2002-2008 Lookback Study Documentation. The amounts are as follows:

Table 2 Definitive Payment Amounts $ millions	
Definitive Payment Amount	$ 256.815
Non-Slice Definitive Payment Amount	$ 198.703
Slice Definitive Payment Amount	$ 58.112

9.4.6 COU Percentages of Definitive Payment Amounts

Issue 1

Whether the return of Lookback Amounts for FY 2007-2008 to Slice customers should be allocated among Slice customers on the basis of each customer's Slice percentage.

Parties' Positions

The Slice Customers Group proposed that the return of Lookback Amounts for FY 2007-2008 should be allocated among Slice customers on the basis of each Slice customer's individual Slice percentage and adjusted through the FY 2008 Slice True-Up Adjustment Charge. Brawley and Gregg, WP-07-E-JP22-01, at 7-8.

BPA Staff's Position

BPA Staff proposed to allocate the return of Lookback Amounts for FY 2007-2008 among Slice customers on the basis of each Slice customer's share of the total FY 2007 Slice revenues. Marks, *et al.*, WP-07-E-BPA-62, at 26. In rebuttal testimony, Staff stated it would consider proposing an allocation of the return of Lookback Amounts among Slice customers on the basis of each customer's Slice percentage. Lee, *et al.*, WP-07-E-BPA-84, at 13.

Evaluation of Positions

Staff proposed to allocate the return of Lookback Amounts for FY 2007-2008 among Slice customers on the basis of each Slice customer's share of the total FY 2007 Slice revenues. Marks, *et al.*, WP-07-E-BPA-62, at 23. For the return of Lookback Amounts to all COUs for FY 2007-2008, Staff proposed to make a lump sum payment to each COU. *Id*. The allocation of the return of Lookback Amounts to all COUs for FY 2007-2008 on the basis of each customer's share of the total FY 2007 PF revenues resulted in Customer Payment Amounts contained in Tables 15.15.1, 15.15.2, and 15.15.3 of the FY 2002-2008 Lookback Study. FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 213-215. The Slice Customers Group proposed that

BPA base the allocation for the Slice customers on each Slice customer's individual Slice percentage and use the FY 2008 Slice True-Up Adjustment Charge as the vehicle through which the allocation method would be implemented. Brawley and Gregg, WP-07-E-JP22-01, at 7-8.

The Slice Customers Group explained that the way to implement this allocation based on Slice customers' individual Slice percentages would be to use the FY 2008 Slice True-Up Adjustment Charge as the "last step" of a process that began with an allocation to each Slice customer of a lump sum payment for the return of the Lookback Amounts for FY 2007-2008 on the basis of FY 2007 Slice revenues. *Id*. Slice customers who signed Interim Agreements would receive advance payments based on the Customer Payment Amounts in Tables 15.15.1, 15.15.2, and 15.15.3 of the FY 2002-2008 Lookback Study and a related true-up amount. Brawley and Gregg, WP-07-E-JP22-01, at 7-8. Slice customers who did not sign Interim Agreements would receive Customer Payment Amounts that were specified in Tables 15.15.1, 15.15.2, and 15.15.3 and related true-up amounts through the FY 2008 Slice True-Up Adjustment Charge. *Id*. The Slice Customers Group assumed that in the "last step" of this process, the FY 2008 True-Up Adjustment would distribute the return of overcharges for FY 2007-2008 based on each Slice customer's Slice percentage, while recognizing that some customers received advance payments through their Interim Agreements. *Id*. However, the Slice Customers Group believed that Staff was not proposing to correct the Customer Payment Amounts in Tables 15.15.1, 15.15.2, and 15.15.3 and related true-up payments through this "last step," which would use the FY 2008 Slice True-Up Adjustment Charge as the vehicle. *Id*. The Slice Customers believed that a "misallocation" among Slice customers of the return of Lookback Amounts for FY 2007-2008 would occur if BPA did not correct the allocation to be based on Slice customers' individual Slice Percentages. *Id*.

Staff disagreed that a "misallocation" would occur among Slice customers if the allocation of the return of Lookback Amounts for FY 2007-2008 were based on each Slice customer's share of the total FY 2007 Slice revenues. Lee, *et al.*, WP-07-E-BPA-84, at 12. An allocation based on Slice customers' shares of the total FY 2007 Slice revenues is simply one method that could be used and in fact is a method that the Slice customers had negotiated for the Interim Agreements. *Id*. at 12-13. However, Staff stated that it would consider proposing to use the Slice Percentage of each Slice customer to allocate the return of Lookback Amounts for FY 2007-2008 using the FY 2008 Slice True-Up Adjustment Charge as the vehicle, as proposed by the Slice Customers Group. *Id*. at 13. Staff considered the option of allocating the return of overcharges on the basis of each Slice customer's share of the total FY 2007 Slice revenues and the option of allocating on the basis of the Slice percentage of each Slice customer, and Staff is indifferent to either option.

As a result, BPA will set each Slice customer's percentage of the Slice Definitive Payment Amount equal to each Slice customer's Slice percentage, instead of equal to each Slice customer's share of the total FY 2007 Slice revenues. BPA then will ensure that the Slice customers who did not sign Interim Agreements receive Customer Payment Amounts based on these percentages through the FY 2008 Slice True-Up Adjustment Charge. *Id*. BPA will ensure that Slice customers do not receive any additional payments for the return of Lookback Amounts for FY 2007-2008 through the FY 2008 Slice True-Up process.

Decision

BPA will allocate the return of FY 2007-2008 overcharges to Slice customers on the basis of each customer's Slice percentage.

9.4.7 Percentages for Calculation of Slice and non-Slice Customer Payment Amounts

COU percentages of the non-Slice Definitive Payment Amount are unchanged from those used in Tables 15.15.1, 15.15.2, and 15.15.3, FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 213-215. COU percentages of the Slice Definitive Payment Amount are set equal to the respective customers' Slice percentages divided by the sum of all customer Slice percentages (22.6278) consistent with the above decision. The following Table shows COU non-Slice and Slice percentages:

Table 3
Non-Slice and Slice Definitive Payment Amount Customer Percentages

Customer Name	Non-Slice Percentage	Slice Percentage
Albion, City of	0.0071%	0.0000%
Alder Mutual	0.0087%	0.0000%
Ashland, City of	0.4008%	0.0000%
Asotin County PUD #1	0.0108%	0.0000%
Bandon, City of	0.1500%	0.0000%
Benton County PUD #1	1.7469%	7.7962%
Benton REA	1.0501%	0.0000%
Big Bend Elec Coop	0.8514%	0.0000%
Big Horn County Electric Coop.	0.0000%	0.0000%
Blachly Lane Elec Coop	0.0000%	0.2907%
Blaine, City of	0.1626%	0.0000%
Bonners Ferry, City of	0.1045%	0.0000%
Burley, City of	0.2602%	0.0000%
Canby, City of	0.3788%	0.0000%
Cascade Locks, City of	0.0481%	0.0000%
Central Electric Coop	0.0000%	1.0149%
Central Lincoln PUD	2.7787%	0.0000%
Central Montana Electric Power Coop	0.0000%	0.0000%
Centralia, City of	0.4452%	0.0000%
Cheney, City of	0.2793%	0.0000%
Chewelah, City of	0.0549%	0.0000%
Clallam County PUD #1	1.4370%	0.0000%
Clark County PUD #1	7.8303%	0.0000%
Clatskanie PUD	0.7415%	4.3111%
Clearwater Power	0.0000%	0.3634%
Columbia Basin Elec Coop	0.1906%	0.0000%
Columbia Power Coop	0.0529%	0.0000%

Table 3 Non-Slice and Slice Definitive Payment Amount Customer Percentages		
Customer Name	Non-Slice Percentage	Slice Percentage
Columbia REA	0.4788%	0.0000%
Columbia River PUD	1.1415%	0.0000%
Consolidated Irrigation District #19	0.0041%	0.0000%
Consumers Power	0.0000%	0.6416%
Coos Curry Elec Coop	0.0000%	0.5864%
Coulee Dam, City of	0.0422%	0.0000%
Cowlitz County PUD #1	9.2352%	0.0000%
Declo, City of	0.0067%	0.0000%
Douglas Electric Cooperative	0.0000%	0.2881%
Drain, City of	0.0474%	0.0000%
East End Mutual Electric	0.0414%	0.0000%
Eatonville, Town of	0.0646%	0.0000%
Ellensburg, City of	0.4584%	0.0000%
Elmhurst Mutual P & L	0.6153%	0.0000%
Emerald County PUD	0.9955%	0.0000%
Energy Northwest	0.0548%	0.0000%
Eugene Water & Electric Board	2.1792%	10.7514%
Fairchild AFB	0.1399%	0.0000%
Fall River Elec Coop	0.0000%	0.3245%
Farmers Electric Company	0.0088%	0.0000%
Ferry County PUD #1	0.1439%	0.0000%
Flathead Elec Coop	3.1416%	0.0000%
Forest Grove, City of	0.5019%	0.0000%
Franklin County PUD #1	0.7915%	3.4696%
Glacier Elec Coop	0.0000%	0.0000%
Grant County PUD #2	3.3715%	0.0000%
Grays Harbor PUD #1	0.9751%	5.1622%
Harney Elec Coop	0.3309%	0.0000%
Hermiston, City of	0.2429%	0.0000%
Heyburn, City of	0.0845%	0.0000%
Hood River Elec Coop	0.2497%	0.0000%
Idaho County L & P	0.1055%	0.0000%
Idaho Falls Power	0.5428%	3.0630%
Inland P & L	1.7547%	0.0000%
Kittitas County PUD #1	0.1455%	0.0000%
Klickitat County PUD #1	0.5774%	0.0000%
Kootenai Electric Coop	0.9003%	0.0000%
Lakeview L & P (WA)	0.6337%	0.0000%
Lane County Elec Coop	0.0000%	0.4182%
Lewis County PUD #1	2.0107%	0.0000%
Lincoln Elec Coop (MT)	0.0000%	0.0000%
Lost River Elec Coop	0.0000%	0.1085%
Lower Valley Energy	1.3295%	0.0000%

Table 3 **Non-Slice and Slice Definitive Payment Amount Customer Percentages**		
Customer Name	Non-Slice Percentage	Slice Percentage
Mason County PUD #1	0.1592%	0.0000%
Mason County PUD #3	1.4700%	0.0000%
McCleary, City of	0.0806%	0.0000%
McMinnville, City of	1.8703%	0.0000%
Midstate Elec Coop	0.8012%	0.0000%
Milton-Freewater, City of	0.1898%	0.0000%
Milton, City of	0.1414%	0.0000%
Minidoka, City of	0.0020%	0.0000%
Mission Valley	0.0000%	0.0000%
Missoula Elec Coop	0.0000%	0.0000%
Modern Elec Coop	0.5109%	0.0000%
Monmouth, City of	0.1547%	0.0000%
Nespelem Valley Elec Coop	0.0970%	0.0000%
Northern Lights	0.0000%	0.2836%
Northern Wasco County PUD	1.0661%	0.0000%
Ohop Mutual Light Company	0.1813%	0.0000%
Okanogan County Elec Coop	0.0000%	0.0805%
Okanogan County PUD #1	0.4121%	2.1880%
Orcas P & L	0.4545%	0.0000%
Oregon Trail Coop	1.4519%	0.0000%
Pacific County PUD #2	0.6994%	0.0000%
Parkland L & W	0.2721%	0.0000%
Pend Oreille County PUD #1	0.0301%	1.6877%
Peninsula Light Company	1.2943%	0.0000%
Plummer, City of	0.0735%	0.0000%
PNGC	3.5409%	12.3742%
Port Angeles, City of	1.5147%	0.0000%
Port of Seattle	0.3135%	0.0000%
Puget Sound Naval Shipyard (Bremerton)	0.5284%	0.0000%
Raft River Elec Coop	0.0000%	0.1745%
Ravalli County Elec Coop	0.0000%	0.0000%
Richland, City of	1.8510%	0.0000%
Riverside Elec Company	0.0375%	0.0000%
Rupert, City of	0.1678%	0.0000%
Salem Elec Coop	0.7583%	0.0000%
Salmon River Elec Coop	0.0000%	0.3468%
Seattle City Light	4.8378%	20.6277%
Skamania County PUD #1	0.2950%	0.0000%
Snohomish County PUD #1	6.4801%	22.0653%
Soda Springs, City of	0.0528%	0.0000%
Southern MT G&T	0.0000%	0.0000%
South Side Electric	0.0999%	0.0000%
Springfield Utility Board	1.8601%	0.0000%

Table 3 Non-Slice and Slice Definitive Payment Amount Customer Percentages		
Customer Name	Non-Slice Percentage	Slice Percentage
Steilacoom, Town of	0.0922%	0.0000%
Sumas, City of	0.0664%	0.0000%
Surprise Valley Elec Coop	0.2584%	0.0000%
Tacoma Public Utilities	8.1628%	0.0000%
Tanner Elec Coop	0.1565%	0.0000%
Tillamook PUD #1	0.9893%	0.0000%
Troy, City of	0.0000%	0.0000%
U.S. DOE Albany	0.0086%	0.0000%
U.S. Naval Station, Everett (Jim Creek)	0.0276%	0.0000%
U.S. Naval Submarine Base, Bangor	0.3740%	0.0000%
Umatilla Elec Coop	0.0000%	1.4473%
Umpqua Indian Utility Cooperative	0.0469%	0.0000%
United Electric Coop	0.3739%	0.0000%
USBIA Wapato	0.0307%	0.0000%
USDOE-Richland	0.3941%	0.0000%
Vera Irrigation District	0.5048%	0.0000%
Vigilante Elec Coop	0.0000%	0.0000%
Wahkiakum County PUD #1	0.0924%	0.0000%
Wasco Elec Coop	0.2098%	0.0000%
Weiser, City of	0.0559%	0.0000%
Wells Rural Electric Company	1.5734%	0.0000%
West Oregon Elec Coop	0.0000%	0.1344%
Whatcom County PUD #1	0.4181%	0.0000%
Yakama Power	0.0765%	0.0000%
TOTAL	**100.0000%**	**100.0000%**

9.4.8 Return of FY 2007-2008 Overcharges to COUs that Did Not Sign Interim Agreements

In the Supplemental Proposal, Staff proposed that COUs that did not sign Interim Agreements should, to the extent possible, be treated comparably to those that signed agreements. Bliven, *et al.*, WP-07-E-BPA-62, at 24. Staff proposed to provide interest to customers that did not sign Standstill Agreements so that the decision not to sign the Standstill Agreement would not materially financially disadvantage nonsigners as compared to signers. *Id*. at 26. Payments of non-Slice Definitive Payment Amounts, plus interest, would be by Electronic Funds Transfer (EFT) as soon as practicable after FERC grants interim approval of the Final WP-07 Supplemental Proposal. *Id*. at 25. The payment of Slice Definitive Payment Amounts will be through the FY 2008 Slice True-Up Adjustment Charges. Lee, *et al.*, WP-07-E-BPA-84, at 14. No party raised an issue with Staff's proposal.

BPA adopts the following components of Staff's proposal. Interest on Slice component will be excluded from the accounting for the Slice True-Up calculation. *Id*. Interest will accrue from April 2, 2008, the date of the Interim Agreement payments, through September 30, 2008 on the amounts COUs would have received had they elected to sign Interim Agreements. Lookback Study, WP-07-E-BPA-44, at 211. The interest rate will be the six-month annual rate of interest posted under the title "Daily Treasury Yield Curve Rates" as published on the U.S. Treasury Department's website at 3:30 pm Eastern Prevailing Time on April 2, 2008. *Id*. at 212. This rate is 1.56 percent and can be found at http://www.treasury.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml.

In order to better achieve comparability of treatment between COUs that did and did not sign Interim Agreements, BPA will pay Slice Definitive Payment Amounts by Electronic Funds Transfer (EFT) as soon as practicable after FERC grants interim approval of the Final WP-07 Supplemental Proposal.

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10.0 FY 2009 LOADS AND RESOURCES

10.1 <u>Introduction</u>

The Supplemental Load Resource Study, WP-07-E-BPA-45, represents the compilation of the loads, sales, contracts, and resource data necessary for developing BPA's wholesale power rates for FY 2009. Documentation supporting the results of the Supplemental Load Resource Study is presented in the Supplemental Load Resource Study Documentation, WP-07-E-BPA-45A. The Load Resource Study is also described in the direct testimony of Hirsch, *et al.*, WP-07-E-BPA-64.

The Supplemental Load Resource Study and supporting documentation are used to (1) provide data to determine resource costs for the Supplemental Revenue Requirement Study, WP-07-E-BPA-46; (2) provide data to derive billing determinants for setting rates and the revenue forecast in the Supplemental WPRDS, WP-07-E-BPA-49; (3) provide load and resource data for use in the Supplemental Risk Analysis Study, WP-07-E-BPA-48; and (4) provide Pacific Northwest (PNW) regional hydro data for use in the market price forecast for the Supplemental Market Price Forecast Study, WP-07-E-BPA-47.

The Supplemental Load Resource Study includes the following related components: (1) a forecast of the Federal system load obligations, comprised of BPA's firm requirements power sales contract (PSC) obligations and other additional BPA contract obligations; (2) Federal system resource forecasts 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 system sales, loads, and contract obligations to the Federal system generating resources and contract purchases; (4) total PNW regional hydro resources; and (5) forecast power purchases that are eligible for the section 4(h)(10)(C) credit.

The Supplemental Load Resource Study was updated as proposed in Staff testimony.

10.2 <u>Federal System Load Obligations</u>

The Federal System Load Obligations forecast includes BPA's forecast firm requirement PSC obligations to public body utilities, cooperative utilities, and Federal agencies (together referred to as Public Agencies), IOUs, and DSIs; contractual obligations to the Bureau of Reclamation (Reclamation); contract obligations outside the PNW region (exports); and contractual obligations within the PNW region (intra-regional transfers-out).

10.3 <u>Federal System Resource Forecast</u>

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.

10.4 Federal System Load Resource Balance

The Federal System Load Resource Balance completes BPA's load and resource picture by comparing forecast Federal system load obligations to Federal system resource output, assuming 1937 water conditions for hydro resources. The result of the Federal system resources less loads is the forecast Federal system monthly firm energy surplus or deficit. If BPA's annual resources are greater than annual load obligations under 1937 critical water conditions, BPA has firm surplus energy. Conversely, if BPA's resources are less than load obligations, BPA must purchase power or otherwise secure resources through augmentation to meet Federal system energy deficits. For FY 2009, the Federal System Load Resource Balance incorporated the contract obligations, contract purchases, resources, and augmentation. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, at 23-24.

10.5 Regional Hydro Resources

This analysis provides total PNW Regional Hydro Resources forecasts for FY 2009 as inputs into the AURORA electric price forecasting model for the Supplemental Market Price Forecast Study, WP-07-E-BPA-47. BPA did not update the PNW Regional Hydro Resources forecasts for the Supplemental Load Resource Study. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, at 25. However, the PNW Regional Hydro Resources forecasts provided as an input to the AURORA model were updated for the Final Supplemental Load Resource Study.

10.6 Estimate of Section 4(h)(10)(C) Credit

BPA funds actions to protect, mitigate, and enhance fish and wildlife affected by Federal hydro operations, as directed by the Northwest Power Act. 16 U.S.C. §§ 839-839h. These program costs are allocated to hydro project purposes for both power and nonpower uses. The Northwest Power Act directs BPA to annually recoup its funding of nonpower purposes through credits, known as "section 4(h)(10)(C) credits" in reference to the authorizing statutory provisions, so that ratepayers pay only their power share of the fish and wildlife costs. 16 U.S.C. § 839b(h)(10)(C). BPA uses a specific methodology to determine the appropriate annual amount of section 4(h)(10)(C) credits. For FY 2009, the section 4(h)(10)(C) credit calculation was not updated from the WP-07 Final Proposal. *See* Supplemental Load Resource Study, WP-07-E-BPA-45, at 26-29. However, BPA updated the section 4(h)(10)(C) credit calculations as needed for the Final Supplemental Load Resource Study.

10.7 Issues

No issues were raised on brief.

11.0 FY 2009 REVENUE REQUIREMENT

11.1 Introduction

BPA's wholesale power rates recover the costs of the generation function only. The Supplemental Revenue Requirement Study, WP-07-FS-BPA-10, 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 non-Federal power suppliers such as Energy Northwest; other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; costs to Power Services of purchasing transmission services, if necessary; and all other generation-related costs incurred by the Administrator pursuant to law. *See* Supplemental Revenue Requirement Study, WP-07-FS-BPA-10.

11.2 Revenue Requirement Development

BPA develops the revenue requirement in conformity with the financial, accounting, and ratemaking requirements of DOE 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 is 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 rate test period and include a 50-year repayment period. In the instant case, this period is one year.
- Operating expenses and minimum required net revenues for each year of the rate test period.
- Annual planned net revenues for risk (PNRR) based on the identified and quantified risks, the Treasury Payment Probability (TPP) standard, and other risk mitigation tools.

Based on these three components, 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. *See* DOE Order RA 6120.2, Power Marketing Administration Financial Reporting, September 20, 1979. In the Supplemental

Proposal, proposed rates have been determined to recover rate test period costs with a very high confidence level.

11.3 Spending Level Development

The development of program levels reflected in the Supplemental Revenue Requirement Study began with the program spending levels used in the WP-07 Final Proposal. Those program spending levels are outcomes of decisions made during the Regional Dialogue process and the two phases of the Power Function Review. Both processes involved extensive discussion with BPA customers and constituents and resulted in decisions about forecasts of program spending levels that would form the basis of the Revenue Requirement Study. These processes are described in the 2007 Wholesale Power Rate Adjustment Proceeding (WP-07) Administrator's Final Record of Decision, WP-07-A-02.

The development of the specific program levels in this Supplemental Proposal occurred primarily in the Integrated Program Review (IPR).

11.3.1 Integrated Program Review

BPA began the IPR process in May 2008 with the first of a series of technical and management-level public workshops. The IPR was designed, in part, to provide an opportunity for customers and constituents to examine, understand, and provide input on changes to program spending level projections for FY 2009 that BPA uses in the Supplemental Revenue Requirement Study. The IPR workshops that focused on FY 2009 examined projected capital investments and operations and maintenance costs of the major programs that affect the calculation of wholesale power rates. The workshops examined the projected spending levels of Columbia Generating Station (CGS), U.S. Army Corps of Engineers (COE), and Bureau of Reclamation (Reclamation) direct funding; conservation, renewables, fish and wildlife, Power Services internal operations, transmission purchases, and ancillary services programs; BPA corporate costs; and Federal and non-Federal debt management. In particular, the IPR included discussion of additional fish and wildlife obligations related to the Columbia Basin Fish Accords, which BPA entered into with certain sovereign entities in 2008, and the issuance of the 2008 Biological Opinion for the Federal Columbia River Power System (BiOp).

11.4 Issues

No issues were raised on initial briefing. In their Brief on Exceptions, CRITFC and the Yakama Nation (not joined by the Nez Perce Tribe), noted they had cooperatively identified with BPA staff several adjustments in BPA proposed spending for the Fish Accords for FY 2008 and 2009 that they wished to see reflected in the IPR close out report, or in this decision. CRITFC, *et al.*, Br. Ex., WP-07-R-JP-13-1, at 3. BPA intends to meet its commitments in the Fish Accords, and its overall fish and wildlife spending levels in the IPR are intended to cover such commitments. BPA appreciates the assistance of CRITFC in developing accurate budgets for FY 2008-2009 Fish Accord implementation. As this is a spending matter relating to implementation of the Fish Accords, BPA will respond to CRITFC and the Yakama Nation in a letter separate from this Record of Decision.

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12.0 FY 2009 MARKET PRICE FORECAST

12.1 Introduction

The FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11 represents the compilation of the loads, sales, contracts, and resource data necessary for developing BPA's wholesale power rates for FY 2009. The documentation for the FY 2009 Market Price Forecast Study can be found in WP-07-FS-BPA-11A. This Market Price Forecast Study is also described in the direct testimony of Petty, *et al.*, WP-07-E-BPA-66.

The FY 2009 Market Price Forecast Study is used for (1) estimating the forward price for a portion of the DSI smelter payments, (2) estimating the uncertainty surrounding a portion of the DSI smelter payments, (3) informing the secondary revenue forecast, and (4) providing a price input used for the risk analysis.

Before adoption by the Administrator for the final Supplemental Proposal, the Supplemental Market Price Forecast Study will be updated as discussed below and as proposed in the Staff's testimony. *Id*. at 6.

12.2 Issues

Issue 1

Whether BPA should update the market price forecast and net secondary revenue forecast for the final Supplemental Proposal.

Parties' Positions

Cowlitz supports updating the market price forecast and net secondary revenue forecast. Cowlitz Br., WP-07-B-CO-01, at 78. The Washington Utilities and Transportation Commission (WUTC) also supports updating the market price forecast and net secondary revenue forecast. WUTC Br., WP-07-B-WU-01, at 27.

BPA Staff's Position

BPA Staff intends to update the natural gas price forecast as well as load and resource changes for the Final Supplemental Proposal. Petty, *et al.*, WP-07-E-BPA-82, at 3, 7. Staff expects the Henry Hub natural gas price forecast to fall into the $7.50/MMBtu to $11.00/MMBtu range. *Id*. at 4. Staff also expects the corresponding electricity price forecast, *id*. at 5, to increase, and thus the forecast of net secondary revenues also to increase. *Id*. at 8.

Evaluation of Positions

For the Supplemental Proposal, Staff did not update the market price forecast in the Supplemental Market Price Forecast Study (WP-07-E-BPA-47) from the WP-07 Final Proposal. Petty, *et al.*, WP-07-E-BPA-66, at 3-4. Staff also stated the inputs to the Supplemental Market Price Forecast Study that they planned to update for the Final Supplemental Proposal. *Id*. at 6.

Cowlitz asserts that the market price forecast in the Supplemental Proposal is out of date and not representative of current market conditions. Cowlitz Br., WP-07-B-CO-01, at 78. Cowlitz also asserts that the market price forecast should be updated and that a reasonable update to the market price forecast could result in an increase of $150 million in secondary revenues. *Id*.

Staff and WUTC agree with Cowlitz that the market price forecast should be updated. Petty, *et al.*, WP-07-E-BPA-02, at 7; WUTC Br., WP-07-B-WU-01, at 27. Staff states in its rebuttal testimony that the market price forecast will be updated for the final Supplemental Proposal. Staff expects the market price forecast and net secondary revenue forecast to increase. Petty, *et al.*, WP-07-E-BPA-82, at 5-8.

BPA believes it is prudent to take a conservative view with regard to the gas price on which to base its market price forecast. BPA is concerned that forecasting high natural gas prices and high electricity prices would lead to a high net secondary revenue forecast, but then actual revenues and market prices may be much lower than those forecast. Indeed, in BPA's WP-02 Supplemental Rate Proceeding, BPA included a high market price forecast, *see* Conger, *et al.*, WP-07-E-BPA-56, and high net secondary revenue forecast. Those high price forecasts and net secondary revenues did not materialize, however, especially in FY 2002, which left BPA financially harmed. SN CRAC ROD, at 1·1, 2.1·1-2.1·2. In addition, BPA is concerned that current prices and forecasts for natural gas delivered in FY 2009 are being driven by a short-term run-up in the natural gas market that will not be sustained into FY 2009.

Staff states that "most industry analysts expect natural gas prices for Henry Hub to be in the range of approximately $7.50/MMBtu to $11.00/MMBtu…." Petty, *et al.*, WP-07-E-BPA-82, at 4. In preparation for the final Supplemental Proposal, BPA has recently reviewed the same source of information used to derive the range of $7.50/MMBtu to $11.00/MMBtu. The current range is $7.50/MMBtu to $12.25/MMBtu.

The natural gas price forecast and corresponding electricity price and net secondary revenue forecasts for FY 2009 will be updated for the final Supplemental Proposal. The forecast from the end of July, using the methodology BPA has historically employed, remains in the range of $7.50 to $11.00/MMBtu. As of the writing of the draft ROD, natural gas prices have dropped precipitously. It is unclear whether this decline is a result of random market price volatility or a more fundamental restructuring of supply and demand that could lead to longer-term lower prices than were forecast earlier this year.

This forecast, however, does not capture the full range of alternative scenarios for natural gas prices, in which a significant downside risk is a real possibility. Natural gas prices could fall below $7.50/MMBtu if current market conditions persist. In addition, a gas price of

$7.50/MMBtu is a higher average annual price than has ever been realized, with the exception of 2006. Even the years of the West Coast energy crisis (2000-2001) and Hurricanes Katrina and Rita (2005) did not see natural gas prices this high.

Consequently, BPA will use the low end of the range, $7.50/MMBtu, for its FY 2009 natural gas price forecast in the final Supplemental Proposal. This decision is made despite concerns that even this forecast may be too high, given the recent decline in prices. Adopting a forecast below $7.50/MMBtu, however, would be inconsistent with the methodology used in this rate case to establish the natural gas price forecast. Should net secondary revenues fall short of this forecast, there are adequate reserves to assure a high likelihood of Treasury payment in 2009. If net secondary revenues do fall short of this forecast, FY 2010-2011 power rates would likely be pushed higher, all else being equal.

While not a subject of this rate case, the issue of sustained below-average water conditions in recent years is a concern. The Columbia basin is now experiencing what is the eighth out of the last nine years of at-or-below-average runoff for January through July, as measured at The Dalles. This is a matter that deserves scrutiny in future rate cases, particularly with respect to forecasting net secondary revenues.

Decision

BPA will update the market price and net secondary revenue forecasts for FY 2009 for the WP-07 Final Supplemental Proposal based on a natural gas price forecast of $7.50/MMBtu.

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13.0 RISK ANALYSIS AND MITIGATION

13.1 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. BPA's rate setting process accounts for risks in two steps: in the risk analysis step, the distributions or profiles characterizing operating and non-operating risks are defined; and in the risk mitigation step, potential risk mitigation measures are tested to assess BPA's ability to recover its costs in the face of these uncertainties. RiskMod and the Non-Operating Risk Model (NORM) are used in the risk analysis step for the WP-07 Supplemental Proposal, and the ToolKit is used to test the effectiveness of risk mitigation options. *See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, and FY 2009 Risk Analysis Study Documentation, WP-07-FS-BPA-12A.

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 hydrosystem operating risks are quantified in RiskMod, and non-operating risks are quantified in NORM. The results from the Risk Analysis are subsequently used in the ToolKit to evaluate whether BPA is able to meet its Treasury Payment Probability (TPP) goal with the risk mitigation measures that are modeled in the ToolKit. These risk mitigation measures typically include starting financial reserves, the CRAC, PNRR (if used), and DDC. FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, at 45-51. RiskMod also is used to calculate the average surplus energy revenues and power purchase expenses reported in the revenue forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13.

The ToolKit is used to measure TPP so that BPA can develop rates that cover 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. § 839e(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 (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 in the 10-Year Financial Plan. 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 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 WP-07 Supplemental Proposal, as affirmed in BPA's revised Financial Plan issued July 31, 2008. 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 Supplemental Proposal, BPA is measuring the TPP for one year. The one-year TPP standard of 97.5 percent is the equivalent of the 95 percent two-year standard from the

10-Year Financial Plan. FY 2009 Risk Mitigation Study, WP-07-FS-BPA-12, at 4. The methodology employed in the ToolKit is consistent with an emphasis on success in recovering all costs, including Treasury payments, for the rate period. FY 2009 Risk Mitigation Study, WP-07-FS-BPA-12, at 4-51. While the 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 44-45.

In the WP-07 Final Proposal, BPA included some new features for its risk mitigation methodology:

- The NORM model was refined and included a number of new nonoperating risks. Risk Analysis Study, WP-07-FS-BPA-04, at 24.

- The NFB Adjustment to the CRAC cap addressed cost uncertainties associated with the FCRPS Biological Opinion and related litigation. BPA developed mechanisms to mitigate the actual costs, if and when they occur. BPA did not quantitatively model these cost uncertainties or the mitigation mechanisms. *Id*.

In addition, BPA made enhancements to the risk mitigation package as a result of issues raised by parties in the WP-07 rate case.

- The Emergency NFB Surcharge was introduced to address the same uncertainties as the NFB Adjustment and also to account for the TPP impact caused by the up-to-one-year lag in collecting revenues through the NFB Adjustment. The Emergency NFB Surcharge is implemented if (1) the Agency Within-year TPP is below 80 percent; and (2) an NFB Trigger Event associated with the FCRPS BiOp has occurred in that fiscal year that decreases the expected PBL net revenue. Lovell and Normandeau, WP-07-E-BPA-34, at 2.

In this WP-07 Supplemental Proposal, BPA has retained this basic approach to risk mitigation and has adjusted several features. Because reserves available for risk attributed to the Power function were high enough to provide sufficient risk mitigation to meet the TPP standard with only a small CRAC and without the use of PNRR, Staff proposed that no PNRR and a CRAC with a cap of $36 million be included for FY 2009. However, if a significant downturn should occur in reserves available for risk attributed to the Power function before the final studies are run, some PNRR or a larger CRAC may be necessary risk mitigation tools; similarly, if Treasury payment risk is reduced, the CRAC may be reduced.

13.2 Addressing the Uncertainty of Additional Fish and Wildlife Costs

Issue 1

Whether BPA should consider alternative river operations in the WP-07 Supplemental Proposal.

Parties' Positions

CRITFC and the Yakama Nation noted that Staff assumed operation of the FCRPS based on the 2006 court-ordered river operation. CRITFC and Yakama Br., WP-07-B-JP13-01, at 8. They were joined in their brief by the Nez Perce Tribe. WP-07-B-NZ-01, at 2. (These three parties are hereafter referred to as the Tribes.) The Tribes assert that Staff did not consider other river operations that could reduce its resources and revenues. *Id*. Specifically, the Tribes expressed concern that Staff did not consider the hydro operations recommended by the plaintiffs in litigation over the prior FCRPS Biological Opinion (BiOp). *Id*.

BPA Staff's Position

BPA Staff's estimated expenditures for its fish and wildlife commitments for FY 2009 were consistent with the costs it previously forecast for the WP-07 rate period. Lefler, *et al.*, WP-07-E-BPA-63, at 10. Nevertheless, Staff expected that during the course of the proceeding events would occur that could provide BPA with new information about its fish and wildlife costs. *Id*. Staff proposed to include in the final Supplemental Proposal the estimated costs of implementing the final FCRPS BiOp and the costs of any associated long-term agreements. *Id*. at 11. In addition, Staff proposed to update known reservoir operating assumptions, including information from the final 2008 FCRPS BiOp for FY 2009. Misley, *et al.*, WP-07-E-BPA-64, at 7.

Evaluation of Positions

Staff did not analyze alternative hydro operations in the Supplemental Proposal's risk analysis because they expected to update the hydro operations in the final Supplemental Proposal. A new 2008 FCRPS BiOp was expected in time for final studies. So, instead of incorporating the expectations of any one rate case party for what the new BiOp might contain, Staff chose to wait and to update the forecast of hydro operations with the best information available by the time of the completion of the final Supplemental Proposal. Once a final 2008 FCRPS BiOp was issued, the plaintiffs' requested operations based on the prior BiOp were moot, although, as discussed under Issue 2, *infra*, BPA anticipates additional litigation on the newly issued FCRPS BiOp and has addressed that risk in its proposal.

Decision

BPA does not need to analyze alternative hydro operations in the Supplemental Proposal. BPA will incorporate the new FCRPS BiOp in the final Supplemental Proposal.

Issue 2

Whether BPA should address uncertainty associated with the FCRPS Biological Opinion.

Parties' Positions

A new FCRPS Biological Opinion was issued by NOAA on May 5, 2008. CRITFC and Yakama Br., WP-07-B-JP13-01, at 8. The 2008 FCRPS BiOp is likely to undergo further legal challenges. *Id*. The Tribes assert those challenges may result in additional costs or reduced revenues to BPA. *Id*. The Tribes state that this uncertainty should be directly addressed by BPA. *Id*.

BPA Staff's Position

BPA Staff's proposed risk mitigation tools provide reasonable protection against such uncertainties. Lovell and Normandeau, WP-07-E-BPA-34, at 12. Staff proposed the Emergency NFB Surcharge and NFB Adjustment to the CRAC cap to respond to FCRPS BiOp uncertainties. *Id*.

Evaluation of Positions

If the Federal court overseeing the litigation regarding the 2008 FCRPS BiOp issues an order that requires actions from BPA different from the final BiOp, and the order is issued in time to incorporate it into the final Supplemental Proposal, BPA will do so. If such an order is issued after the latest opportunity to incorporate it into the final Supplemental Proposal, the order would likely meet the definition of an NFB Trigger Event. If BPA is in a cash crunch at the time, *see* Normandeau, *et al.*, WP-07-E-BPA-73, at 5, BPA will implement either the NFB Adjustment procedures or the Emergency NFB Surcharge procedures. Lefler, *et al.*, WP-07-E-BPA-63, at 12.

BPA will incorporate into the final Supplemental Proposal all the new information developed by the time the Integrated Program Review (IPR) process is concluded. Developments in the FCRPS BiOp litigation that occur after the conclusion of the IPR process that decrease BPA's net revenue can be accommodated by the NFB Adjustment, or if BPA is experiencing a cash shortage, by the Emergency NFB Surcharge. Russell, *et al.*, WP-07-E-BPA-86, at 4.

As noted above, Staff's WP-07 Supplemental Proposal directly addressed uncertainty arising from the possibility of legal challenges to the new BiOp that could change BPA's revenues or fish and wildlife costs. Lefler, *et al.*, WP-07-E-BPA-63, at 12.

Decision

BPA will consider uncertainty associated with the FCRPS Biological Opinion and potential related litigation and proposed the NFB Surcharge and NFB Adjustment to address such uncertainties.

Issue 3

Whether BPA's risk analysis tools incorporate sufficient uncertainty.

Parties' Positions

The Tribes acknowledge that a new FCRPS Biological Opinion was issued on May 5, 2008 and that they support that BiOp and the associated Fish Accord MOAs executed between BPA, other Federal agencies, and the Tribes. CRITFC and Yakama Br., WP-07-B-JP13-01, at 5-7. The Tribes claim that the 2008 FCRPS BiOp is likely to undergo further legal challenges, which may result in additional costs or lost revenues to BPA, and assert that Staff has not adequately addressed the uncertainty of additional BiOp costs or BiOp-associated lost revenues. *Id*. at 8-9.

BPA Staff's Position

BPA Staff stated its intention to update much of the information about the costs of meeting BPA's fish and wildlife obligations in the final Supplemental Proposal. Russell, *et al.*, WP-07-E-BPA-67, at 41-42; Homenick and Lennox, WP-07-E-BPA-65, at 6-8.

Evaluation of Positions

The Tribes argue that the Supplemental Proposal did not incorporate enough uncertainty over possible future fish and wildlife costs, and therefore Staff's proposed rates were not adequate to meet those uncertain costs at the confidence level that the 95 percent TPP standard requires. CRITFC and Yakama Br., WP-07-B-JP13-01, at 8-9.

Staff proposed specific updates that BPA would make to the fish and wildlife costs in the final Supplemental Proposal. Lovell and Normandeau, WP-07-E-BPA-34, at 12. The final Supplemental Proposal will include the best information available at the time regarding fish and wildlife costs for FY 2009, as described in the IPR. *Id*. Staff further proposed how the NFB Adjustment and the Emergency NFB Surcharge would respond to any later changes in FCRPS BiOp-related costs. Normandeau, *et al.*, WP-07-E-BPA-86, at 4. Staff's proposal, therefore, is to have the risk analysis tools respond to some of the uncertainty in fish and wildlife costs and to have other mechanisms, such as the NFB mechanisms, which are not risk analysis tools, available to respond to other fish and wildlife uncertainties.

Decision

BPA's risk analysis tools, in the context of BPA's overall risk approach, incorporate sufficient uncertainty.

13.3 Emergency NFB Surcharge

Issue 1

Whether the TPP threshold of below 80 percent for application of the Emergency NFB Surcharge is appropriate.

Parties' Positions

The Tribes state that the Emergency NFB Surcharge would not trigger unless an NFB Trigger Event lowers the TPP to below 80 percent. CRITFC and Yakama Br., WP-07-B-JP13-01, at 15. The Tribes assert that this is a significant reduction from BPA's one-year TPP goal of 95 percent. *Id*. The Tribes argue that this means that BPA is accepting a 20 percent probability of deferring all or part of a Treasury payment before triggering the surcharge. *Id*. *See also,* CRITFC and Yakama, Br. Ex., WP-07-R-JP13-1 at 5-6.

BPA Staff's Position

BPA Staff explains that the 95 percent TPP standard, or more specifically, the 97.5 percent one-year TPP standard Staff has proposed in the Supplemental Proposal, is a standard for "overall" probability. Lovell and Normandeau, WP-07-E-BPA-34, at 12-13. Consistent with stated financial risk tolerance, Staff proposed that BPA could tolerate a higher probability of a Treasury deferral before triggering the Emergency NFB Surcharge. *Id.*

Evaluation of Positions

The 95 percent TPP standard, or more specifically, the 97.5 percent one-year TPP standard Staff has proposed in the Supplemental Proposal, is a standard for "overall" probability. The Tribes suggest a number that is part of a "conditional probability" calculation and present it for implicit comparison to an "overall" probability. A conditional probability is a probability that Event B will happen given that Event A has already happened. For example, it might be known that there is a 20 percent chance that Event B will happen if Event A has already happened, and a 0 percent chance that Event B will happen if Event A has not already happened. What is the chance that Event B will happen? It depends on how likely Event A is. The overall probability encompasses the likelihood of Event A happening: suppose Event A has a one-in-eight chance of occurrence; that is, there is a 12.5 percent chance Event A will happen. Then there is an overall probability of only 12.5% x 20% = 2.5 percent that Event B will happen. Russell, *et al.*, WP-07-E-BPA-86, at 12.

The Tribes have compared a 20 percent chance of a deferral *given that BPA is already in a cash crunch* to the overall probability of a deferral that BPA's TPP standard says is acceptable, 2.5 percent. This is not appropriate. Their calculation needs to incorporate the probability of Event A – the probability that BPA would already be in a cash crunch at the time an NFB Trigger Event occurs. Unfortunately, neither BPA nor the Tribes can calculate the probability that BPA might experience circumstances in which a "within-year" TPP is as low 80 percent, so BPA cannot quantitatively assess the degree of risk of this sort contained in Staff's proposal.

(The "within year" TPP of 80 percent is a special threshold designed for the Emergency NFB Surcharge; it is not a revised standard of the TPP, because the TPP is not a "within-year" standard in and of itself. *See* Lovell and Normandeau, WP-07-E-BPA-34, at 5.) Thus, the fact that – *in a cash crunch* – BPA could tolerate, say, a 19 percent probability of a Treasury deferral without triggering the Emergency NFB Surcharge does not by itself conflict with BPA's stated financial risk tolerance; that is, the 97.5 percent one-year TPP standard. *Id*. at 12-13.

The Tribes' analysis does not acknowledge the importance of conditional probabilities; the likelihood of BPA being in a position of having only an 80 percent within-year TPP must be taken into account when comparing 80 percent to BPA's one-year TPP standard of 97.5 percent. Thus, the Tribes' analysis failed to demonstrate that the 80 percent within-year TPP threshold for the triggering of the Emergency NFB Surcharge is inconsistent with BPA's TPP standard.

Decision

The 80 percent threshold for within-year TPP required before implementing an Emergency NFB Surcharge is appropriate.

Issue 2

Whether the Emergency NFB Surcharge "Trigger Event" should be expanded.

Parties' Positions

The Tribes assert that BPA should modify the NFB design so that it triggers whenever an Endangered Species Act (ESA) obligation is established. CRITFC and Yakama Br., WP-07-B-JP13-01, at 22. The Tribes also assert that BPA should trigger an emergency surcharge for any reason if its ability to repay the Treasury is compromised. *Id*. at 23.

BPA Staff's Position

BPA Staff believes that its proposal has adequately addressed the risks of higher costs in FY 2009 due to ESA obligations (including the new FCRPS BiOp and related litigation). It is highly unlikely that financial impacts from other ESA obligations could decrease BPA's net revenue very substantially during FY 2009, although BPA could consider modifying or expanding the NFB clauses in future rate cases if determined necessary or appropriate. *See* Normandeau, *et al.*, WP-07-E-BPA-73, at 17, and Russell, *et al.*, WP-07-E-BPA-86, at 11.

Evaluation of Positions

The Tribes urge BPA to expand the definition of Trigger Event to include all possible ESA obligations, not only those related to the FCRPS BiOp litigation. CRITFC and Yakama Br., WP-07-B-JP13-01, at 22.

The likelihood that other ESA obligations could significantly reduce BPA's cash flow during FY 2009 is so low that expanding the definition of Trigger Event as the Tribes suggest is not warranted. Normandeau, *et al.*, WP-07-E-BPA-73, at 17. The Tribes did not offer evidence that the risk of other ESA-related cost increases (other than FCRPS BiOp litigation) was significantly likely.

The Tribes proposed broadening the use of the Emergency NFB Surcharge to respond to any circumstance that threatens BPA's ability to make its Treasury payment. CRITFC and Yakama Br., WP-07-B-JP13-01, at 23.

Doing so, however, would fundamentally change BPA's financial risk tolerance as reflected in BPA's TPP standard. Russell, *et al.*, WP-07-E-BPA-86, at 13. Further, maximizing TPP is not the intent of BPA's TPP standard, as the Tribes imply; BPA's risk mitigation measures must only meet BPA's TPP goal, not eliminate the possibility of Treasury deferrals. *Id*. at 13-14.

The Tribes are suggesting a basic change in BPA's financial risk standard. The TPP standard reflects BPA's tolerance for financial risk. BPA does not now have a TPP standard that applies to individual years within a rate period or a within-year TPP standard. What the Tribes propose would require the adoption of such standards, but the Tribes do not describe how such standards would be defined, measured, or implemented. Normandeau, *et al.*, WP-07-E-BPA-86, at 13.

It has never been BPA's intent to have a 100 percent TPP. Such a standard would require rates to be prohibitively high as well as inconsistent with BPA's competing obligations to keep rates as low as possible consistent with sound business principles. 2007 Final Administrator's ROD, WP-07-A-02 at 5-4.

Decision

It is not necessary to expand the definition of "Trigger Event" for the Emergency NFB Surcharge for this rate period.

Issue 3

Whether the Emergency NFB Surcharge includes a requirement that BPA must reduce costs or increase revenues before BPA will apply the surcharge.

Parties' Positions

The Tribes contend that the Emergency NFB Surcharge contains language that implies that BPA must make cost cuts before deciding whether to address additional fish and wildlife costs. CRITFC and Yakama Br., WP-07-B-JP13-01, at 18.

BPA Staff's Position

This issue was raised only in brief; BPA Staff has not had an opportunity to file responsive testimony on this topic.

Evaluation of Positions

The Tribes contend that because Staff proposed language in the revised Emergency NFB Surcharge to consider "expense reductions and revenue increases" when calculating the Agency Within-Year TPP, the implication is that "Bonneville will make additional cost reductions, including fish and wildlife, before deciding to trigger a surcharge…" CRITFC, *et al.*, Br., WP-07-M-69, at 47; CRITFC and Yakama Br., WP-07-B-JP13-01, at 18.

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 is required to *cut* fish and wildlife expenditures or other costs prior to triggering the NFB Surcharge.

Staff's proposal allows BPA to calculate the Agency Within-Year TPP by taking a financial snapshot at a particular point in time. In order for that analysis to most accurately reflect BPA's financial outlook for the balance of that fiscal year, it is necessary to consider all relevant factors in order to project BPA's ability to make its end-of-year payment to Treasury. In that regard, BPA will add the following definition to the Emergency NFB Surcharge in the WP-07 rate case to provide some clarity:

> (c) The <u>Agency Within-Year TPP</u> 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 bolded 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 its end-of-year payment to the Treasury.

Decision

The revised Emergency NFB Surcharge "Trigger Event" language does not contain provisions that require BPA to reduce costs or increase revenues before triggering the Emergency NFB Surcharge.

Issue 4

Whether the Emergency NFB Surcharge proposal restricts BPA's ability to assure repayment to the Treasury.

Parties' Positions

The Tribes express concerns that the definition of NFB Trigger Event in BPA's proposal includes restrictions on BPA's ability to use the Emergency NFB Surcharge to meet its TPP compared to an earlier characterization of NFB Trigger Event. The Tribes state that these limitations reduce BPA's abilities to trigger the emergency NFB surcharge "for arrangements that neither BPA nor the parties have envisioned at this time" and reduce BPA's ability to assure repayment to the Treasury after meeting its costs. CRITFC, *et al.*, Br., WP-07-M-69, at 45-46; CRITFC and Yakama Br., WP-07-B-JP13-01, at 17-18; CRITFC and Yakama, Br. Ex., WP-07-R-JP13-1, at 6.

BPA Staff's Position

This issue was raised only in briefing; BPA Staff has not had an opportunity to file responsive testimony on this topic.

Evaluation of Positions

The earliest mention of the concept of NFB Trigger Event in the record is in Staff's proposal of the NFB Adjustment in its WP-07 Initial Proposal. Staff provided its first characterization of Trigger Event in its direct testimony:

> The NFB Adjustment will "trigger" if changes to the anadromous fish portion of the Fish and Wildlife program reduce [the Power function's] modified net revenue below what they would otherwise be, but 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.

Normandeau, *et al.*, WP-07-E-BPA-14, at 13-14.

The proposed GRSPs in Staff's WP-07 Initial Proposal retained the same definition of Trigger Event as the previous GRSPs:

> **a. 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.

WP-07-E-BPA-07, at 84-85.

In rebuttal testimony, Staff cited concerns raised by the Tribes and NWEC/SOS that Staff had overstated its TPP due to timing issues with the NFB Adjustment, and in response to those concerns, proposed the Emergency NFB Surcharge. Lovell and Normandeau, WP-07-E-BPA-34. Staff indicated that the Emergency NFB Surcharge was intended to respond to the same circumstances as the NFB Adjustment:

> The Emergency NFB Surcharge addresses the same FCRPS BiOp changes proposed for the NFB Adjustment to the CRAC cap.

Id. at 5.

The Hearing Officer approved a BPA motion to open the record to allow Staff to add the Emergency NFB Surcharge to its rate proposal on April 13, 2006. *See* WP-07-O-33. BPA said in its motion that it had engaged parties in extensive discussions of the Emergency NFB Surcharge. *Id*. BPA provided a more rigorous definition of NFB Trigger Event in Attachment A to the Hearing Officer's order approving BPA's motion:

> (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:
>   i. A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");
>   ii. 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;
>   iii. A new NMFS FCRPS BiOp; or
>   iv. 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.

WP-07-O-33, Attachment A, at 3-4.

Staff's Initial Proposal included the same four conditions that could trigger the NFB Adjustment as are found in the later definition of Trigger Event in WP-07-O-33. The first condition, a court-ordered change, and the third condition, a new NMFS FCRPS BiOp, are virtually the same in both definitions. The second condition was elaborated in the later order: "an agreement related to litigation" has been changed to "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." The thrust of this change is to clarify what "related to litigation" means. The fourth condition was changed from a brief phrase, "Recovery plans under the ESA," to a more precise wording that specifies that BPA's commitment is part of this condition, and that this condition, too, is related to the Litigation.

The Tribes argue that the definition of Trigger Event in Attachment A to WP-07-O-33 is a restriction compared to this passage from Staff's rebuttal testimony:

> NFB triggering events are changes in the FCRPS Endangered Species Act compliance that result in financial impacts due to the anadromous fish portion of BPA's fish and wildlife obligations. Such changes can arise from a court order (including court-approved agreement) agreements related to litigation, a new NMFS FCRPS BiOp, or BPA commitments to implement Recovery Plans under the ESA related to litigation.

Lovell and Normandeau, WP-07-E-BPA-34, at A-4.

It is clear, however, that the only significant change from the earlier definition (quoted in the previous paragraph) to the later definition in WP-07-O-33 is to specify for the second and fourth conditions that "related to litigation" means "results in the resolution of issues in, or the withdrawal of parties from, the Litigation."

The Tribes argue that the refinement in the definition of the kinds of FCRPS BiOp changes that can trigger the NFB mechanisms amounts to "limitations" on BPA's ability to use the NFB mechanisms. They did not identify any events or categories of events that would have qualified under the earlier definition of Trigger Event that would fail to qualify under the later definition. Both definitions allow for arrangements that were not envisioned at the time of the crafting of the definitions. The later definition is merely a more carefully worded version of the earlier definition.

Decision

BPA's Emergency NFB Surcharge proposal does not improperly restrict BPA's ability to meet its obligations to the Treasury.

Issue 5

Whether a delay in collecting the Emergency NFB Surcharge could affect BPA's ability to pay its obligations.

Parties' Positions

The Tribes contend that there could be a delay of at least two months and potentially more in the process for the Emergency NFB Surcharge, including the time needed to notify parties, hold a workshop, announce the surcharge, and begin billing. CRITFC and Yakama Br., WP-07-B-JP13-01, at 16. The Tribes imply, but do not state, that this could affect BPA's ability to pay the obligations that the surcharge was designed to address. The Tribes ask that BPA provide an analysis of how the schedule for implementing the surcharge will affect BPA's ability to repay the Treasury and that BPA provide an opportunity for rebuttal of this analysis. *Id*.

BPA Staff's Position

BPA Staff 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. Lovell and Normandeau, WP-07-E-BPA-34, at A-6 and 7. The delay in receiving funds from customers was taken into account in the Supplemental Proposal GRSPs. *Id*.

Evaluation of Positions

The Tribes assert that there may be a delay in when BPA collects the funds from the Emergency NFB Surcharge. The Tribes assert that the customers will need to raise their rates to collect the additional revenue and send the payments to BPA; this will add at least one month for the billing cycle, and the receipt of the surcharge revenues could be delayed by at least two months and potentially more. The Tribes state that BPA should modify its proposal to expedite the collection of the revenues. CRITFC and Yakama Br., WP-07-E-JP13-03, at 12.

The collection of funds from the customers for the Emergency NFB Surcharge does not need to wait for customer utilities to raise rates to their end-use customers, contrary to the Tribes' assertion. The collection schedule takes into account the billing cycle; that is the meaning of the phrase, "number of billing months payable before the end of the then current fiscal year." There will be a delay in collecting funds through the Surcharge, and this has been appropriately anticipated in the GRSPs.

The Tribes' request for further analysis is not timely for the WP-07 Supplemental Proposal, as it comes in their Initial Brief.

The delay in receiving funds from customers was taken into account in the Supplemental Proposal GRSPs:

> Each Customer Percentage will be multiplied by the 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 G.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. In the discretion of the Administrator, BPA may collect the

> Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

Proposed GRSPs, WP-07-E-BPA-51, at 90.

Decision

Delays in collecting funds via the Emergency NFB Surcharge have been appropriately anticipated in the design of the Surcharge, and therefore they do not constitute a risk to BPA's ability to meet its obligations.

13.4 The CRAC and the DDC

Issue 1

Whether BPA should eliminate use of the DDC.

Parties' Positions

The Tribes assert that the DDC will reduce the size of reserves and reduce BPA's ability to repay the Treasury after meeting its costs. CRITFC and Yakama Br., WP-07-B-JP13-01, at 23. They argue that BPA should eliminate the DDC provision. *Id*.

BPA Staff's Position

The Supplemental Proposal meets the TPP standard while taking into account the DDC mechanism. Therefore, eliminating the DDC would not help meet the TPP standard; it is already met. Russell, *et al.*, WP-07-E-BPA-86, at 14.

Evaluation of Positions

The Tribes may be under the impression that it is BPA's goal to minimize the likelihood of a Treasury deferral, or conversely, that it is BPA's goal to have as high a TPP as possible. That is not the case. The TPP standard defines a level of risk that the Administrator has determined is acceptable in carrying out his responsibilities. BPA is able to meet that standard with the DDC as proposed in the Supplemental Proposal. It may be true that implementing the DDC would reduce BPA's financial reserves, but the financial risk any such reduction could create is within BPA's risk tolerance, as evidenced by meeting the TPP standard while taking the DDC into account.

It has never been BPA's intent to have a 100 percent TPP. Such a standard would require rates to be prohibitively high and would be inconsistent with BPA's competing obligation to keep rates as low as possible consistent with sound business principles. WP-07 Administrator's Final ROD, WP-07-A-02, at 5-4.

Decision

BPA is able to meet its TPP standard with the current definition of the DDC. Therefore, the DDC does not need to be eliminated.

Issue 2

Whether BPA should improve the CRAC.

Parties' Positions

The Tribes argue that BPA should eliminate the limit on how much can be collected by the CRAC; at a minimum, BPA should increase the limit. CRITFC and Yakama Br., WP-07-B-JP13-01, at 22. BPA should also make the CRAC forward looking: it should begin collecting additional revenues as soon as the obligations are established and continue to collect the funds as long as the obligations are known. *Id*.

BPA Staff's Position

BPA Staff's proposal is able to meet its TPP standard with the current cap and definition of the CRAC. Russell, *et al.*, WP-07-E-BPA-86, at 10.

Evaluation of Positions

The purpose of the CRAC is to enable BPA to meet its TPP standard, not to exceed it, so an increase in the cap is not justified. Russell, *et al.*, WP-07-E-BPA-86, at 10. The Tribes' second suggestion, to trigger the CRAC "as soon as the obligations are established," is also not justified, because determining when the obligations are "established" is subjective. *Id*.

Decision

BPA is able to meet its TPP standard with the current cap and definition of the CRAC. Therefore, the CRAC is strong enough and does not need to be "improved."

13.5 Treasury Payment

Issue 1

Whether BPA will meet its TPP goal if it experiences additional fish and wildlife costs.

Parties' Positions

The Tribes analyzed the Supplemental Proposal under two hypothetical cases where BPA's costs were increased or revenues were reduced as a result of implementing potential court-ordered actions in relation to the FCRPS BiOp. CRITFC and Yakama Br., WP-07-B-JP13-01, at 12-13; CRITFC and Yakama, Br. Ex., WP-07-R-JP13-1, at 5. The Tribes assert that their analysis shows that BPA is not able to meet its TPP goals if its Biological Opinion costs are higher than it assumes. CRITFC and Yakama Br., WP-07-B-JP13-01, at 14.

BPA Staff's Position

The Tribes modeled only one of the two major tools BPA has proposed. Russell, *et al.*, WP-07-E-BPA-86, at 8. They modeled the NFB Adjustment but did not model the impact of the Emergency NFB Surcharge. *Id*. The lack of modeling of the impact of the Emergency NFB Surcharge is a serious defect in their analysis. *Id*.

Evaluation of Positions

The Tribes analyzed the Supplemental Proposal under two hypothetical cases where BPA's costs were increased or revenues were reduced as a result of implementing potential court-ordered actions in relation to the FCRPS BiOp. The purpose was to test whether the CRAC and NFB Adjustment were adequate to maintain the TPP goal. The Tribes first analyzed a hypothetical case that assumed reduced revenues of $100 million in FY 2008 and FY 2009. BPA's ToolKit model showed that the TPP was reduced from the 97.5 percent goal to 95.1 percent. *See* Sheets, *et al.*, WP-07-E-JP13-7O (attachment entitled "Toolkit $100 Million Addition with CRAC and NFB"). In a second hypothetical case, the Tribes assumed $200 million in reduced revenues in FY 2008 and FY 2009. When the Tribes made these changes in the ToolKit, the TPP was reduced to 91.6 percent. *See* Sheets, *et al.*, WP-07-E-JP13-7P (attachment entitled "Toolkit $200 Million Addition with CRAC and NFB"). CRITFC and Yakama Br., WP-07-B-JP13-01, at 12-13. The Tribes assert that this analysis shows that BPA is not able to meet its TPP goals if its BiOp costs are higher than BPA assumes. *Id*. at 14.

Staff proposed not to model the expense and revenue uncertainties associated with potential future court-related actions to the FCRPS BiOp due to lack of information available for future events, whether interim changes or a new BiOp altogether. Normandeau, *et al.*, WP-07-E-BPA-14, at 13. To address the uncertainty related to BPA's future fish and wildlife obligations, Staff proposed the NFB Adjustment in its WP-07 Initial Proposal. The Tribes claimed in their WP-07 direct case that the NFB Adjustment may not always be able to provide sufficient TPP support. Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, at 54-55.

The time lag in the recovery of cash through an NFB Adjustment of up to one year does prevent the NFB Adjustment from providing adequate 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, Staff proposed and BPA adopted the Emergency NFB Surcharge in its WP-07 Final Proposal. 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 reduce BPA's ability to make the payment to Treasury.

In their analysis, the Tribes modeled only one of the two major tools BPA has proposed. They modeled the NFB Adjustment by assuming that the cap on the CRAC that applies to FY 2009 rates would be increased by either $100 million or $200 million. However, they did not model the impact of the Emergency NFB Surcharge, which could take effect entirely within a fiscal year. BPA's computer application for measuring TPP, the "ToolKit," is an annual model. That is, the time step used internally by the ToolKit is an entire year. This means the ToolKit is not set up to model intra-year risks or intra-year risk treatments. Although it is not the Tribes' fault they could not model the impact of the Emergency NFB Adjustment with the tools available, nonetheless, the lack of modeling of the impact of the Emergency NFB Adjustment is a serious defect in their analysis. Russell, *et al.*, WP-07-E-BPA-86, at 8.

The Emergency NFB Surcharge will be implemented very rapidly if an NFB Trigger Event occurs that is estimated to reduce BPA's net revenue at a time when BPA is short of cash. When the Tribes reduced net revenue by $100 or $200 million per year, the result was that more of the 3,000 games resulted in a deferral at the end of FY 2009. In many, or perhaps even all, of those additional games resulting in deferrals, the within-year TPP would have fallen below 80 percent; after all, they actually did result in deferrals in the modeling. Thus, the Emergency NFB Surcharge would have kicked in to provide needed cost coverage. But because it was not modeled, the impact of the Surcharge was ignored. The irony of this is that it was the Tribes' testimony in the WP-07 rate case on this specific issue that persuaded BPA to create the Emergency NFB Surcharge. *Id*. at 8-9. In their Brief on Exceptions in this proceeding, CRITFC and Yakama (not joined by the Nez Perce Tribe) assert that BPA's lack of modeling is a serious defect as BPA has not provided "empirical analysis" about the effect of the Emergency NFB Surcharge, a shortcoming that can and should be cured. CRITFC and Yakama, Br. Ex., WP-07-R-JP13-1, at 5. BPA disagrees that the Surcharge must be modeled before it can be found satisfactory— the Surcharge is specifically designed to address additional BiOp-related costs should they occur, and it does not carry any limitation on the amount that could be recovered should it be deemed a cost that BPA must recover. BPA believes it would be impractical and inefficient to expend limited staff time in this proceeding to develop this substantial new modeling capability when unnecessary. Modeling is not the only way to demonstrate how rate provisions work; BPA has provided a logical analysis instead of a modeling analysis.

The Tribes may misunderstand BPA's TPP standard, which calls for BPA to set rates high enough to achieve a particular TPP. The standard does not call for BPA to constantly take corrective action, once rates have been set, to maintain TPP at any particular level. Russell, *et al.*, WP-07-E-BPA-86, at 6. "BPA shall establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making its U.S. Treasury payments in full and on time for each 2-year rate period." 1993 Administrator's Final ROD, WP-93-A-02, at 58.

The Tribes argue that there is no uncertainty around the range of potential costs that might result from a court-ordered action or new BiOp, arguing that the costs will either be there or not. CRITFC Br., WP-07-M-69, at 38. This argument ignores the objective of risk mitigation, which is to set rates and provide risk mitigation features that will be able to adjust later for uncertainties that BPA faces in the FY 2007-2009 rate period, including FCRPS Biological Opinion litigation.

In the case of the FCRPS BiOp risk, whether there is uncertainty over the range of possible costs 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.

As described above, the Tribes' analysis of TPP under the assumption of higher fish and wildlife costs is flawed. In addition, the implication that BPA's risk mitigation tools should be capable of maintaining BPA's TPP at 97.5 percent no matter what events occur in the future is erroneous. BPA's TPP standard requires that BPA set rates to meet the TPP target; it does not require that BPA take steps to maintain TPP at a particular level no matter what happens. The question of whether BPA would be able to meet its TPP goal if certain events occurred is not relevant to BPA's TPP standard.

Decision

BPA is able to meet its TPP goal. BPA is not required by its TPP standard to show that if certain events occur after the completion of rate setting, BPA's TPP still meets the target set in BPA's TPP standard. BPA is also not required to model the Emergency NFB Surcharge in various hypotheticals in order to rely on its performance in addressing specific risks.

Issue 2

Whether BPA's Supplemental Proposal assures Treasury repayment on a current basis.

Parties' Positions

The Tribes assert that BPA's proposal does not assure repayment of the Treasury on a current basis after meeting its costs. CRITFC and Yakama Br., WP-07-B-JP13-01, at 9, 11, 13.

BPA Staff's Position

BPA Staff's entire Supplemental Proposal presents evidence that BPA has adequate plans for meeting its financial obligations, including those to the Treasury.

Evaluation of Positions

While the Tribes describe how important it is for BPA to meet its obligations to the Treasury, they do not offer actual evidence in their direct testimony (WP-07-E-JP13-07-E1-CC1), their WP-07 direct testimony (WP-07-E-CR/NZ/YA-01), or their surrebuttal testimony (WP-07-E-JP13-03) that BPA's proposal is not adequate to meet those obligations on a current basis or define how they are interpreting the term "on a current basis." The entire record consists of the three repetitions of this claim in headings in their Initial Brief, WP-07-B-JP13-7-E1.

In their first Brief on Exceptions, the Tribes argued that BPA's TPP standard of 92.6 percent does not assure repayment on a current basis. CRITFC, *et al.*, Br. Ex., WP-07-M-77, at 9. The Administrator concluded that the Tribes were essentially arguing for a different TPP standard, and rejected their claim. WP-07 Final ROD, WP-07-A-02, at 5-3. In their current Initial Brief, the Tribes argue that it is Staff's proposal (instead of the TPP standard) that fails to assure repayment on a current basis, but they have failed to make a reasonable argument that this is in fact the case. CRITFC and Yakama Br., WP-07-JP13-7-E1.

In their Brief on Exceptions in this Supplemental proceeding, CRITFC and Yakama clarified that "BPA's standard of 'on time and in full' is a good measurement for 'on a current basis.'" CRITFC and Yakama Br. Ex., WP-07-R-JP13-1, at 4. Yet the standard of 'on time and in full' is part of BPA's existing TPP policy, which is that "BPA shall establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making its U.S. Treasury payments in full and on time *for each 2-year rate period.*" 1993 Administrator's Final ROD, WP-93-A-02, at 58 (emphasis added). If CRITFC and Yakama are nonetheless intending to imply that BPA must maximize TPP, BPA has already addressed this issue, see above, in section 13.3, issue 2.

Decision

BPA's proposal adequately ensures BPA's timely Treasury repayment, and parties have not shown otherwise.

Issue 3

Whether BPA adequately considered the political and other risks of deferring a Treasury Payment.

Parties' Positions

The Tribes contend that BPA's risk analysis fails to accurately assess the risks related to a Treasury Payment deferral. CRITFC and Yakama Br., WP-07-B-JP13-01, at 10. The Tribes are concerned that because of the political impacts of missing a Treasury payment, BPA will cut its commitments to fish and wildlife. *Id*. at 20. The Tribes contend that it would be "inappropriate for Bonneville to reduce its MOA commitments to the tribes rather than proactively address TPP risk in this proceeding." *Id*.

BPA Staff's Position

If BPA can prudently reduce its costs, thereby reducing its financial obligations, it will do so, consistent with its contractual and statutory obligations. Russell, *et al.*, WP-07-E-BPA-86, at 9-10.

Evaluation of Positions

The Tribes contend that BPA's risk analysis fails to accurately assess the risks related to a Treasury Payment deferral. CRITFC and Yakama Br., WP-07-B-JP13-01, at 10. The Tribes state that "failure to make annual payments to the Treasury [would be] perceived as a subsidy for the Northwest," giving the "Northwest a competitive advantage over other regions." *Id*. The Tribes believe the Treasury should not subsidize BPA rates, and BPA rates should not put other regions of the country at an "unfair disadvantage." *Id*. at 11. The Tribes apparently fear that because of the political impacts of missing a Treasury payment, BPA may be forced to consider cutting costs instead of missing a Treasury payment. The Tribes express concern that if BPA faces such an event, it will cut its commitments to fish and wildlife, including potentially its Fish Accord MOA commitments with the Tribes. *Id*. at 20. The Tribes contend that it would be "inappropriate for Bonneville to reduce its MOA commitments to the tribes rather than proactively address TPP risk in this proceeding." *Id.*

This issue is highlighted in the CRITFC brief, but neither the brief nor the cited testimony, which contains exactly the same language as the brief, mentions anything about political risks or subsidies. Because these issues were not raised earlier, BPA Staff has not had an opportunity to file responsive testimony.

Treasury deferrals are not Federal taxpayer subsidies to BPA ratepayers. When BPA has failed to make complete Treasury payments on time, BPA has recorded the amounts of shortfalls and has always subsequently paid to the Treasury the entirety of all shortfalls and all appropriate additional interest payments.

BPA's TPP standard is a probabilistic one, reflecting a standard that rates will be high enough to make it certain that BPA could make all of its Treasury payments on time nearly all the time. The 95 percent TPP standard for a two-year rate period is a compromise among many competing priorities; in a one-year rate period, the TPP standard allows for a 2.5 percent probability that BPA will not be able to make its Treasury payment. One option when a Treasury payment is in jeopardy thus is to miss at least part of the Treasury payment, and BPA's enabling statutes contemplate this. In fact, BPA is required to prioritize its financial obligations, and payments to the Treasury are the lowest priority; BPA is required to meet its other financial obligations before paying the Treasury. *See* Federal Columbia River Transmission System Act, section 13(b), 16 U.S.C. § 838k(b). Of course, if BPA can prudently reduce its costs, thereby reducing its financial obligations, it will do so, but only if such reductions are consistent with its contractual and statutory obligations. Russell, *et al.*, WP-07-E-BPA-86, at 9-10.

If BPA faced a potential Treasury deferral, BPA would explore all available sources of liquidity. For instance, BPA could obtain cash by borrowing for long-lived assets that no longer have associated debt. BPA could also convert deferred borrowing to cash by issuing debt to the Treasury. Even if BPA focused solely on reducing costs, it need not mean budget cuts focused on specific programs. BPA could pursue a wide variety of actions, such as renegotiating power sales and purchase contacts, negotiating the deferral of some payments, imposing freezes on hiring, selling inventories, deferring maintenance, and/or reducing the use of leased space.

When facing a potential deferral, BPA has other options besides reducing costs and missing a Treasury payment. BPA would reduce its costs only in ways that would be consistent with its contractual and statutory obligations, including all relevant MOA commitments to the Tribes.

Decision

As demonstrated in Staff's Supplemental Proposal, BPA has adequately considered the political and other risks of deferring a Treasury payment.

13.6 Reserve Levels

Issue 1

Whether BPA's financial reserves are unreasonably high.

Parties' Positions

PPC asserts that BPA will carry Agency financial reserves of about $1.5 billion into FY 2009, of which $1.03 billion represents reserves available for risk. O'Meara, *et al.*, WP-07-E-PP-09, at 29. PPC asserts that BPA's financial reserves are unreasonably high. PPC Br., WP-07-B-JP25-01, at 50. PPC argues that "BPA should modify its approach to quantifying necessary reserves for risk, so that the agency is not in the position of holding on to significantly more of customers' dollars than will be required for the agency to make its Treasury Payment Probability." *Id*. at 51.

BPA Staff's Position

BPA Staff has proposed a DDC in its Supplemental Proposal. Normandeau, *et al.*, WP-07-E-BPA-73, at 11. Staff proposes to calculate in September of 2008 whether that DDC will trigger for application to FY 2009 rates. Russell, *et al.*, WP-07-E-BPA-81, at 4. If the DDC triggers, Staff proposes to apply the DDC to non-Slice power rates, thereby refunding money to non-Slice power customers. *Id*.

Evaluation of Positions

BPA faces large financial risk and needs to maintain large financial reserves, as shown by the fact that even with a point estimate of reserves available for risk attributed to the power function at the start of FY 2009 of $1,031 million, a CRAC was still needed to meet the one-year rate period TPP standard of 97.5 percent. *See* Normandeau, *et al.*, WP-07-E-BPA-73, at 6 and 9. PPC does not present any evidence that BPA's reserves are unreasonably high. In addition, BPA's rates include a DDC provision, which will rebate funds to customers if reserves grow beyond the level needed to support BPA's TPP. Russell, *et al.*, WP-07-E-BPA-81, at 4.

Decision

BPA's financial reserves are not unreasonably high.

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14.0 FY 2009 RESIDENTIAL EXCHANGE PROGRAM AVERAGE SYSTEM COSTS AND EXCHANGE LOAD FORECASTS

14.1 Introduction

The Northwest Power Act, 16 U.S.C. § 839, *et seq.*, established the REP to provide residential and small farm customers of PNW utilities a form of access to low-cost Federal power. Under the Northwest Power Act, BPA "purchases" power from each participating utility at that utility's average system cost (ASC). 16 U.S.C. § 839c(c)(1). The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's PF Exchange rate. *Id*. The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. 16 U.S.C. § 839c(c)(2). The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities. 16 U.S.C. § 839c(c)(3).

The REP does not involve a conventional purchase and sale of power. Under the normal implementation of the REP, no actual power is transferred either to or from BPA. The "exchange" has been commonly described as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the less expensive power "sold" to the participating utility. As discussed below, however, an actual power sale may occur under an "in-lieu" transaction, where BPA purchases power from a source other than the utility and sells actual power to the utility. 16 U.S.C. § 839c(c)(5).

When a participating utility's ASC is less than the PF Exchange rate, the utility may elect to deem its ASC equal to the PF Exchange rate. By doing so, the utility avoids making actual monetary payments to BPA. The amount the utility would otherwise pay BPA is accumulated in a "deemer account." Then, when the utility's ASC is higher than the PF Exchange rate, benefits that would otherwise be paid to the utility act as a repayment of the "deemer balance." Only after the benefits have completely repaid the "deemer balance," reducing the "deemer account" to zero, would the utility again receive actual monetary payments from BPA. Avista Corporation (Avista), Idaho Power Company, and NorthWestern Energy have deemer balances. Boling, *et al.*, WP-07-E-BPA-57, at 3. The issue of deemer balances with Idaho Power Company and Avista is currently in dispute. Forman, *et al.*, WP-07-E-BPA-76, at 64-75. If settlement of the deemer disputes occurs after this Supplemental Proceeding, BPA expects to reflect the terms of such settlement in the respective IOUs' Lookback Amounts. Forman, *et al.*, WP-07-E-BPA-76, at 68. *See* Chapter 8 for a complete discussion of the issues raised by parties regarding the deemer balances.

A participating utility's ASC is the sum of a utility's production and transmission-related costs (Contract System Costs) divided by the utility's Contract System Load. *See* BPA's Proposed 2008 ASC Methodology (2008 ASCM), at 1. Section 5(c)(7) of the Northwest Power Act lists the costs that cannot be included in a participating utility's ASC. 16 U.S.C. §§ 839c(c)(7)(A), (B), and (C). These include the costs to serve a new large single load (NLSL); the costs to serve extraregional load that occurs after December 5, 1980; and the costs of a generating facility terminated prior to commercial operation. For FY 2009 and thereafter, a utility's Contract

System Load is defined as the total retail load included in the Federal Energy Regulatory Commission (FERC) Form 1, or for a consumer-owned utility (preference customer), the total retail load from the most recent annual audited financial statement as adjusted pursuant to the 2008 Average System Cost Methodology. *See* 2008 ASCM, at 1. The resulting quotient (the utility's Contract System Costs divided by Contract System Loads) is the utility's ASC. *Id*.

Each participating utility's ASC is determined in accordance with an ASC Methodology, an administrative rule developed by BPA in consultation with its customers. 16 U.S.C. §§ 839c(c)(7). The ASC Methodology preceding BPA's 2008 ASCM was developed in 1984 (1984 ASCM). *See* Methodology for Sales of Electric Power to Bonneville Power Administration, 49 Fed. Reg. 39,293, 39,297 (Oct. 5, 1984). On February 7, 2008, BPA commenced a consultation process pursuant to section 5(c)(7) of the Northwest Power Act to revise the 1984 ASCM. *See* 73 Fed. Reg. 7270 (Feb. 7, 2008). The currently proposed (pending FERC approval) 2008 ASCM includes five major changes from the 1984 ASCM. McHugh, *et al.*, WP-07-E-BPA-71, at 3. The first major change is the source of data for the ASC determinations. *Id*. Under the 1984 ASCM, BPA used IOU state public utility commission data to determine ASCs (known as the "jurisdictional approach"). *Id*. BPA has proposed changing from the jurisdictional approach to a FERC Form 1 approach. *Id*. The FERC Form 1 is an annual filing that all IOUs are required to file with FERC that contains the utility's financial information. *Id*.

Second, the 2008 ASCM requires one ASC determination per utility for each BPA rate period rather than a new ASC determination in each jurisdiction each time the utility changes its retail rates. *Id*. Third, the 2008 ASCM includes return on equity in ASC at the level approved in the exchanging utility's most recently approved rate order from its state regulatory commission. *Id*. Fourth, the 2008 ASCM includes in ASC imputed Federal income taxes at the marginal Federal income tax rate. *Id*. Fifth, the 2008 ASCM includes in ASC all transmission plant and related expenses. *Id*. BPA proposed numerous other changes in the 2008 ASCM. Staff used the proposed new 2008 ASCM to forecast ASCs for the Supplemental Proposal. *Id*.

14.2 Forecast of Average System Costs and Loads for Exchanging Utilities

BPA does not establish utilities' ASCs in wholesale power rate proceedings. Instead, BPA's rate proceedings merely forecast exchanging utilities' ASCs in order to calculate the forecast amount of REP costs that must be recovered in rates pursuant to section 7(a) of the Northwest Power Act. 16 U.S.C. § 839e(a). The 1984 ASCM did not prescribe any particular method for forecasting ASCs in BPA's rate proceedings. Boling, *et al.*, WP-07-E-BPA-83, at 32. Historically, these forecasts were made by viewing the last ASCs filed by participating utilities and then escalating the ASC input data through the BPA rate period. *Id*. As noted above, BPA has proposed to change the 1984 ASCM. Because the 2008 ASCM is not yet approved by FERC, BPA has not established any ASCs for the participating utilities with which to forecast ASCs. Using the participating utilities' prior ASC filings would not be appropriate because those filings were developed under the 1984 ASCM, which is substantively different from the proposed 2008 ASCM. The 2008 ASCM likely will be in place during FY 2009. McHugh, *et al.*, WP-07-E-BPA-71, at 1-5. The ASC forecasts BPA uses to set rates should reflect as closely as possible the ASCs that will be established for the participating utilities for FY 2009. To provide the best forecast, in a separate proceeding BPA developed ASC forecasts under the proposed 2008 ASCM through an "expedited ASC review process." 73 Fed. Reg. 7,539, 7,547 (Feb. 8, 2008). The expedited review process occurred in a forum separate from the rate case. *Id.*; *see also* McHugh, *et al.*, WP-07-E-BPA-71, at 3. Although participation in the process was mandatory for any utility wishing to participate in the REP in FY 2009, any party with an interest in the ASC forecasts could intervene and participate in the process. *See* 73 Fed. Reg. 7539, 7,547 (Feb. 8, 2008). In the expedited review process, participating utilities were required to file with BPA base ASCs that conformed to the proposed 2008 ASCM. BPA reviewed these filed ASCs under the terms and provisions of the proposed 2008 ASCM and worked with the exchanging utilities to address questions and issues regarding the filed ASCs. The expedited review process was the forum for parties to raise any and all issues related to the forecast ASCs. Once completed, the results of the expedited review process are used to establish the forecast ASCs for FY 2009 and incorporated into BPA's Final Supplemental Proposal. *Id.*; *see also* McHugh, *et al.*, WP-07-E-BPA-71, at 23. BPA officially notes the final 2008 ASCM and the ASCM Record of Decision filed with FERC on July 7, 2008, and will include it in the record of this proceeding.

Issue 1

Whether BPA should use its proposed 2008 ASCM and the results of the expedited process to forecast ASCs for FY 2009.

Parties' Positions

The WUTC supports Staff's proposal to use the 2008 ASCM to forecast ASCs for FY 2009. WUTC Br., WP-07-B-WU-01, at 27.

APAC objects to the use of the new ASC Methodology as it may be applied to any future rate period, as both unreasonable and unlawful. APAC Br. Ex., WP-07-R-AP-01, at 29.

BPA Staff's Position

BPA Staff proposed using the expedited ASC review process in conjunction with the 2008 ASCM to forecast ASCs for purposes of setting rates for FY 2009. McHugh, *et al.*, WP-07-E-BPA-71; *see also* 73 Fed. Reg. 7539, 7547 (Feb. 8, 2008).

Evaluation of Positions

Staff proposed using the 2008 ASCM to forecast ASCs to ensure that BPA's 2009 power rates were established using the best available data. McHugh, *et al.*, WP-07-E-BPA-71, at 3. The 2008 ASCM includes a number of cost categories that were excluded in the 1984 ASCM. *Id.* Some of the changes include a different source for data, the allowance of Federal income taxes, the inclusion of return on equity and all transmission plant costs, and several changes in the procedures for determining ASCs. *Id.* Because the 2008 ASCM would not be finalized and approved by FERC before completing the WP-07 rate proceeding, BPA proposed to conduct an "expedited ASC review process" using the provisions of the 2008 ASCM to calculate forecast ASCs for BPA's FY 2009 rates. *Id*. Staff proposed that the results of the expedited process would be incorporated into the final Supplemental Proposal. *Id*.

The WUTC supports Staff's proposal to use the 2008 ASCM expedited process forecast of participating utilities' ASCs in the final Supplemental Proposal. WUTC Br., WP-07-B-WU-1, at 27.

APAC raises for the first time in its Brief on Exceptions a general objection to BPA's use of its proposed 2008 ASCM to "any future rate period," and that the use of such methodology is both "unreasonable and unlawful." APAC Br. Ex., WP-07-R-AP-01, at 29. Though not exactly clear from its brief, BPA presumes APAC's objection is to BPA's use of the 2008 ASCM for the FY 2009 ASC forecasts. If that is what APAC is attempting to argue, BPA considers APAC's position unfounded and without support in the record. BPA notes that APAC raises this issue for the *first time* in its Brief on Exceptions. At no other point in this proceeding has APAC, or any other party, raised an objection to BPA's proposal to use the 2008 ASCM for the FY 2009 ASCs. Since this is the first time any party has opposed BPA's proposal, there is no evidence on the record to support APAC's argument. BPA Staff explained that they used the 2008 ASCM as the basis for the FY 2009 ASC because "[t]his is the methodology that we believe will be in effect during the FY 2009 rate period." McHugh, *et al.,* WP-07-E-BPA-71, at 9. This proposal makes perfect sense because in order to set rates, BPA must have ASC forecasts that are as accurate as possible. BPA filed the proposed ASCM with FERC in July of 2008, and expects to receive approval on or before October 1, 2008. If the rate case ASCs were not developed to reflect the new 2008 ASCM, a mismatch would exist between the forecast ASCs used to set rates and the ASCs utilities would file with BPA under the REP on October 1. APAC does not explain why such a mismatch would be appropriate, or why BPA's desire to have a close relationship between the forecast ASCs and the actual ASCs is unreasonable. Nor does APAC explain why it would be appropriate to use the old 1984 ASC methodology. For these reasons, APAC's assertions that use of the 2008 ASCM for FY 2009 is "unlawful" and "unreasonable" must be rejected.

Decision

BPA will use its proposed 2008 ASCM and the results of the expedited review process for the forecast of ASCs for FY 2009.

Issue 2

Whether BPA should update the expedited review ASCs for the most current market and gas price forecasts.

Parties' Positions

The WUTC requests BPA to update the forecast ASCs from the expedited review process with updated gas and market price forecasts for FY 2009. WUTC Br., WP-07-B-WU-01, at 27.

BPA Staff's Position

Staff did not address this issue in testimony.

Evaluation of Positions

The WUTC suggests BPA should update the forecast ASCs of the IOUs for the most current market and gas price actual and forecast data. WUTC Br., WP-07-B-WU-01, at 27. The WUTC notes that the data and forecasts included in the Supplemental Proposal are "two years out-of-date." *Id*. The WUTC notes that in rebuttal testimony, Staff agreed to propose to update these figures for its FY 2007-2008 backcast of ASCs. *Id*., *citing* Boling, *et al.*, WP-07-E-BPA-83, at 31. Similarly, the WUTC requests that BPA also use updated information for its FY 2009 rates. *Id*. This issue was not raised by any parties in testimony and is being raised for the first time in brief. This issue was, however, discussed in the 2008 ASCM consultation process, and Staff agreed to update the natural gas and market price forecasts used in the expedited process with the forecasts to be used in the final Supplemental Proposal.

Decision

BPA has updated the expedited review FY 2009 forecast ASCs with BPA's market and gas price forecasts and will use such ASCs in the final Supplemental Proposal.

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15.0 FY 2009 WHOLESALE POWER RATE DESIGN

15.1 Introduction

For the Supplemental Proposal, Staff recommended no change to rate design and to continue use of the Partial Resolution of Issues that was used for the WP-07 Supplemental rate design. Evans, *et al.*, WP-07-E-BPA-31, Attachment A; Administrator's ROD, WP-07-A-02, Attachment 1. The following language is contained in the Partial Resolution of Issues:

> 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.

Staff used this methodology, including Table 1 and an updated revenue requirement, and then adjusted the rates presented in the PF-07R rate schedules proportionally as necessary to recover the revenue requirement. No rate case party opposed the Staff recommendation of no change to the rate design contained in the Partial Resolution of Issues.

Aside from the issues addressed below, parties raised no issues regarding the following Supplemental Proposal rate design elements: (1) removal of Firm Power Products and Services (FPS) posted rates for Demand, HLH Energy, LLH Energy, and Capacity without Energy (Fisher, *et al.*, WP-07-E-BPA-69, at 3); (2) replacement of all references to REP with Residential Sales and Purchase Agreement (RPSA) (*id*. at 10); (3) update of the CRAC, DDC, and NFB Adjustments (*id*. at 2-3); (4) update of the Low Density Discount (*id*. at 9); (5) update of Conservation Rate Credit language (*id*.); (6) update of the GTA Delivery Charge to reflect the Transmission Services rate proceeding for FY 2008-2009 (*id*.); and (7) various minor edits and additions to the GRSPs and Rate Schedules (*id*. at 10).

15.2 Allocation of Trigger Amount to Surplus Power Sales

Issue 1

Whether the section 7(b)(2) trigger amount should be allocated in part to BPA's surplus power rate.

Parties' Positions

The IOUs argue that section 7(b)(3) of the Northwest Power Act requires the section 7(b)(2) trigger amount to be allocated for collection through charges "*for all other power* sold by the Administrator *to all customers*." IOU Br., WP-07-B-JP6-01, at 109-110, *citing* 16 U.S.C. § 839e(b)(3) (emphasis added by IOUs). The IOUs argue the statutory language is plain, which means BPA must apply the trigger amount to BPA's surplus firm power (FPS) rate and to secondary power sold under the Slice rate. IOU Br., WP-07-B-JP6-01, at 110-111.

CUB argues that surplus sales fit the category of all other power sold by the Administrator, and because the Administrator's responsibility is mandatory, the Administrator must allocate 7(b)(3) amounts to surplus sales. CUB Br., WP-07-B-CU-01, at 10.

Alcoa argues that section 7(b)(3) language is emphatic that the trigger amount must be spread over all other power sold by the Administrator to *all customers*, and in that way the statute established a balance among the constituent groups of the Northwest Power Act that must be respected by BPA. Alcoa Br., WP-07-B-AL-01, at 5. This provision is not discretionary. *Id*.

The WUTC argues that BPA should modify its section 7(b)(3) methodology by allocating section 7(b)(2) protection amounts to revenue generated by sales of power to customers including under FPS contracts, pre-subscription contract rates, and market-based secondary energy sales. WUTC Br., WP-07-B-WU-01, at 29.

Cowlitz argues that a 7(b)(3) allocation to surplus power sales would offset revenues that would have otherwise been credited to the wholesale power rates charged to BPA's preference customers with a result, in economic terms, of placing back into preference customers' wholesale power rates the costs that were supposedly removed by operation of section 7(b)(2). Cowlitz Br., WP-07-B-CO-01, at 43-47. Section 7(b)(3) does not direct BPA to "allocate" the trigger amount to other power rates, but to "recover" the amounts from "other" power sales. *Id*. at 44. The IOUs propose only an "allocation," wherein the rates would remain the same but the allocation will only cause the surplus revenue credit to decrease or a surplus revenue deficit to increase. *Id*. at 45. Allocating the trigger amount to the FPS rates, with the "net effect" of shrinking the secondary revenues credit and raising the PF Preference rate, is ultimately a "plain violation" of the section 7(b)(2) statutory guarantee. *Id*. at 46.

PPC argues that the allocation of the trigger amount to surplus power rates would be contrary to an equitable allocation of the benefits of surplus power sales, and the costs of the REP cannot be allocated to BPA's preference customers. PPC Br., WP-07-B-JP25-01, at 42; PPC Br. Ex., WP-07-R-PP-01, at 28-32. PPC argues a 7(b)(3) allocation to surplus power sales would offset, virtually dollar for dollar, revenues that would have otherwise been credited to the wholesale power rates charged to BPA's preference customers with a result, in economic terms, of placing back into preference customers' wholesale power rates the costs that were supposedly removed by operation of section 7(b)(2). *Id*. at 43. PPC also argues that the costs of residential exchange benefits must not fall on preference customers. *Id*. at 42-43.

WPAG argues that the IOUs take the phrase in section 7(b)(3) out of context and create a legal argument that conflicts with both the underlying purpose and the specific language of section 7. WPAG Br., WP-07-B-WA-01, at 39. Applying the section 7(b)(3) surcharge to secondary and surplus sales, as advocated by the IOUs, will not recover additional revenues, since these are sales made at market prices that will not change regardless of the costs allocated to them. *Id*. The proposal made by the IOUs conflicts with the operation of the section 7(b)(2) rate test and operates to negate its fundamental purpose. *Id*. As a consequence, the IOU proposal contravenes a fundamental tenet of statutory interpretation. *Id*.

The Slice Customer Group argues that in order to implement the IOU proposal, BPA would have to impose the section 7(b)(3) surcharge on the PF rate, which is the very rate that the section 7(b)(2) rate test was intended by Congress to protect. Slice Br., WP-07-B-JP22-01, at 4. The PF rate under which the Slice product is sold contains an identical credit, but it is provided in kind by the delivery of secondary energy to the Slice purchasers on an as-available basis. *Id*. So while the delivery mechanism is different, the secondary credit for Slice and non-Slice customers is identical. *Id*. And all preference customers, whether they are Slice or non-Slice, purchase under a PF rate that has no separate secondary or surplus rate component. *Id*.

NRU states that it opposes BPA's draft decision to recover part of the section 7(b)(3) amount from the FPS rate. NRU Br. Ex., WP-07-R-NR-01, at 1-4. NRU notes that if BPA nevertheless determines to do this, NRU believes BPA must assure that this decision affects Slice and Non-Slice customers equitably. *Id*.

BPA Staff's Position

BPA Staff expressed concern that allocating a portion of the trigger amount to surplus sales, thus reducing the surplus revenue credit to all rates served by FBS and NR resources, might result in the PF Preference rate bearing some of the costs of its own rate protection. Doubleday, *et al.*, WP-07-E-BPA-78, at 13. However, Staff noted that there are statutory interpretation issues raised by the IOUs' argument regarding the meaning of "the projected amounts to be charged for firm power" and "the power costs for general requirements of such customers" in section 7(b)(2) of the Northwest Power Act. *Id*. at 21-22. Staff stated that BPA would address parties' properly raised legal interpretation issues in the Draft and Final Records of Decision in this proceeding, and if the IOUs' argument were adopted by the Administrator, Staff would make the necessary changes to the Implementation Methodology. *Id*.

Evaluation of Positions

A. Review of Statutory Language

As noted previously, if the Program Case exceeds the 7(b)(2) Case in the 7(b)(2) rate test, the rate test is said to "trigger." The difference between the two cases is called the "trigger amount" or "7(b)(3) allocation amount." If there is a trigger amount, section 7(b)(3) of the Northwest Power Act prescribes the manner in which the trigger amount is allocated. Section 7(b)(3) provides, in pertinent part, 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) (emphasis added). Section 7(b)(3) is unambiguous. The trigger amount must be recovered from "*all other power* sold by the Administrator to all customers," *id*. (emphasis added), which includes secondary power sales at the FPS rate.

BPA currently sells power to meet the requirements of preference customers under the PF Preference rate. *See* Wholesale Power Rate Schedules and GRSPs, WP-07-E-BPA-51, at 7. BPA sells power to regional utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act at the PF Exchange rate. *Id*. at 9. BPA sells firm power to its direct service industrial (DSI) customers at the IP rate. *Id*. at 50. BPA sells power to meet the requirements of preference customers' new large single loads and power to meet the requirements of BPA's IOU customers at the NR rate. *Id*. at 33-47. BPA sells surplus firm and secondary power to regional and extraregional customers at the Firm Power Products and Services (FPS) rate. *Id*. BPA cannot recover the trigger amount from sales at the PF Preference rate, which meets BPA's preference customer requirements, because such recovery is precluded by section 7(b)(3). 16 U.S.C. § 839e(b)(3).

In each rate proceeding, including the instant case, BPA has recovered trigger amounts from sales under the PF Exchange rate, the IP rate, and the NR rate, to the extent such sales were forecast in the rate setting process. No party disputes this treatment. However, the IOUs, Alcoa, and CUB raise the issue of why BPA fails to recover trigger amounts from sales under the FPS rate. BPA has never constructed rates to recover trigger amounts from sales under the FPS rate schedule or its predecessors, the Surplus Firm Power (SP) and Nonfirm Energy (NF) rate schedules. Out of all BPA rate proceedings since 1985, the effective date of section 7(b)(3), only four had positive trigger amounts (1987, 1996, 2002, and 2007 rate proceedings), and two of those were conducted assuming the 2000 REP Settlement Agreements, or amendments thereto, governed REP benefits. As a result of this limited experience with the proper treatment of trigger amounts, this issue has not arisen before, so it is before the Administrator as one of first impression.

The legislative history of the Northwest Power Act assists in understanding the statutory language. The report of the House Committee on Interior and Insular Affairs states that "[a]mounts not recoverable from preference customers because of this [7(b)(2) rate] ceiling are to be recovered through supplemental rate charges for *all other power sold by BPA* under other provisions of section 7, as subsection 7(b)(3) specifies." H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 52 (1980) (emphasis added).

The report of the House Committee on Interstate and Foreign Commerce states that "[i]n the event that this rate ceiling is triggered, then the additional needed revenues must be recovered *from BPA's other rate schedules*." H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2nd Sess. 69 (1980) (emphasis added).

The report of the Senate Committee on Energy and Natural Resources states that section 7(b) establishes "… a supplemental rate charge to recover any costs not recovered as a result of the rate test, to be applied through *rates to all other power sales of the Administrator…*" S. Rep. No. 96-272, 96th Cong., 1st Sess. 32 (1979) (emphasis added).

Most importantly for the current issue, the legislative history also directly addresses whether the trigger amount should be allocated to BPA's rate for secondary power sales. The Senate report states that "[t]he balance of the revenues not recovered due to the rate limit adjustment is then spread to rates for all other BPA power sold, *including nonfirm*." *Id*. at 59 (emphasis added). The term "nonfirm" from the Senate report refers to "secondary" in today's language.

Therefore, the foregoing statutory language and legislative history confirm that under the plain language of section 7(b)(3), BPA must recover part of the trigger amount from the FPS rate for surplus firm and secondary power sold under that rate.

B. Recovery of the Trigger Amount

The IOUs argue BPA must allocate section 7(b)(2) trigger amounts to all power sold by the Administrator to all customers, other than power sold for the general requirements of PF Preference rate customers. IOU Br., WP-07-B-JP6-01, at 109. The IOUs note that pursuant to Northwest Power Act section 7(b)(3), section 7(b)(2) trigger amounts removed from the BPA rate for "firm power for the combined general requirements of public body, cooperative and Federal agency customers" must be allocated for collection through charges "*for all other power* sold by the Administrator *to all customers*." 16 U.S.C. § 839e(b)(3) (emphasis added). *Id*. The IOUs state that the legislative history of the Northwest Power Act expressly recognizes and acknowledges that amounts allocated pursuant to section 7(b)(3) are to be spread to rates for BPA power, including BPA surplus sales of secondary energy: "The balance of the revenues not recovered due to the rate limit adjustment is then spread to rates for all other BPA power sold, including nonfirm." *Id*., *citing* S. Rep. No. 96-272, 96th Cong., 2d Sess. 59 (1979).

CUB, Alcoa, and the WUTC raise essentially the same argument as the IOUs. It should be noted that these parties' argument that trigger amounts are to be "allocated" to surplus sales or surplus revenues is not the strict language of section 7(b)(3). Section 7(b)(3) uses the term "recover." Therefore, it is important to determine whether there is a material difference between allocating and recovering.

As noted above, the IOUs note that the section 7(b)(2) trigger amount removed from the PF Preference rate must be allocated to the rates for the sale of all other power to all customers. IOU Br., WP-07-B-JP6-01, at 110. These other rates include the PF Exchange rate, IP rate, NR rate, FPS rate, and the portion of the Slice rate attributable to secondary energy because these rates are not the PF Preference rate charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers. *Id*., *citing* 16 U.S.C. §§ 839(b)(1), 839e(b)(2). The IOUs argue that nothing precludes BPA from allocating section 7(b)(2) trigger amounts to the FPS rate, including without limitation FPS contract rates, pre-Subscription contract rates, FPS secondary energy sales rates, and the portion of the Slice rate attributable to secondary energy. *Id*.

The IOUs note the FPS rate is the rate at which BPA sells, for firm delivery, essentially all of its power that it does not sell under the PF, NR, or IP rates. IOU Br., WP-07-B-JP6-01, at 111. Power sales under the FPS rate include, for example, BPA's pre-Subscription Contract power sales and BPA's secondary energy sales (other than secondary energy sold under the Slice rate). *Id*. Although the Slice rate is labeled as a PF rate, BPA in fact sells under the Slice rate to PF Preference rate customers both firm power to meet their regional firm load net requirements and secondary power. *Id*. Secondary energy sales are sales of power in excess of BPA's forecast firm resources available to meet firm load obligations under critical water conditions:

> On a resource planning basis and with system augmentation, BPA forecasts sufficient firm resources available to meet firm load obligations under critical water conditions. However, rates are set assuming that better than critical water conditions will occur. BPA projects secondary energy sales and revenues using 50 historical water-years as determined in RiskMod.

Id., *quoting* Supplemental WPRDS, WP-07-E-BPA-49, at 46.

The IOUs note that BPA projects substantial secondary energy sales:

> BPA expects to generate secondary energy that will produce about $743.9 million in revenues in FY 2009. Of that total, $743.9 million in forecast secondary revenue, 22.63 percent or about $168.3 million will be sold to BPA's Slice product customers producing no incremental revenue. The remaining $575.6 million is forecast to be marketed by BPA and is a revenue credit to non-Slice rates. *See* Supplemental WPRDS Documentation, WP-07-E-BPA-49A, Table 2.5.3 (RDS 11).

Id. BPA's Initial Proposal did not allocate costs to its rate for secondary energy sales, notwithstanding the fact that the Initial Proposal projected secondary energy sales of $743.9 million in revenues for FY 2009:

> Secondary and Other Revenue recognizes that BPA collects revenues from certain classes of service to which costs are not allocated. BPA credits these revenues to classes of service served with firm power. Projected secondary energy sales are the largest source of revenue credits.

Id.

Staff does not dispute that nothing precludes BPA from allocating part of the trigger amount to secondary sales. Brodie, *et al.*, WP-07-E-BPA-78, at 15. Staff's concern is whether trigger amounts can be recovered from fixed-rate contracts and market-negotiated prices. *Id*. This concern arises from a change of circumstances since passage of the Northwest Power Act. At the time the Act was being drafted, BPA had little to no firm surplus. This condition in the late 1970s led to notices of insufficiency to preference customers, a prime factor leading Congress to consider the need for legislation. Despite the general lack of firm surplus, BPA still had secondary energy, or nonfirm power, as it was called at that time. However, at that time, most of BPA's sales of secondary energy were made at rates determined in rate proceedings and posted as a fixed rate. *See* BPA 1979 Rate Schedules and GRSPs. Under this rate design, a supplemental rate charge, as allowed by section 7(b)(3), could be applied. Under such a rate design, BPA could determine its posted rate and then, if necessary as occasioned by section 7(b)(3), add a supplemental rate charge. In such instances, assuming purchasers were willing to pay BPA's fixed price, BPA's total revenues should increase, allowing recovery of the section 7(b)(2) rate protection.

Today, such a rate design is not in place. Almost coincident with the effective date of section 7(b)(3), July 1, 1985, BPA began pricing secondary energy at market-based negotiated rates. During those years, BPA found itself with amounts of firm surplus. BPA began selling these amounts at negotiated contract rates. With the advent of these two pricing schemes, the ability to add supplemental rate charges to increase revenues to recover a portion of trigger amounts was lost because the rates were ostensibly recovering as much revenue as the market would permit. Given these circumstances, BPA never allocated any trigger amounts to firm surplus and secondary sales.

BPA must address the question of how to recover the trigger amounts from surplus sales. Cowlitz argues that pursuant to section 7(b)(3), the costs preference customers are excused from paying pursuant to section 7(b)(2) "shall be *recovered* through supplemental rate charges for all other power sold by the Administrator to all customers." Cowlitz Br., WP-07-B-CO-01, at 43, *citing* 16 U.S.C. § 839e(b)(3) (emphasis added by Cowlitz). Cowlitz argues that the purpose of section 7(b)(3) was to assure that BPA had a clear mechanism to actually recover the costs from which preference customers were to be excused pursuant to section 7(b)(2) (the "7(b)(2) trigger amount"): supplemental rate charges applicable to *other* sales. *Id*. Cowlitz states that through this mechanism, Congress sought to ensure that the 7(b)(2) trigger amount would not be recovered, directly or indirectly, from PF Preference sales. *Id*.

Cowlitz fails to mention, however, that Congress also expressly directed that BPA must recover part of the trigger amount from BPA's rates for other sales, including surplus sales at the FPS rate. 16 U.S.C. § 839e(b)(3). Therefore, there must be a mechanism in order to fulfill this express Congressional requirement that is consistent with the implementation of the section 7(b)(2) rate test.

Cowlitz argues that more generally, section 7(b)(3) was to assure simultaneously that BPA recover all of its costs and that benefits of preference to preference customers would not be diminished by reason of the broader distribution of FCRPS benefits authorized by section 5(c) of the Northwest Power Act, *i.e.*, the Residential Exchange Program or REP. *Id*.

This argument is overbroad. Cowlitz fails to mention, as discussed in greater detail at the beginning of this chapter, that section 7(b)(2) *does not preclude the allocation of REP costs to the PF Preference rate*. 16 U.S.C. §§ 839e(b)(1), 839e(b)(2). Indeed, Cowlitz completely fails to mention section 7(b)(1) of the Northwest Power Act, which *expressly requires* BPA to allocate REP costs to the PF rate after the FBS is exhausted. 16 U.S.C. § 839e(b)(1). Such is the case in this proceeding. The section 7(b)(1) loads greatly exceed the size of the FBS. As a result, almost all of the REP costs are allocated to the PF rate. *See* Supplemental WPRDS, WP-07-E-BPA-49.

PPC states the context in which the section 7(b)(3) was developed is important here. PPC Br. Ex., WP-07-R-PP-01, at 27. PPC argues BPA must carry out its obligations under section 7(b)(3) in light of the compromise central to the passing of the Northwest Power Act: that preference customers would not pay the costs of REP benefits. *Id*. PPC makes this argument repeatedly in numerous forms and on numerous grounds. Its repetition, however, does not make it true. PPC's current position is a stark reversal of its recognition that REP costs can be allocated to the PF Preference rate, a position PPC had held since BPA's first development of rates under the Act in 1981, through the filing of its briefs in *PGE* and *Golden NW*. As established in great detail and length at the beginning of this chapter, *the Northwest Power Act does not preclude preference customers from paying the costs of the REP*. Although parties must review BPA's more detailed explanation to fully understand this fact, PPC's claim is unequivocally refuted, as just one example, by section 7(b)(1) of the Northwest Power Act, which expressly requires BPA to recover REP costs from preference customers after FBS resources are exhausted. 16 U.S.C. § 839e(b)(1).

Cowlitz and PPC argue that section 7(b)(3) does not direct BPA to "allocate" the trigger amount to other power rates, but to "recover" the amounts from "other" power sales. Cowlitz Br., WP-07-B-CO-01, at 44; PPC Br. Ex., WP-07-R-PP-01, at 29. Cowlitz and PPC argue that the suggestion to "allocate" the 7(b)(2) trigger amount in a fashion to shift recovery of some of such amount through PF Preference sales conflicts directly with the requirement in section 7(b)(3) that the supplemental rate charges "recover" the section 7(b)(2) trigger amount from somewhere other than the PF Preference rate. *Id*.

This argument lacks merit. Sections 7(b)(1), 7(c) and 7(f) are the primary rate directives regarding the costs to be recovered from the PF, IP, and FPS rates, respectively. These sections do not mention the word "allocate." Instead, they simply require the respective rates to "recover" costs. Section 7(b)(1) requires that the PF Preference and PF Exchange rates "*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 costs of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) [the REP] and then from other resources." 16 U.S.C. § 839e(b)(1) (emphasis added). Section 7(c)(1)(A) of the Northwest Power Act requires BPA's pre-1985 rates for the DSIs to be "set at a level which the Administrator estimates will be sufficient to *recover* the cost of resources the Administrator determines are required to serve such customers' load and the net costs incurred by the Administrator pursuant to section 5(c) of this Act …" 16 U.S.C. § 839e(c)(1)(A) (emphasis added). Section 7(b)(3) is consistent with such directives, and simply requires BPA to "recover" the trigger amount through supplemental rate charges. Section 7(e) of the Northwest Power Act grants BPA broad discretion in the manner of designing and implementing such supplemental charges. 16 U.S.C. § 839e(e). Furthermore, as discussed in greater detail below, BPA does not propose to recover *any* of the section 7(b)(3) amount from the PF Preference rate. BPA proposes to recover the 7(b)(3) amount only through supplemental rate charges to rates *other than* the PF Preference rate. As explained more fully below, a reduction in the amount of the surplus revenue credit to BPA's customers, including preference customers, does not impair the rate protection provided by section 7(b)(2).

Cowlitz cites Staff's rebuttal testimony regarding the IOU proposal to include the FPS rate in the rates to which the 7(b)(2) trigger amount is allocated, thereby allocating the section 7(b)(2) trigger amount to secondary energy sales. Cowlitz Br., WP-07-B-CO-01, at 44 . Cowlitz notes Staff's rebuttal testimony, which states that the IOUs' proposal to allocate some of the 7(b)(3) amount to surplus power sales would raise the level of BPA's firm power rates and would raise the PF Preference rate and cause it to bear some of the 7(b)(2) trigger amount. *Id*. Cowlitz quotes Staff's testimony as stating "secondary sales revenues cannot be increased through supplemental rate charges," so any allocation of the 7(b)(2) trigger amount to such sales simply creates a revenue deficiency that would need to be reallocated to rates other than the PF Preference rate. *Id*. Cowlitz argues that the result of the reallocation of this revenue deficiency is the same as if the trigger amount had been allocated only to the adjustable firm power rates, other than PF Preference, in the first instance. *Id*. Cowlitz argues that it is not reasonable to employ a useless mechanism that cannot further the purposes of the statutory goal. *Id*.

In response to Cowlitz's argument, however, although Staff testified as noted by Cowlitz above, Staff's testimony was based upon the proposed Implementation Methodology, Legal Interpretation and BPA's traditional rate setting practices. Brodie, *et al.*, WP-07-E-BPA-78, at 21. Staff repeatedly qualified their testimony, noting that the IOUs had raised a new argument BPA had not previously considered, and any changes to BPA's Legal Interpretation could affect the implementation of the 7(b)(2) rate test. *Id*. Staff stated that although they have performed the ratemaking steps in the sequence used in many prior rate cases, they had not considered that the sequencing could be viewed from a different perspective. *Id*. at 13. Staff credited the secondary sales revenues prior to the section 7(b)(2) rate test in reliance on the language in the proposed Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act, which instructs that secondary revenues will be credited in both the Program and 7(b)(2) Cases. *Id*. at 14.

The crediting of the secondary revenue prior to the rate test is the proper implementation of the statutory directives. Section 7(b)(2) specifies that the rate test compare "the projected amounts to be charged for firm power for the combined general requirements" with "the power costs for general requirements …" 16 U.S.C. § 839e(b)(2). The projected amounts and the power costs are net of projected secondary revenues, as required by section 7(g) of the Northwest Power Act. 16 U.S.C. § 839(g). The Senate Report describes the rate test: "The rate adjustment is established by determining the average difference for the specific rate year and each of the ensuing 4 years by subtracting these rate limit costs from the costs of the Regional Rate…" S. Rep. No. 96-272, 96th Cong., 1st Sess. 58 (1979). The "Regional Rate" is what is now called the Program Case rate. The construction of the Regional Rate is described in the Senate Report as including "Federal Base System resource costs *reduced by revenues from the sale of nonfirm* attributed to the Federal Base System resources …." *Id*. at 57 (emphasis added). The 7(b)(2) Case rate is also described in the Senate Report with similar language as "…the costs of available Federal Base System resources …." This language makes clear that the "projected amounts" and "power costs" are to include the secondary revenue credit.

In their rebuttal testimony, Staff confirmed that they had not come to a firm conclusion on this issue. Staff stated "[t]he IOUs present an interesting argument that we will consider. We will review the entire record of this proceeding and make a recommendation to the Administrator that incorporates both the best evidence and the best legal argument." *Id*. at 20. "We will consider the IOUs' argument based on the entire record of this proceeding and make the best recommendation to the Administrator." *Id*. at 21. "In addition, there are statutory interpretation issues raised by the IOUs' argument regarding the meaning of 'the projected amounts to be charged for firm power' and 'the power costs for general requirements of such customers' in section 7(b)(2) of the Northwest Power Act. BPA will address parties' properly raised legal interpretation issues in the Draft and Final Records of Decision in this proceeding. Should the IOUs' argument be adopted by the Administrator, we will make the necessary changes to the Implementation Methodology." *Id*. at 21-22. "There are statutory interpretation issues raised by the IOUs' sequencing proposal regarding the meaning of 'the projected amounts to be charged for firm power' and 'the power costs for general requirements of such customers' in section 7(b)(2). BPA will address parties' properly raised legal interpretation issues in the Draft and Final Records of Decision in this proceeding." *Id*. at 22. "We will consider both of the IOUs' suggestions should the Administrator decide to change the sequencing based on the record of this proceeding." *Id*. at 23. Thus, Staff recognized that further review of the IOUs' legal and factual arguments could require Staff to change their position and require amendment of the Legal Interpretation and Implementation Methodology.

Further, although the IOU proposal to allocate some of the 7(b)(3) amount to surplus power sales would raise the level of BPA's firm power rates and would raise the PF Preference rate, this is a proper result of implementing the statutory directives. In other words, the Northwest Power Act requires BPA to recover the trigger amount from all other power sales, which include surplus sales. Allocating or supplementally charging the trigger amount to surplus sales has the effect of reducing the portions of the trigger amount recovered from other rates, including the PF Exchange rate. If the PF Exchange rate is lower as a result of some of the trigger amount now being borne by other power sales, this will increase the amount of REP benefits provided to exchanging utilities, which will increase the PF Preference rate. As noted previously, the Northwest Power Act expressly contemplates the PF Preference rate recovering some REP costs, depending on the magnitude of the 7(b)(2) trigger.

C. FPS Rate Design and Supplemental Rate Charges

Cowlitz quotes Staff's testimony as stating "secondary sales revenues cannot be increased through supplemental rate charges," so any allocation of the 7(b)(2) trigger amount to such sales simply creates a revenue deficiency that would need to be reallocated to rates other than the PF Preference rate. *Id*. Staff, however, was assuming BPA's existing FPS rate design. When BPA's rate design accommodates flexibility to sell at market prices, BPA and purchasers agree on the price, and the transaction is consummated. BPA cannot negotiate a price, consummate the sale, and then add a supplemental rate charge after the sale. Thus, Staff's testimony described a difficulty with BPA's current FPS rate design. This does not mean, however, that the surcharge cannot be recovered as a part of the overall revenues recovered or that there is no rate design that would accommodate the application of a supplemental rate charge.

Cowlitz argues that the IOUs purport to interpret section 7(b)(3) to require that what section 7(b)(3) terms "amounts *not* charged to [preference] customers by reason of [section 7(b)](2)" are in fact charged to such customers by reason of section 7(b)(3), which is an erroneous interpretation of the statute. Cowlitz Br., WP-07-B-CO-01, at 46. Cowlitz argues that allocating the 7(b)(2) trigger amount to the FPS rates, with the "net effect" of shrinking the secondary revenues credit and raising the PF Preference rate, is ultimately a "plain violation" of the statutory guarantee. *Id*. Similarly, PPC argues that if BPA were to do as the IOUs urge, it would purport to "allocate" amounts to be recovered pursuant to section 7(b)(3) to sales of surplus power. PPC Br., WP-07-B-JP25-01, at 43; PPC Br. Ex., WP-07-R-PP-01, at 25; APAC Ex. Br., WP-07-R-AP-01, at 19-20. PPC claims this creates the illusion that more dollars are available for residential exchange benefits without raising the PF Exchange rate. *Id*. PPC states this 7(b)(3) "allocation" to surplus power sales would offset, virtually dollar for dollar, revenues that would have otherwise been credited to the wholesale power rates charged to BPA's preference customers. *Id*. The result, in real economic terms, would be to place back into preference customers' wholesale power rates exactly the costs that were supposedly removed by operation of section 7(b)(2). *Id*. PPC argues that there would be a pretext of honoring 7(b)(2), but in truth it would be circumvented. *Id*.

If one understands BPA's statutory rate directives, however, Cowlitz, PPC and APAC's argument is not persuasive. First, as noted previously, if the rate test triggers, there is a "trigger amount," which is not allocated to the PF Preference rate for preference customers. Contrary to Cowlitz's argument, if some of the trigger amount were allocated to the FPS rate, as required by law, this *would not* charge that trigger amount to preference customers' PF Preference rate. The trigger amount would be charged to the FPS rate, *not* the PF Preference rate. This would not be a violation of the statutory guarantee of section 7(b)(2).

Because charging some of the trigger amount to the FPS rate does *not* result in directly charging some of the trigger amount to the PF Preference rate, Cowlitz and PPC must argue that charging some of the trigger amount to the FPS rate somehow *indirectly* charges some of the trigger amount to the PF Preference rate. They argue that if some of the trigger amount is charged to the FPS rate, this would offset revenues that would have otherwise been credited to the PF Preference rate, which would place into the PF Preference rate costs that were supposedly removed by operation of section 7(b)(2). To understand this argument, one must understand that BPA forecasts surplus power sales revenues in its power rate cases. BPA then provides the difference between BPA's surplus revenue and the costs allocated to the surplus power as a revenue credit to all regional firm power rates. The surplus power revenue credit reduces the level of such rates. Therefore, this revenue credit does not apply *only* to the PF Preference rate.

If BPA were to charge some of the trigger amount to surplus sales through the FPS rate, some of the revenue BPA received from surplus sales would be used to pay the trigger amount, as required by law. Because some of the revenue would be used to pay the trigger amount, such revenue would not be available to be used as a credit to reduce all of BPA's regional firm power rates. Thus, the revenue credit would be smaller as a result of the FPS rate paying some of the trigger amount, and all of BPA's regional firm power rates would be slightly higher than if the FPS rate had not recovered some of the trigger amount. The fact that all of BPA's regional firm power rates would receive a slightly lower surplus revenue credit, however, does not constitute a violation of section 7(b)(2) or a denial of the proper amount of rate protection for preference customers.

PPC states that BPA appears to justify its position in part by claiming that because revenues generated from the sale of surplus power is used to reduce *all* BPA firm power rates, the proposed application of 7(b)(3) is permissible: "[T]his revenue credit does not apply *only* to the PF Preference rate… The fact that all of BPA's regional firm power rates would receive a slightly lower surplus revenue credit, however, does not constitute a violation of section 7(b)(2) or a denial of the proper amount of rate protection for preference customers." PPC Br. Ex., WP-07-R-PP-01, at 29. PPC argues section 7(b)(2) is concerned only with protecting preference customer rates from the costs of the REP and the fact that other rates are also burdened is irrelevant. *Id*. BPA agrees that section 7(b)(2) only protects BPA's preference customers, but the nature of the revenue credit is still relevant. BPA explains elsewhere why BPA's recovery of part of the trigger amount from BPA's surplus power sales, as required by section 7(b)(3), is consistent with section 7(b)(2). Given that BPA has implemented section 7(b)(3) in a manner consistent with section 7(b)(2), it is the nature of the revenue credit that if such credit is lower, BPA's power rates will all be higher because the revenue credit applies to all BPA firm power rates. This is not an event dependent on section 7(b)(2).

BPA must apply the Northwest Power Act so that meaning is given to each statutory provision. Section 7(b)(3) of the Act is particularly clear in requiring that the trigger amount will be recovered from "all other power sold by the Administrator to all customers." 16 U.S.C. § 839e(b)(3). This language is unambiguous. Further, as noted previously, the legislative history confirms the plain language, and further confirms that the trigger amount will be allocated to BPA's secondary, or "nonfirm," power sales. S. Rep. No. 96-272, 96th Cong., 1st Sess. 59 (1979). Thus, BPA *must* recover some of the trigger amount from the FPS rate. On the other hand, pursuant to section 7(g), BPA allocates the benefits of selling surplus power equitably to power rates:

> [*e*]*xcept to the extent that the allocation of costs and benefits is governed* by provisions of law in effect on the effective date of this Act, or *by other provisions of this section*, the Administrator shall equitably allocate to power rates, *in accordance with* generally accepted ratemaking principles and *the provisions of this Act*, all costs and benefits *not otherwise allocated* under this section, including, but not limited to … the sale or inability to sell excess power.

16 U.S.C. § 839e(g) (emphasis added).

In contrast to the unequivocal direction of section 7(b)(3) to allocate part of the trigger amount to all power sales, including surplus, section 7(g) requires an "equitable" allocation of the benefits of selling excess power. More significantly, however, section 7(g) expressly makes the allocation of surplus power revenues subservient to the cost recovery provisions of section 7(b)(3). Section 7(g) recognizes that the benefits from the sale of excess power (that is, surplus power) are limited by the clause "except to the extent that the allocation of costs and benefits is governed … by other provisions of this section…" *Id*. Section 7(b)(3) directs BPA to expressly recover part of the trigger amount from the FPS rate for surplus sales, and section 7(g) directs BPA to determine the amount of the benefits of surplus power sales in a manner that respects the recovery of the trigger amount from surplus sales. The fact that the surplus revenue credit may be larger when no trigger amount is allocated to the FPS rate than when a trigger amount is allocated, as the law requires (with the consequent result that the PF Preference rate and all other BPA firm power rates may be slightly higher), does not mean BPA has improperly implemented section 7(b)(2) or 7(b)(3) of the Northwest Power Act.

The Cowlitz and PPC argument is thus reduced to one of appearance. However, this appearance is the result of sequencing, as raised by the IOUs and discussed below. The section 7(b)(2) rate test requires that "the projected amounts to be charged" include the surplus revenue credit. At the time of the section 7(b)(2) rate test, it is not known if the rate test will trigger, resulting in a trigger amount that would reduce the revenue credit. Therefore, the rate test is first performed as if the rate test does not trigger, allowing the full amount of surplus revenues to be included in the revenue credit. It is only after the section 7(b)(2) rate test that the trigger amount is known and the surplus revenue credit to all firm power rates is reduced by a share of the trigger amount. This creates an iterative loop in the ratemaking process, requiring at first the use of an interim surplus revenue credit until the amount of the final surplus revenue credit can be established.

Cowlitz argues that the IOUs are not really proposing the statutory mechanism, a "supplemental rate charge," at all. Cowlitz Br., WP-07-B-CO-01, at 45; APAC Br. Ex., WP-07-R-AP-01, at 20. Cowlitz claims that the IOUs propose only an "allocation" wherein the rates would remain the same but the allocation "will only cause the surplus revenue credit to decrease or a surplus revenue deficit to increase." *Id*. Cowlitz claims that the IOUs recognize this, suggesting that risks of variable revenue collection are the same whether or not gross secondary sales revenue or net (less section 7(b)(2) trigger amounts) are credited to "PF rates." *Id*., *citing* LaBolle, *et al.*, WP-07-E-JP6-08, at 56. Cowlitz argues that this confirms that the object of the IOUs' proposal is to expand the pool of rates used to recover section 7(b)(2) trigger amounts to all PF rates, including the PF Preference rate, which is what section 7(b)(3) expressly prohibits by requiring that the trigger amount be recovered, exclusively, through "other" sales, and it would cause the PF Preference rate to "exceed in total" the rate limit created by section 7(b)(2). Cowlitz Br., WP-07-B-CO-01, at 46. Cowlitz cites its rebuttal testimony, which states:

> … if a portion of the reduced revenue credits were to be allocated to the PF Preference rate, then the resulting PF Preference rate would exceed the upper limit or ceiling resulting from operation of § 7(b)(2), and the amounts purportedly not charged to preference customers by reason of § 7(b)(2) would in fact be recovered through the PF Preference rate instead of through surcharges to other sales.

Id., *quoting* Schoenbeck and Beck, WP-07-E-JP17-2, at 3-4; *see also* Brodie, *et al.*, WP-07-E-BPA-78, at 13.

Cowlitz's arguments continue to miss the point. The rate protection established through the section 7(b)(2) rate test cannot be final until the surplus revenue credit has been established. The level of the surplus revenue credit is not known until after all costs that are the responsibility of surplus sales have been established. That an interim surplus revenue credit assuming no section 7(b)(2) rate test trigger has been performed at one point of the ratemaking process is not indicative of the final surplus revenue credit due to all firm power rates. It is only after the section 7(b)(2) rate test that the final level of the surplus revenue credit can be established, once the trigger amount that the surplus rates must recover is known. Under section 7(g), the firm power rates, including the PF Preference rate, are entitled to the benefits of surplus power sales that are "not otherwise allocated." 16 U.S.C. § 839e(g). Section 7(b)(3) specifies the calculation of an "otherwise allocated" amount to surplus power sales.

PPC argues that taking away the surplus sales revenue credit BPA has incorporated into the preference customers' wholesale power rates would violate the requirements of section 7(g) of the Northwest Power Act. PPC Br., WP-07-B-JP25-01, at 41-42. PPC states that section 7(g) provides that "the Administrator shall equitably allocate to power rates … the sale of or inability to sell excess electric power." *Id*., *citing* 16 U.S.C. § 839e(g). PPC argues given that BPA is required to "equitably allocate" revenues from surplus sales, BPA may not lawfully fund the REP with surplus sales revenues. *Id*. PPC argues that doing so would effectively assign the entire benefit of surplus sales to the IOUs, with publics bearing the entire cost, and all risks associated with an underrecovery. *Id*. PPC claims this is neither "equitable" nor an "allocation" of benefits to any party that supports BPA's revenue requirement. *Id*.

PPC's argument, however, is not persuasive and confuses two separate statutory provisions. Section 7(b)(3) of the Northwest Power Act does not involve the allocation of a particular type of costs to power rates (*e.g.*, conservation, fish and wildlife, etc.). Instead, section 7(b)(3) involves the application of supplemental rate charges to BPA's non-PF Preference rates in order to recover amounts not charged preference customers as a result of section 7(b)(2) of the Northwest Power Act. Section 7(b)(3) provides, in pertinent part, that "[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of [section 7(b)](2) 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). Thus, there is no conflict between allocating part of the trigger amount to BPA's surplus sales and the equitable allocation of the costs and benefits of "the sale of or inability to sell excess electric power."

Furthermore, PPC has only quoted one portion of section 7(g) of the Northwest Power Act. Section 7(g) provides:

> *Except to the extent that the allocation of costs and benefits is governed by* provisions of law in effect on the effective date of this Act, or *by other provisions of this section*, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this Act, all costs and benefits *not otherwise allocated under this section*, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under section 6, the costs of credits granted pursuant to section 6, operating services, and the sale or inability to sell power.

16 U.S.C. § 839e(g) (emphasis added). To the extent there were any conflict between the allocation of the trigger amount to surplus power and the allocation of section 7(g) costs to rates, section 7(g) expressly provides that its directives are subservient to other statutory directives in section 7, including section 7(b)(3). However, there is no conflict. Section 7(b)(3) is clear that

the surcharge is recovered from all rates, including rates for secondary. This results in a net revenue credit that is then, pursuant to section 7(g), equitably allocated by the Administrator.

PPC argues that for many years, BPA has credited the revenues from surplus sales to preference customer rates. PPC Br., WP-07-B-JP25-01, at 42. PPC argues that Staff cannot now, in pursuit of greater residential exchange benefits for its investor-owned utility customers, abandon its obligation and divert these revenues. *Id*.

First, Staff is not failing to credit any revenues from surplus sales to the PF Preference rate. Even under the allocation of part of the trigger amount to BPA's surplus sales as required by the plain language of section 7(b)(3), BPA will continue to credit substantial surplus revenues to the PF Preference rate. Furthermore, even if there were a conflict and there were no language making section 7(g) subservient to other rate directives, the statutory requirement to allocate part of the trigger amount to surplus sales and the allocation of the costs or benefits of the sale or inability to sell power must be read to give effect to both provisions. This would be accomplished by determining the trigger amount to be allocated to surplus sales and then determining a revenue credit for BPA's power rates, including the PF Preference rate.

PPC states that BPA asserts a small increase in the PF Preference rate as a result of its proposed application of 7(b)(3) is permissible: "Staff is not failing to credit *any* revenues from surplus sales to the PF Preference rate…. BPA will continue to credit substantial revenues to the PF Preference rate." PPC Br. Ex., WP-07-R-PP-01, at 29. PPC has mischaracterized BPA's position. BPA concluded that it does not matter if there is a small or large increase in the PF Preference rate as a result of BPA's statutorily required recovery of part of the trigger amount from BPA's surplus sales. The amount is irrelevant because BPA has proposed the proper manner in which to recover the trigger amount from surplus sales in a manner consistent with sections 7(b)(2) and 7(b)(3). (It is also arguably consistent with regional preference.) PPC argues that section 7(b)(2) and the *PGE* and *Golden Northwest* decisions stand for the proposition that *any* increase in the PF Preference rate above the section 7(b)(2) rate ceiling is impermissible. *Id. citing PGE*, 501 F.3d at 1028, 1036 (finding that preference customers are protected from costs of the REP in excess of the section 7(b)(2) ceiling regardless of the mechanism used as justification); *Golden Northwest*, 501 F.3d at 1048 (citing *PGE* for the proposition that "burdening preference customers with part of the REP" is impermissible). As explained in this subsection, however, BPA's recovery of part of the trigger amount from surplus sales is not increasing the PF Preference rate in excess of the 7(b)(2) rate ceiling. Also, as noted previously in BPA's extensive review of the Northwest Power Act and its legislative history at the beginning of this chapter, REP costs are properly allocated to preference customers as required by law and in compliance with section 7(b)(2) of the Act. 16 U.S.C. § 839e(b)(1).

Second, BPA is not proposing to allocate some of the trigger amount to secondary sales in order to increase REP benefits for exchanging preference and IOU customers, as PPC presumes. Instead, after over 20 years of experience with BPA's Legal Interpretation and Implementation Methodology, BPA is reviewing such methodologies to ensure that BPA will properly develop its rates by complying with the plain language of the Northwest Power Act. Because BPA will soon be implementing the REP for the first time in many years, it is important to properly establish the PF Exchange rate. The most important thing, however, is to properly interpret and apply BPA's statutory ratemaking directives, regardless of whether they increase or decrease REP benefits. In any case, even if the language of section 7(b)(3) were ambiguous such that the Administrator could choose to allocate the surcharge to secondary sales, the impact of the choice on REP benefits would not be an impermissible consideration. At the time the Northwest Power Act was passed, rates were generally cost-based, and Congress intended that the REP allow IOUs to share in the economic benefits of the low-cost Federal hydrosystem. H. Rep. 96-976, Pt. II, 96th Cong., 2d Sess. 35 (1980). Now that secondary power is selling in excess of cost, it is not unreasonable to dedicate some of that excess to recovering the section 7(b)(3) surcharge.

WPAG argues that the IOUs take the phrase in section 7(b)(3) out of context and create a legal argument that conflicts with both the underlying purpose and the specific language of section 7. WPAG Br., WP-07-B-WA-01, at 39. WPAG claims the IOU proposal conflicts with the operation of the section 7(b)(2) rate test, and operates to negate its fundamental purpose. *Id*. As a consequence, WPAG argues that the IOU proposal contravenes this fundamental tenet of statutory interpretation. *Id*. The WPAG argument rests on the flawed presumption that preference customers are entitled to a certain level of surplus revenue credit. There is no guaranteed level of surplus revenue credit due to the preference customers. The fact that an interim revenue credit used prior to the section 7(b)(2) rate test is at a specific level does not create an entitlement to a final credit at that level.

WPAG argues that statutory provisions must be interpreted in a manner that harmonizes their operation, and not in a way that renders a provision surplusage. *Id*., *citing* 2A, *Sutherland Statutory Construction,* § 46.06 (5th ed. 1992). This is achieved by BPA's interpretation. The WPAG argument, however, is self-contradictory. WPAG argues that to give full effect to section 7(b)(2), the provisions of section 7(b)(3) should be ignored. The WPAG argument renders ineffective the instruction in section 7(b)(3) to recover trigger amounts from "… all other power sold by the Administrator to all customers." 16 U.S.C. § 839e(b)(3). The WPAG interpretation introduces an unsupported limitation to the meaning of "all other power." Conversely, the recovery of trigger amounts from surplus power does not render ineffective the rate protection afforded under section 7(b)(2). Rate protection is still provided based on "the projected amounts to be charged for firm power …" 16 U.S.C. § 839e(b)(2). It is the final revenue credit, the one determined in concert with the recovery of trigger amounts pursuant to section 7(b)(3), that is included in the projected amounts to be charged to preference customers. It is this amount of credit, not the interim credit, that is properly included in the section 7(b)(2) rate test. Because this final revenue credit is the amount actually included in the rates to preference customers, this same final revenue credit is used in the section 7(b)(2) rate test, giving full effect to the rate protection afforded to preference customers under section 7(b)(2). Under the construct detailed herein, there is no further adjustment to the PF Preference rate after the section 7(b)(2) rate test due to the application of section 7(b)(3) to the surplus revenue credit.

In its Brief on Exceptions, PPC notes the IOUs and others (including CUB, Alcoa, OPUC, IPUC, and WUTC) argue that the amounts excluded from preference customer rates by operation of section 7(b)(2) should be recovered from and offset the revenues generated by BPA from the sale of surplus power. PPC Br. Ex., WP-07-R-PP-01, at 24. PPC notes that BPA proposed in the Draft ROD to adopt their position. *Id*. PPC states BPA's primary justification is the mistaken conclusion that "[s]ection 7(b)(3) does not require that a supplemental rate charge must produce additional revenue." *Id*. PPC argues this conclusion is an erroneous reading of the Northwest Power Act that disregards important language choices made by Congress. *Id*. First, contrary to PPC's statement, BPA's primary justification for allocating some of the trigger amount to surplus sales is that section 7(b)(3) of the Northwest Power Act expressly requires that the trigger amount "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) (emphasis added). This language is unequivocal. Because surplus power sales are "power sold by the Administrator" and surplus power purchasers are "customers" of the Administrator, some of the trigger amount must be recovered from BPA's surplus sales. Not only is the statutory language unequivocal, the legislative history confirms the statutory language with regard to surplus power sales. It provides that "the balance of the revenues not recovered due to the rate limit adjustment is then spread to rates for all other BPA power sold, *including nonfirm*." S. Rep. No. 96-272, 96th Cong., 1st Sess. 59 (1979). Neither PPC nor any other preference customer nor any other party has been able to refute this direct statutory requirement.

PPC's Brief on Exceptions argues BPA's proposed interpretation of section 7(b)(3) renders meaningless the requirement to impose a supplemental rate charge. PPC Br. Ex., WP-07-R-PP-01, at 25. PPC states Congress acknowledged the intent of the supplemental rate charge when it stated that, "[i]n the event that [the 7(b)(2)] rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules." *Id*. PPC notes BPA acknowledges that its interpretation of section 7(b)(3) results in no additional revenue to the agency. *Id*. PPC similarly argues that the SP-93 rate schedule recognizes that the overall revenue recovery by BPA under this schedule is increased as a result of the supplemental rate charge for transmission. *Id*. PPC claims that unlike the SP-93 rate, BPA's proposal for "supplemental charges" to FPS rates in this case does not result in an increase in revenues that will be recovered under those rates. *Id*. PPC argues BPA's interpretation is contrary to Congressional direction, and overlooks two canons of statutory interpretation. *Id*. First, where a statute does not expressly define a term of settled meaning, "courts interpreting the statute must infer, unless the statute otherwise dictates, that Congress means to incorporate the established meaning of th[at] ter[m]." *Id*. PPC states Webster's dictionary defines supplement as "to fill up or supply by additions; add something to." *Id*. PPC contends BPA's proposed conclusion that "supplemental rate charge" does not require the generation of additional revenue is contrary to the plain meaning of the phrase and converts a charge that is intended to add to a particular rate to an accounting entry that does nothing more than reallocate constant revenues. *Id*.

In response, section 7(b)(3) does not contain language requiring that supplemental rate charges must produce increased revenues. 16 U.S.C. § 839e(b)(3). Instead, the emphasis in section 7(b)(3) is on recovering the trigger amount "through supplemental rate charges for all other power sold by the Administrator to all customers." *Id*. This is what BPA proposes to do. Furthermore, the interpretation of "supplemental rate charges" must be undertaken in the factual context of the term. The section 7(b)(2) trigger amount is only recovered from non-PF Preference rates. As explained previously, however, when BPA uses a market-based rate, power sales are made at the market rate and there is little opportunity to add an additional charge on top of the market rate once the parties have agreed upon price. This is a function of rate design that was needed in order for BPA to conduct its business "in accordance with sound business principles," as required by law and based on the way power is now marketed and traded on the

West Coast, in contrast to the largely fixed or cost-based rates at the time the Northwest Power Act was enacted. Significantly, when BPA sold power prior to the Northwest Power Act at fixed rates, BPA's power was priced lower than other sources and there was the possibility or likelihood that BPA could add a charge to its fixed rate and still be able to make the sale. However, as the power markets became larger and more sophisticated, BPA could not simply sell power at fixed rates. Other parties could price their power a fraction below BPA's power and steal BPA's sales. BPA was also faced with purchasing power, when needed, at market prices. When BPA developed surplus power, BPA was able to develop rates that accommodated market prices and significantly increased its participation in the market. This change in rate design made it harder to add charges to the rate, but had the benefit of significantly increasing BPA's revenues from surplus power sales, to the benefit of BPA's preference customers. BPA's excess revenues from surplus power sales are multiple hundreds of millions of dollars. Indeed, the surplus revenue credit for the unbifurcated PF rate in the instant case is approximately $500 million, that is, *over half a billion dollars*, and this is *after* BPA's recovery of a portion of the trigger amount from surplus rates. These sums are far greater than when the Act was passed. This significantly reduces the level of the PF Preference rate paid by BPA's preference customers. It would make no sense to conclude that a rate design change that allowed BPA to provide hundreds of millions of dollars in rate reduction benefits to preference customers should be interpreted as precluding the Congressionally-directed allocation of part of the trigger amount to BPA's surplus sales, even though preference customers continue to receive over half a billion dollars in benefits from the secondary revenue credit and over half a billion dollars of rate protection from section 7(b)(2).

As noted previously, BPA must recover a part of the trigger amount from the FPS rate for its surplus sales. Therefore, BPA has redesigned its FPS rate in order to recover a supplemental rate charge under section 7(b)(3) of the Act. Section A.2 of BPA's WP-09 FPS rate schedule provides that "[a] supplemental rate charge of 8.80 mills/kWh shall be included in each FPS energy rate charge as determined pursuant to paragraph A.1 above." FY 2009 Supplemental Rate Schedules and GRSPs, WP-07-A-05A. Thus, BPA's FPS rate for surplus power sales recovers revenues, and does so through a supplemental rate charge within the context of BPA's rate design and section 7(b)(3). One of the most important principles of section 7(b)(3) is that the trigger amount must be *recovered through supplemental rate charges <u>for all of BPA's sales</u>* (other than PF Preference sales). As long as the trigger amount is recovered through a supplemental rate charge in a rate, it is of less importance whether such recovered costs produce "increased" revenues, particularly given the current facts.

PPC argues that when interpreting a statute, meaning must be given to every clause and word of the statute, including the requirement to "recover[] through supplemental rate charges." PPC Br. Ex., WP-07-R-PP-01, at 26. *Id*. As a general principle of statutory construction, BPA agrees. BPA's interpretation gives effect to every relevant clause and word of the statute. As noted above, BPA's WP-09 FPS rate schedule provides that "[a] supplemental rate charge of 8.80 mills/kWh shall be included in each FPS energy rate charge as determined pursuant to paragraph A.1 above." 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009), WP-07-A-05A. Thus, the FPS rate and BPA's supplemental rate charge in the FPS rate "recover" part of the trigger amount. There is no dispute that BPA recovers revenue through the FPS rate, which includes the supplemental rate charge. Also, the word "supplement" means "1. something added to complete a thing, supply a deficiency, or reinforce or extend a whole." *Random House College Dictionary*, Rev. Ed. 1980. BPA's supplemental rate charge to the FPS rate has been added to, or "supplements," the FPS rate and is part of BPA's recovery of the trigger amount. Further, BPA's supplemental "rate" charge is a part of BPA's FPS "rate." In addition, a charge is "a fee or price charged." *Random House College Dictionary*, Rev. Ed. 1980. BPA's supplemental rate "charge" is imposed in BPA's FPS rate at 8.80 mills per kWh and recovered by BPA as part of the price of surplus power BPA sells. Furthermore, BPA's interpretation also gives effect to every relevant *provision* of the Act: preference customers continue to receive tremendous benefits from the secondary revenue credit; preference customers receive over half a billion dollars in rate protection from section 7(b)(2); and a portion of the trigger amount is recovered from BPA's surplus sales through the supplemental rate charge contained in BPA's FPS rate schedule. PPC's analysis, in contrast, patently deletes an express ratemaking directive from the Northwest Power Act, namely, that the trigger amount *shall be recovered from all other power sold by the Administrator to all customers*. 16 U.S.C. § 839e(b)(3). Although PPC argues that rules of statutory construction should apply, it does not emphasize a rule that may be applicable here. Although BPA does not agree with PPC's arguments, even if one assumed its arguments were valid, this would not preclude BPA from allocating some of the trigger amount to surplus power sales. This is because if two provisions of law appear inconsistent, one must interpret them in a manner that gives meaning to both.

"If possible, we must give these apparently conflicting provisions a sensible reading that avoids redundancy or surplusage." *Love v. Thomas*, 858 F.2d 1347, 1354 (9th Cir. 1988). "In cases of seeming conflict in the provisions of a statute, the construction which would permit both provisions to stand should be employed." *Korte v. U.S.*, 260 F.2d 633, 636 (1959) (quoting *U.S. v. Moore*, 95 U.S. 760, 763 (1877)). "Under accepted canons of statutory interpretation, [the Ninth Circuit] must interpret statutes as a whole, giving effect to each word and making every effort not to interpret a provision in a manner that renders other provisions of the same statute inconsistent, meaningless or superfluous." *Garcia v. Brockway*, 526 F.3d 456, 463 (9th Cir. 2008) (quoting *Boise Cascade Co. v. EPA*, 942 F.2d 1427, 1432 (9th Cir. 1991) (citing *Aluminum Co. of Amer. v. Bonneville Power Admin.*, 891 F.2d 748, 755 (9th Cir. 1989)). "[W]here possible, provisions of a statute should be read so as not to create a conflict." *Doe v. Rumsfeld*, 435 F.3d 980, 987 (9th Cir. 2006) (*quoting La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 370 (1986)). The courts must interpret a "statute 'as a symmetrical and coherent regulatory scheme' and 'fit, if possible, all parts into a harmonious whole.'" *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000) (quoting *Gustafson v. Alloyd Co.*, 513 U.S. 561, 569 (1995); *FTC v. Mandel Bros., Inc.*, 359 U.S. 385, 389 (1959) (internal citations omitted).

> [A] statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence or word shall be superfluous, void or insignificant. This rule has been repeated innumerable times. Another rule equally recognized is that every part of a statute must be construed in connection with the whole, so as to make all the parts harmonize, if possible, and give meaning to each.

Wash. Market Co. v. Hoffman, 101. U.S. 112, 115 (1879).

As noted above, BPA's interpretation, which provides for recovery of part of the trigger amount from BPA's surplus sales through a supplemental rate charge in the FPS rate schedule, harmonizes the need to recover the trigger amount through supplemental rate charges with the statutory direction to recover the trigger amount from all of the Administrator's power sales, and with the rate protection afforded preference customers by section 7(b)(2) of the Act. BPA's approach also continues to provide an approximately $500 million secondary revenue credit to the unbifurcated PF rate and provides $517.6 million of rate protection to preference customers under section 7(b)(2).

D. Contractually Specified Rate Levels

Cowlitz argues that Staff recognized that for FPS sales at contractually specified prices, "the contractually specified rate prevents a supplemental rate charge from being added to the contractually specified rate and producing additional revenue." Cowlitz Br., WP-07-B-CO-01, at 45. The IOUs addressed this issue at length. IOU Br., WP-07-B-JP6-01, at 118-124. The IOUs observe that at one point during cross-examination, Staff appeared to propose a test to limit the other rates to which trigger amounts could be allocated: allocate trigger amounts to only those rates where such allocation results in an increase in BPA's revenues. *Id.*, *citing* Tr. 254. The IOUs argue that this test would arbitrarily and unjustifiably fail to comply with the requirements of section 7(b)(3) to allocate trigger amounts to all other power sold to all customers. *Id*. The IOUs argue that Staff erroneously asserts that the allocation of the section 7(b)(2) trigger amount is somehow limited to "BPA firm, adjustable [rate] loads": "[t]he rate test can result in a reallocation of costs from the loads of Priority Firm Power (PF) preference customers to other BPA firm, adjustable rate loads." *Id.*, *citing* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, at 1. The IOUs state that Staff does not provide an adequate rationale for the assertion that the allocation of the section 7(b)(2) trigger amount should be limited to "BPA firm, adjustable [rate] loads." *Id*. The IOUs note that although the Supplemental Proposal did not justify limiting the allocation of 7(b)(2) trigger amount only to other BPA firm, adjustable rate load, Staff later asserted four rationales for doing so:

> First, firm loads are the loads that are allocated BPA's costs. Second, by "adjustable rate loads," BPA means those loads that pay rates established and therefore adjustable in the section 7(i) process, not loads that pay a rate established and then incorporated in a contract. Section 7(b)(3) states that the amounts not charged to PF Preference customers by reason of 7(b)(2) will be recovered through supplemental rate charges. Therefore, only firm power sold under contracts that allow this type of rate adjustment can be allocated these supplemental rate charges. Third, the 7(b)(3) reallocation amounts are costs that have to be collected from other (non-PF Preference) sales. Therefore, the rates applied to these sales to recover these costs have to be adjusted and set in a section 7(i) process. If not, then there is a risk of under-recovery of the costs. Fourth, if the sales are not firm sales on an annual basis then there is a chance that a part or all of the amounts reallocated to these sales could come back to PF Preference sales because the forecasted secondary sales did not materialize. If

> one or both of these events were to happen, the rate protection afforded preference customers through section 7(b)(2) of the Northwest Power Act would be limited. To prevent this from happening, 7(b)(3) reallocation amounts are only reallocated to firm, adjustable rate loads.

Id., *quoting* Response to Data Request No. JP6-BPA-25 (emphasis added). The IOUs state that these four rationales are not persuasive. IOU Br., WP-07-B-JP6-01, at 120.

The IOUs argue that Staff's first rationale is unclear and circular, merely states a conclusion, and does not explain, for example, why the FPS rate for secondary energy sales is not allocated any section 7(b)(2) trigger amount. *Id*.

The IOUs note that Staff's second rationale in effect argues that the incorporation of a rate level into a contract prevents BPA from allocating section 7(b)(2) trigger amounts to that rate. *Id*. The IOUs state that the fact that BPA and a purchaser may agree to a price under the FPS rate schedule for a particular transaction does not preclude the inclusion of a supplemental rate charge in that agreed-upon price. *Id*. Further, Staff failed to reconcile its second rationale with the fact that BPA already allocates costs to services that have rates set forth in contract; for example, the FPS contract sales. *Id*., *citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 21, Table 2.4.2. Moreover, the IOUs note that Staff already allocates projected costs to sales rates set in contract that are greater than the projected revenues from such sales. IOU Br., WP-07-B-JP6-01, at 121. For FY 2009, Staff allocates $579 million of projected costs to FPS contract sales for which BPA Staff projects $113 million of revenues. *Id*., *citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 24, Table 2.5.4. The IOUs state that this rationale does not explain, for example, why the FPS rate for secondary energy sales is not allocated any section 7(b)(2) trigger amount. IOU Br., WP-07-B-JP6-01, at 121.

The IOUs state that Staff's third rationale in effect argues that the 7(b)(2) trigger amounts cannot be allocated to rates that are not set in a section 7(i) process because there is a risk of cost underrecovery. *Id*. The IOUs state that this argument ignores the fact that all of BPA's rates are set in a section 7(i) process and that BPA sets rates in the aggregate during the section 7(i) process to recover its projected costs in the aggregate. *Id*. The IOUs argue that this rationale does not explain, for example, why the FPS rates for FPS contract sales and for secondary energy sales are not allocated any section 7(b)(2) trigger amount; allocation of section 7(b)(2) trigger amount to the FPS rate for secondary energy sales does not increase the risk of underrecovery. *Id*. Further, the IOUs state that Staff's third rationale flies in the face of the legislative history described above that clearly reflected a Congressional intent that the 7(b)(2) trigger amount would be allocated to sales of secondary energy. *Id*. Also, the risks of secondary energy sales revenues being less than projected are the same, regardless of whether Staff (i) allocates costs to secondary energy sales and credits to the PF rates the *net secondary energy sales revenues* (secondary energy sales revenues less costs allocated to such sales) or (ii) allocates no costs to secondary energy sales and credits to the PF rates the *gross secondary energy sales revenues*. *Id*. In either event, if secondary energy sales revenues are less than projected, the effect on BPA's cost recovery will be the same. *Id*. The IOUs state that allocation of the 7(b)(2) trigger amount to secondary energy sales is not too risky. *Id*.

The IOUs observe that Staff's fourth rationale in effect argues that any allocation of any section 7(b)(2) trigger to the FPS rate for secondary energy sales could result in PF Preference rate customers somehow bearing a section 7(b)(2) trigger amount in the PF Preference rate, even though no section 7(b)(2) trigger amount is allocated to the PF Preference rate. *Id*. The IOUs state that the allocation of the 7(b)(2) trigger amount to secondary energy sales is not too risky, concerns about burdening the PF Preference rate are misplaced and do not justify Staff's failure to allocate the 7(b)(2) trigger amount to the FPS rate, and the statutory requirement to allocate the 7(b)(2) trigger amount to all other rates to power sold to all customers does not permit Staff to allocate 7(b)(2) trigger amount only to firm, adjustable rates. *Id*. Further, the fact that actual secondary energy sales may be less or different than those projected by Staff in its rate case is irrelevant to the section 7(b)(2) rate test and the allocation of any section 7(b)(2) trigger amount. *Id*. The section 7(b)(2) rate test and the allocation of any section 7(b)(2) trigger amount are based on projected costs and revenues and are not "trued up" by BPA in subsequent rate cases. *Id*.

After reviewing the language of section 7(b)(3) and the IOUs' foregoing arguments, Staff's previously stated concerns do not present a persuasive rationale that overcomes the clear direction of the statute to recover trigger amounts from all other power sold.

The IOUs note that BPA previously has had rate schedules that include not only a charge as mutually agreed by BPA and the purchaser, but also an additional rate charge. IOU Br., WP-07-B-JP6-01, at 125. The SP-93 rate schedule is an example of a flexible rate schedule under which BPA sold surplus power at rates that were "as mutually agreed by BPA and the purchaser" and that included under certain circumstances a fixed transmission rate charge. *Id*. SP-93 states in part as follows:

> **B. Flexible Rate**
>
> Energy charges or demand and energy charges may be specified at a higher or lower average rate as mutually agreed by BPA and the purchaser. In no case shall the rate exceed 100 percent of the fixed and variable unit costs of generation and transmission of BPA's highest cost resource including exchange resources. No resource cost determination is needed for sales at less than or equal to the Contract rate.
>
> **C. Intertie Charge**
>
> Rates in sections II.A and II.B that equal or exceed the Contract rate shall be increased by the following charges for transactions over the Pacific Northwest-Pacific Southwest Intertie.
>
> 1. $.706 per kilowatt per month of billing demand and
>
> 2. 1.69 mills per kilowatthour of billing energy.

> Rates in section II.B having an energy-only charge that equals or exceeds 33.36 mills per kilowatthour shall be increased by 3.11 mills per kilowatthour for transactions over the Pacific Northwest-Pacific Southwest Intertie.

Id., *quoting* BPA's 1993 Wholesale Power Rate Schedules and GRSPs, WP-07-E-JP6-18. The IOUs conclude that any argument that BPA cannot have a rate schedule that provides for rates as mutually agreed by BPA and the purchaser that also includes an additional rate charge is inconsistent with BPA's own past ratemaking practices. *Id*.

The IOUs are correct that BPA has made provisions for recovering certain costs through additional rate charges even when the rates are set by mutual agreement. BPA has frequently recovered transmission costs through contract and flexible rates by apportioning a specified amount of the revenues received to transmission cost recovery.

PPC, however, argues that unlike the SP-93 rate, BPA's proposal for "supplemental charges" to FPS rates in this case does not result in an increase in revenues that will be recovered under those rates. This argument was addressed previously. PPC Br. Ex., WP-07-R-PP-01, at 25. Similarly, Cowlitz argues that the contractually specified rate prevents a supplemental rate charge from being added to the contractually specified rate and producing additional revenue. Cowlitz Br., WP-07-B-CO-01, at 45, *citing* Brodie, *et al.*, WP-07-E-BPA-78, at 15. Cowlitz claims that the IOU proposal is only an allocation, wherein the rates would remain the same but the allocation will only cause the surplus revenue credit to decrease or a surplus revenue deficit to increase. Cowlitz Br., WP-07-B-CO-01, at 45, *citing* LaBolle, *et al.*, WP-07-E-JP17-2, at 3. Cowlitz argues that this is what section 7(b)(3) expressly prohibits by requiring that the trigger amount be recovered, exclusively, through "other" sales, and the proposal would cause the PF Preference rate to "exceed in total" the rate limit created by section 7(b)(2). Cowlitz Br., WP-07-B-CO-01, at 45-46.

Although Cowlitz's argument may have appeal to one unfamiliar with BPA's ratemaking, it is not persuasive to knowledgeable reviewers. As established previously, section 7(b)(3) does not require that a supplemental rate charge must produce additional revenue. Also, BPA's supplemental rate charge has been incorporated as a component in BPA's FPS rate schedule, which unquestionably recovers revenue from BPA's surplus sales. BPA has at various times recovered revenue for specific reasons under contractually determined rates. This shows that the recovery for specific reasons can be accomplished even though the ultimate rate is unaffected.

Furthermore, there is little distinction between whether the trigger amount is allocated or recovered. Section 7(b)(3) requires recovery from all other power sold. If that recovery reduces the surplus revenue credit or increases the surplus revenue deficit, section 7(b)(3) instructs that surplus power must be included. The fact that such recovery causes the PF Preference rate to increase from a level determined at an interim step of the rate setting process does not mean that the final rate exceeds in total the rate limit created by section 7(b)(2). To hold such a position requires an exclusionary reading of section 7(b)(3). Because the final revenue credit, as determined in concert with section 7(b)(3), is the amount actually included in the rates to preference customers, this same final revenue credit is used in the section 7(b)(2) rate test, giving full effect to the rate protection afforded to preference customers under section 7(b)(2). Under the construct detailed herein, there is no further adjustment to the PF Preference rate after the section 7(b)(2) rate test due to the application of section 7(b)(3) to the surplus revenue credit.

Cowlitz claims that the *PGE* court stressed the importance of understanding the "net effect" of the REP Settlements:

> BPA's preference customers are paying for the REP Settlement the same as BPA's other customers. This is in plain violation of the Rates Adjustment Test, which guarantees preference customers rates as if "no purchases or sales … were made [under the REP program]."

Id. at 46, citing *PGE*, 501 F.3d at 1036. Cowlitz argues that allocating the 7(b)(2) trigger amount to the FPS rates, with the "net effect" of shrinking the secondary revenue credit and raising the PF Preference rate, is ultimately just such a "plain violation" of the statutory guarantee. Cowlitz Br., WP-07-B-CO-01, at 46.

Once again, Cowlitz's argument fails under knowledgeable review. The *PGE* court reviewed the section 7(b)(2) rate test, which compares the Program Case rate with the 7(b)(2) Case rate. It is the 7(b)(2) Case rate that is constructed as if no purchases or sales were made under the REP. The Program Case rate contains REP costs, including the costs of section 7(b)(2) rate protection as recovered pursuant to section 7(b)(3). Whereas the surplus revenue credit may be reduced compared to the initial credit determined prior to the section 7(b)(2) rate test, such reduction to the initial credit does not take place in the construction of the 7(b)(2) Case rate. Therefore, even though the recovery of trigger amounts from surplus power sales may be perceived as a cost of the REP, which it is not, the section 7(b)(2) rate test fully protects such recovery of trigger amounts from surplus power through increases in the PF Preference rate.

E. Sequencing

The IOUs argue that BPA should change the sequencing of its rate design steps to accommodate the allocation of section 7(b)(2) trigger amounts to all power sold by the Administrator to all customers, other than power sold for the general requirements of PF Preference rate customers. IOU Br., WP-07-B-JP06-01, at 127. The section 7(b)(2) rate test and the allocation of the trigger amount are sequenced near the end of the RAM process, after the over and under-recoveries from FPS sales have been reallocated and are reflected in the PF rates. *Id*., *citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 23, Table 2.5.3, and 24, Table 2.5.4. The IOUs argue BPA should change the sequencing of its rate design steps to adopt one of two possible sequences. IOU Br., WP-07-B-JP06-01, at 135. Under the first sequencing approach, the IOUs argue that BPA should sequence the allocation of FPS rate secondary energy sales revenues after the section 7(b)(2) rate test and the allocation of the trigger amount. *Id*. This sequencing would permit BPA to accommodate the allocation of trigger amounts to the FPS rates. *Id*. In other words, it is premature to allocate secondary energy sales revenues until after allocation of the section 7(b)(2) trigger amount. *Id*.

As discussed above, this sequencing would not be allowed under the meaning of "the projected amounts to be charged for firm power" in section 7(b)(2). 16 U.S.C. § 839e(b)(2). As noted above, the Senate Report clearly shows that this phrase was meant to include the credits from the sales of surplus power by referring to the costs of the FBS resources *reduced by revenues from the sale of nonfirm*. S. Rep. No. 96-272, 96th Cong., 1st Sess. 57 (1979). Therefore, the IOUs' first sequencing argument is not allowed by section 7(b)(2).

The second IOU alternative sequence is to iterate between the allocation of the section 7(b)(2) trigger amount and the allocation of the secondary energy sales revenue. IOU Br., WP-07-B-JP06-01, at 135. This could be accomplished in the following manner: (1) develop the unbifurcated PF rate (using an interim secondary energy sales revenue credit assuming no trigger amount) and determine the trigger amount; (2) allocate the trigger amount among FPS sales, the portion of the Slice rate attributable to secondary energy, and the PF Exchange rate; (3) repeat step 1 (taking into account the reduced secondary energy surplus revenue credit, for example, that results from the allocation of the trigger amount) and determine a new trigger amount; (4) repeat step 2 (allocating the new trigger amount to all rates other than PF Preference rate); and (5) repeat steps 3 and 4 on an iterative basis until the trigger amount is unchanged in subsequent repetitions. *Id*.

This approach has merit, if step 2 of the IOU alternative also includes sales under the IP and NR rates. In this way, the amount of the revenue credit for surplus sales is properly determined only after the appropriate determination of the trigger amount to be recovered from these sales has been determined.

Cowlitz claims the IOUs try to disguise what they propose as a "sequencing" approach to allocating trigger amounts to reduce forecast secondary revenues. Cowlitz Br., WP-07-B-CO-01, at 46, *citing* LaBolle, *et al.*, WP-07-E-JP6-08, at 58-59. Cowlitz notes that since long before the Northwest Power Act, sales of secondary (nonfirm) energy have been treated as very significant credits to offset the costs of BPA's firm power. *Id*. Cowlitz argues the IOU sequencing approach is a demand to adopt an improper, additional assumption between the Program Case and the 7(b)(2) Case: the additional assumption that secondary revenues are lower in the 7(b)(2) Case than in the Program Case. *Id*. Cowlitz states that the IOUs are forced to advocate an "iterative" approach because they are asking BPA to shrink the forecasted secondary revenues in the Program Case by an amount based on a number that can only be determined *after* completion of the 7(b)(2) Case, the trigger amount. *Id*. Cowlitz argues that like any additional assumption manifestly not an unavoidable consequence of one of the Five Assumptions, this additional assumption is improper. *Id*.

BPA does not read the IOUs' second alternative in the same manner as Cowlitz. First, BPA's view of the IOU alternative would create a situation where the secondary revenues are higher in the 7(b)(2) Case than in the Program Case, not lower, as Cowlitz claims. This would result from the revenue credits being identical in step 1, then the Program Case credit declining through the subsequent steps while the 7(b)(2) Case credit remains constant. Although unstated by the IOUs, BPA reads the IOU proposal in this manner as a result of the way the 7(b)(2) Case is constructed; that is, there is no REP in the 7(b)(2) Case and, therefore, there are no effects of the section 7(b)(2) rate test in the 7(b)(2) Case.

Second, both cases still receive significant credits to offset the costs of BPA's firm power, but here, as discussed above, the credits are determined only after all of the allocations under section 7 have been completed. This is consistent with section 7(g)'s direction that the benefits of excess power are allocated after the allocation of costs and benefits governed by other statutory provisions.

Finally, Cowlitz argues that any additional assumption manifestly not an unavoidable consequence of one of the Five Assumptions is an improper additional assumption. BPA does not read the IOU alternative in this way. Congress directed that the "projected amounts to be charged for firm power" be compared to the "power costs … if, the Administrator assumes [the Five Assumptions.]" 16 U.S.C. § 839e(b)(2). The revenue credits from the sales of surplus power are to be included in the "projected amounts to be charged for firm power," as indicated in the Senate Report cited above. *See* S. Rep. No. 96-272, 96th Cong., 1st Sess. 57 (1979). However, Congress did not exempt the surplus sales producing the revenue credit included in the "projected amount" from the recovery of trigger amounts under section 7(b)(3). If Congress had meant to exempt the surplus sales from the application of section 7(b)(3) to allow the full credit to be applied in the section 7(b)(2) rate test, it certainly could have done so. Lacking that instruction from Congress, BPA cannot impose this restriction on the application of section 7(b)(3). A significant revenue credit still affords the preference customers significant rate benefits. In this way, BPA gives effect to both sections 7(b)(2) and 7(b)(3).

F. Section 7(b)(3) Recovery of Trigger Amounts from Surplus Sale under the Slice Rate

As discussed above, the trigger amount removed from the PF Preference rate must be recovered by rates for the sale of all other power to all customers. These other rates include the PF Exchange rate, IP rate, NR rate, and the FPS rate. The IOUs argue that this recovery should also include the portion of the Slice rate attributable to secondary energy. IOU Br., WP-07-B-JP6-01, at 127. Under the Slice rate, BPA sells about 400 aMW of secondary power, which is about 22 percent of BPA's secondary power. *Id*.

To clarify the facts regarding Slice sales, there is no distinction under the Slice contract between firm and secondary power sales. Under the Slice contract, BPA sells firm power to the purchasers. However, there is a provision in the Slice contract for the advance sale of surplus power to Slice purchasers. The distinction between requirements power and surplus power depends on the purchaser's load in each hour, not on the status of Federal system generation. Even though the Federal system may be generating secondary energy on a particular hour, it does not necessarily follow that the Slice purchaser is receiving surplus power. That being said, it is still true that BPA's forecast of the amount of secondary energy available to be marketed by BPA is reduced by about 22 percent, reflecting the delivery of this energy to Slice purchasers. Therefore, BPA does forecast a surplus component of the Slice sales for the rate period. Thus, the surplus sale under the Slice rate is an expected sale of surplus power. The question then is whether this sale fits within the statutory definition of "… all other power sold by the Administrator to all customers" under section 7(b)(3).

The Slice Customers Group argues that the IOUs take this phrase out of context and create a legal argument that conflicts with both the underlying purpose and the specific language of section 7, particularly with regard to its application to the PF rate under which the Slice product is purchased. Slice Br., WP-07-B-JP22-01, at 3. The PF rate for all preference customers contains a credit based on the revenues forecast to be obtained from the sales of secondary energy by BPA. *Id*. at 4. The PF rate under which the Slice product is sold contains an identical credit, but it is provided in kind by the delivery of secondary energy to the Slice purchasers on an "as available" basis. *Id*. So although the delivery mechanism is different, the secondary credit for Slice and non-Slice customers is identical. *Id*. All preference customers, whether they are Slice or non-Slice, purchase under a PF rate that has no separate secondary or surplus rate component. *Id*.

The IOUs propose that if BPA were to allocate the trigger amount to the surplus portion of the Slice rate, BPA's revenues from the Slice rate would increase:

> A. (Mr. Bliven) So in that instance, we believe that if you were in a situation where you had to allocate trigger amounts to the surplus portion of the [Slice] rate, that that would create an additional cost to the [Slice] purchasers that would have to be factored into the rate that we charge them and would increase their rate for the amount of power they were projected to purchase.

IOU Br., WP-07-B-JP6-01, at 133, *quoting* Tr. 277-78.

The Slice Customer Group argues that in order to implement the IOU proposal, BPA would have to impose the section 7(b)(3) surcharge on the PF rate, which is the very rate that the section 7(b)(2) rate test was intended by Congress to protect. Slice Br., WP-07-B-JP22-01, at 4. The Slice Group claims the proposal flies in the face of this statutory directive contained in section 7(b)(2). *Id*. The Slice Group argues the IOU proposal would operate to deprive preference customers who purchase power under the PF rate through the Slice product of their section 7(b)(2) rate protection. *Id*.

The surplus portion of sales under the Slice rate does not serve the general requirements of these preference customers. Therefore, it is not afforded the rate protections under section 7(b)(2). Only the section 7(b)(1) PF Preference rate for the general requirements of public body, cooperative, and Federal agency customers is entitled to the protection of section 7(b)(2). Therefore, the surplus portion of sales under the Slice rate is a part of "… all other power sold by the Administrator to all customers" under section 7(b)(3). However, contrary to Staff's discourse during cross-examination, it is not necessary to add a separate charge to the Slice rate in order to accomplish a recovery of trigger amounts from Slice purchasers. The end effect of allocating 7(b)(2) trigger amounts to surplus is a small decrease to the PF Exchange rate. This somewhat increases the net costs of the REP. The PF rate for Slice purchasers is constructed on a different basis than the PF rate for non-Slice customers, resulting in a different reflection of the change on the two rates. Non-Slice customers will bear their proportionate share of the increased net costs of the REP through the reduced surplus revenue credit. Slice customers will bear their proportionate share of the increased net costs of the REP without further modification to the Slice rate.

In its Brief on Exceptions, NRU notes that it opposes BPA's draft decision to recover part of the section 7(b)(3) amount from the FPS rate. NRU Br. Ex., WP-07-R-NR-01, at 1. NRU notes that if BPA nevertheless determines to do this, NRU believes BPA must assure that this decision affects Slice and Non-Slice customers equitably. *Id*. NRU states that BPA's proposal to recover any section 7(b)(3) amount from its FPS rate will have the effect of reducing revenues from FPS sales that would otherwise be credited to the Priority Firm (PF) rate, thus leading to an increase in the PF rate. *Id*. Because of the differing designs of the Slice and non-Slice PF rates, however, there is no credit for the sale of surplus firm power built into the Slice PF rate. *Id*. Rather, "the PF rate under which the Slice product is sold contains an identical credit, but it is provided in kind by the delivery of secondary energy to the Slice purchasers on an as-available basis." *Id*. The Draft ROD notes:

> The PF Rate for Slice purchasers is constructed on a different basis than the PF rate for non-Slice customers, resulting in a different reflection of the change on the two rates. Non-Slice customers will bear their proportionate share of the increased net costs of the REP through the reduced surplus revenue credit. Slice customers will bear their proportionate share of the increased net costs of the REP without further modification to the Slice rate.

Draft ROD, WP-07-A-03, at 293.

NRU notes the rate directives of the Northwest Power Act charge BPA with the responsibility of establishing "rate or rates of general application for power sold to meet the general requirements of public body, cooperative, and Federal agency customers[.]" NRU Br. Ex., WP-07-R-NR-01, at 2, citing 16 U.S.C. § 839e(b)(1). NRU states that, at the same time, provided the rates are established "in a rate schedule of general application," the Administrator is not prohibited from establishing "a uniform rate or rates for the sale of peaking capacity or from establishing time of day, seasonal rates, or other rate forms." *Id. citing* 16 U.S.C. § 839e(e). NRU concludes the Act thus gives the Administrator discretion as to how the agency designs its rates. *Id*. NRU states this discretion is not unbounded because the language states Congress' intent that BPA's rate design discretion is to be exercised within the confines of "uniform rates" and "rates of general application." *Id.* NRU argues that differing rate forms that result in unequal responsibility among the same rate class of preference customers for REP costs, however, appear to defeat the Congressional intention of establishing "uniform" rates. *Id.* NRU notes that such a decision would raise questions about cost shifts between Slice and Non-Slice customers, which are contrary to a key policy objective governing the development and offering of the Slice rate in the first instance.

NRU states that BPA's demonstration at the August 27, 2008, workshop on the Draft ROD did not address this issue in terms of the relative impact on Slice and Non-Slice preference customers' rates and cost responsibility. NRU Br. Ex., WP-07-R-NR-01, at 3-4. In particular, the worksheet BPA provided did not show the bottom line increase to the Slice rate compared to the Non-Slice rate as a result of the proposed 7(b)(3) adjustment. *Id*. NRU's preliminary calculations based on the information provided at the workshop showed that the Non-Slice rate appears to increase by 1.6 percent as a result of BPA's proposed adjustment, while the Slice rate increases by only 1.2 percent. *Id*. NRU cannot verify whether this math is correct given the ex parte rules. *Id*.

In response to NRU's comments, the demonstration in the workshop shows that Slice and non-Slice rates proportionately share the $27.2 million increase in net exchange costs. By focusing on percentage increases, NRU has inadvertently misapplied the mathematical comparison. In the workshop example, allocating 7(b)(3) amounts to all non-PF Preference loads, including secondary, increased the non-Slice PF Preference rate by $0.43/MWh, or about $21 million in additional revenues. At the same time, the Slice rate increased by about $6.2 million. Therefore, in this example, the non-Slice PF Preference customers would pay about 77.2 percent of the increased REP costs and the Slice PF customers would pay about 22.8 percent of the increased REP costs. Considering rounding of the rates, these percentages of the split between Slice and non-Slice customers are consistent with the way other costs are apportioned. The fact that the non-Slice PF rate has a secondary revenue credit included, and the Slice rate does not, makes the non-Slice PF rate relatively lower, leading to the NRU calculation of a greater percentage change. This does not mean the non-Slice rate is bearing more than its share of the cost increase. It is simply an outcome of the calculation of a percentage increase from a smaller base.

NRU states that if BPA determines to adjust the FPS rates for 7(b)(3) amounts over the objections of public power, then NRU utilities need assurance that the rate impact of this adjustment at a minimum will be equitably shared between the Slice and Non-Slice preference customer groups. NRU Br. Ex., WP-07-R-NR-01, at 2. In such case, NRU specifically requests that the Administrator demonstrate, in the final studies for this WP-07 supplemental rate case and in all subsequent rate cases where the crediting of surplus sales revenue costs and credits is an issue, that the Administrator's allocation of the 7(b)(3) amounts to surplus sales results in an equitable sharing of these costs and credits between Slice and Non-Slice preference customers. *Id*. NRU suggests that if such a demonstration cannot be made, then the Slice and Non-Slice rates will need to be adjusted until the 7(b)(3) allocation to surplus sales can be demonstrated to be equitably shared in terms of rate effects and cost responsibility between both preference customer groups. *Id*.

In response, because the only ratemaking effect of allocating the 7(b)(3) amount to all non-PF Preference loads, as the Northwest Power Act requires, is to modestly increase the forecast net REP benefits, and the Slice customers pay their percentage of the net REP benefits as a matter of course, the NRU request for a separate accounting is unnecessary. Furthermore,
In response to NRU's concern that the rate effect of allocating 7(b)(3) rate protection amounts to secondary revenue sales may lead to cost shifts between the Slice and non-Slice customers, BPA has performed a scenario analysis. The analysis compares (1) the WP-07 Supplemental Final Proposal ratemaking with (2) a scenario without the 7(b)(3) amount allocated to secondary sales. This analysis addresses NRU's request for a demonstration that there are no cost shifts between Slice and non-Slice customers as a result of the allocation of 7(b)(3) amount to secondary sales. For FY 2009, the analysis produced a non-Slice PF rate of $26.46/MWh, an REP net benefits amount of $239.637 million, and a Slice cost of $517.65 million. The actual Final Proposal produced a non-Slice PF rate of $26.90/MWh, an REP net benefits amount of $266.798 million, and a Slice cost of $523.524 million.

To be equitable, the Slice cost should recover 22.63 percent of the increased net REP costs. The difference in net REP costs is $266.798 million - $239.637 million = $27.162 million. Slice should recover $27.162 million * 22.63% = $6.146 million. The actual difference in Slice costs is $523.524 million - $517.65 million = $5.874 million.

However, because the non-Slice PF rate increased by $0.44/MWh due to the allocation of 7(b)(3) amounts to secondary sales, the net cost of system augmentation paid by the Slice customers was reduced by $0.272 million. Therefore, the observed increase in the Slice cost of $5.874 million was net of a reduction in net system augmentation costs paid by Slice customers. The observed increase in Slice costs of $5.874 million, when added to the $0.272 million in reduced net augmentation costs, yields the $6.146 million that is the Slice share of the increased net REP costs. This analysis shows that the Slice customers are paying 22.63 percent of the increased REP benefits, although there is a small secondary effect of slightly reducing their net system augmentation costs.

G. Separately Stating the Supplemental Rate Charge in a Rate Schedule

The IOUs argue that section 7(b)(3) of the Northwest Power Act does not require that supplemental rate charges under that section be separately stated. IOU Br., WP-07-B-JP6-01, at 130. Indeed, BPA has historically included, without separately stating, supplemental rate charges in rates. *Id*. For example, the PF Exchange rate for the period FY 2002-2006 included a section 7(b)(3) allocation of a trigger amount that was not separately stated as a supplemental rate charge in the rate schedule. *Id*., *citing* Tr. 253-54. The IOUs note that WP-07-E-JP6-20 is the PF-02 rate schedule, which includes the PF Exchange rate. *Id*. No supplemental rate charge is separately stated in that rate schedule for the PF Exchange rate. *Id*. Similarly, WP-07-E-JP6-21 is the PF-07 rate schedule, which includes the PF Exchange rate. *Id*. Again, no supplemental rate charge is separately stated in that rate schedule for the PF Exchange rate. *Id*. Rather, these PF Exchange rates included – without separately stating as a supplemental rate charge – a section 7(b)(3) allocation of a trigger amount. *Id*. Indeed, BPA cannot point to any rate schedule it has previously adopted, be it PF Exchange rate, IP rate, or otherwise, that separately states any supplemental rate charge for 7(b)(2) trigger amount. *Id*.

Although BPA recognizes that a 7(b)(3) supplemental rate charge is not required to be separately stated in a rate schedule, BPA is not prohibited from doing so. The IOUs identify no reason why BPA should not separately state a supplemental rate charge. Further, it is true that prior rate schedules did not separately state a supplemental rate charge even when such a charge was included in rates. However, there are good reasons for BPA to separately state a supplemental rate charge. First, BPA has proposed, and is adopting, a new rate design for the PF Exchange rate. *See* Section 15.3, Issue 1. The new design of the PF Exchange rate includes a different supplemental rate charge for each participant in the REP. This supplemental rate charge is subject to change during the rate period if a participant's ASC changes during the rate period. In order to make these differential supplemental rate charges transparent, especially when a recalculation is necessary during a rate period, the separate statement of the 7(b)(3) supplemental rate charge is helpful.

Second, Alcoa raised an issue regarding the proper calculation of the IP rate in this proceeding. In its argument, Alcoa states that section 7(c) is clear on the procedures that BPA must use to properly determine the IP rate. 16 U.S.C. § 839e(c). Even though BPA does not disagree with Alcoa, and BPA's proposed rate design conforms to Alcoa's position, the separate statement of the 7(b)(3) supplemental rate charge in the IP rate schedule assists in understanding that the IP rate has been properly constructed pursuant to section 7(c).

Finally, if a 7(b)(3) supplemental rate charge is to be included in the FPS rate, it will need to be noted as such in the rate schedule. The IOUs cite to BPA's SP-93 rate schedule, which included a fixed transmission rate component within the flexible rate. If such a rate component is to be included in the FPS rate schedule, it should be separately stated.

H. Section 7(b)(3) and Flexible Rate Schedules

The IOUs argue that BPA can and must include a section 7(b)(3) supplemental rate charge for section 7(b)(2) trigger amounts in a flexible rate schedule such as the FPS rate schedule. IOU Br., WP-07-B-JP6-01, at 131-132. The IOUs state that if, assuming *arguendo*, BPA concludes it cannot include a section 7(b)(3) supplemental rate charge in a flexible rate schedule such as the FPS rate schedule (*e.g.*, FPS-07R), then BPA must not adopt any such flexible rate schedule. *Id*. BPA's selection of a revenue crediting methodology must not be permitted to frustrate the requirement of section 7(b)(3). *Id*. The IOUs state that this is particularly true inasmuch as BPA is not required to adopt a flexible rate for the sale of surplus power but rather could elect to adopt a fixed rate for such sales. *Id*., *citing* Tr. 263. A fixed rate for the sale of surplus power could include a section 7(b)(3) supplemental rate charge for a section 7(b)(2) trigger amount: "I think [Staff] would agree that Bonneville could allocate supplemental rate charges to a fixed rate." IOU Br., WP-07-B-JP6-01, at 132, *quoting* Tr. 261. The IOUs claim the adoption of a market-based FPS rate provides significant benefits to the PF Preference rate, regardless of whether those benefits are provided through a revenue credit or a net revenue credit that reflects the allocation of 7(b)(2) trigger amount to the FPS rate. IOU Br., WP-07-B-JP6-01, at 132. Therefore, the IOUs conclude that allocating a portion of the 7(b)(2) trigger amount to the FPS rate does not unfairly burden the PF Preference rate. *Id*. The IOUs also note that, particularly given that the alternative is to adopt a fixed rate for BPA's surplus power sales that includes an allocation of 7(b)(2) trigger amount but that almost certainly reduces BPA's total surplus power revenue, allocating the section 7(b)(2) trigger amount to the FPS rate cannot be fairly said to result in PF Preference customers paying for their own protection. *Id*.

The IOUs note that, given that the Northwest Power Act *requires* BPA to recover some of the trigger amount from BPA's surplus power sales, BPA *cannot* use a rate design that would frustrate this statutory imperative. As the IOUs point out, adopting a fixed rate for surplus sales in order to allow for a supplemental rate charge would reduce BPA's total surplus power revenue. This results from a fixed rate being either below market, leaving producer surplus in the hands of the purchaser, or above market, thereby not capturing all of the consumer surplus available. In either situation, BPA's total revenues from the sale of surplus power is reduced, almost invariably more than the trigger amount being recovered through the fixed rates. In such situations, the rates to all of BPA's customers, including preference customers, would be much higher. Therefore, the better option for all customers would be to use a rate design that allows for flexible pricing but still allows for supplemental rate charges.

I. Inclusion of a 7(b)(3) Supplemental Rate Charge in a Flexible Rate Schedule

The IOUs argue that BPA can have a flexible rate schedule under which BPA sells surplus power at rates that are as mutually agreed by BPA and the purchaser and that include a supplemental rate charge. IOU Br., WP-07-B-JP6-01, at 128. The IOUs note that the SP-93 rate schedule demonstrates that BPA has historically adopted a flexible rate schedule under which BPA sells surplus power at rates that are mutually agreed by BPA and the purchaser and that include a fixed transmission rate charge. *Id*. BPA's proposed schedule FPS-07R, Firm Power and Capacity without Energy, like the SP-93 rate schedule, is a flexible rate schedule under which BPA sells surplus power at rates that are as mutually agreed by BPA and the purchaser. *Id*. The IOUs state that there is no reason that BPA cannot and should not include a section 7(b)(3) supplemental rate charge for trigger amounts in the FPS-07R rate schedule. *Id*. The fact that BPA and a purchaser may agree to a price under the FPS rate schedule for a particular transaction does not preclude the inclusion of a supplemental rate charge in that agreed-upon price. *Id*. The IOUs note that some parties erroneously assume that a supplemental rate charge must be in addition to, rather than included in, the price agreed upon by BPA and the purchaser that is equal to a market price. *Id*. at n. 57.

BPA agrees with the IOUs' reasoning. Because section 7(b)(3) directs the recovery of trigger amounts from all other power sold, surplus sales must share in this recovery. Given the current rate design of the FPS rate, the most practical way to achieve this is to specify a certain portion of the rate for the express purpose of recovering the trigger amount allocated to surplus sales. Such a rate would necessarily have an allocated cost component. Further, in order not to jeopardize the flexible rate design and diminish BPA's revenues from surplus sales, the addition of a 7(b)(3) supplemental rate charge should be paired with a flexible rate component. Working together, the flexible rate component and the supplemental rate charge could continue to maximize BPA's revenues from surplus sales. This would be consistent with BPA's broad rate design authority granted by section 7(e) of the Northwest Power Act. 16 U.S.C. § 839e(e).

Therefore, BPA will adopt an FPS rate design that has both a 7(b)(3) supplemental rate charge, if such is indicated by application of sections 7(b)(2) and 7(b)(3), and a flexible rate component that may be either positive or negative, such that the resulting rate after adding the two components together equals the charge as mutually agreed by BPA and the purchaser. For contract rates, the sum of the 7(b)(3) supplemental rate charge, if such is indicated by application of sections 7(b)(2) and 7(b)(3), and the flexible rate component shall equal the contract rate as mutually agreed by BPA and the purchaser.

J. Application of the Recovery of Trigger Amounts to the FY 2002-2008 Rates

The IOUs argue that BPA is failing to honor the clear statutory mandate in section 7(b)(3) for the FY 2002-2009 rate periods in that BPA has allocated no section 7(b)(2) trigger amounts to any power sold at the FPS rate schedule or to any of the secondary power sold at the Slice rate. IOU Br., WP-07-B-JP6-01, at 110, *citing* Tr. 252-254. The IOUs state that BPA has allocated section 7(b)(2) trigger amounts predominantly to the PF Exchange rate for the FY 2002-2008 rate period and exclusively to the PF Exchange rate for the FY 2009 rate period. IOU Br., WP-07-B-JP6-01, at 110.

In the discussion above, BPA has addressed the section 7(b)(3) issue with regard to FY 2009 and forward. However, BPA is not willing to revise its treatment of the application of section 7(b)(3) in the Lookback analysis for FY 2002-2008. This issue was not raised in either the WP-02 or original WP-07 rate proceedings. BPA has limited the construct of the Lookback analysis to issues that had to be addressed because of the need to revise WP-02 base rates to reflect changes in loads and market prices occurring during the fall/winter of 2000/2001. These changes would have affected the calculation of the 7(b)(2) rate test and the establishment of a revised PF Exchange base rate. It is therefore appropriate for BPA to address the issues emanating from such changes. Moreover, it is appropriate to entertain testimony, comments, and briefing on these issues in this WP-07 Supplemental Proceeding. Because the load and market price changes were addressed through CRACs and not through revised base rates in BPA's WP-02 supplemental proceeding, the parties had no opportunity to address the effect of the changes on the 7(b)(2) rate test during the WP-02 supplemental proceeding. The allocation of part of the trigger amount to other power sales, in contrast, occurs *after* the 7(b)(2) rate test analysis has been conducted. Because the 7(b)(2) rate test concluded, in both the WP-02 and WP-07 rate cases, that there was a "trigger" amount required to be reallocated pursuant to section 7(b)(3), the issue of how that amount should be recovered from non-PF Preference power sales was an issue that could have been raised and reviewed during those proceedings. The parties, however, did not do so. Because the section 7(b)(3) issues raised by the IOUs, CUB, and Alcoa were not raised at the time those rates were being established, BPA declines to apply its decision herein to the FY 2002-2008 period.

The IOUs quote the Draft ROD's conclusion that BPA would not recover any of the trigger amount from surplus power sales for the Lookback analysis for FY 2002-2008. IOU Br. Ex., WP-07-R-JP6-01, at 17. The IOUs note that the Draft ROD recognizes— at least on a "going-forward basis"—that, under section 7(b)(3) of the Northwest Power Act, section 7(b)(2) trigger amounts are to be recovered from power sold at the FPS rate schedule and secondary energy sold at the Slice rate. *Id*. The IOUs argue the statutory requirement to recover section 7(b)(2) trigger amounts from power sold at the FPS rate and secondary energy sold at the Slice rate was applicable during all relevant periods, including the FY 2002-2008 period. *Id*. The IOUs state that merely because the issue was not raised in the WP-02 or original WP-07 rate proceedings provides no basis for failing to recover section 7(b)(2) trigger amounts as required by the Northwest Power Act. *Id*. The IOUs note that BPA recognized "[b]ecause BPA did not expect the IOUs to sign RPSAs to implement the REP, issues affecting the 7b2 trigger amount did not receive great scrutiny due to the expectation that the PF Exchange Rate would not be used to establish IOU REP benefits." *Id*. The IOUs conclude, accordingly, there is no reason to have expected section 7(b)(3) issues to be raised in the WP-02 or original WP-07 proceedings. *Id*. The IOUs state the statutory requirement to recover section 7(b)(2) trigger amounts from power sold at the FPS rate schedule and secondary energy sold at the Slice rate should be applied in BPA's Lookback analysis. *Id*.

BPA's approach to determining the Lookback is addressed in greater detail elsewhere in this ROD. Basically, BPA is placing itself in the winter/spring of 2000/2001 when BPA was developing a supplemental WP-02 rate proposal, and determining how BPA would have developed a revised base PF Exchange rate in the absence of the REP Settlement Agreements. Because BPA's base rates were established prior to significant increases in public agency loads and market prices for power, the base rates initially established in May 2000 were inadequate to recover BPA's costs and could not be approved by FERC. BPA then developed CRACs to address BPA's cost recovery problems. BPA was not concerned about conducting the 7(b)(2) rate test because the IOUs had already signed the REP Settlement Agreements and such Agreements were not affected by the rate test. In the absence of the REP Settlement Agreements, however, BPA would have conducted the 7(b)(2) rate test in order to establish revised base rates, including the PF Exchange rate. In developing the PF Exchange rate that would have been established absent the REP Settlement Agreements, BPA uses the information available at the time BPA developed its supplemental WP-02 proposal. Despite the fact that BPA did not expect the IOUs to sign new RPSAs to participate in the REP, parties to BPA's initial WP-02 rate case were still responsible for raising issues regarding the rate test. BPA responded to these issues in the May 2000 ROD. If a party did not raise an issue, however, BPA logically assumes that BPA would not have addressed such issue in the supplemental WP-02 rate case. For example, certain parties in the WP-02 rate case argued that resources dedicated by preference customers and IOUs in their contracts pursuant to section 5(b) cannot be included in the 7(b)(2) Case resource stack. This issue was moot at the time the May 2000 WP-02 base rates were developed because FBS resources were sufficient to meet preference customer loads in the 7(b)(2) Case. Because this issue was raised in the initial WP-02 rate case, however, BPA would have had to address the issue in a supplemental WP-02 rate case conducted to establish revised base rates when circumstances changed and the FBS resources were no longer adequate to meet preference customer loads. No party, however, argued in the WP-02 rate case that the trigger amount should have been recovered from surplus rates. BPA therefore assumes it would not have addressed the issue in developing a revised WP-02 PF Exchange rate.

Decision

BPA will recover part of the trigger amount from BPA's forecast surplus power sales on a going-forward basis, beginning with rates being established for FY 2009. Such recovery will be accomplished, on a prospective ratemaking basis only, through the incorporation of a 7(b)(3) supplemental rate charge in the FPS rate schedule. No 7(b)(3) supplemental rate charge is necessary to accomplish such recovery through an allocation of trigger amounts to the surplus portion of the Slice rate. The 7(b)(3) supplemental rate charge will be separately stated in the PF Exchange, IP, NR, and FPS rate schedules, but will not require a minimum price or charge for FPS transactions. The recovery of trigger amounts will not be applied to the rates developed in the Lookback analysis for FY 2002-2008.

15.3 7(b)(3): Multiple PF Exchange Rates

Issue 1

Whether the section 7(b)(2) trigger amount should be allocated to the PF Exchange customer class through utility-specific supplemental rate charges.

Parties' Positions

The OPUC argues that BPA Staff's proposal would take benefits from higher-cost investor-owned utilities and spread them to consumer-owned utilities. OPUC Br., WP-07-B-PU-02, at 25. The OPUC claims that Staff's proposal is not rational because it does not meet the objectives for the change in policy stated by BPA and is not based on relevant factors. *Id*. at 27. Also, the proposal does not appear to fall within the scope of authority delegated to the agency. *Id*. at 28.

Cowlitz argues that offering differential PF Exchange rates to the IOUs based on their ASCs undermines the legislative goal of the REP and the design of sections 5(c) and 7(b)(1) of the Northwest Power Act. Cowlitz Br., WP-07-B-CO-01, at 65-67; Cowlitz Br. Ex., WP-07-R-CO-01, at 29-31. Cowlitz maintains that Staff's proposal is an extrastatutory means of giving more IOUs access to REP benefits. *Id*.

BPA Staff's Position

For each exchanging utility qualifying for REP benefits in the zero-trigger case, in the event the 7(b)(2) rate test triggers, a utility-specific Supplemental 7(b)(3) charge will be developed. Fisher, *et al*., WP-07-E-BPA-69, at 6. Thus, the total rates charged to the PF Exchange customer class (*i.e.*, the base PF Exchange rate plus the utility-specific Supplemental 7(b)(3) charges) will maintain the proportionality of REP benefits among exchanging utilities that was established in the first (zero-trigger) step. *Id*. Staff deferred discussion on the legal merits of this issue to this ROD. Fisher, *et al*., WP-07-E-BPA-78, at 7.

Evaluation of Positions

The PF Exchange rate applies to BPA's power sales to utilities participating in the Residential Exchange Program (REP). 16 U.S.C. § 839c(c). The difference between BPA's PF Exchange rate and the exchanging utility's average system cost of resources (ASC), multiplied by the utility's residential and small farm load, equals the monetary benefits provided to the utility under the REP. The PF Exchange rate also applies to actual power sales under in-lieu transactions. 16 U.S.C. § 839c(c)(5). An in-lieu transaction occurs when BPA acquires a less expensive resource rather than the utility's resource priced at its ASC, resulting in a power sale in the amount of the in-lieu resource acquisition. *Id*.

The PF Exchange rate is equal to the unbifurcated PF rate (if the section 7(b)(2) rate test does not trigger) plus a transmission rate. Fisher, *et al*., WP-07-E-BPA-69, at 4. If the section 7(b)(2) rate test triggers, the trigger amount (7(b)(3) rate protection amount) is removed from the

PF Preference rate and allocated through supplemental rate charges to all other power sold by the Administrator to non-preference customers. *Id.*; 16 U.S.C. § 839e(b)(3). In previous rate cases where the section 7(b)(2) rate test triggered, the trigger amount was allocated *pro rata* to non-preference power sales based on load. *Id.*

In the past, the design of the PF Exchange rate was consistent, but not identical to, the design of the PF Preference rate. Fisher, *et al.*, WP-07-E-BPA-69, at 5. That is, the PF Exchange rate included monthly demand and energy components. *Id.* Staff now proposes to modify the design of the PF Exchange rate into a single annual energy rate applicable to all months of the year. *Id.* There is no particular need for the PF Exchange rate to be time-differentiated as with the PF Preference rate. *Id.* Time differentiation is incorporated into the PF Preference rate to inform customers which time periods are more costly to serve load. *Id.* The price signals in the PF Preference rate allow a customer to save more by reducing its load on BPA in more costly time periods and to save less when it reduces its load on BPA in less costly time periods. *Id.*

This is not the case with the PF Exchange rate. *Id.* This rate is used solely to determine the monetary benefits of exchanging utilities. *Id.* It is used in conjunction with the utilities' ASCs, which are not time-differentiated. The comparison of one rate that is time-differentiated with a rate that is not approaches a level of accuracy in rate setting that is neither warranted nor necessary. *Id.* Also, because of the procedures that are being proposed to apply Lookback Amounts to IOU REP benefits, the application of a time-differentiated PF Exchange rate is further unnecessary. *See* Marks, *et al.*, WP-07-E-BPA-62.

If the section 7(b)(2) rate test does not trigger, the 7(b) rate (the unbifurcated PF rate) is used for both the PF Preference rate and the PF Exchange rate. Fisher, *et al.*, WP-07-E-BPA-69, at 5. In this circumstance, utilities with ASCs greater than the PF Exchange rate receive positive REP benefits. *Id.* (Exchanging utilities with ASCs less than the PF Exchange rate were able to deem their ASC equal to the PF Exchange rate to avoid paying REP benefits to BPA.) *Id.* at 5-6. If the section 7(b)(2) rate test triggers and the trigger amount is allocated, in part, to the PF Exchange rate on a load *pro rata* basis, high-ASC utilities will receive reduced benefits, and utilities with lower ASCs may receive no REP benefits whatsoever. *Id.* at 6. This has previously occurred in the development of BPA's rates and subsequent implementation of the REP. *Id.* In summary, under the load *pro rata* allocation, fewer residential and small farm consumers of regional utilities receive REP benefits. *Id.* Because the REP was originally intended to provide utilities, particularly investor-owned utilities, a form of access to the benefits of the Federal Columbia River Power System (FCRPS), which consumer-owned utilities (COUs) receive directly through requirements power purchases at the PF Preference rate, the *pro rata* allocation arguably limits the intent of the REP. *Id.* Thus, a load *pro rata* allocation limits BPA's ability to spread the benefits of the FCRPS as broadly as possible. *Id.*

Staff proposed a two-step process to develop the PF Exchange rate. *Id.* The first step, as in the past, is calculating a base PF Exchange rate assuming a zero 7(b)(2) rate trigger, then comparing the base PF Exchange rate to the ASC of each exchanging utility to see if the individual utilities would qualify for REP benefits (*i.e.*, ASC greater than the base PF Exchange rate). *Id.*

In the second step, for each exchanging utility qualifying for REP benefits in the zero-trigger case, in the event the section 7(b)(2) rate test triggers, a utility-specific Supplemental 7(b)(3) charge will be developed. *Id*. Thus, the total effective rates for REP participants (*i.e.*, the base PF Exchange rate plus the utility-specific Supplemental 7(b)(3) charges) will maintain the proportionality of REP benefits among exchanging utilities that was established in the first (zero-trigger) step. *Id*.

Staff's proposed allocation allows a greater number of residential and small farm consumers of regional utilities to receive a form of benefit from the FCRPS. *Id*. at 7. The total amount of REP benefits paid to residential and small farm consumers is the same as in the load *pro rata* method. *Id*. The rate protection for preference customers is the same as in the load *pro rata* method. The only difference is that BPA's allocation proposal spreads REP benefits over a larger number of consumers, thereby better achieving BPA's goal of spreading the benefits of the FCRPS as broadly as possible. *Id*.

Also, this proposed allocation methodology helps achieve one of the goals of the implementation of the REP. *Id*. The proposed ASC Methodology repeats this goal of the 1984 ASC Methodology, that it "should give participating utilities an incentive to minimize their costs." 73 Fed. Reg. 7270 (February 7, 2008), Section I.A; 1984 Average System Cost Methodology Administrator's Record of Decision, ASC-83, at 9. The proposed allocation allows lower ASC utilities to continue to receive REP benefits, resulting in somewhat lower REP benefits for higher ASC utilities. Fisher, *et al.*, WP-07-E-BPA-69, at 7.

Finally, this is an area BPA can employ to better meet the Recommendations of Representatives of the Investor-Owned and Certain Consumer-Owned Utilities Regarding the Residential Exchange Benefits for Customers Served by the Pacific Northwest Investor-Owned Utilities dated November 7, 2007. *Id*., *citing* Bliven, *et al.*, WP-07-E-BPA-52. This group of customers recommended that BPA seek ways to more broadly distribute REP benefits among the IOUs without increasing REP benefit costs to COUs. Fisher, *et al.*, WP-07-E-BPA-69, at 7.

In the event of a utility's request to exchange after rates are set and a section 7(b)(3) reallocation needs to occur, the utility's Supplemental 7(b)(3) charge will be the customer's average system cost minus the Base PF Exchange rate. *Id*. Similar to the Targeted Adjustment Charge (TAC), setting the Supplemental 7(b)(3) charges in this way protects BPA from unexpected costs imposed by unexpected exchanging utilities. *Id*. at 8.

The proposed ASC Methodology allows a utility to have more than one ASC for a particular rate period if it expects new resources to come on-line. *Id*. If a particular exchanging utility has a new resource that begins serving retail load, or a resource is removed from serving retail load, then the ASC for that utility will change if this resource change was recognized in the ASC determination process. *Id*. The change of the ASC will be effective on the date of commercial operation of the new resource, or retirement or transfer date of the removed resource. *Id*. The change of the ASC will require a modification of the utility-specific Supplemental 7(b)(3) charges for all utilities participating in the REP for that year. *Id*. BPA will recalculate the Supplemental 7(b)(3) charges for all utilities using the same input data as used in the final rate proposal for the relevant rate period. *Id*. This helps BPA to make the REP benefits/costs forecast in the rate case more closely reflect the actual REP costs BPA incurs when actually implementing the REP. It is important to recognize, however, that although BPA forecasts REP costs as accurately as possible, the actual ASC benefits provided under the REP will always be different than the forecast costs due to factors such as actual residential loads occurring during the implementation of the REP.

The OPUC argues that BPA's reliance on the Recommendations of the Investor-Owned and Certain Consumer-Owned Utilities is misplaced. OPUC Br., WP-07-B-PU-02, at 24. The OPUC states that the investor-owned utilities are not authorized to decide how REP benefits received on behalf of their residential and small-farm customers should be distributed throughout the region. *Id*. at 24-25.

However, the investor-owned utilities are not deciding how to distribute REP benefits. The distribution is determined by the relationships among the ASCs, the PF Exchange rate plus Supplemental 7(b)(3) charges, and the exchange loads of each of the utilities participating in the REP.

The OPUC argues that BPA's goal of more broadly spreading the REP benefits is thwarted by Idaho Power's deemer balance. *Id*. at 25. The OPUC notes that any benefits that would have been due to Idaho Power would instead be redirected to consumer-owned utilities through the presence of Idaho Power's deemer balance. *Id*.

First, although it is true that Idaho Power's residential consumers do not directly benefit from Staff's proposal, they indirectly benefit through a reduction in Idaho Power's deemer balance. Brodie, *et al.*, WP-07-E-BPA-78, at 8. A reduction of a deemer balance allows the utility to move towards receiving positive exchange benefits, which will then be passed through directly to the utility's residential consumers. *Id*. The allocation increases the likelihood that more utilities would be able to participate in the REP, whether now or in the future, and thus helps to broaden the benefits to more consumers. *Id*. The fact that applying what might otherwise be positive REP benefits to a deemer balance results in a benefit to consumer-owned utilities is simply a result of implementing BPA's rate directives and contractual commitments in the context of the REP. *Id*. Further, Idaho Power is not the only utility that would potentially receive REP benefits as a result of Staff's proposal. PacifiCorp would not receive benefits if Staff's proposal were rejected. PacifiCorp has substantial service territory in the state of Oregon, so the OPUC position would harm a significant number of residential consumers in the state of Oregon. Avista is another utility that most likely would not receive any REP benefits if Staff's proposal were rejected. This is a result of the way the previous *pro rata* method worked. If the section 7(b)(2) rate test triggered, then low-ASC utilities would be completely eliminated from access to REP benefits, rather than having access to reduced benefits. The Staff proposal would allow the low-ASC utilities to remain as participants in the event of a rate test trigger, albeit with reduced benefits.

Second, the OPUC concern is a result of Staff's proposed treatment of the return of the deemer repayment amount from Idaho Power. In the Supplemental Proposal, Staff included Idaho Power's deemer repayment amount with the Lookback Amount, and together they were used to reduce the PF Preference rate. This proposal did benefit the consumer-owned utilities only.

However, as a result of proposed decisions on related issues in this ROD, this is no longer the case. The deemer repayment amount is no longer being included with the Lookback Amounts. More importantly, the deemer repayment amount is no longer being used solely to reduce the PF Preference rate. Other participants in the REP should see benefits from the deemer repayment amount. *See* Section 9.3.3, Issue 1.

The OPUC argues that Staff's proposal does not meet the objective to "incent" utilities to minimize costs. OPUC Br., WP-07-B-PU-02, at 26. The OPUC notes that since the enactment of the Northwest Power Act, investor-owned utilities have been subject to a single PF Exchange rate. *Id*. The OPUC claims that BPA's change in policy is unfair to the utilities that have made decisions based on the current policy that has been effective for over 20 years. *Id*. Further, the OPUC notes that at no place in the record has BPA made a finding that any investor-owned utility has acted inefficiently with respect to resource cost acquisitions since enactment of the Northwest Power Act. *Id*.

Although it is true that Staff's proposal would change the structure of the PF Exchange rate, the investor-owned utilities have not been subject to the single PF Exchange rate since 1996. Beginning in 1997, and continuing to this date, the investor-owned utilities' residential consumers have been provided REP benefits under REP settlements. Therefore, for the past 11 years, the investor-owned utilities have not been influenced by either the level or the design of the PF Exchange rate. Prior to 1997, the rate test rarely triggered, or if it did, it was in small amounts. (The largest pre-1997 rate test trigger was 0.4 mills/kWh. In contrast, triggers since 1997 have been in the range of 3 to 8 mills/kWh.) As a result, the section 7(b)(3) allocation of trigger amounts had little effect on which participating utilities continued to receive benefits. Such is not the case now. Therefore, the Staff proposal restores the balance in the distribution of REP benefits that existed prior to the period of the various settlements.

Furthermore, the cost minimization goal has been a stated objective of the REP since 1984. Brodie, *et al.*, WP-07-E-BPA-78, at 4. BPA's Average System Cost Methodology Record of Decision (ROD), June 1984, states: "The ASC methodology must be designed so that BPA does not become the 'deep pocket' to which participating utilities may shift excessive or improper resource costs. The methodology should give participating utilities an incentive to minimize their costs." *Id*., *citing* 1984 ASCM ROD, at 9. That Staff has now proposed a new mechanism to further assist in meeting that goal should not be a surprise to the OPUC or the rest of the region. Brodie, *et al.*, WP-07-E-BPA-78, at 4. Staff recognized that the cost structures of the various participating utilities are a product of many events and decisions, of which BPA's REP is one; hopefully, a minor one. Brodie, *et al.*, WP-07-E-BPA-78, at 4. But, as the Administrator stated in 1984, BPA should not become the "deep pocket" for excessive or improper resource costs. *Id*. at 4-5. The proposed allocation methodology is another way of helping achieve the Administrator's 1984 goal.

The OPUC argues that the Staff proposal penalizes utilities that invest the most in conservation and renewables. *Id*. at 27. Investor-owned utilities that operate in jurisdictions with more stringent conservation and renewables standards will be penalized. *Id*. The OPUC claims Staff's proposal is less supportive of renewables and conservation and is a step back from BPA's responsibilities to promote conservation and renewables. *Id*.

BPA acknowledges that conservation and renewables standards will increase the ASCs of those utilities required to participate in such programs relative to those that are not required to participate. Brodie, *et al.*, WP-07-E-BPA-78, at 5. However, BPA does not agree with OPUC's conclusion that Staff's proposed allocation methodology penalizes the utilities. *Id*. at 5. At this time, both Washington and Oregon have such standards. *Id*. Most of the service territories of the participating IOUs are in these two states. *Id*. Therefore, the majority of the IOUs' consumers are already subject to somewhat similar standards. *Id*. Furthermore, although Idaho has yet to adopt renewable and conservation standards, Idaho Power is actively engaged in pursuing renewable energy sources, as is NorthWestern Energy. *Id*. Thus, all of the participating utilities are facing similar cost pressures resulting from these standards. *Id*. Furthermore, utilities' ASCs generally rise with increases in their production and transmission-related costs. These costs include many costs other than conservation and renewables costs. Under the Staff proposal, exchanging utilities' residential consumers will receive higher REP benefits if the utilities' ASCs rise due to higher conservation and renewables costs, all else being equal. The consumers' benefits will simply not increase as much as they would have under the previous implementation of the REP. Furthermore, the REP was not designed to provide conservation and renewables incentives to regional utilities. Instead, it was intended to provide a form of access to the benefits of the low-cost regional Federal hydrosystem. The Staff proposal is consistent with this intent.

The OPUC states that case law sets forth that the standard for an agency's decision to modify a prior standard must be "rational, based on consideration of relevant factors, and within the scope of authority delegated to the agency[.]" *Id*., *quoting Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983). The OPUC argues that Staff's proposal fails on all counts.

First, the OPUC argues that Staff's proposal is not rational because it does not meet the objectives for the change in policy stated by BPA and is not based on relevant factors. *Id*. The OPUC notes that a primary purpose of the Northwest Power Act is to achieve wholesale rate parity among Northwest utilities. *Id*. The OPUC states that Staff's rate proposal is inconsistent with this primary purpose because it redistributes benefits that would have gone to higher-cost utilities (and thus, directly have met the goal of achieving wholesale rate parity) to lower-cost utilities that already have more wholesale rate parity with consumer-owned utilities than the higher-cost utilities. *Id*.

As discussed above, the Staff proposal meets the stated objectives. The proposal also is consistent with wholesale rate parity. The premise of wholesale rate parity is discussed in the legislative history of the Northwest Power Act:

> … This exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980). Wholesale rate parity means what it says: parity of wholesale power rates between preference customers and investor-owned utilities. This is achieved in the REP through power sales to both BPA's preference customers for their requirements purchases and investor-owned utility customers for their REP purchases at the PF rate. The Northwest Power Act, however, establishes an exception to this principle, which is the section 7(b)(2) rate test. The proposed Supplemental 7(b)(3) charges allow wholesale rate parity to withstand the effects of the rate test on the base PF Exchange rate. When the section 7(b)(2) rate test triggers, the PF Exchange rate must necessarily increase. It then becomes a question of whether the exception to wholesale rate parity reduces the REP benefits to all participants or eliminates some participants while reducing the benefits to others by a smaller amount. Wholesale rate parity, however, is preserved under the Staff proposal.

Second, the OPUC argues that BPA is not authorized to pursue a new regulatory scheme in pursuit of its goal of spreading the benefits of the FCRPS at the expense of the underlying purpose of the Northwest Power Act, which is to achieve wholesale rate parity. *Id*.

In addition to the reasons earlier stated, the OPUC's argument fails because BPA is specifically authorized by section 7 of the Northwest Power Act to implement the proposed Supplemental 7(b)(3) charges. First, section 7(e) states that "[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time of day, seasonal rates, *or other rate forms*." 16 U.S.C. § 839e(e) (emphasis added). The base PF Exchange rate is the rate of general application. The utility-specific Supplemental 7(b)(3) charges are authorized under "other rate forms." Second, section 7(b)(3) itself authorizes such charges. Section 7(b)(3) states: "[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) (emphasis added). Here, the statement is in the plural, "charges." Clearly this allows for different levels of charges to be included in the rates for "all other power sold."

The legislative history also adds to the understanding of the discretion granted by Congress:

> This subsection [7(e)] also clarifies that the rate directives contained in this bill only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money.

H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 53 (1980). Congress delegated the form of rates to the Administrator. The Staff proposal is a form of rates within that discretion.

Finally, BPA has already held that:

> [i]t is important to recognize the distinction drawn by Congress regarding the allocation of the costs under section 7(b)(3). For allocations of a net revenue surplus or deficiency under section 7(b)(3), such amounts are "recovered from, or repaid to, customers over a reasonable period of time after July 1, 1985, through a supplemental rate charge or credit applied proportionately for all other power sold

by the Administrator." In other words, Congress knew how to provide for proportional allocations of the referenced costs and expressly did so. For general allocations of the 7(b)(2) trigger amount, however, Congress did not require a proportional allocation, but rather provided that such amounts are recovered through "supplemental rate charges for all other power sold by the Administrator to all customers." This means that BPA is not required to proportionally allocate the trigger amount to all other power sold by the Administrator to all customers.

2002 Administrator's Record of Decision, WP-02-A-02, at 12·36; *see also* WP-02-A-02, at 12·43. Utility-specific supplemental 7(b)(3) charges are within the scope of authority delegated to the Administrator.

In its Brief on Exceptions, the OPUC recommends that BPA adopt a two-step approach to incorporate 7(b)(3) charges in its ratemaking formulas. OPUC Br. Ex., WP-07-R-PU-01, at 1-2. First, BPA should use information from the calculation of residential exchange benefits for the IOUs in aggregate, and for the publics in aggregate, using a single 7(b)(3) surcharge. *Id*. Then, BPA should develop utility-specific supplemental surcharges to redistribute the IOU-aggregate residential exchange benefits among the IOUs. *Id*. The OPUC states that by doing so, BPA will achieve the goal of broadening the benefits of the Federal system without the drawback of transferring benefits available to the IOUs to public agencies. *Id*. The OPUC notes that if BPA adopts the policy of utility-specific 7(b)(3) surcharges for public agencies as well, BPA should spread the public exchange benefits over public utilities using the dollars available to the publics under a single 7(b)(3) surcharge. *Id*. The OPUC states this would accomplish the goal of spreading the benefits more broadly over the public agencies as well without transferring dollars from IOUs to publics, or visa versa, as a result of adopting the utility-specific 7(b)(3) surcharges. *Id*.

In response, BPA understands the OPUC's concerns on this issue and respects its proposal. Nevertheless, BPA does not believe it is appropriate to distinguish between public agency exchanging utilities and IOU exchanging utilities. In all other aspects of BPA's ratemaking, BPA views utilities participating in the REP as members of the same class. Indeed, section 5(c)(1) of the Northwest Power Act, which establishes the REP, provides that "[w]henever *a Pacific Northwest electric utility* offers to sell electric power to the Administrator …" 16 U.S.C. § 839c(c)(1) (emphasis added). Thus, the Act does not differentiate the types of utilities participating in the REP. Therefore, BPA will develop utility-specific supplemental surcharges without differentiating between public agencies and IOUs. BPA also notes that, given the limited extent of public agency participation in the REP, BPA's allocation of the surcharges will have little of the effect identified by the OPUC.

Cowlitz argues that Staff's proposal is illegal for the same reason the REP Settlements were; BPA is again "insisting on greater flexibility in designing a REP program than Congress was willing to give it." Cowlitz Br., WP-07-B-CO-01, at 65-66, *citing PGE*, 501 F.3d at 1036. Section 5(c) ties the "cost benefits" to IOUs to the ASCs of each utility. Cowlitz Br., WP-07-B-CO-01, at 66. Cowlitz claims offering differential PF Exchange rates to the IOUs based on their ASCs undermines that legislative goal and the design of section 5(c) of the Northwest Power Act. *Id*. Cowlitz states that the notion that BPA can invent multiple, utility-specific rates to make a different allocation of benefits not only conflicts with section 5(c), but also conflicts with section 7(b)(1) as well. *Id*. Pursuant to section 7(b)(1), BPA is to develop "a rate or rates *of general application* for electric power sold to meet general requirements of [preference customers] and loads of electric utilities under section 5(c) of this Act." *Id*., *citing* 16 U.S.C. § 839e(b)(1) (emphasis added by Cowlitz). Cowlitz argues that customer-specific rates are manifestly not rates of general application; they apply only to a single customer. Cowlitz Br., WP-07-B-CO-01, at 66. Cowlitz contends BPA's proposal to develop an extrastatutory means of giving more IOUs access to REP benefits represents the same unlawful decision "ignor[ing] the exchange program Congress created in the NWPA and that BPA implemented through its regulations." *Id*., *citing PGE*, 501 F.3d at 1036.

Cowlitz errs in its application of the Northwest Power Act to Staff's proposal. First, nothing in section 5(c) of the Act speaks to the *rate* that REP participants will pay for purchases from BPA. This direction is provided solely in section 7 of the Act. Therefore, there can be no conflict between supplemental rate charges and section 5(c). Second, the base PF Exchange rate is developed in common with the PF Preference rate as directed by section 7(b)(1) of the Act. The base PF Exchange rate is a rate of general application under section 7(b)(1) and applies generally to all utilities participating in the REP. The supplemental 7(b)(3) rate charges are *not* developed under section 7(b)(1), but under section 7(b)(3). Third, Congress limited itself to directing the amount of costs to be collected from customer classes, not the specific form of that collection. Section 7(e) specifically provides the Administrator the discretion to design rates and to establish "other rate forms." 16 U.S.C. § 839e(e). Congress clarified that the Act's rate directives only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money. *See* H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 53 (1980). The utility-specific supplemental 7(b)(3) charges are authorized "rate forms." Fourth, section 7(b)(3) itself authorizes such differential charges by use of the plural "supplemental rate charges." 16 U.S.C. § 839e(b)(3). So, too, does section 7(b)(1), which speaks of a rate or rates of general application. 16. U.S.C. § 839e(b)(1). As noted previously, section 7(b)(3) does not preclude different levels of charges to be included in the rates for "all other power sold." Therefore, utility-specific supplemental rate charges are consistent with sections 5(c), 7(b)(1), 7(b)(3), and 7(e) of the Northwest Power Act and therefore are not "extrastatutory." In addition, the supplemental rate charges apply to all utilities participating in the REP, not just IOUs. Also, the application of the supplemental charges may provide an exchanging utility more or fewer REP benefits, thereby establishing that the proposal does not simply favor the IOUs. Moreover, the proposed utility-specific supplemental rate charges are an intra-class allocation matter; that is, the development of utility-specific supplemental rate charges has no financial effect on Cowlitz or other non-exchanging utilities.

In its Brief on Exceptions, Cowlitz notes that section 7(b)(3) directs BPA to recover section 7(b)(2) trigger amounts "through supplemental rate changes for all other power sold by the Administrator [*i.e.*, other than power sold to preference customers at the PF Exchange rate] to all customers." Cowlitz Br. Ex., WP-07-R-CO-01, at 29. BPA recognized that the "*pro rata* allocation" method it has previously employed for allocating amounts to be recovered through section 7(b)(3) might mean that "fewer residential and small farm consumers of regional utilities receive REP benefits," limiting BPA's Subscription goal "to spread the benefits of the

FCRPS as widely as possible." *Id. citing* Draft ROD, WP-07-A-03, at 298. Thus, BPA proposes to develop "utility-specific Supplemental 7(b)(3) charges" in service of that goal. *Id*.

Cowlitz objects to any BPA assertion of authority to establish "utility-specific" rates or charges for the sale of power. Cowlitz Br. Ex., WP-07-R-CO-01, at 29. Cowlitz states that although "utility-specific rates" may in this case represent an "intra-class allocation matter" for the IOUs with "no financial effect on Cowlitz," BPA's claimed authority to establish "utility-specific" rates may threaten Cowlitz's interests in other contexts. *Id*. Cowlitz does not cite any "interests in other contexts" to which it refers. BPA notes, however, that BPA is not simply determining individual rates for individual utilities, rather, as explained below, BPA is employing a common methodology that applies to all utilities, which can result in utilities' individual rates properly differing from other utilities' rates.

Cowlitz states BPA agrees that the PF Exchange rate is a "rate of general application," as required by section 7(b)(1). Cowlitz Br. Ex., WP-07-R-CO-01, at 29. Cowlitz contends that BPA claims, however, that section 7(b)(3) surcharges are not subject to any requirement of "general application," and are appropriate under section 7(e). *Id*. at 29-30. In support of this interpretation, BPA cites legislative history of section 7(e) to the effect that the section 7 rate directives "only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money." *Id*. at 30, *citing* Draft ROD, WP-07-A-03, at 303. Cowlitz notes that section 7(e) states that "[n]othing in this Act prohibits the Administrator from establishing, *in rate schedules of general application*, a uniform rate or rates for the sale of peaking capacity or from establishing time of day, seasonal rates, or other rate forms." *Id*. *citing* 16 U.S.C. § 839e(e) (emphasis added). Cowlitz states that, according to BPA, "[t]he utility-specific Supplemental 7(b)(3) charges are authorized under 'other rate forms'" pursuant to section 7(e). Cowlitz Br. Ex., WP-07-R-CO-01, at 30. Cowlitz argues the first difficulty with BPA's position is that "BPA's rate design authority under section 7(e) is expressly limited to designing rates of general application." *Id*.

In response, however, the PF Exchange rate is a rate schedule of general application whose generally applicable provisions can result in differences in individual rates. Section 7(e) refers to "rate *schedules* of general application," which are sometimes referred to generally as "rates." 16 U.S.C. § 839e(e). BPA's rate schedules are multiple page rules containing provisions on availability, billing factors, adjustments, demand charges, energy charges, and special rate provisions. *See, e.g.*, 2007 Wholesale Power Rate Schedules. The PF Preference rate schedule, for example, has different rates for different types of service, including the Full Service Product; the Actual Partial Service Product—Simple; the Actual Partial Service Product—Complex; the Block Product; the Block Product with Factoring; the Block Product with Shaping Capacity; the Slice Product; and PF Exchange Power. *Id*. In addition, the PF Preference rate schedule includes adjustments, charges, and special rate provisions such as the Conservation Rate Credit; the Conservation Surcharge; Cost Contributions; the Cost Recovery Adjustment Clause (CRAC); the Dividend Distribution Clause; the Emergency NFB Surcharge; the Flexible Priority Firm Power Rate Option; the Green Energy Premium; the Low Density Discount; Rate Melding; the Targeted Adjustment Charge; and the Unauthorized Increase Charge. *Id*. Despite all of these different surcharges, charges, credits and clauses, no party has claimed that the PF Preference rate schedule is not a rate of general application, that is, a rate that applies generally to all of the sales of different classes of power made under that rate schedule. Thus, the fact that a rate may differ among different customers within a class based on which sub-elements of the rate apply to a particular customer does not mean the rate fails to apply generally to all power sales under the schedule. Instead, specific provisions will affect particular customers in particular ways. Thus, a 7(b)(3) surcharge, like other surcharges and charges, applies generally but the particular application depends on the circumstances of the purchaser.

The PF Exchange rate schedule is one of general applicability. Like the PF Preference rate schedule, it contains numerous charges and surcharges. The initial WP-07 PF Exchange rate schedule included a demand charge; energy charge; transmission charges; adjustments; charges; and special rate provisions, which include a conservation surcharge, cost recovery adjustment clause, dividend distribution clause, emergency NFB surcharge, and low density discount. These charges and surcharges are applied generally to each customer purchasing under the PF Exchange rate in accordance with General Rate Schedule Provisions, which establish the manner in which the charges and surcharges are determined and applied to individual customers. The 7(b)(3) surcharge is also of general applicability. When BPA develops PF Exchange rates, BPA first establishes the base PF Exchange rate, also called the unbifurcated PF rate. This base PF Exchange rate applies equally to all utilities participating in the Residential Exchange Program. Section 7(b)(2) of the Northwest Power Act, however, establishes a rate test, which provides cost protection to BPA's preference customers. The rate test can trigger, resulting in an amount of dollars that are allocated to non-PF Preference rates. Part of this trigger amount is allocated to the PF Exchange rate class. The Northwest Power Act does not prescribe the manner in which BPA allocates the trigger amount to non-PF Preference rate schedules or to the members of each class responsible for paying part of the trigger amount (the PF Exchange, IP, NR and FPS purchasers). Therefore, the Administrator must determine how to do so.

The legislative history of the Northwest Power Act explains the intent of establishing the REP, noting that "[t]his exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost federal resources marketed by BPA …" H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2d Sess. 35 (1980). These lower-cost Federal resources consist primarily of the Federal hydroelectric dams in the Pacific Northwest. The Flood Control Act of 1944 provides that "[e]lectric power and energy generated at reservoir projects under the control of the Department of the Army and in the opinion of the Secretary of the Army not required in the operation of such projects shall be delivered to the Secretary of Energy who shall transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles." 16 U.S.C. § 825s. Reading the Flood Control Act and the Northwest Power Act *in pari materia*, BPA allocates the 7(b)(2) trigger amount to the PF Exchange rate class in a manner that allows reasonable participation by utilities in the REP. BPA allocates respective 7(b)(3) surcharges to exchanging utilities' base PF Exchange rates according to the utilities' net REP benefits in the absence of the trigger. Thus, exchanging utilities receive the same base PF Exchange rate, subject to a surcharge applied generally to all such utilities based on established criteria. These criteria do not change and apply the same standards to utilities generally.

Cowlitz argues that the concept of a "utility-specific rate" is an oxymoron, at least in the context of wholesale rates for sales to utilities, and conflicts with the requirement that rates be "of general application." Cowlitz Br. Ex., WP-07-R-CO-01, at 30. Cowlitz states that, in the utility context, the concept of a rate is a charge "for a service open to all and upon the same terms" (Black's Law Dictionary 1134 (5th ed. 1979)), or in this context, open to all members of each customer class. *Id*. Cowlitz argues that as the scope of the customer class is reduced to a single customer, what is involved is no longer a "rate of general application." *Id*. Section 7(e), however, 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. § 389e(e). Thus, section 7(e) recognizes that the final rates established within such rate schedules may reflect numerous "rate forms." Section 7(e) allows BPA to develop reasonable allocations of costs through charges and surcharges. Furthermore, as noted above, BPA's base PF Exchange rate applies to all exchanging utilities and the allocation of the 7(b)(3) surcharge to the base PF Exchange rate for each exchanging utility is done through the application of standards that apply to all exchanging utilities.

Cowlitz states that BPA also argues that section 7(b)(3) affords express authority to make "supplemental rate charges," arguing that the plural "charges" language "allows for different levels of charges to be included in the rates for 'all other power sold.'" Cowlitz Br. Ex., WP-07-R-CO-01, at 31, *citing* Draft ROD, WP-07-A-03, at 303. Cowlitz argues that, nevertheless, what is involved are still a "*rate* charges." *Id.* Cowlitz claims the adjective "rate" negates the idea of a utility-specific charge. *Id.* To the contrary, however, section 7(b)(3)'s reference to "rate charges" does *not* negate the idea of utility-specific charges. It simply means that upon the 7(b)(2) rate test triggering, BPA's non-PF Preference rates will incur supplemental charges that apply generally, based on general criteria, but which may have different effects on different customers based on the application of the generally applicable criteria to a customer's particular circumstances. This has been typical of BPA ratemaking under the Northwest Power Act. If Congress had intended BPA to be constrained to applying identical "supplemental rate charges" to the base PF Exchange rate or other rates, it could have easily done so. However, Congress did not do so, preferring instead to leave rate design issues to the Administrator's determination.

Cowlitz argues the simple reason for use of the plural term "charges" is that the rate schedules applicable to each *class* of customers subject to section 7(b)(3)—not a single customer—might be adjusted upwards by the charge necessary to recover the trigger amount. Cowlitz Br. Ex., WP-07-R-CO-01, at 30-31. In other words, there can be plural "charges" because there are plural rate tariffs. *Id.* at 31. BPA agrees that the reference to plural "charges" generally refers to the fact that there may be supplemental charges to a number of non-Preference rates. Nevertheless, the language does not preclude the Administrator's reasonable design of the manner in which such charges will be allocated to and recovered from rates. Cowlitz also argues that use of the plural "charges" does not mean that BPA can pick and choose how much of the section 7(b)(3) surcharge amount individual customers or customer classes must bear. *Id.* Cowlitz, however, has mischaracterized BPA's allocation of a surcharge amount to the PF Exchange rate. BPA does not "pick and choose" how much of the surcharge amount will be allocated to each exchanging utility's PF Exchange rate. Instead, BPA has established a methodology that applies generally to all exchanging utilities. The allocated surcharge amounts are determined through this generally applicable methodology. The specific amount allocated to an exchanging utility depends on the utility's circumstances as applied to the surcharge methodology. This is similar to, for example, BPA's low density discount (LDD). BPA has established a methodology for determining each qualifying utility's LDD. The fact that each utility's LDD may be different is a result of each utility's circumstances applied to the LDD methodology. This, however, does not mean that such rate design conflicts with the development of rate schedules of general applicability.

Decision

Utility-specific supplemental 7(b)(3) charges are rational, based on consideration of relevant factors, and within the scope of authority delegated to BPA. BPA Staff's proposal is adopted, and the PF Exchange rate will include utility-specific supplemental 7(b)(3) charges.

15.4 DSI Rates

Issue 1

Whether BPA's proposed revised IP rate is consistent with statutory directives or will fail to recover all of the costs BPA will incur in the event a DSI customer requests service under the rate schedule.

Parties' Positions

Alcoa argues that the IP rate is not consistent with the requirements of section 7(c) of the Northwest Power Act, primarily because BPA has ignored the requirement that the IP rate be "equitable in relation" to the rates that preference customers charge their industrial customers. Alcoa Br., WP-07-B-AL-1, at 10.

PNGC argues that BPA proposes to revise and lower the IP rate in this Supplemental Proceeding, for no reason compelled by the Ninth Circuit's rulings in *PGE* and *Golden NW*. PNGC Br., WP-07-B-PN-1, at 10. PNGC claims that BPA has not articulated a policy reason for reducing the IP rate, and it continues to forecast no sales under it. *Id*. Therefore, PNGC concludes, BPA should not revise its IP rate as proposed. *Id*. BPA should either make an IP rate that will recover all the costs of serving DSI customers, as required by statute and the *Golden NW* decision, or if BPA believes the section 7 rate directives do not allow it to recover in the IP rate all costs of DSI sales under that schedule, BPA should revoke the rate schedule in its entirety. *Id*. at 11.

BPA Staff's Position

BPA Staff addressed these issues in rebuttal testimony. Fisher, *et al.*, WP-07-E-BPA-79. The proposed IP-07R rate was developed in conformance with all relevant statutory rate directives. *Id*. at 8. Moreover, the current rate proposal does not project any actual power sales to the DSIs under the IP rate. *Id*. at 4. Should BPA determine that it will make such sales under the IP rate, pursuant to a court decision or otherwise, Staff's internal analysis shows that BPA could provide up to 340 aMW of power to the DSIs at the same cost already included in rates for the monetized power sale that is currently being provided. *Id*. at 9. Thus, there is no violation of ratemaking directives, nor is there a cost recovery problem. *Id*.

Evaluation of Positions

Alcoa argues that even in the absence of physical power service to the DSIs, Alcoa retains an interest in assuring that BPA's IP rate is designed according to the statute so that if the IP rate is to be applied in the future, the rate is crafted in a lawful manner. Alcoa Br., WP-07-B-AL-01, at 10. Alcoa states that it is also important to assure that if BPA goes through the exercise of designing the IP rate, it does so correctly so as not to mislead BPA's other customers as to the correct statutory outcomes. *Id*.

Staff agrees with Alcoa that an IP rate that is calculated in each of BPA's general rate cases must conform to the relevant statutory rate directives as well as the legislative history. Fisher, *et al.*, WP-07-E-BPA-79, at 19. As discussed below, Alcoa's arguments notwithstanding, BPA has properly calculated the IP rate in this rate proceeding.

Alcoa argues that there are two sources of authority that reveal that BPA's approach to the IP rate is unsupported and fails to result in a faithful calculation of the rate. Alcoa Br., WP-07-B-AL-01, at 10. First, Alcoa argues that BPA ignores the express terms of the Northwest Power Act that the rate applicable to DSIs shall be "equitable in relation to" the rates that preference utilities charge to their own industrial customers. 16 U.S.C. §§ 839e(c)(1), 839e(c)(1)(B), 839e(c)(2). *Id*. Second, Alcoa argues that the legislative history of the Northwest Power Act similarly confirms that BPA's approach to DSI rates is inconsistent with the intent of Congress and the statute's purposes. *See* S. Rep. No. 96-272, 96th Cong., 1st Sess. at 59 (1979). *Id*.

Alcoa's view of BPA's statutory rate directives is oversimplified, and its reading of the legislative history of the Northwest Power Act is overly selective. The IP rate is not final with the application of the section 7(c)(2) margin. Fisher, *et al.*, WP-07-E-BPA-79, at 15. Another component is the floor rate test. *Id*. The floor rate test ensures that the proposed IP rate is not less than the IP rate in effect during the year ending June 30, 1985. *Id*. The floor rate test in this proposal did not result in a change to the proposed IP rate, but there could be circumstances in which the floor rate test increases the IP rate to a higher level than the applicable wholesale rate plus the section 7(c)(2) margin. *Id*. A second component is the section 7(c)(3) value of power system reserves credit. *Id*. at 16. This credit, included in the IP rate when the DSIs provide power system reserves to BPA, will result in a lower IP rate. *Id*. Because BPA has forecast zero power sales to the DSIs, BPA did not include any credit for power system reserves to the DSIs. *Id*. Another component of IP rate development Alcoa has omitted from its testimony is the application of the section 7(b)(3) supplemental rate charge. *Id*. If the section 7(b)(2) rate test has triggered, as it has in this proposal, the cost of the rate protection afforded to preference customers is applied to all other power sold by BPA, including power sold under the IP rate schedule. *Id*.

Alcoa argues that the Senate Report is emphatic that the DSI ratemaking directives apply indefinitely, describing their duration as "1985-86 and all future." Alcoa Br., WP-07-B-AL-01, at 10. Alcoa argues that it clarifies again that the touchstone of the IP rate's design is the rate charged by preference customers to their own non-DSI industrial customers. *See also* Senate Report at 56 (the DSI rate "will be based upon the retail rates applicable to industry served by BPA preference utility customers"). *Id*. at 11. Alcoa further argues that the Senate Report explains that the section 7(c)(2) "typical margin" (or "markup" in the words of the Senate Report) that the IP rate receives above the preference rate is intended to substitute for "the typical margin of cost" that preference customers add to the power they sell to their own non-DSI industrial customers after they buy it at the preference rate. *Id*. In its reading of the Senate Report, Alcoa has concentrated solely on the section 7(c)(2) "typical margin" (or "markup" in the words of the Senate Report) that the IP rate receives above the preference rate. Lost in its argument is any mention of the other IP rate adjustments described in the Senate Report. Along with the description of the "typical margin," the Senate Report describes the DSI floor rate adjustment, the adjustment for reserves, the adjustment for allocated resource costs, and the adjustment for PF rate protection allocated to the IP rate:

> (2) 1985-86 and all future. The rate will be set at a level no less than that set for the year 1984-85 and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers. This level is determined by applying a typical margin of cost ("markup" between the preference customers' retail industrial rates and their respective wholesale power costs) to the BPA wholesale rates to the preference customers for all power used to serve their industries. The rate is then adjusted for reserves [*DSI floor rate adjustment*].
>
> (3) The rates set under paragraphs (1) [*pre-1985 rates*] and (2) above are adjusted to reflect the credits for the value of power system reserves made available to the region's power system through the ability of BPA to interrupt service to the DSI loads. These credits to the DSI rate are then shared as a cost of reserves to all firm power sales, including that portion of the DSI load considered as not providing these reserves (currently 50 percent of the DSI load) [*DSI adjustment for reserves*].
>
> (4) Revenue adjustments will be made to all sales other than the DSIs to cover the difference after 1984-85 between revenues collected from the DSI rate and all other rates and the cost of power required to serve the regional loads [*DSI adjustment for allocated resource costs*].
>
> (5) Rate adjustments applicable in accordance with section A.5 below are reflected directly in the DSI rate through 1984-85 but only indirectly beginning in 1985-86 to the extent they modify the rates from BPA to public bodies and cooperatives for power that serves retail industrial customers [*DSI typical margin adjustment*].

> (6) Rate adjustments to recover revenues not recovered from the public body, cooperative, and Federal agency customers because of the preference customer rate limit and any adjustments for compliance or noncompliance with conservation standards are reflected directly in the DSI rate. At-site discounts apply for the duration of present contracts that contain them [*DSI adjustment for PF rate protection allocated to the IP rate*].

S. Rep. No. 96-272, 96th Cong., 1st Sess. 60-61 (1979) (summary descriptions added).

Alcoa argues that the Senate Report also serves to illustrate how the absence of DSI loads is causing BPA to ignore the rate directives of the Northwest Power Act. Alcoa Br., WP-07-B-AL-01, at 10. Alcoa argues that consistent with these directives, Mr. Speer recommended a logical and statutorily grounded basis for developing the IP rate: the preference customer rate plus the reasonable margin ($0.57 per MWh) that BPA has calculated in the past as applying to the preference customers' own industrial loads. Speer, WP-07-E-AL-4, at 3-4.

Contrary to Alcoa's argument that the absence of DSI load has caused BPA to ignore the ratemaking directives, its own oversimplified recommendation of simply adding the typical margin of $0.57/MWh to the PF Preference rate clearly ignores the requirements of section 7(c) and Congressional intent as outlined above. Staff's Supplemental Proposal did not have a complete absence of DSI loads, as Alcoa alleges. A token amount of DSI load (0.0001 aMW) was assumed for ratemaking purposes. Supplemental WPRDS Documentation, WP-07-E-BPA-49A, at 16. Staff's Supplemental Proposal then conducted all of the DSI rate-related ratemaking steps required by the rate directives on this token amount of DSI load. Although, due to rounding to the nearest thousand dollars, the printed documentation often displayed zero costs being allocated to DSI load during the ratemaking process, the rate model used to calculate the Initial Proposal rates and made available to all parties reveals that the initial allocation of resource costs to the 0.0001 aMW DSI load was about $45; then, after all of the DSI-related ratemaking steps, the final cost allocated to DSI load was about $28, resulting in a per megawatt-hour rate of $32.07. Thus, it is Alcoa's proposed method of simply adding a typical margin amount to the PF Preference rate that falls short of the full implementation of the DSI rate directives. Staff's Supplemental Proposal had a non-zero amount of DSI load and comprehensively followed the DSI rate directives.

In its Brief on Exceptions, Alcoa argues that BPA's IP rate contains an unexplained error. Alcoa Br. Ex., WP-07-R-AL-01. Alcoa agrees with BPA's statement that, as a matter of law, BPA was compelled to revise the WP-07 IP rate in this proceeding because the PF rate was being adjusted and the IP rate is established based initially on the PF rate. *Id.* at 2. Alcoa is concerned, however, because the IP rate rose between the time BPA made its initial proposal and issuance of the Draft ROD. *Id.* Alcoa had expected the IP rate to drop by about ten cents per MWh, but instead it rose by $2.76/MWh. *Id.*

Alcoa and BPA appear to agree as to the proper methodology for computing the IP rate. *Id.* at 2-4. Alcoa agrees, for example, that initially the rate is based on the PF rate plus an industrial margin, which has been calculated at $0.57. *Id.* at 2. Alcoa also recognizes that the IP rate is subject to the section 7(b)(2) rate test and, as appropriate, a supplemental charge pursuant to section 7(b)(3). *Id.* at 3. Alcoa notes as well that the so-called DSI floor rate is inapplicable and that BPA is making no downward adjustment for value of reserves. *Id.* at 3-4. Alcoa also observes correctly that the section 7(b)(3) cost reallocation went down for non-PF Preference rate customers as a result of BPA's decision to assign a portion of the reallocation to surplus power sales. *Id.* at 4.

BPA and Alcoa essentially agree on all of these points. However, BPA believes that Alcoa does not fully appreciate the effects of other matters on the IP rate, which even in its final form is still significantly lower than the original WP-07 IP rate of $45.08 MWh. Alcoa, however, believes the increase of $2.76/MWh is in error: "[O]ne would not expect the IP rate to go up by $2.76/MWh at the same time as the PF rate goes down, as BPA made no change in assumptions regarding the size of the DSI load, and hence any costs allocated to the DSIs. Instead … the applicable statutes would seem to dictate that the DSI rate would remain roughly the same or go down to reflect the allocation of the 7(b)(3) charge to surplus loads." *Id.* at 4.

BPA understands Alcoa's confusion, but Alcoa has, in fact, failed to account for the effects of changes made to BPA's original proposal. For example, as Alcoa notes, BPA decided to reallocate a portion of the 7(b)(3) cost reallocation to surplus power sales. This action meant, in turn, that the revenue credit for secondary sales attributed to the PF rate had to be decreased. The consequence of this decrease is that the unbifurcated PF rate went up, since the PF rate was no longer receiving the entire credit attributable to secondary sales. This change in turn increased the section 7(b)(2) rate test trigger, causing an increase in the 7(b)(3) supplemental rate change assigned to the IP rate. In addition, the Initial Proposal posted PF rate was net of a credit for the Lookback amount of returned FY 2002-06 REP settlement benefits, while in the Final Proposal the credit is a billing adjustment. Therefore, the Final Proposal posted PF rate is higher in the amount of the Lookback credit. The Final WP-07 Supplemental Rate Case IP rate consists of the applicable PF rate at the flat DSI load shape of $25.44/MWh, plus an industrial margin amount of $0.573/MWh, plus the 7(b)(3) supplemental rate change of $8.803/MWh, for a total average IP rate of $34.82/MWh. The allocation of costs to the IP rate pool and the subsequent ratemaking steps to determine the final level of the IP rate can be seen in the FY 2009 WPRDS Documentation, WP-07-FS-BPA-13A, Section 2. Clearly, policy and data changes leading to a higher flat PF Preference rate and a larger 7(b)(3) supplemental rate charge are responsible for the increase in the IP rate from the Initial Proposal to the Final. BPA hopes this explanation clarifies the issue raised by Alcoa.

Alcoa also argues that BPA's response to PNGC regarding the amount of power the DSIs are entitled to in the absence of the monetary benefit is erroneous. *Id*. at 4. Alcoa bases this conclusion on statements in the Draft ROD which Alcoa views as contradictory. On the one hand, BPA determined that:

> BPA would not necessarily incur a revenue shortfall if it were to sell physical power to the DSIs at the proposed IP rate. The proposed rates already recover $55 million for the monetized power sale, which would be used to offset cost increases resulting from a power sale. There is no evidence that BPA would sell the DSIs 577 aMW of power. Therefore, a cost under-recovery from that level of sales [as argued by PNGC] is speculative and unfounded.

Id. at 5, citing Draft ROD, WP-07-A-03, at 310-311. Alcoa argues that this statement conflicts with BPA's statement to the following effect:

> The IP rate is determined by reference to the PF Preference rate adjusted for the typical margin, the floor rate test, the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate. In other words, by statutory design, the IP rate is not designed to recover a specific set of allocated costs. Instead, the cost of providing service to DSI load is incorporated into BPA's total system costs, and rates are developed to recover all of BPA's costs in a manner consistent with all rate directives.

Id., citing Draft ROD, WP-07-A-03, at 309. Alcoa incorrectly assumes that BPA intended the former statement to mean that "BPA's other customers are to be insulated from providing cost-based and adequate physical power service to the DSIs." *Id.* Alcoa also argues that "the 'Draft Decision' implies that the Monetary Benefit is a settlement of a dollar amount reflecting an amount of money that the other customers can 'afford' as opposed to an amount of power that BPA has determined is available for DSI service and therefore a power sale that is monetized." *Id*. at 6. Alcoa states that characterizing this arrangement as a "monetized power sale" is "both accurate and necessary" because the Ninth Circuit, in *PGE* and *Golden Northwest,* "rejected BPA's authority to 'settle' on lump sum payments to its customers in lieu of following the rate directives set forth in its statutes." *Id.* Thus, Alcoa argues, BPA should not place a "ceiling" on DSI sales based on "the amount of market power BPA concludes it can purchase in the future for the amount of the Monetary Benefit." *Id.* To do so would, according to Alcoa, be "contradicting its own understanding of the statutory basis for setting the DSI rate." *Id.*

In this instance, Alcoa seems to be attributing intentions on the part of BPA that simply do not exist. BPA was responding only to PNGC's very limited argument that in 2009, BPA could face an under-recovery problem if BPA, for whatever reason, sold 577 aMW of power to the DSIs at the IP rate. BPA's response basically indicates that PNGC's arguments are highly speculative because (a) there is no basis to conclude that any power will be sold at the IP rate; (b) if such sales were made, there is no basis to conclude that they would be in the amount of 577aMW; and (c) the $55 million currently attributable to the monetized power would become available to support sales to the DSIs.

Nothing more should be read into BPA's decision. BPA understands the statutory requirements for setting the IP rate and BPA intends to set its rates in accordance with statutory requirements, both now and in the future. Although, BPA does not necessarily agree with Alcoa's interpretation of the *Golden Northwest* and *PGE* opinions, there is, in any case, no basis to conclude that BPA intends to treat the IP rate as a "marginal cost" rate rather than a "cost-based" rate. Neither is there a basis to conclude that BPA does not intend to "adhere to the statutory method for calculating the IP rate." *Id.* at 6.

PNGC argues that Staff proposes to revise *and lower* the IP rate in this Supplemental Proceeding for no reason compelled by the Ninth Circuit's rulings in *PGE* and *Golden NW.* PNGC Br., WP-07-B-PN-01, at 10. PNGC goes on to argue that, indeed, Staff has so far articulated no policy reason for reducing the IP rate, and it continues to forecast no sales under it. *Id*. PNGC has characterized the proposed reductions to be, from Staff's point of view, a convenient byproduct of Staff's proposed revised treatment of the section 7(b)(3) reallocations of section 7(b)(2) rate protection amounts. *Id*.

Staff agreed that one of the reasons the WP-07 Supplemental Proposal's IP rate is lower than the previous IP rate, along with being linked to a lower PF Preference rate, is that the 7(b)(3) supplemental rate change applied to all non-PF Preference rates is smaller, as described in Staff's rebuttal testimony:

> In the WP-07 Final Proposal, the section 7(b)(3) reallocation amount was distributed to the PF Exchange, IP and NR rates on a pro rata basis using the forecast loads of the three rates. This pro rata reallocation increased the PF Exchange rate to the point that only four of the potential 12 participating utilities remained in the REP, thereby reducing the PF Exchange loads in FY 2009 from almost 5,961 aMW to 2,551 aMW. For ratemaking purposes, the assumed IP load and NR load were each one-tenth of an average annual kilowatt. Therefore, in the WP-07 Final Proposal, the IP load was allocated about 0.0000039 percent of the section 7(b)(3) reallocation amount.
>
> In the Supplemental Proposal, the section 7(b)(3) reallocation method has been changed. Using the new proposed method, participating utilities that would be eligible for REP benefits prior to the section 7(b)(2) rate test remain viable participants in the REP after the reallocation of the rate protection. This new method has two steps. First, the section 7(b)(3) amount is reallocated on a pro rata basis based on forecast PF Exchange, IP and NR loads. The second step reallocates the section 7(b)(2) rate protection amount allocated to the PF Exchange class among the PF Exchange customers on a pro rata basis using pre-rate test REP benefits. This method results in a much larger PF Exchange load than using the prior method. In the Supplemental Proposal, the PF Exchange load is forecast to be 5,525 aMW. The IP and NR loads remain at one-tenth of an average annual kilowatt. Therefore, the IP rate was allocated 0.0000018 percent of the section 7(b)(3) reallocation amount. Application of this lower allocation amount leads to a reduction in the IP-07R rate.

Fisher, *et al.*, WP-07-E-BPA-79, at 2-3. As Staff noted further, "[t]he IP rate is set appropriately. It is properly linked to the PF Preference rate and it has been allocated its share of the section 7(b)(3) reallocation amount." *Id*. at 8.

PNGC argues that while BPA says it forecasts no DSI sales under the IP rate schedule and has allocated no costs to be recovered under that rate, it has chosen to reduce the IP energy rate by about 30 percent. PNGC Br., WP-07-B-PN-01, at 10.

As Staff has shown, the Supplemental Proposal has significantly more load than the WP-07 Final Proposal. This significantly increased load reduces the amount of the section 7(b)(2) rate protection allocated to the IP rate pursuant to section 7(b)(3). This is appropriate.

PNGC argues that inserting a "plug" number to avoid a "divide by zero error" is insufficient to support making an IP rate. PNGC Br., WP-07-B-PN-01, at 11. PNGC goes on to argue that making an IP rate based on such calculations is a fiction. *Id*. PNGC contends that using the "plug" number to produce a reduction in an already inadequate IP energy rate of about 30 percent, so that BPA can offer the DSIs a soft landing in the event the Ninth Circuit rules against BPA in *PNGC v. BPA*, is unlawful, arbitrary, and an abuse of discretion. *Id*.

PNGC's arguments are flawed. The IP rate in this proceeding was developed in conformance with all statutory requirements. The fact that the IP-07R rate is lower than the IP-07 rate is a product of those requirements and the level of loads in the case. No cost recovery issue is presented on that basis. The statutory directives governing calculation of the IP rate do not require that the rate recover the full cost of supplying actual power to the DSIs. Section 7(c) specifies how the IP rate is to be established:

> *The rate* or rates *applicable to direct service industrial customers shall be established* … 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 … 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 …

16 U.S.C. § 839e(c) (emphasis added). The IP rate is determined by reference to the PF Preference rate adjusted for the typical margin, the floor rate test, the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate. In other words, by statutory design, the IP rate is not designed to recover a specific set of allocated costs. Instead, the cost of providing service to DSI load is incorporated into BPA's total system costs, and rates are developed to recover all of BPA's costs in a manner consistent with all rate directives.

The current rate proposal does not forecast any sales to the DSIs under the IP rate and therefore no costs to serve the DSIs. However, for ratemaking purposes, some amount of load had to be attributed to the IP rate. Otherwise, there would be a zero in the denominator, which would create a nullity. Even though the load is small, it bears a proportionate share of costs. Therefore, Staff properly assumed a very small amount of load to the IP rate, one-tenth of an average annual kilowatt.

Decision

The IP-07R rate has been developed in conformance with statutory ratemaking directives.

Issue 2

Whether BPA would face a cost recovery deficit if it were to sell 577 aMW of power to the DSI smelters at the proposed IP rate.

Parties' Positions

PNGC argues that BPA faces a potential shortfall of $104 million if a decision is made to sell 577 aMW of power to the DSIs. PNGC Br., WP-07-B-PN-01, at 10.

BPA Staff's Position

BPA has not made any commitment to provide physical power service to DSIs and, if it should, there is no basis to argue that BPA would take the kind of financial risk envisioned by PNGC.

Evaluation of Positions

As noted above, PNGC argues that BPA faces a potential shortfall of $104 million if a decision is made to sell 577 aMW of power to the DSIs. PNGC Brief, WP-07-B-PN-01, at 10. PNGC's argument fails on two counts. First, it fails to take into account that the $55 million cost of the monetized power sale to the DSIs is already in rates. If BPA decides to sell power rather than monetize the power sale, the cost of the monetized power sale would go away and become available to defray the cost of providing power to the smelters. Second, the PNGC argument fails because it presumes a specific future that BPA has not yet decided, that of a 577 aMW sale of power in place of the monetized power sale. BPA does not set rates based on speculative outcomes of ongoing processes.

Moreover, Staff identified information presented at a customer workshop on February 13, 2008, which indicated that through FY 2009, BPA could sell up to 350 aMW of power at no cost increase to PF Preference customers. Fisher, *et al.*, WP-07-E-BPA-79, at 9. Staff noted further that the analysis was based on market price assumptions and rate assumptions incorporated into the Supplemental Proposal. *Id.* at 4. This level of actual power deliveries would not create a cost recovery problem because the $55 million currently being recovered in rates for the monetized sale would be freed up and could be expended, as necessary, to defray the costs of an actual power sale. *Id.* at 9. Thus, even if such sales were made, BPA would still be recovering its system costs in the aggregate, as required by law. Any sales for subsequent years would be addressed as appropriate in future rate proceedings.

Decision

BPA would not necessarily incur a revenue shortfall if it were to sell physical power to the DSIs at the proposed IP rate. The proposed rates already recover $55 million for the monetized power sale, which would be used to offset cost increases resulting from a power sale. There is no decision that BPA would sell the DSIs 577 aMW of power. Therefore, a cost underrecovery from that level of sales is speculative and unfounded.

Issue 3

Whether BPA's proposed IP rate fails to recover its costs and should therefore be revoked.

Parties' Positions

PNGC argues that BPA should either develop an IP rate that will recover all of the costs of serving DSI smelter load or revoke the proposed IP rate schedule. PNGC Br., WP-07-B-PN-01, at 11.

BPA Staff's Position

By statutory design, the IP rate is not developed based on the direct cost of service to DSI load. Fisher, *et al.*, WP-07-E-BPA-79, at 3-4.

Evaluation of Positions

PNGC argues that Staff's proposed revised IP rate schedule will fail to recover all of the costs BPA will incur in the event that a DSI customer requests service under this schedule, BPA enters a contract for such service (under section 5(d)), acquires resources to serve the DSI load, and commences sales. PNGC Br., WP-07-B-PN-01, at 9-10.

Staff established that the IP rate proposed in the Supplemental Proposal is sufficient to recover the costs allocated to DSI load and is consistent with the rate directives of section 7(c) of the Northwest Power Act. Fisher, *et al.*, WP-07-E-BPA-79, at 3. Given the assumptions in the Supplemental Proposal, the proposed IP rate has been established properly. *Id*. A properly constructed IP rate that conforms to statutory rate directives may or may not recover the full cost of supplying actual power to DSIs in isolation from all other rates. *Id*. This is because the IP rate is not designed to recover a specific set of allocated costs. *Id*. It is established by reference to the PF Preference rate adjusted for the floor rate test, the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount. *Id*. The costs of supplying power to the DSIs under the IP rate would be included in BPA's total costs, and BPA would develop all rates to recover all of BPA's costs in a manner consistent with the rate directives. *Id*.

PNGC's argument is not persuasive. The rate for DSIs is to be set in accordance with section 7(c) of the Northwest Power Act. Staff has properly stated the basis for the IP rate. The IP rate is not a cost-based rate under the Northwest Power Act. Thus, the IP rate is not responsible for recovering specific costs. The IP rate is to be set based on the five factors described above: the applicable wholesale rate plus the typical margin, the floor rate adjustment, a value of reserves credit, and an allocation of preference rate protection pursuant to section 7(b)(3).

PNGC also argues that BPA should not revise its IP rate schedule as proposed. *Id*. at 11. PNGC states that BPA should either make an IP rate that will recover all the costs of serving DSI customers, as required by statute and the *Golden NW* decision, or if BPA believes the section 7 rate directives do not allow it to recover in the IP rate schedule all costs of DSI sales under that schedule, BPA should revoke the schedule in its entirety. *Id*.

Section 7(c) bars BPA from setting an IP rate that "recovers all the costs of serving DSI customers." Section 7(c) does not contemplate the IP rate being established based on direct cost of service to the DSIs. Rather, it specifies that the IP rate is to be based on the applicable wholesale rate adjusted for the floor rate test, the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount.

PNGC provides no reasonable basis for either not revising the IP rate schedule or revoking the IP rate schedule in its entirety. In this proceeding, BPA is considering all of its rates to ensure that all rates are set in accord with *Golden NW*. The Court remanded BPA's WP-02 rates based on a fundamental flaw. The Court's direction to BPA was "to set rates in accordance with this opinion." *Golden NW*, 501 F.3d at 1053. The Court's direction was not limited to any specific rates. Thus, the direction must be read as referring to all of BPA's rates. This is a logical conclusion because the costs of the REP settlements affect the level of all rates, especially the IP rate, which is determined based on the PF Preference rate. Because the same fundamental flaw the Court found with the WP-02 rates exists in the WP-07 rates, BPA has chosen to correct the error in the WP-07 rates in this proceeding. Once BPA determined to adjust the PF Preference rate, the IP rate had to be adjusted as well. To not do so when the PF Preference rate is being adjusted would be a violation of law, which directs that the IP rate is to be established based on the PF Preference rate. Therefore, BPA has no choice; the IP rate must be revised.

Decision

The IP-07R rate should not be revoked because it was developed in accordance with all legal requirements. The IP rate must be reestablished if the PF Preference rate changes.

15.5 Making the Conservation and Rate Credit Available to the Investor-Owned Utilities

Issue 1

Whether BPA should make the Conservation and Renewables Discount (C&RD), currently known as the Conservation Rate Credit (CRC), available to IOUs in FY 2009.

Parties' Positions

For FY 2009 forward, the OPUC recommends that BPA make the C&RD available to the IOUs. OPUC Br., WP-07-B-PU-02, at 33. The OPUC argues that making the C&RD available to all IOUs would provide certain and meaningful benefits to all IOUs, regardless of ASC and deemer status, and would benefit all of BPA's customers by reducing BPA's load obligations. *Id*.

BPA Staff's Position

Staff did not address the CRC and did not propose IOU participation in the CRC as part of the WP-07 Supplemental Proposal.

Evaluation of Positions

The OPUC refers to the C&RD, which was a rate discount established in the WP-02 power rate case and made available to BPA's preference customers purchasing under the PF-02, NR-02, and RL-02 rate schedules. The IOUs were offered C&RD benefits under the terms of the then-existing REP Settlement Agreements. The C&RD was designed to provide an incentive to customers to develop conservation through qualified measures recommended by the Regional Technical Forum, as adopted by BPA. BPA took a relatively hands-off approach to administering the C&RD in order to allow its customers more local control over the conservation and renewable resources being developed. In addition, the C&RD served as a catalyst to support BPA customer efforts to develop conservation and renewable resources in the aftermath of the deregulation of the wholesale power market. Administrator's Final Record of Decision, WP-02-A-02, at 10-97. In the WP-07 rate proceeding, BPA replaced the C&RD with the CRC, which returned the conservation focus to the development of cost-effective conservation measures. Pyrch, *et al.*, WP-07-E-BPA-24, at 4-5. The conservation developed under the CRC would be applied by BPA toward achieving its share of the Northwest Power and Conservation Council's conservation target. *Id*.

BPA appreciates the OPUC's suggestion for BPA to continue providing conservation program dollars to the IOUs through the CRC, as was done with the REP Settlement Agreements. However, the underlying policy reasons for BPA's past offerings have changed since the REP Settlement Agreements were signed. In FY 2002-2006, a fundamental purpose of the C&RD was to serve as a catalyst for renewing the region's efforts to develop conservation and renewable resources. BPA believes much has been achieved in the region since it first offered the C&RD. BPA recognizes regional mechanisms now exist that serve the same purpose. In particular, some states, such as Oregon, passed new laws aimed at developing conservation and renewable resources. For example, in 1999 Oregon passed Senate Bill 1149, which directs that funds be collected by PacifiCorp and Portland General Electric as a 3 percent public purposes charge from their retail customers. In turn, these monies fund the Oregon Energy Trust, which invests in conservation, renewable resources, and market transformation programs in the service territories of these two IOUs. The Oregon Energy Trust began operation in March 2002.

BPA's current policy for the CRC reflects a return to acquiring conservation based on its obligation to serve load under power sales contracts executed pursuant to section 5(b) of the Northwest Power Act. Consequently, BPA is not making conservation program monies available to IOUs under an RPSA, which does not supply power to meet load. As currently established, the CRC is intended to reduce the loads of BPA's firm power customers, and hence the power supply obligation of the Administrator. Because BPA is not supplying power to serve the loads of IOUs under section 5(b), there is no statutory reason, especially because payments made under the REP Settlement Agreements have ended, for BPA to offer IOUs the CRC. Assuming that the OPUC meant to suggest that the CRC should be available to the IOUs, the

OPUC's recommendation to provide such benefits to all IOUs, regardless of ASCs and deemer status, is a policy matter left to the discretion of the Administrator.

The OPUC provides an example whereby, pursuant to the "in-lieu" provisions in the Northwest Power Act, BPA would be allowed to acquire power to serve the IOUs' REP loads. OPUC Br., WP-07-B-PU-02, at 33. The OPUC claims that the amount of power needed for such an "in-lieu" sale would decline to the extent qualifying exchange load is reduced through conservation. *Id*. The OPUC's example does not, however, provide a basis for BPA to provide the CRC to IOUs. To the contrary, BPA does not enter into a load-serving obligation with utilities under section 5(c) of the Northwest Act, but merely into an exchange of resources. Even if there were in-lieu purchases in the future, BPA has never indicated that it intends to apply the CRC to sales under 5(c) of the Northwest Power Act.

Decision

BPA will not make the CRC available to IOUs through the REP in FY 2009.

15.6 PF Exchange Rate and Deemer Balance Adjustments

Issue 1

Whether BPA should credit the deemer repayments against the PF Exchange rate only.

Parties' Positions

The IOUs argue that BPA should apply any deemer payments that BPA receives or withholds from an exchanging utility against the PF Exchange rate only. IOU Br., WP-07-B-JP6-01, at 89-94; IOU Br. Ex., WP-07-R-JP6-01, at 19.

BPA Staff's Position

In the Initial Proposal, deemer repayments were modeled as credits to the PF Preference rate alone. Staff considered parties' subsequent arguments and changed the treatment of deemer payments so that they are now a reduction to BPA's program costs and affect all rate pools equally.

Evaluation of Positions

The IOUs argued in their Initial Briefs that there is no basis for BPA to assume or determine that any of the PF Preference rate customers, the DSIs, or the PF Exchange customers of BPA are any more or less entitled than any of these other customer groups to any allocation of deemer balances. IOU Br., WP-07-B-JP6-01, at 89-94. The IOUs contend that BPA specifically recognized that the PF Preference rate, the PF Exchange rate, and the New Resources rate may also be entitled to some return of the deemer balances. *Id., citing* Tr. 182, line 9, through page 183, line 17.

In the Draft ROD, BPA agreed, and noted that "the deemer repayment amount is no longer used solely to reduce the PF Preference rate. Other participants in the REP should see benefits from the deemer repayment amount." Draft ROD at 300. This adjustment means that when funds associated with the deemer repayments become available, they will be applied generally to BPA's program costs, with the result that all rates, including the PF Exchange rate, will be reduced.

The IOUs acknowledge that BPA's proposal to apply deemer balances to BPA's general costs, which affects all rates including the PF Exchange rate, is an improvement from BPA's original proposal. IOU Br. Ex., WP-07-R-JP6-01, at 19. However, the IOUs argue that the deemer repayment amount should be used *solely* to reduce the PF Exchange rate. *Id.* The IOUs contend that the PF Preference customers are not entitled to further reductions in their rates because they have already received the full section 7(b)(2) protection based on REP costs that include the deemer costs. *Id.*

The IOUs' proposal to credit only the PF Exchange rate with deemer repayment is flawed. The IOUs erroneously presume that deemer repayment is associated with current REP benefits. It is not. The deemer repayment stems from previous periods where an exchanging utility's ASC was below the PF Exchange rate. Boling, *et al.*, WP-07-E-BPA-57, at 3. In these instances, the deemer provision allowed the utility to avoid making an immediate payment to BPA, which effectively increased the cost of the REP in that past period to all ratepayers, not just the PF Exchange customers. The customers paying the PF Exchange rate as a class were not impacted any more or less than BPA's other ratepayers by the fact that the deeming utility did not make payments to BPA. To now designate the repayment of such deemer balances, when and if it occurs, to only one class of customers is improper and inequitable.

The IOUs contend that the PF Preference customers are not entitled to further reductions in their rates because they have already received the full section 7(b)(2) protection based on REP costs that include the deemer costs. IOU Br. Ex., WP-07-R-JP6-01, at 19. This argument is unpersuasive. The fact that the preference customers' rates reflect section 7(b)(2) protections is immaterial. The deemer balances were accumulated after the application of the statutory protections afforded to preference customers under sections 7(b)(2) and 7(c)(1)(A). It is, therefore, irrelevant that today's preference customers are receiving 7(b)(2) protection from today's REP costs.

Decision

Repayments of deemer balances will not be credited solely against the PF Exchange rate, but will be reflected in all rates through lower BPA program costs.

16.0 SECTION 7(b)(2) RATE TEST

16.1 <u>Introduction</u>

16.1.1 <u>BPA's Statutory Rate Directives</u>

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) for the general requirements of those customers if certain assumptions are made. 16 U.S.C. § 839e(b)(2). The effect of this comparison (hereafter called rate test) is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain costs resulting from the provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

To understand the context of the development of BPA's rates and the implementation of the section 7(b)(2) rate test, it is helpful to review the genesis of the Northwest Power Act. BPA was established by the Bonneville Project Act of 1937 (Project Act), 16 U.S.C. § 832, *et seq*. The Project Act authorized BPA to market 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*. BPA's customers also included IOUs and DSIs. Starting 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 2, at 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 to 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. 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*.

Numerous, complex tradeoffs were necessary in order to resolve the competing claims for BPA's low-cost hydropower in the late 1970s, and to solve the electric power planning uncertainties facing the PNW at that time. The provisions of the Northwest Power Act reflect the give and take of those tradeoffs. The Northwest Power Act established new directives regarding regional electric power planning, establishing the Pacific Northwest Electric Power and Conservation Planning Council (Regional Council). 16 U.S.C. § 839b. The Act granted the Administrator new authority to acquire resources to serve BPA's customers. 16 U.S.C. § 839d. The Act also established new directives regarding BPA's power sales, 16 U.S.C. § 839c, and new directives for the establishment of BPA's rates for power and transmission services, 16 U.S.C. § 839e.

The Northwest Power Act 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 Act also established the right of BPA's preference customers and investor-owned utility customers to receive service from BPA to meet their net requirements. 16 U.S.C. § 839c(b)(1). Similarly, the Act required BPA to establish initial long-term power sales contracts with its DSI customers, and provided the Administrator the discretionary authority to serve the DSIs after their initial contracts expired. 16 U.S.C. § 839c(d).

Although the Northwest Power Act established the right of BPA's IOU customers to receive service from BPA to meet their net requirements, the rate applicable to such service would be set at the cost of new resources rather than the embedded cost of the hydrosystem. Therefore, the Act also established the REP. 16 U.S.C. § 839c(c). As noted above, 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 Pacific Northwest utilities (both preference customers and IOUs) a form of access to low-cost Federal power. Under the program, a Pacific Northwest utility may sell power to BPA at a rate based on the utility's average system cost of its resources. BPA is required to purchase that power and sell, in exchange, an equivalent amount of power to the utility at BPA's PF rate. This is the same rate that applies to BPA's sales of power to its preference customers, although the Act provides that the PF rate for the REP may be higher than the PF rate for preference customers due to the section 7(b)(2) rate test. 16 U.S.C. § 839e(b)(3). When a utility's ASC is higher than BPA's PF rate, the difference between the two rates is multiplied by the utility's residential load to determine an amount of money that is paid to the utility as REP benefits. These benefits must be passed through directly to the utility's residential and small farm consumers through lower retail rates. The utilities themselves receive no benefits from the REP. The cost of BPA providing these benefits to exchanging utilities' residential consumers is borne primarily by BPA's publicly owned utility and DSI customers, subject to the rate test in section 7(b)(2) of the Northwest Power Act.

The Northwest Power Act also established new ratemaking directives. Section 7(a)(1) of the Act reiterated BPA's most critical rate directive: BPA's rates must be established to recover BPA's costs. Section 7(a)(1) provides:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to

> recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law. Such rates shall be established in accordance with sections 9 and 10 of the Federal Columbia River Transmission System Act [16 U.S.C. 838g and 838h], section 5 of the Flood Control Act of 1944 [16 U.S.C. 825s], and the provisions of this chapter.

16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Act governs review and approval of BPA's rates, conditioning such approval on the ability of BPA's rates to recover BPA's total costs:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6) of this section, upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates—
> (A) 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,
> (B) are based upon the Administrator's total system costs, and
> (C) 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).

The Act also establishes specific rate directives for the power sold to BPA's customer classes, including preference, IOU, and DSI customers. Section 7(b)(1) of the Northwest Power Act prescribes the manner in which BPA will allocate costs to the rate that applies to sales to preference customers and the loads of utilities (primarily IOUs) participating in the REP. Section 7(b)(1) expressly provides that REP costs can be allocated to BPA's rate for preference customers, which also applies to the REP:

> 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 5(c). 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 5(c) and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). The foregoing reference to "electric power acquired by the Administrator under section 5(c)" is a reference to the resources exchanged with BPA under the REP, which, as noted above, is a program established in section 5(c) of the Northwest Power Act.

In simple terms, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is insufficient to meet such loads. When the FBS "runs out," BPA then is directed to allocate the costs of the REP resources to the preference customers' requirements loads and REP loads. Thus, the Northwest Power Act expressly directs BPA to allocate REP costs to BPA's preference customers' PF rate after first allocating FBS costs to such rate. This statement of the plain language of the Act must be reemphasized to ensure it is understood. The Northwest Power Act establishes there are circumstances (lack of sufficient FBS resources) where the Act expressly directs BPA to allocate REP costs to BPA's preference customers' PF rate. In the instant case, the FBS is insufficient to serve all of the requirements of the preference and REP customers. Because the amount of REP resources acquired by BPA under section 5(c) is equal to the loads placed on BPA by participants in the REP, and the FBS exceeds preference loads, the total resources provided by the FBS and REP resources exceed the loads specified in section 7(b)(1).

Section 7(c) prescribes the manner in which BPA establishes rates for the DSIs:

> 839e(c)(1) The rate or rates applicable to direct service industrial customers shall be established—
>
> (A) for the period prior to July 1, 1985, at a level which the Administrator estimates will be sufficient to recover the cost of resources the Administrator determines are required to serve such customers' load and the net costs incurred by the Administrator pursuant to [16 U.S.C. 839c(c)], based upon the Administrator's projected ability to make power available to such customers pursuant to their contracts, to the extent that such costs are not recovered through rates applicable to other customers; and
>
> (B) 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.
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> 839e(c)(2). 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—
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> (A) the comparative size and character of the loads served,
>
> (B) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and
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> (C) direct and indirect overhead costs, 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.

16 U.S.C. § 839e(c). Section 7(c) prescribes different rate directives for DSI rates prior to and after July 1, 1985. Prior to July 1, 1985, the DSIs paid the cost of resources the Administrator determined were required to serve the DSIs' load and the net costs of the REP to the extent that such costs were not recovered through rates applicable to other customers. Thus, if preference customers were allocated REP costs after FBS resources proved inadequate to meet preference and REP loads, the DSIs did not pay the REP costs allocated to preference customers. After July 1, 1985, the DSIs' rates are based on BPA's power rates for preference customers and a typical margin included by preference customers in their retail industrial rates. *Id*.

BPA's other firm power rates are also subject to the effect of different rate directives after July 1, 1985. This occurs through the rate test established in section 7(b)(2) of the Northwest Power Act. During the development of the Northwest Power Act, preference customers were concerned about additional costs they might incur under the new Act. Senator Jackson of Washington explained:

> Publicly owned utilities in the region and nationally have expressed concern that the proposed regional legislation adversely affects the preference clause. Northwest preference customers have sought to address this issue through amendments to establish a "preference customer rate limit" which would preserve the financial benefits of the preference clause for public agencies. The public power council amendments would require BPA to test the estimated power costs to preference customers under the bill against the costs which these customers would have encountered *in the absence of legislation.*
>
> A number of specific assumptions are set forth in the amendments which would guide BPA in making the determination of costs *in the absence of legislation*.

Cong. Rec. Senate, S3999 (April 5, 1979); reprinted in Legislative History at 526F; *see also* Cong. Rec. H2060 (April 5, 1979) (Congressman Duncan discusses the "'rate cap' amendment to ensure that preference customers will pay no more under this bill than they would without it"); *reprinted in* Legislative History at 528 (emphasis added).

The preference customer amendments were the basis for sections 7(b)(2) and 7(b)(3) of the Act. Simply stated, the sections would test (1) preference customers' costs under the Act, with (2) preference customers' costs without the Act as established by a number of assumptions incorporated into section 7(b)(2). Senator Jackson's and Representative Duncan's remarks recognize the rate test was not solely a matter of protecting preference customers from the cost of the REP, but rather from "power costs to preference customers under the bill," which are reflected in the statutory language. *Id*. This is confirmed elsewhere in the legislative history.

The report of the Senate Committee on Energy and Natural Resources noted the rate test is a comparison of costs in the absence of the bill, not simply the REP:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater *than would occur in the absence of the regional program established in S. 885*.

S. Rep. No. 272, 96th Cong., 1st Sess. 20 (1979) (emphasis added).

The report of the House Committee on Interior and Insular Affairs characterized the test as generally ensuring costs benefits of preference rights, not simply precluding the allocation of REP costs:

> Subsection 7(b)(2) establishes a "rate ceiling" for BPA's preference customers, and specifies the method of calculating this ceiling, in order to insure such customers *the cost benefits of their preference rights for sales under this subsection.* Amounts not recoverable from preference customers because of this ceiling are to be recovered through supplemental rate charges for all other power sold by BPA under other provisions of section 7, as subsection 7(b)(3) specifies.

Id. at 52. This general intent is also recognized in the report of the House Committee on Interstate and Foreign Commerce. The report states:

> In addition, section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed *in the absence of this legislation*. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could pay less – but not more – for power under the legislation than they would have in any five-year period.

H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980) (emphasis added). The report also notes:

> Section 7(b)(2) establishes a "rate ceiling" for preference customers that seeks to assure these customers that their rates will be no higher than they would have been *had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this Northwest Power Act*. The assumption[s] to be made by the Administrator in establishing this ceiling are specifically set forth. It is through rate ceilings that this Northwest Power Act provides additional protection to public bodies and cooperatives' preference customers as to the price of the sale of power by the Administrator. In the event that this rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules.

Id. at 68-69; *see* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). This language recognizes BPA incurs costs under the Act by BPA's "power sales" with "non-preference customers," such as BPA's sales to the DSIs, and "purchase transactions," such as exchange purchases under the REP. This language also emphasizes something of critical importance. Although the legislative history speaks in general terms about a comparison of costs in the absence of the Northwest Power Act or some of the costs incurred thereunder, the report emphasizes that "[*t*]*he assumption*[*s*] *to be made by the Administrator in establishing this ceiling are specifically set forth*." In other words, the statutory language of section 7(b)(2), which requires BPA to incorporate *a number* of significant factors in conducting the rate test, governs the costs from which preference customers are protected. If the only purpose of section 7(b)(2) had been to protect preference customers from the costs of the REP, the test would have compared a case where the REP existed and a case where it did not. Congress did not choose to do so.

BPA acknowledges Congress intended to provide preference customers, in a general sense, protection from excessive REP costs. This is not the same thing as precluding the allocation of *any* REP costs to preference customers. The report of the House Committee on Interior and Insular Affairs states:

> … This [residential] exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region. Consumers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since, as discussed below, the DSIs of BPA are required to pay the costs of the exchange during its initial years while a "rate ceiling" protects the customers of preference utilities during later years.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980) (emphasis added). The foregoing language demonstrates the need to view such language in the context of the statutory rate directives. The report states preference customers would not suffer adverse consequences of the REP because "the DSIs of BPA are required to pay the costs of the exchange during its initial years." Reviewing the statutory language, however, it is true that the DSIs were expected to pay *the majority of costs of the REP* prior to July 1, 1985. Section 7(b)(1) of the Act, however, provides that REP costs can be allocated to preference customers' loads if the FBS resources become insufficient to meet such loads, and the DSIs do not pay the REP costs paid by other customers. 16 U.S.C. § 839e(b)(1). Thus, the report language is somewhat accurate, but is not in accord with the precise statutory requirements of section 7. Similarly, the report states that "a 'rate ceiling' protects the customers of preference utilities during later years," but the rate ceiling determines a trigger amount from *all of the factors* included in the rate test, not simply the REP. However, *in a general sense*, the rate test protects customers from REP costs because the REP costs are *part* of the calculation of the trigger amount.

The foregoing examination the legislative history of the Northwest Power Act provides the context for reviewing section 7(b)(2) of the Northwest Power Act, which states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that—
>
> (A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are—
>
> (i) served by the Administrator, and
>
> (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;
>
> (B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;
>
> (C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;
>
> (D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –
>
> (i) purchased from such customers by the Administrator pursuant to section 6, or
>
> (ii) not committed to load pursuant to section 5(b),
>
> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and
>
> (E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from—

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this Act

were not achieved.

16 U.S.C. § 839e(b)(2).

In summary, the rate test involves the projection and comparison of wholesale power costs for general requirements of BPA's public body, cooperative, and Federal agency customers (7(b)(2) Customers) in two cases. The two sets of costs 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), including adjustments to determine section 7(b)(2) general requirements (7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates. Next, each nominal rate is discounted to the test year of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average Program Case rate is greater than the average 7(b)(2) Case rate, the rate test triggers. Based on the extent to which the test triggers, the amount to be reallocated to non-PF Preference rates in the rate test period is calculated. 16 U.S.C. § 839e(b)(3).

As noted previously, section 7(b)(2) of the Northwest Power Act became applicable to BPA's rate development on July 1, 1985. *See* 16 U.S.C. §§ 839e(b)(2), 839e(b)(3), 839e(c)(1)(B), 839e(c)(2)(C). This section, however, does not repeal or eliminate the rate directives used to develop BPA's 1981 and subsequent power rates. Instead, the Act requires the rate test to be applied after the existing section 7(b)(1) rate directives. In order to conduct the rate test, BPA must first determine "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers" (the "Program Case rate"). This means BPA must first determine the rate to be charged preference customers using the rate directives of section 7(b)(1). In other words, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is insufficient to meet such loads. When the FBS "runs out," BPA then allocates the costs of the REP resources to the preference customers' and REP loads in an amount needed to meet the loads not met by the FBS, and then, if necessary, costs from other resources. Thus, during the development of BPA's post-1985 power rates, including BPA's WP-02 and WP-07 power rates, BPA must allocate REP costs to the PF rate if the FBS is insufficient (which is true in BPA's WP-02 and WP-07 rates). In other words, prior to conducting the section 7(b)(2) rate test, the PF rate properly includes REP costs in the Program Case. Furthermore, sections 7(b)(2) and 7(b)(3) do not remove specific costs from the rates to preference customers; rather, the costs to preference customers are just limited to a certain amount. Therefore, even though the rate test lowers the rate to preference customers, it does not actually remove REP costs from the preference customer rate. REP costs remain in the rate, except in the extremely unusual event, which has never occurred in the history of ratemaking under the Northwest Power Act, that the rate test trigger was so large that it increased the PF Exchange rate to a level that completely eliminated REP benefits. Therefore, even though the 7(b)(2) Case rate does not contain any REP costs, the section 7(b)(3) rate protection does not eliminate REP costs from the Program Case rate.

This result is due to the 7(b)(2) Case rate being the same as the Program Case rate except for the exclusions to the Program Case rate and the Five Assumptions applied to the 7(b)(2) Case rate. (One of the Five Assumptions in the 7(b)(2) Case is that the REP does not take place.) BPA then compares the Program Case rate with the 7(b)(2) Case rate. If the Program Case rate exceeds the 7(b)(2) Case rate, the rate test triggers and the difference, the "trigger amount," must be allocated to rates other than the PF Preference rate through section 7(b)(3) of the Act.

It is possible for the section 7(b)(2) rate test to trigger even if no utility is participating in the REP. Assume, for example, a hypothetical case with no DSI loads in addition to no REP loads. If the FBS is not sufficient to meet the general requirements of preference customers, the costs of new resources are included in the preference customers' rates in proportion to the amount of new resources needed to meet preference customers' remaining general requirements. In the Program Case, the new resource costs will be the average cost of all new resources. In the 7(b)(2) Case, the new resource costs will be the least expensive resources in the 7(b)(2)(D) resource stack. If the 7(b)(2)(D) resource stack resources are cheaper than the average cost of all new resources, then the 7(b)(2) Case rates will be cheaper than the Program Case rates, causing the section 7(b)(2) rate test to trigger.

Section 7(b)(3) of the Northwest Power Act governs the allocation of costs in the event the section 7(b)(2) rate test triggers. Section 7(b)(3) provides that "[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 test triggers, the trigger amount must be allocated away from preference customers' power sales priced under section 7(b) 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 among participating utilities. A utility will receive no benefits when its ASC rate drops below BPA's PF Exchange rate.

As long as the trigger amount allocated to the PF Exchange rate does not raise the PF Exchange rate so high that the REP is completely eliminated, the PF Preference rate will properly be recovering *some* REP costs. Thus, section 7(b)(2) does not protect the PF Preference rate from *all* REP costs (unless the trigger amount allocated to the PF Exchange rate raises the PF Exchange rate so high that the REP is completely eliminated), only from *additional* REP costs. As noted previously, if Congress had intended to simply eliminate REP costs from the PF Preference rate, the section 7(b)(2) rate test would have been a comparison of a Program Case rate with the REP with a 7(b)(2) Case rate without the REP, *with no other differences between the two Cases*. Obviously, Congress did not do this. Although the REP is included in the

Program Case and excluded in the 7(b)(2) Case, there are *numerous* other factors that Congress included in the rate test. These include the exclusion from the Program Case of costs of conservation, resource and conservation credits, experimental resources, and uncontrollable events; in the 7(b)(2) Case, Within and Adjacent DSI loads are included in the general requirements of preference customers; preference customers are served first with FBS resources not obligated under contracts in effect at the time the Act was signed; preference customers are served, after the FBS is exhausted, with either resources purchased from such customers by the Administrator or resources not committed to load under section 5(b) of the Act; and monetary savings from reduced financing costs and reserve benefits are not achieved. It is this *combination* of *many* factors that produces the result of the rate test, not simply the REP. Some of the differences result in lower rates to preference customers, others in higher costs to preference customers. The REP, however, is the largest and most costly BPA program that is treated differently in the two Cases and therefore the primary focus of attention in assessing the effects of the rate test. Basically, when Congress established the REP, preference customers wanted some protection from the costs of the REP becoming extremely high and thereby excessively raising the PF Preference rate. In recognition that other aspects of the Northwest Power Act provided benefits to preference customers, Congress chose to test the REP benefits against the other costs and benefits of the Act. The rate test addresses this balancing, but not by a test based solely on the REP or by a requirement that absolutely no REP costs be included in the PF Preference rate, but rather on a rate test based on a combination of factors. Indeed, the section 7(b)(2) rate test can (i) ”trigger” even in the absence of REP costs, and (ii) not “trigger” even with substantial REP costs.

This understanding is reflected in the legislative history of the Northwest Power Act. Appendix B to the Senate Report projected REP costs and cost allocations under the Act and demonstrated the understanding, from the inception of the Act, that projected REP costs (indeed, substantial projected REP costs) could be allocated to preference customers in the development of BPA’s rates. S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-79 (1979). The Senate base case analysis projected REP payments to IOUs for FY 1995 alone in excess of $750 million, without creating any trigger amount under section 7(b)(2). *Id*., at 69-71 (explanation: IOU Exchange rate [ASC, line 60] = 33.7, BPA PF Exchange rate [line 72] = 20.1, Exchange load [line 72] = 6,421 aMW; [33.7–20.1=13.6 × 6,421 aMW × 8,760 [hours per year] = $765 million).

As discussed above, the portion of BPA’s costs that remain allocated to preference customers may be limited by the section 7(b)(2) rate test, depending on the determination of the trigger amount in that test. Also as noted above, a trigger amount is not the same thing as removing REP costs because the trigger amount is determined using *all* of the Five Assumptions listed in section 7(b)(2). 16 U.S.C. § 839e(b)(2). When BPA calculates the trigger amount, BPA cannot quantify the synergy between the Five Assumptions that results in the trigger amount. It is not possible or meaningful to segregate the individual component contributions of any single section 7(b)(2) assumption to the trigger amount because all five hypothetical assumptions must be made in concert. Thus, under sections 7(b)(2) and 7(b)(3), BPA removes the *trigger amount* from the costs allocated to the preference customers’ rate, *not* REP costs. Similarly, under section 7(b)(3), when BPA reallocates the trigger amount to non-preference rates, BPA reallocates the *trigger amount* and *not* REP costs. The trigger amount, however, affects the costs properly allocated to the PF Preference rate.

BPA notes that its preference customers repeatedly refer to section 7(b)(2) as a "rate ceiling." The legislative history of the Northwest Power Act also mentions section 7(b)(2) operating as a "rate ceiling." *See* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). It is important to recognize, however, that section 7(b)(2) does not establish an *absolute* rate ceiling on the PF Preference rate. BPA acknowledges that when it conducts the section 7(b)(2) rate test and a trigger amount is produced, the trigger amount is allocated to non-preference customers pursuant to section 7(b)(3). The PF Preference rate, after the allocation of the trigger amount to non-preference customers, is established at a specific level. This has been characterized as a "rate ceiling." However, section 7(b)(2) does not establish an absolute rate ceiling because, as recognized since the inception of the rate test, there may be circumstances where BPA's paramount statutory ratemaking requirement to recover its costs would govern over section 7(b)(2). 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.

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)." *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 2008 Legal Interpretation. 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. *See* 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).*

See Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 2008 Legal Interpretation (emphasis added).

Such a condition could arise. In the hypothetical example begun above, if the costs of BPA's new resources exceeded the costs of the 7(b)(2)(D) resource stack resources, a rate test trigger would occur, all other things being equal. In this case, assume there are no other loads to which to allocate the trigger amount. In such case, the preference customers would be due rate protection, but there would be no one to absorb the trigger amount. In such an instance, the trigger amount would necessarily be required to be paid by preference customers under section 7(a). In such an instance, the "rate ceiling" would be exceeded.

In addition, even if one were to assert the erroneous argument that there is a specific "rate ceiling" (because there are circumstances where this is not correct), it certainly does not limit the actual amount of REP benefits that may be provided during the rate period and therefore does not form a "cost ceiling." The difference between these two concepts is significant. A "rate ceiling" would be the maximum amount of forecast REP benefits allowed to be included in rates during a ratemaking proceeding. A "cost ceiling" would extend to the maximum amount that BPA could pay exchanging utilities in REP benefits. However, REP benefits are determined *after* rates are established and in effect. There is no basis for a cost ceiling on the amount of REP benefits that BPA may actually pay in implementing the REP in any of BPA's statutes, GRSPs, policies, or procedures, and the REP benefit amount is subject only to the amount of benefits determined in such implementation. Further, the term "rate ceiling" does not occur in the Northwest Power Act; it is only referenced in the legislative history. The concept of a "cost ceiling" also does not occur in the Act. If Congress had intended that section 7(b)(2) would constitute a "cost ceiling," it would have said so. Indeed, just the opposite is true. In describing the rate test in section 7(b)(2), Congress directs BPA to look at "projected amounts," not amounts that will actually occur during the period following establishment of the rates. Thus, although section 7(b)(2) provides extensive rate protection to BPA's preference customers in the establishment of the PF Preference rate (through what is sometimes referred to as a "rate ceiling"), it does not establish a "cost ceiling."

In its Brief on Exceptions, WPAG notes BPA's statement in the Draft ROD that the actual REP payments made to the IOUs, and those BPA has forecast it would have made in the FY2002-FY2008 period absent the REP Settlement Agreements, are not subject to any limit due to the operation of the 7(b)(2) rate ceiling test. WPAG Br. Ex., WA-07-R-WA-01, at 32-33. WPAG notes that, according to BPA, the section 7(b)(2) rate test operates only on a forecast rate-setting basis, and BPA is free to pay the IOUs whatever level of benefits result from the application of the ASCM. *Id*. WPAG argues that BPA is incorrect because the purpose of the rate test, as established by Congress, is to provide preference customers real cost protection, and not the illusion of cost protection that could be forecast on the one hand and then taken away in reality on the other. *Id*. Although WPAG's argument might be initially attractive to someone not familiar with the operation of the REP, BPA's rate directives, and general ratemaking principles, it fails under any semblance of knowledgeable review.

Ironically, WPAG cites legislative history that undermines its argument. WPAG Br. Ex., WA-07-R-WA-01, at 33. WPAG notes the purpose of the rate test was described in the legislative history of the Northwest Power Act as follows:

> … section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed in the absence of this legislation. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could *pay* less – but not more – for power under the legislation than they would have in any five-year period.

Id. citing H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2d Sess. 34 (1980) (emphasis added). As can be seen from the legislative history, section 7(b)(2) only provides *price* benefits, not cost benefits, and 7(b)(2) rate protection is provided to preference customers *in the rates they pay* for the rate period that are established in a particular BPA rate hearing, based on the "five-year period" forecasted in the section 7(b)(2) rate test conducted for that rate proceeding. In other words, BPA establishes rates for specific rate periods. For example, BPA is establishing new power rates, including the PF Preference rate for preference customers, for FY 2009. The PF Preference rate BPA establishes for FY 2009 will only be in effect for one year. It will have no effect in any other year. In developing the FY 2009 PF Preference rate, BPA conducts the

7(b)(2) rate test and applies any resulting rate protection to that rate. In conducting the rate test, section 7(b)(2) directs that "[a]fter July 1, 1985, the *projected* amounts to be charged for firm power for the combined general requirements of [preference customers], exclusive of [Applicable 7(g) Costs], may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if the Administrator assumes [the Five Assumptions] …" 16 U.S.C. § 839e(b)(2). Thus, BPA uses the "year after July 1, 1985," that is, FY 2009, and forecasts costs for the following four years in order to conduct the rate test. The rate test thus only establishes the rate protection provided for the PF Preference rate for its rate period, in this instance, FY 2009. It has no remaining effect for any period outside FY 2009. The FY 2009 PF Preference rate has therefore been established consistent with section 7(b)(2) and preference customers have received all the protection they are entitled to receive by law through the establishment of the PF Preference rate for the FY 2009 rate period. Section 7(b)(2) does not require any subsequent true-ups in future rates, just as ASCs are not subject to true-ups once they have been determined.

WPAG argues that if BPA pays actual REP benefits in excess of the levels used to implement the 7(b)(2) rate test, the inevitable result of such overpayments will be either the decrease in BPA's financial reserves for which BPA's preference customers will be charged later, or the triggering of a cost recovery adjustment clause to recoup the costs of REP payments in excess of forecast levels, again from preference customers. WPAG Br. Ex., WA-07-R-WA-01, at 33. WPAG claims that in either case, the net result is that the rates paid by preference customers will be increased above the amounts, determined pursuant to the 7(b)(2) rate test, that BPA can lawfully charge those customers. *Id*. This argument is incorrect. The base PF Preference rates paid by preference customers for the rate period for which the 7(b)(2) rate test was conducted will not be increased at all, much less above the amounts BPA can lawfully charge such customers. The amount BPA can lawfully charge such customers was determined in the rate case after running the rate test and preference customers are only charged such rates. Any possible increases to the PF Preference rate during the rate period could only occur through the implementation of BPA's CRACs, which may not trigger at all. Furthermore, WPAG has not provided the necessary context for reviewing this issue. BPA's costs of implementing the REP are a program cost, just like BPA's other program costs such as, for example, BPA's purchase power costs or conservation costs. If BPA pays actual REP benefits during a rate period that exceed (or underrun) the REP benefits forecasted in the BPA rate proceeding, this inaccuracy (the difference between the rate case forecasted REP costs and the actual REP costs incurred from the actual implementation of the REP during the rate period) is simply accounted for in BPA's next rate development proceeding, just as it is with other BPA costs. It may well be that the decrease in one cost offsets the increase in another cost so that BPA's forecasted reserves are unaffected. Contrary to WPAG's claim, the costs of such inaccurate forecasts are not allocated solely to preference customers, but are recovered from BPA's rates generally. Similarly, the imposition of CRACs is based on percentage increases in all rates, not just the PF Preference rate. The recovery of costs incurred from inaccuracies in forecasting in subsequent rate development is a normal occurrence in utility ratemaking. Congress was well aware that ratemaking, including the section 7(b)(2) rate test, is performed on a forecasted basis. *See, e.g.,* S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-79 (1979) (Appendix B). Thus, Congress was aware that forecasts used in rate development may differ from the actual results that occur during the rate period.

Congress, however, did not provide any mechanism that would retroactively compare actual REP costs with REP costs forecasted in the rate case and make an adjustment for any such differences.

Similarly, just as REP costs may be higher during the rate period than BPA's rate case forecast, such costs may be lower than BPA's rate case forecast. This would mean BPA did not have to spend as much during the rate period as forecasted in BPA's rate case. BPA, however, does not subsequently make a special adjustment to reflect this savings, for example, by noting that the 7(b)(2) rate test would have had a smaller trigger if BPA had forecasted lower REP costs, thus reducing 7(b)(2) rate protection and increasing the PF Preference rate for the period. Instead, the fact that BPA's actual REP costs during the rate period were lower than BPA forecasted in its rate case would simply mean that BPA's preference customers, and other customers, would benefit by the fact that BPA's reserves going into the next rate period would be higher and BPA's prospective rate increases would be lower, all else being equal. Forecasting inaccuracies regarding the REP, and other BPA costs, are the same normal, longstanding occurrences that have existed for all BPA costs ever since BPA began developing rates under the Northwest Power Act, including the implementation of new rate directives in 1985.

It is also important to understand the operation of the REP and why there will always be some differences between BPA's REP costs as forecasted in BPA's rate cases and the REP costs BPA actually incurs from the implementation of the REP during a BPA rate period. Under the REP, regional utilities offer to sell power to BPA at the average system cost of their resources. 16 U.S.C. § 839c(c)(1). BPA is required to purchase such power and, in exchange, sell the same amount of power back to the utility at BPA's PF Exchange rate. *Id*. BPA is required by law to establish a methodology to calculate utilities' ASCs and to periodically make ASC determinations. 16 U.S.C. § 839c(c)(7). BPA calculates the positive difference between a utility's ASC and the PF Exchange rate, multiplies that difference by the utility's residential and small farm load, and provides monetary benefits to the utility, which are required by law to be passed through directly, and in their entirety, to the utility's residential and small farm consumers. 16 U.S.C. § 839c(c)(3). Historically, through FY 2008 (ending September 30, 2008), BPA implemented the REP under the 1981 ASC Methodology (1981-1983) and the 1984 ASC Methodology (1984-2008). Under the REP, exchanging utilities made average system cost (ASC) filings with BPA throughout each BPA rate period. These filings occurred each time the utility had a retail rate change before its state utility commission. Thus, a utility's ASC could change many times during a BPA rate period, thereby affecting the REP benefits the utility's residential consumers received during the rate period. BPA is required by law to pay the exchanging utilities the amount of benefits determined under the implementation of the REP. In contrast, when setting rates, BPA must forecast its costs, including REP costs, in order to determine how to set its rates to recover BPA's total costs. When BPA forecasts its REP costs, BPA cannot perfectly predict the future to know how often utilities will make new ASC filings, how utilities' total and residential loads will change, how the PF Exchange rate might change due to cost recovery adjustment clauses, and numerous other factors. One thing that is known is that BPA's rate case REP forecast will not perfectly predict the REP costs BPA will incur during the rate period. This is also true of all of BPA's other costs. All of BPA's other costs will turn out to be either higher or lower than BPA's rate case forecasts. Nevertheless, BPA does not make any adjustments to its rates to reflect this fact. Instead, when BPA subsequently develops rates for its next rate period, BPA reviews it total costs and establishes new rates to recover those costs.

WPAG argues BPA cannot do indirectly what it lacks the authority to do directly. WPAG Br. Ex., WA-07-R-WA-01, at 34. WPAG argues that paying actual REP benefits in excess of levels forecast in the applicable 7(b)(2) rate test results in preference customers paying indirectly amounts in excess of the amounts that Congress intended them to pay, claiming this is a type of "end around" that the Ninth Circuit found unlawful in the *PGE* and *GNA* decisions. *Id*. WPAG argues BPA would be free to make actual REP benefit payments in excess of levels forecast in the applicable section 7(b)(2) rate ceiling test if, but only if, the costs of such overpayments are borne by customers other than BPA's preference customers. *Id*. Once again, WPAG's arguments, including use of the term "end around," may appeal to parties unfamiliar with BPA's ratemaking and the REP, but such arguments fail under knowledgeable review. WPAG's arguments are based on a mischaracterization of section 7(b)(2). Section 7(b)(2) is a statutory mechanism for determining cost protection that is used in establishing the PF Preference rate for a rate period. Preference customers receive significant reductions in the PF Preference rate through the implementation of section 7(b)(2). During the rate period, preference customers pay the PF Preference rate that reflects the protection provided by section 7(b)(2), including any protection from REP costs resulting from the rate test. Recall that BPA must forecast REP costs because the REP has not yet been implemented for the rate period and REP costs are incorporated in the rate test by the elimination of the REP from the 7(b)(2) Case. This is all that section 7(b)(2) requires. Neither section 7(b)(2), nor any other provision of the Northwest Power Act (or any other Act), requires BPA to develop rates and then make later adjustments to rates to reflect the actual costs incurred through future implementation of the REP during the rate period. Such a suggestion would turn the most fundamental utility ratemaking principles on their heads. Simply stated, section 7(b)(2) limits the REP costs (among other costs) allocated to the PF Preference rate, but does not limit the REP costs BPA incurs in the actual implementation of the program.

Furthermore, as a practical matter WPAG's concern has been largely eliminated. BPA recently revised its ASC Methodology, which is used in implementing the REP. Under BPA's 2008 ASC Methodology, utilities no longer file new ASCs with BPA whenever they have a retail rate change, which has previously been difficult to predict. The new ASC Methodology also does not rely on information from state retail rate proceedings to develop utilities' ASCs. Instead, utilities now file their ASCs with BPA once for the rate/exchange period *prior to BPA's rate cases*. Therefore, BPA now knows the utilities' ASCs for purposes of its rate case REP cost forecast for the upcoming rate period. Needless to say, this makes BPA's rate case REP forecasts much more accurate in reflecting the REP costs BPA will actually incur during the rate period. Although the rate case forecasts will not perfectly match the actual REP costs incurred during the rate period (due largely to the continued inability to know actual utility loads prior to the rate period), BPA has tremendously reduced the potential differences between rate case REP forecasts and actual REP costs incurred during implementation of the program during the rate period.

Certain preference customer witnesses claimed that preference customers are protected by section 7(b)(2) from bearing any REP costs. IOU Br., WP-07-B-JP6-01, at 98. Statements such as these are overbroad, misleading, confusing, and fail to recognize that (i) *only purchases at the PF Preference rate are entitled to section 7(b)(2) protection*, and (ii) any other purchase – including any purchase by a preference customer from BPA at any rate other than the PF Preference rate – is not entitled to section 7(b)(2) protection. *Id*. The Five Assumptions in the 7(b)(2) Case and the subtraction of Applicable 7(g) Costs from the Program Case may or may not result in a trigger amount that is removed from the PF Preference rate. *Id*. at 99. Accordingly, there is no absolute protection under the section 7(b)(2) rate step that ensures the PF Preference rate will never bear REP costs. *Id*. Moreover, other rates paid by preference customers receive no section 7(b)(2) protection and must be allocated a portion of any section 7(b)(2) trigger amount. *Id*. The 2007 Final ROD (July 2006) states as follows:

> 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.)

Id., *citing* 2007 Wholesale Power Rate Adjustment Proceeding (WP-07) Administrator's Final Record of Decision (July 2006), WP-07-A-02, at 10·34.

Thus, if the section 7(b)(2) rate test triggers, amounts not included in the PF Preference rate by reason of the section 7(b)(2) rate test are to be recovered through rates for all other power sold by the Administrator to all customers, including preference customer purchases from BPA at any rate other than the PF Preference rate. *Id*. In other words, preference customers are not protected from having to bear any costs of the REP. *Id*. at 100. Section 7(b)(3) requires that any section 7(b)(2) trigger amount be applied to all rates other than the PF Preference rate for all other power sold by the Administrator to all customers. *Id*. Those rates include, for example, the FPS, IP, NR, and PF Exchange rates. *Id*. To the extent preference customers purchase power from BPA under rates other than the PF Preference rate, such preference customers appropriately bear an allocation of any section 7(b)(2) trigger amount. *Id*.

If the section 7(b)(2) rate step does not trigger, then the two rates (*i.e.*, the PF Preference and the PF Exchange rates) are identical both before and after the section 7(b)(2) rate test has been conducted. *Id*. at 101. In the event there is a trigger, the PF Exchange rate and other rates may be modified by the section 7(b)(2) rate test and the allocation pursuant to section 7(b)(3) of any resulting section 7(b)(2) trigger amount. *Id*. Indeed, the section 7(b)(2) trigger amount, if any, is to be removed from the PF Preference rate and allocated to all other rates for power sold by the Administrator to all customers. *Id*.

16.1.2 Implementation of Section 7(b)(2)

Pursuant to section 7(b)(2), BPA was required to implement the rate test for the first time in BPA's 1985 rate case. Prior to the 1985 rate case, BPA established a "Legal Interpretation of

Section 7(b)(2) of the PNW Electric Power Planning and Conservation Act." 49 Fed. Reg. 23,998 (1984), also published as b2-84-FR-03. BPA also developed a "Section 7(b)(2) Implementation Methodology," b2-84-F-02.

Because the average Program Case rate was higher than the average 7(b)(2) Case rate in the WP-07 Initial Proposal, the rate test triggered, and an adjustment to the preference customers' PF Preference rate was required. During the WP-07 rate proceeding, however, the litigants developed a Partial Resolution of Issues. *See* 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 did not fully litigate all issues regarding section 7(b)(2) in the WP-07 rate proceeding. For example, BPA did not litigate 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 and revised the Legal Interpretation and Implementation Methodology. Such a change would have had a dramatic effect on the section 7(b)(2) rate test by significantly reducing the reallocation amount, and thereby reducing the PF Exchange rate and making greater REP benefits available to exchanging utilities. Instead, given the Partial Resolution of Issues, BPA used the WP-07 Initial Proposal treatment of section 7(b)(2) issues to develop its final WP-07 rates.

Now, however, BPA has reopened the WP-07 docket in response to the *PGE* and *Golden NW* opinions. Whereas the WP-07 Initial Proposal and, hence, the WP-07 Final Proposal relied upon the Partial Resolution of Issues with respect to section 7(b)(2) issues, that is not the situation in the reopened proceeding. The WP-07 Final Proposal relied upon the REP settlements that were the subject of the *PGE* decision. The WP-07 Final Proposal rates allocated the costs of the REP settlements in a manner that the *Golden NW* Court held contrary to the Northwest Power Act. As a result, BPA must revisit its rate setting in light of the Court's holdings. By reinstituting the REP, a large number of issues relating to section 7(b)(2) have arisen. In response, prior to reopening the rate proceeding, BPA conducted a series of public workshops to identify and seek input on various issues pertaining to the interpretation and implementation of section 7(b)(2). After considering that input, BPA formulated a new Legal Interpretation and Implementation Methodology and has proposed them for adoption in this proceeding.

In summary, BPA has followed the provisions of section 7(b)(2) of the Northwest Power Act, BPA's proposed Legal Interpretation, and the proposed Implementation Methodology in developing its Supplemental Proposal rates. BPA, however, has used the 1984 Legal Interpretation and 1984 Implementation Methodology, with one necessary revision, for the Lookback analysis.

A number of the issues raised by parties in this proceeding go straight to the heart of the meaning and import of section 7(b)(2). BPA's construction of the 7(b)(2) Case has been challenged by both preference customers and IOUs. BPA found it necessary to reexamine its approach to the interpretation and implementation of section 7(b)(2) in response to the substantial number and depth of issues raised by parties. This examination was also needed because BPA had not reviewed the 1984 Legal Interpretation and 1984 Implementation Methodology in 24 years, despite significant changes in the electric industry and extensive experience gained under implementing the 1984 directives. In doing so, BPA returned to the text of the Northwest Power Act; not just section 7(b)(2), but almost all parts of the Act, especially sections 3 (Definitions), 5 (Sale of power), 6 (Conservation and resource acquisition), and 7 (Rates). BPA also extensively examined the legislative history of the Northwest Power Act, relying heavily upon the report of the Senate Committee on Energy and Natural Resources, No. 96-272, the report of the House Committee on Interstate and Foreign Commerce, No. 96-976, Part I, and the report of the House Committee on Interior and Insular Affairs, No. 96-976, Part II. These legal and implementation issues regarding the section 7(b)(2) rate test are addressed in this chapter. As a result of issues raised by parties and the resulting decisions by the Administrator, revisions to both the proposed Legal Interpretation and proposed Implementation Methodology will be necessary.

16.2 General Section 7(b)(2) Legal Issues

Issue 1

Whether (1) the net cost of the REP in the Program Case and (2) the amount of revenues in excess of the embedded cost of serving the DSIs plus the value of the uncompensated reserve benefits provided by DSIs in the Program Case are the only primary drivers of the section 7(b)(2) rate test.

Parties' Positions

Cowlitz argues when the Appendix B Numerical Analysis is analyzed consistent with the language in the Northwest Power Act, the balance between two main drivers dominates whether and how much the section 7(b)(2) rate test triggers to provide rate protection. Cowlitz Br., WP-07-B-CO-01, at 8. These two main drivers are: (1) the net cost of the REP in the Program Case; and (2) the amount of revenues in excess of the embedded cost of serving the DSIs plus the value of the uncompensated reserve benefits provided by DSIs in the Program Case. *Id*.

The IOUs argue other potential important factors exist that can affect the size of the section 7(b)(2) trigger amount. IOU Br., WP-07-B-JP6-01, at 103. The first two factors discussed by Cowlitz – net cost of the REP and DSI effects – are not necessarily the two dominant factors affecting the size of any 7(b)(2) trigger amount. *Id*.

BPA Staff's Position

BPA Staff states although Cowlitz/Clark made a series of modifications in the 2002 RAM, which they argue essentially eliminated the differences created by the assumptions listed in section 7(b)(2), this is not the case. Doubleday, *et al.*, WP-07-E-BPA-85, at 5. Simply assuming no DSI load, an FBS large enough to serve preference customer load in the Program Case, and no reserve or financing benefits, does not cover all of the differences between the Program and 7(b)(2) Cases. *Id*.

Evaluation of Positions

Cowlitz notes that Congress considered a document entitled "Appendix B Numerical Analysis of Rate Directives" reflecting the operation of section 7(b)(2) under a broad range of future scenarios, which is Appendix B to Senate Report No. 96-272. Cowlitz Br., WP-07-B-CO-01, at 8. Cowlitz admits Appendix B qualifies its relevance to BPA's ratemaking because "the circumstances assumed in preparing the analysis will change over time." *Id*. Cowlitz also admits that Appendix B acknowledged that notwithstanding such changes, "as a matter of law under this act rates shall be established pursuant to specific statutory provisions in section 7 and 9 …" *See* S. Rep. No. 96-272, 96th Cong., 1st Sess. 31-32 (1979). Thus, although Appendix B can be helpful when reviewing the Northwest Power Act, it is not dispositive of Congressional intent. Indeed, the Ninth Circuit Court of Appeals has acknowledged this fact in *Central Lincoln Peoples' Util. Dist. v. Johnson*:

> In support of their argument, the IOUs point to no language in the statute mandating that they be treated on the same basis as the DSIs. They look instead to Appendix B of the report of the Senate Committee on Energy and Natural Resources which suggests that, before June 1985, only two basic rate pools should exist. *See* Senate Report, *supra, at* 56-57. The import of this language is questionable, however, because the appendix states that the new resource rate applies to "utilities" and the DSIs are not utilities, and also because *the appendix was incorporated into the Senate Report with reservations*. *Id.* Furthermore, other legislative history suggests that BPA has the discretion to treat DSIs in a separate rate pool. Both House Reports and the Senate Report contain language indicating that only the DSIs, not the IOUs, should pay the exchange resource costs that the preference and IOUs' residential customers do not pay. *See* House

Report, Part II, *supra, at* 35; House Report, Part I, *supra, at* 29-30; Senate Report, *supra, at* 459.

735 F.2d 1101, 1122 (9th Cir. 1984) (emphasis added). Appendix B can be interpreted in a manner supporting many disparate arguments. For example, as noted earlier, Appendix B to the Senate Report projected REP costs and cost allocations under the Act and demonstrated the understanding, from the inception of the Act, that projected REP costs (indeed, substantial projected REP costs) could be allocated to preference customers in the development of BPA's rates. S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-79 (1979). The Senate analysis projected REP payments to IOUs for FY 1995 alone in excess of $750 million, without creating any trigger amount under section 7(b)(2). *Id*. In practice, of course, such results have not occurred and may never occur. However, the fact that Cowlitz relies on Appendix B establishes a relatively weak foundation for Cowlitz's argument.

Relying on Appendix B, Cowlitz argues there are two main drivers of the section 7(b)(2) rate test: (1) the net cost of the REP in the Program Case; and (2) the amount of revenues in excess of the embedded cost of serving the DSIs ("excess DSI revenues") plus the value of the uncompensated reserve benefits provided by DSIs in the Program Case. Cowlitz Br., WP-07-B-CO-01, at 8-9. Cowlitz claims if the net cost of the REP (before section 7(b)(2)) is equal to or less than the sum of the excess DSI revenues and reserve benefits, then section 7(b)(2) will generally not trigger, or will trigger by a very small amount. *Id*. If the net cost of the REP (before section 7(b)(2)) exceeds the sum of the excess DSI revenues and reserve benefits, then section 7(b)(2) will trigger by approximately the amount of such excess. *Id.* Cowlitz argues the WP-02 rate case involves less than 33 percent of the DSI loads assumed for the Appendix B Numerical Analysis (and WP-07 has no sales to DSIs), the industrial margin is much smaller than assumed, and BPA has not obtained power system reserves from the DSIs in any time frame included in this Supplemental case. *Id*. at 9. Cowlitz argues that if BPA were proposing to faithfully implement section 7(b)(2) as illustrated in the Appendix B Numerical Analysis, the rate test should trigger by the preliminary REP benefit amount, and all of the resulting surcharge must be allocated to the PF Exchange rate as the only rate available to surcharge. *Id.* Cowlitz contends that when it incorporated assumptions to eliminate the effects of all Five Assumptions except the cost of the REP into BPA's RAM model, the RAM still produced significant REP benefits to be paid for entirely by preference customers. *Id.*

Staff addressed Cowlitz's analysis in its rebuttal testimony. Doubleday, *et al.*, WP-07-E-BPA-85, at 5. Staff stated that although Cowlitz/Clark made a series of modifications in the 2002 RAM, which they argue essentially eliminated the differences created by the assumptions listed in 7(b)(2), this is not the case. *Id*. Simply assuming no DSI load, an FBS large enough to serve preference customer load in the Program Case, and no reserve or financing benefits, does not cover all of the differences between the Program and 7(b)(2) Cases. *Id*. The amount of surplus sales contracts served in each Case is different because the 7(b)(2) Case serves only pre-Act contracts first. *Id*. Because the contract sales served first are different, the amount of FBS resources available to serve PF load is different in each Case. *Id*. The Program Case has the cost and power amounts associated with "New Resources," while the 7(b)(2) Case does not. *Id*. The 7(b)(2) Case PF loads are higher to reflect the fact that conservation programs in the Program Case have not occurred in the 7(b)(2) Case. *Id.*

In addition, even if there were a situation where the only difference between the Program and 7(b)(2) Cases was the cost of the REP, then the section 7(b)(2) rate test trigger might or might not be large enough to force the REP benefits to zero. *Id*. The section 7(b)(2) rate test trigger is the result of discounting, averaging, and rounding two streams of rates over five years, one stream from the Program Case and the other from the 7(b)(2) Case. *Id*. Therefore, the actual trigger calculated and applied in the rate period may not be perfectly associated with the monetary differences between the Program and 7(b)(2) Cases in that period; that is, the rate protection amount calculated as the section 7(b)(2) rate test trigger times the PF Preference load may not be equal to the simple average of the annual revenue requirement differences between the Program and 7(b)(2) Cases in the rate period alone. *Id*.

The IOUs raise similar arguments. The IOUs argue other potential important factors exist that can affect the size of the 7(b)(2) trigger amount. IOU Br., WP-07-B-JP6-01, at 103. The first two factors discussed by the witnesses for Cowlitz and Clark – net cost of the REP and DSI effects – are not necessarily the two dominant factors affecting the size of any section 7(b)(2) trigger amount. *Id*. The section 7(b)(2) rate test entails subtraction of Applicable 7(g) Costs from the Program Case, as well as making the Five Assumptions in the 7(b)(2) Case. *Id*. There is no basis for concluding that any of the Five Assumptions or the subtraction of Applicable 7(g) Costs will be immaterial – or "less significant" – factors under all circumstances for purposes of the section 7(b)(2) rate test, regardless of any numerical examples in the Appendix B legislative history referenced by witnesses for Cowlitz and Clark. *Id*.

Cowlitz notes Staff's statement that the actual trigger calculated may not be perfectly associated with the monetary differences between the Program Case and the 7(b)(2) Cases and argues that Staff does not dispute the general conclusion of its testimony: BPA's RAM model produces very substantial REP benefits, paid for by preference customers, under conditions when section 7(b)(2) shows Congress intended that it should not do so. Cowlitz Br., WP-07-B-CO-01, at 9-10. Cowlitz argues with the departure of most DSI load, only very substantial financing benefits from passage of the Act could possibly have permitted the REP to continue to provide benefits to the residential and small farm customers of IOUs without raising the PF Preference rate. *Id*. at 10.

Cowlitz, however, ignores the other factors needed to calculate the section 7(b)(2) rate test trigger. The differential in the cost of new resources between the two Cases will affect the trigger if the FBS is not large enough to meet loads. The discounting, rounding, and averaging of the stream of rates also influences the trigger. Even if Cowlitz were correct, these other factors must be considered. For example, suppose that conditions were as Cowlitz postulates and the section 7(b)(2) rate test fully protected preference customers from REP costs in each year of the Five-Year Period. Now assume that REP costs decreased through the period such that the Program Case rate, all other things being equal, decreased from $34/MWh in the first year to $30/MWh in the fifth year. The costs of the REP are such that in the first year, the 7(b)(2) Case rate would be $24/MWh. All other things being equal, the 7(b)(2) Case would remain constant through the Five-Year Period. Given these conditions, and the discount rates in the Supplemental Proposal, the trigger would be $6.7/MWh. This is calculated as:

	Year 1	Year 2	Year 3	Year 4	Year 5	5-Yr. Avg.
Program Rate	34.00	33.00	32.00	31.00	30.00	
7(b)(2) Rate	24.00	24.00	24.00	24.00	24.00	
Discount Factor	0.9386	0.8790	0.8227	0.7700	0.7214	
Discounted Program	31.91	29.01	26.33	23.87	21.64	26.55
Discounted 7(b)(2)	22.53	21.11	19.74	18.48	17.31	19.83
					Trigger	6.7

Under these conditions, the trigger is calculated at $6.7/MWh, but in Year 1 it requires a trigger of $10/MWh to fully protect preference customers from all REP costs. The difference, $3.3/MWh, could produce REP benefits in the range of $215 million (7,500 aMW of preference load multiplied by the $3.3/MWh). As a result, there can be substantial REP benefits in Year 1 even though the section 7(b)(2) rate test fully protected preference customers in each year of the Five-Year Period.

Decision

The net cost of the REP in the Program Case and the amount of revenues in excess of the embedded cost of serving the DSIs plus the value of the uncompensated reserve benefits provided by DSIs in the Program Case are not the only primary drivers of the section 7(b)(2) rate test.

Issue 2

Whether Staff configured the section 7(b)(2) rate test to produce REP benefit results similar to the WP-02 results with the REP settlements.

Parties' Positions

Cowlitz argues that Staff proposes to add numerous additional, improper assumptions concerning the amount of load in the 7(b)(2) Case, the availability of resources to meet that load, and the costs of such resources. Cowlitz Br., WP-07-B-CO-01, at 2. Cowlitz claims that individually and collectively, the departures operate to assign substantially higher costs than permitted to the 7(b)(2) Case and to "eviscerate" the rate protection provided by Congress. *Id*. Cowlitz argues that BPA is now poised to commit a parallel error to the REP settlements, because the numerous additional, improper assumptions amount to the same sort of insistence on "greater flexibility than Congress was willing to give" that got BPA where it is now. *Id*. at 3.

APAC argues that in its reconstruction of the section 7(b)(2) rate test for FY 2002-2006, Staff revises the 1984 Implementation Methodology for the section 7(b)(2) rate test in significant respects. APAC Br., WP-07-B-AP-01, at 49. APAC argues that Staff, without abiding by due process requirements, has unilaterally changed that interpretation and has applied the "new" version in its proposal. *Id*. In particular, Staff proposes to alter retroactively its treatment of mid-Columbia resources as to their availability in the resource stack. *Id*.

BPA Staff's Position

As these are legal issues, BPA Staff deferred comment to this ROD.

Evaluation of Positions

Cowlitz argues that Staff proposes to make departures from the Five Assumptions, adding numerous additional, improper assumptions concerning the amount of load in the 7(b)(2) Case, the availability of resources to meet that load, and the costs of such resources. Cowlitz Br., WP-07-B-CO-01, at 2. Cowlitz claims that individually and collectively, the departures operate to assign substantially higher costs than permitted to the 7(b)(2) Case and to eviscerate the rate protection provided by Congress. *Id*. Cowlitz argues that BPA is now poised to commit a parallel error to the REP settlements, because the numerous additional, improper assumptions amount to the same sort of insistence on "greater flexibility than Congress was willing to give" that got BPA where it is now. *Id*. at 3.

BPA understands that parties make colorful arguments in order to convince BPA, or a reviewing court, that their positions are correct. Despite the negative characterizations, accusations, and motivations directed at the agency, however, BPA and reviewing courts must look past such tactics and review the facts and the law. BPA will address each of Cowlitz's accusations separately. First, BPA disputes that either the Staff proposals or the Administrator's decisions work to "eviscerate" rate protections to preference customers. BPA has approached its implementation of section 7(b)(2) thoughtfully and carefully in order to abide by the will of Congress as stated in the Northwest Power Act and its legislative history. The implementation of the section 7(b)(2) rate test will not "commit a parallel error to the REP settlements." Rather, BPA lays out its case in this ROD as to why its implementation of the rate test is in accord with the express instructions of Congress. In addition, it is important to recall that section 7(b)(2) clearly states that the implementation of the rate test is to be "as determined by the Administrator." 16 U.S.C. § 839e(b)(2). Congress was specific in its direction of what to assume in the rate test, but granted the Administrator deference in implementing such instructions.

APAC argues that in its reconstruction of the section 7(b)(2) rate test for FY 2002-2006, Staff revises the 1984 Implementation Methodology for the section 7(b)(2) rate test in significant respects. APAC Br., WP-07-B-AP-01, at 49. The 1984 Implementation Methodology was adopted in 1984 after extensive notice and comment. *Id*. Now, without abiding by these due process requirements, APAC argues that Staff has unilaterally changed that interpretation and has applied the "new" version in its proposal. *Id*. In particular, Staff proposes to alter retroactively its treatment of mid-Columbia resources as to their availability in the resource stack. *Id*. An agency cannot in one case both adopt a new regulation and apply it retroactively to a prior period. *Id*.

APAC's accusation is based on a significant mischaracterization of BPA's proposal. Staff did not base the section 7(b)(2) rate test for FY 2002-2006 on its proposed 2008 Implementation Methodology. Staff also did not base the section 7(b)(2) rate test for FY 2007-2008 on the proposed 2008 Implementation Methodology. Staff did assume a change in *one* provision in the 1984 Implementation Methodology—relating to the treatment of the mid-Columbia resources—which would have been necessitated at the time BPA developed its supplemental WP-07 proposal in the winter and spring of 2000-2001 due to changed facts based on the assumed absence of the 2000 REP Settlement Agreements. However, changing one element of the Implementation Methodology for valid reasons does not equate to the adoption of the proposed 2008 Implementation Methodology, particularly when parties have been free to propose changes to the Implementation Methodology in BPA's previous rate cases. Furthermore, BPA has not made the proposed assumption unilaterally. Instead, the assumption was raised at the beginning of this proceeding, and all parties have had a full opportunity to address this issue in the formal evidentiary proceeding through discovery, direct and rebuttal testimony, cross-examination of adverse witnesses, briefing on the proposed Interpretation and Methodology, and oral argument to the Administrator. BPA's decision is based on the law and the evidence. In any event, however, APAC's assertion that BPA is using its proposed 2008 Implementation Methodology for the FY 2002-2008 Lookback period is an obvious mischaracterization.

Further, APAC's charge that BPA's proposed treatment of the mid-Columbia resources has been implemented without due process is entirely without merit. First, BPA uses the 1984 Implementation Methodology for FY 2002-2008, with one assumed change that would have been necessitated at the time BPA developed its supplemental WP-07 rate proposal and which would have been accommodated in that proceeding. After FY 2002-2008, for FY 2009, BPA used a proposed revised Implementation Methodology for the 7(b)(2) rate test. This is plainly not a unilateral change in the Methodology. Instead, Staff proposed a new Implementation Methodology at the outset of this proceeding. APAC's claim that there has been a lack of notice and comment for the proposed Methodology is baseless. Notice was given in the Federal Register announcing the reopening of this proceeding: "The WP–07 Supplemental Proceeding also includes proposed revisions to BPA's Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology." 78 Fed. Reg. 7539 (February 8, 2008). Part V of the Notice fully described BPA's intent to modify the Legal Interpretation and Implementation Methodology. *Id*. at 7,550. The Notice identified the major changes to both documents. *Id*. at 7,550-7,551. Further, all parties received notice and have had opportunity in this proceeding to comment on the proposed Interpretation and Methodology. APAC has had opportunity to seek discovery, proffer direct and rebuttal testimony, cross-examine witnesses, brief the proposed Interpretation and Methodology, and present oral argument to the Administrator on this issue. In conclusion, APAC's charge that BPA is adopting a new rule and applying such rule retroactively lacks merit.

Decision

The net cost of the REP in the Program Case and the amount of revenues in excess of the embedded cost of serving the DSIs plus the value of the uncompensated reserve benefits provided by DSIs in the Program Case are not the only primary drivers of the section 7(b)(2) rate test. The reconstruction of the costs and rates for FY 2002-2008 is based on the existing Legal Interpretation and Implementation Methodology, with one assumed change explained later. BPA is not adopting new rules and applying them retroactively. Parties have been afforded full *due process to review and contest any proposed changes to the Legal Interpretation and Implementation Methodology*

Issue 3

Whether section 7(b)(2) requires that no REP costs can be allocated to preference customers.

Parties' Positions

PPC argues that the costs of REP benefits must not fall on preference customers. PPC Br., WP-07-B-JP25-01, at 42-43, *citing PGE*.

Tillamook and Central Lincoln (hereafter, Tillamook) argue that the Northwest Power Act categorically prohibits BPA from recovering or retaining any portion of the costs of the LRAs from its preference customers. Tillamook Br., WP-07-B-JP24-01, at 16.

BPA Staff's Position

As these are legal issues, BPA Staff deferred comment to this ROD.

Evaluation of Positions

In its discussion of whether to allocate 7(b)(2) trigger amounts to surplus sales pursuant to section 7(b)(3) of the Northwest Power Act, PPC argues that "the costs of residential exchange benefits must not fall on preference customers." PPC Br., WP-07-B-JP25-01, at 42-43, *citing PGE*. In its discussion on whether BPA can recover LRA costs from preference customers, Tillamook argues the Northwest Power Act categorically prohibits BPA from recovering or retaining any portion of the costs of the LRAs from its preference customers. Tillamook Br., WP-07-B-JP24-01, at 16. In its argument, Tillamook equates LRA costs to REP costs incurred under section 5(c). Logically, then, Tillamook is arguing that the Act prohibits BPA from recovering REP costs from preference customers.

Both PPC's and Tillamook's arguments grossly misstate the statutory structure and requirements of the Northwest Power Act and the *PGE* opinion, and present an argument never before raised by BPA's preference customers in any BPA rate case conducted since the establishment of the Northwest Power Act. Indeed, the statutory rate directives are so straightforward that BPA's preference customers did not even make this argument in their briefs in the *PGE* and *Golden NW* litigation. PPC and Tillamook are well aware that preference customers may properly pay *some* costs of the REP in the PF Preference rate under the Northwest Power Act.

In *PGE* and *Golden NW,* the Court was dealing with BPA's 2000 REP Settlement Agreements and the allocation of the cost of the *settlement agreements* to BPA's rates, including the PF Preference rate. The Court was reviewing the lawfulness of allocating REP settlement costs to the PF Preference rate *using section 7(g)* of the Northwest Power Act. *PGE,* 501 F.3d at 1013, 1028. The Court was *not* reviewing and addressing the fundamental cost allocations and basic development of BPA's power rates and the manner in which BPA has developed its base rates since 1980 (including the implementation of revised rate directives in 1985), where REP costs can be allocated to the PF Preference rate under section 7(b)(1) of the Act. 16 U.S.C. § 839e(b)(1).

The *PGE* opinion is best interpreted as concluding that the section 7(b)(2) rate test protects preference customers *in a general manner* from costs of the REP, but not from *all* costs of the REP. This is supported by the fact that *PGE* and *Golden NW* did not quote or specifically review *all* of the language of section 7(b)(1), *which expressly states that preference customers can be allocated costs of the REP in the PF Preference rate*. Section 7(b)(1) states:

> 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 5(c). 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 5(c)* and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). The foregoing reference to "electric power acquired by the Administrator under section 5(c)" is a reference to the resources exchanged with BPA under the REP, a program established in section 5(c) of the Northwest Power Act.

In simple terms, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is insufficient to meet such loads. When the FBS "runs out," BPA then is directed to allocate the costs of the *REP resources* to the preference customers' and REP loads (the PF rate). Thus, *the Northwest Power Act expressly directs BPA to allocate REP costs to BPA's preference customers' PF rate* after first allocating FBS costs. In the event the 7(b)(2) rate test does not trigger, the pre-rate test PF rate becomes the final PF Preference rate. This statement of the plain language of the Act must be reemphasized to ensure it is understood. The Northwest Power Act establishes there are circumstances (lack of sufficient FBS resources) where the Act expressly directs BPA *to allocate REP costs to BPA's preference customers' PF rate*. There can be no reasonable dispute that BPA can allocate REP costs to the PF Preference rate. Indeed, this is why BPA's preference customers have never contended otherwise, even in their briefs to the Court in *PGE* and *Golden NW*. It would be improper for any party to claim that the Ninth Circuit in *PGE* and *Golden NW* concluded that BPA could never allocate REP costs to the PF Preference rate. After reviewing section 7(b)(1) in its entirety, which the Court did not do in *PGE* and *Golden NW*, it is unreasonable to think the Court would adopt an interpretation directly contrary to the plain language of the Northwest Power Act, particularly when consistently interpreted and implemented by BPA since the enactment of the Northwest Power Act and unopposed by preference customers during that entire time.

Section 7(b) of the Northwest Power Act added new rate directives effective July 1, 1985. *See* 16 U.S.C. §§ 839e(b)(2), 839e(b)(3), 839e(c)(1)(B), 839e(c)(2)(C). The Act, however, did not repeal or eliminate the basic rate directives used to develop BPA's 1981 and subsequent power rates. Instead, the Act added, among other directives, a test for the PF rate beginning July 1, 1985, which was applied to the PF Preference rate developed after applying the existing section 7(b)(1) rate directives. This is the section 7(b)(2) rate test. Section 7(b)(2) provides that:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements public body, cooperative, and Federal agency customers, exclusive of amounts charged such under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes [the Five Assumptions].

16 U.S.C. § 839e(b)(2).

Thus, in order to conduct the rate test, BPA must first determine "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers" (the "Program Case rate"). This means BPA must first determine the rate to be charged preference customers using the rate directives of section 7(b)(1). In other words, BPA first allocates the costs of FBS resources to preference customer and REP loads until the amount of the FBS is insufficient to meet such loads. When the FBS "runs out," BPA then allocates the costs of the *REP resources* to the preference customers' and REP loads in an amount needed to meet the loads not met by the FBS. Thus, during the development of BPA's post-1985 power rates, including BPA's WP-02 and WP-07 power rates, *BPA must allocate REP costs to the PF rate* if the FBS is insufficient (which is true in BPA's WP-02 and WP-07 rates). In other words, prior to conducting the 7(b)(2) rate test, *the PF rate properly includes REP costs* in the Program Case. Then, if the rate test does not trigger, the pre-rate test PF rate becomes the final PF Preference rate, which then includes REP costs. Even if the rate test triggers, REP costs remain allocated to the PF Preference rate (except in the extremely unusual event, which has never occurred in the history of rate setting under the Northwest Power Act, that the rate test trigger was so large that it increased the PF Exchange rate to a level that completely eliminated REP benefits).

If the Program Case rate exceeds the 7(b)(2) Case rate, the rate test triggers, and the difference is the "trigger amount," which must be allocated to rates other than the PF Preference rate. As noted above, as long as the trigger amount allocated to the PF Exchange rate does not raise the PF Exchange rate so high that the REP is completely eliminated, the PF Preference rate will properly retain *some* REP costs. Thus, section 7(b)(2) does not protect the PF Preference rate from *all* REP costs (unless the trigger amount allocated to the PF Exchange rate raises the PF Exchange rate so high that the REP is completely eliminated), only from *additional* REP costs.

Some parties have the mistaken impression that the 7(b)(2) rate test *completely* precludes any REP costs from being allocated to the PF Preference rate. *See* Tr. 661. As is evident from the foregoing discussion, this is simply wrong. The section 7(b)(2) rate test is designed to offer preference customers rate protection, but it does not protect the PF Preference rate from *all* REP costs. If Congress had intended to simply eliminate REP costs from the PF Preference rate, the 7(b)(2) rate test would have been a comparison of a Program Case rate with the REP with a 7(b)(2) Case rate without the REP, *with no other differences between the two Cases*. Obviously, Congress did not do this. Although the REP is included in the Program Case and excluded in the 7(b)(2) Case, there are *numerous* other factors that Congress included in the rate test. These include the exclusion from the Program Case of costs of conservation, resource and conservation credits, experimental resources, and uncontrollable events; in the 7(b)(2) Case, preference customers include the DSIs in their general requirements; preference customers are served with FBS resources not obligated under contracts in effect at the time the Act was signed; preference customers are served, after the FBS, with resources purchased from such customers by the Administrator or resources not committed to load under section 5(b) of the Act; and monetary savings from reduced financing costs and reserve benefits are not achieved. It is this *combination* of *many* factors that produces the result of the rate test, not simply the REP. The REP, however, is the largest and most costly BPA program, and therefore the primary focus of attention in addressing the effects of the rate test. Basically, when Congress established the REP, preference customers wanted some protection from the costs of the REP becoming extremely high and thereby excessively raising the PF Preference rate. The rate test addresses this problem, but not by a test based solely on the REP or by a requirement that absolutely no REP costs be included in the PF Preference rate, but rather on a rate test based on a combination of factors. Indeed, the 7(b)(2) rate test can (i) "trigger" even in the absence of REP costs, and (ii) not "trigger" even with substantial REP costs.

Further, no party has argued that IOUs cannot receive REP benefits. In the event an IOU receives REP benefits, preference customers properly pay some of those costs in the PF Preference rate. Moreover, Appendix B to the Senate Report projected REP costs and cost allocations under the Northwest Power Act and demonstrated the understanding, from the inception of the Act, that projected REP costs (indeed, substantial projected REP costs) could be allocated to preference customers in the development of BPA's rates. S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-79 (1979). The Senate analysis projected REP payments to IOUs for FY 1995 alone in excess of $750 million, without creating any trigger amount under section 7(b)(2), which means preference customers paid part of the cost of the REP. *Id*.

As discussed above, the portion of BPA's REP costs that remain allocated to preference customers under the section 7(b)(2) rate test may be limited, depending on the determination of the trigger amount in that test. As noted above, a trigger amount is not the same thing as REP costs because the trigger amount is determined using *all* of the Five Assumptions listed in section 7(b)(2). 16 U.S.C. § 839e(b)(2). When BPA calculates the trigger amount, BPA cannot quantify the synergy between the five assumptions that results in the trigger amount. It is not possible or meaningful to segregate the individual component contributions of any single section 7(b)(2) assumption to the trigger amount because all five hypothetical assumptions must be made in concert. Thus, under sections 7(b)(2) and 7(b)(3), BPA removes the *trigger amount* from the costs allocated to the preference customers' rate, *not* REP costs. Similarly, under section 7(b)(3), when BPA reallocates the trigger amount to non-preference rates, BPA reallocates the *trigger amount* and *not* REP costs. The trigger amount, however, affects the REP costs properly allocated to the PF Preference rate.

The *PGE* opinion made a number of statements regarding the allocation of REP costs to preference customers. Some of these statements referenced the legislative history of section 7(b)(2). It is helpful to review the legislative history to provide a context to the Court's statements. During the development of the Northwest Power Act, preference customers were concerned about additional costs they might incur under the new Act. Senator Jackson of Washington explained:

> Publicly owned utilities in the region and nationally have expressed concern that the proposed regional legislation adversely affects the preference clause. Northwest preference customers have sought to address this issue through amendments to establish a "preference customer rate limit" which would preserve the financial benefits of the preference clause for public agencies. The public power council amendments would require BPA to test the estimated power costs to preference customers under the bill against the costs which these customers would have encountered *in the absence of legislation.*
>
> A number of specific assumptions are set forth in the amendments which would guide BPA in making the determination of costs *in the absence of legislation*.

Cong. Rec. Senate, S3999 (April 5, 1979); reprinted in Legislative History at 526F; *see also* Cong. Rec. H2060 (April 5, 1979) (Congressman Duncan discusses the "'rate cap' amendment to ensure that preference customers will *pay no more under this bill* than they would without it"); *reprinted in* Legislative History at 528 (emphasis added).

The preference customer amendments were the basis for sections 7(b)(2) and 7(b)(3) of the Act. Simply stated, the sections would test (1) preference customers' costs under the Act, with (2) preference customers' costs without the Act as established by a number of assumptions incorporated into section 7(b)(2). Senator Jackson's and Representative Duncan's remarks recognize the rate test was not solely a matter of protecting preference customers from the cost of the REP, but rather from "power costs to preference customers under the bill," which are reflected in the statutory language. *Id*. This is confirmed elsewhere in the legislative history.

The report of the Senate Committee on Energy and Natural Resources noted the rate test is a comparison of costs in the absence of the bill, not simply the REP:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater *than would occur in the absence of the regional program established in S. 885*.

S. Rep. No. 272, 96th Cong., 1st Sess. 20 (1979) (emphasis added).

The report of the House Committee on Interior and Insular Affairs characterized the test as generally ensuring costs benefits of preference rights, not simply precluding the allocation of REP costs:

> Subsection 7(b)(2) establishes a "rate ceiling" for BPA's preference customers, and specifies the method of calculating this ceiling, in order to insure such customers *the cost benefits of their preference rights for sales under this subsection.* Amounts not recoverable from preference customers because of this ceiling are to be recovered through supplemental rate charges for all other power sold by BPA under other provisions of section 7, as subsection 7(b)(3) specifies.

Id. at 52. This general intent is also recognized in the report of the House Committee on Interstate and Foreign Commerce. The report states:

> In addition, section 7(b) reserves for preference customers the price benefits for Federal power that they would have enjoyed *in the absence of this legislation*. This is accomplished by a "rate ceiling" which governs preference customer general requirements rates. Under this provision, the Northwest preference customers could pay less – but not more – for power under the legislation than they would have in any five-year period.

H.R. Rep. No. 976, Part I, 96th Cong., 2d Sess. 34 (1980) (emphasis added). The report also notes:

> Section 7(b)(2) establishes a "rate ceiling" for preference customers that seeks to assure these customers that their rates will be no higher than they would have been *had the Administrator not been required to participate in power sales or purchase transactions with non-preference customers under this Northwest Power Act*. The assumption[s] to be made by the Administrator in establishing this ceiling are specifically set forth. It is through rate ceilings that this Northwest Power Act provides additional protection to public bodies and cooperatives' preference customers as to the price of the sale of power by the Administrator. In the event that this rate ceiling is triggered, then the additional needed revenues must be recovered from BPA's other rate schedules.

Id. at 68-69; *see* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980). This language recognizes BPA incurs costs under the Act by BPA's "power sales" with "non-preference customers," such as BPA's sales to the DSIs, and "purchase transactions," such as exchange purchases under the REP. This language also emphasizes something of critical importance. Although the legislative history speaks in general terms about a comparison of costs in the absence of the Northwest Power Act or some of the costs incurred thereunder, the report emphasizes that "[*t*]*he assumption*[*s*] *to be made by the Administrator in establishing this ceiling are specifically set forth*." In other words, the statutory language of section 7(b)(2), which requires BPA to incorporate *a number* of significant factors in conducting the rate test, governs the costs from which preference customers are protected. If the only purpose of section 7(b)(2) had been to protect preference customers from the costs of the REP, the test would have compared a case where the REP existed and a case where it did not. Congress did not choose to do so.

BPA acknowledges Congress intended to provide preference customers, in a general sense, protection from excessive REP costs. This is not the same thing as precluding the allocation of *any* REP costs to preference customers. The report of the House Committee on Interior and Insular Affairs states:

> … This [residential] exchange will allow the residential and small farm consumers of the region's IOUs to share in the economic benefits of the lower-cost Federal resources marketed by BPA and will provide these consumers wholesale rate parity with residential consumers [of] preference utilities in the region. Consumers of preference utilities will not suffer any adverse economic consequences as a result of this exchange since, as discussed below, the DSIs of BPA are required to pay the costs of the exchange during its initial years while a "rate ceiling" protects the customers of preference utilities during later years.

H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 35 (1980) (emphasis added). The foregoing language demonstrates the need to view such legislative history in the context of the statutory rate directives. The report states preference customers would not suffer adverse consequences of the REP because "the DSIs of BPA are required to pay the costs of the exchange during its initial years." Reviewing the statutory language, however, it is true that the DSIs were expected to pay *the majority of costs of the REP* prior to July 1, 1985. Section 7(b)(1) of the Act, however, provides that REP costs can be allocated to preference customers' loads if the FBS resources become insufficient to meet such loads, and the DSIs do not pay the REP costs paid by other customers. 16 U.S.C. § 839e(b)(1). Thus, the report language is somewhat accurate, but is not in accord with the precise statutory requirements of section 7. Similarly, the report states that "a 'rate ceiling' protects the customers of preference utilities during later years," but the rate ceiling determines a trigger amount from *all of the factors* included in the rate test, not simply the REP. However, *in a general sense*, the rate test protects customers from REP costs because the REP costs are *part* of the calculation of the trigger amount.

Given the foregoing review, one can view the Court's statements in *PGE.* In *PGE*, the Court correctly stated:

> When the rate ceiling has been triggered, § 7(b)(3) mandates that *further REP benefits* must be paid for by non-preference customers (i.e., IOUs, DSIs, and all other customers) through supplemental rate charges.

PGE, 501 F.3d at 1015 (emphasis added). This statement is correct because it recognizes, as expressly provided in the law (16 U.S.C. § 839e(b)(1)), that REP costs are allocated to the PF Preference rate prior to the 7(b)(2) rate test and the existence of a trigger amount (which is determined in part by assuming no REP in the 7(b)(2) Case) will reduce the costs allocated to the PF Preference rate. Similarly, the Court states:

> In the event that this rate ceiling is triggered, then the *additional needed revenues* must be recovered from BPA's other rate schedules.

Id. at 1016, *citing* H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2nd Sess. 69 (1980) (emphasis added). The foregoing statement is correct because it recognizes that after the rate test, the trigger amount is allocated to all power sales other than PF Preference rate sales. Thus, if REP costs had previously been allocated to the PF rate before the rate test, the rate test will allocate the trigger amount away from the PF Preference rate, but certain REP costs will remain allocated to the PF Preference rate.

As noted above, the legislative history of the Act states the general proposition that the PF Preference rate is protected from REP costs. However, it emphasizes that "[*t*]*he assumption*[*s*] *to be made by the Administrator in establishing this ceiling are specifically set forth*." *Id*. at 68-69; *see* H.R. Rep. No. 976, Part II, 96th Cong., 2d Sess. 36 (1980) (emphasis added). In other words, the statutory language of section 7(b)(2), which requires BPA to incorporate *a number* of significant factors in conducting the rate test, governs the costs from which preference customers are protected. If the only purpose of section 7(b)(2) had been to protect preference customers from the costs of the REP, the test would have compared a case where the REP existed and a case where it did not. Congress did not choose to do so. Thus, although in a general sense the PF Preference rate is protected from REP costs, the language of the Act proves this is not a protection from all REP costs. The rate ceiling determines a trigger amount (rate protection) from *all of the factors* included in the rate test, not simply the REP. However, because Congress recognized the REP could be a costly program and was a central concern in establishing section 7(b)(2), the legislative history refers to the general protection from REP costs provided to the PF Preference rate. As noted above, the Court in *PGE* makes a number of statements about the allocation of REP costs to the PF Preference rate. *See PGE,* 501 F.3d at 1015-1016, 1021, 1036. The Court's statements regarding the allocation of costs to the PF Preference rate must be viewed in light of the statutory language and legislative history which, when understood, do not completely preclude the allocation of REP costs to the PF Preference rate, but provide significant protection from REP costs through the operation of the multiple assumptions that drive the 7(b)(2) rate test.

In summary, sections 7(b)(2) and 7(b)(3) of the Northwest Power Act do not preclude the allocation of REP costs to the PF Preference rate (unless the trigger amount is so high that it increases the PF Exchange rate to level that would eliminate any benefits under the REP, which has never happened in the history of the Act). This is the result of applying the complex but understandable language of sections 7(b)(1), 7(b)(2), and 7(b)(3) of the Act. This was BPA's original interpretation of the Act in 1985, when the 7(b)(2) rate test was first implemented. Until this Supplemental Proceeding, this interpretation had never been challenged by any party in any contested BPA rate proceeding since and including BPA's 1985 rate case, when section 7(b)(2) was first implemented. This interpretation also was not challenged by BPA's preference customers in the *PGE* or *Golden NW* litigation. BPA understands that the Ninth Circuit included general language in its opinions regarding the allocation of REP costs to BPA's preference customers. As noted previously, however, the Court was addressing the allocation of REP *settlement* costs to the PF Preference rate *under section 7(g)* of the Northwest Power Act. The Court was not addressing the allocation of *REP* costs to power rates under subsection 7*(b)(1)*, which expressly requires the allocation of REP costs to the PF Preference rate in prescribed circumstances. Section 7(b)(1) is therefore essential to any determination of this issue. Further, the Court's examination of section 7(b)(3) of the Act was in the context of the rate test being performed in the Rate Design Step of BPA's 2002 rate development, which the Court concluded was circumvented by the allocation of REP settlement costs using section 7(g) in BPA's Subscription Step. The Court was not reviewing the normal allocation of a trigger amount after conducting the 7(b)(2) rate test, which requires the trigger amount (*which is different than REP costs*) to be allocated to "all other power sold by the Administrator," meaning power other than requirements sales to preference customers at the PF Preference rate. Also, the Court's general statements regarding the allocation of REP costs to preference customers were not necessary for the Court to reach its decision. The Court concluded that BPA's allocation of REP settlement costs using section 7(g) was inconsistent with section 7(b)(2) of the Act. On remand, BPA can properly implement section 7(b)(2) (in the absence of the REP settlements) in accordance with the law. Given the foregoing background, this has been a difficult issue, and BPA wants to act in a manner consistent with the Court's decisions and the law. Therefore, BPA has reviewed the Court's general statements in *PGE* and *Golden NW* regarding the allocation of REP costs to preference customers, and has reviewed the statutory language in sections 7(b)(1), 7(b)(2), and 7(b)(3) of the Act and the legislative history of the Act. After an extremely thorough review, BPA respectfully believes it must follow the statutory language requiring BPA to allocate REP costs to the PF Preference rate, which still allows BPA to continue to grant enormous rate protection to BPA's preference customers under section 7(b)(2), and to allocate the trigger amount to all power sales other than the PF Preference rate pursuant to section 7(b)(3).

Decision

Section 7 of the Northwest Power Act allows REP costs to be recovered through the PF Preference rate, subject to the determination of section 7(b)(2) rate test protection.

16.3 Conservation Load Adjustment

Issue 1

Whether conservation should modify the amount of loads in the 7(b)(2) Case.

Parties' Positions

Cowlitz argues that BPA's adjustment of the 7(b)(2) Case loads for conservation is contrary to the definition of "general requirements" in section 7(b)(4) of the Northwest Power Act. Cowlitz Br., WP-07-B-CO-01, at 16-17; Cowlitz Br. Ex., WP-07-R-CO-1, at 3-21. Cowlitz contends that the only adjustment allowed by the Act to the loads in the 7(b)(2) Case is the addition of the "within-and-adjacent" DSI loads discussed in the First Assumption. *Id.* at 17. Though acknowledging that conservation is a "resource" under the Northwest Power Act, Cowlitz nonetheless claims that section 7(b)(2)(D) does not require or allow that conservation be considered as a "resource" for purposes of section 7(b)(2). *Id.* at 20. Cowlitz argues that conservation is simply a load reduction, that it does not provide electric power, that it cannot possibly meet customers' general requirements, that "power costs for general requirements" in section 7(b)(2) refers to the costs of electric power and, as such, conservation cannot be a power cost for purposes of the section 7(b)(2) cost comparison. Cowlitz Br. Ex., WP-07-R-CO-1, at 3-21. Cowlitz concludes that adjusting the 7(b)(2) Case loads for conservation is contrary to the plain language of the Northwest Power Act and its legislative history, particularly Appendix B to the Senate Report on S. 885, and results in less rate protection for preference customers than statutorily required. Cowlitz Br., WP-07-B-CO-01, at 18; Cowlitz Br. Ex., WP-07-R-CO-1, at 14-20. It urges that past practice not be used to perpetuate a misapplication of the Northwest Power Act. Cowlitz Br. Ex., WP-07-R-CO-1, at 20.

APAC argues that the only changes that may be made to the 7(b)(2) Case loads are specifically identified in the First and Third Assumptions of section 7(b)(2), that loads may only be augmented for the DSI "within and adjacent" service obligation specified in section 7(b)(2)(A), and that BPA's adjustment for conservation is contrary to the term "general requirements" in section 7(b)(4) of the Act. APAC Br., WP-07-B-AP-01, at 37; APAC Br. Ex., WP-07-R-AP-01, at 16. It argues two additional points. First, it argues that existing conservation is not a resource used to meet general requirements under the Act, but is already reflected as a reduction in general requirements. Therefore, 7(b)(2) load is load net of existing conservation and it must be served with electric power. WP-07-R-AP-01, at 17. Second, it argues that BPA's substitution of current prices for historical prices of conservation impermissibly penalizes conservation, and by financing it out of current rates unlawfully increases the PF rate and subsidizes REP costs. *Id.* at 17-18. (This second argument is addressed under another issue.)

The PPC raises issues similar to Cowlitz and APAC. PPC Br., WP-07-B-JP25-01, at 28-29. The PPC also argues that the costs of conservation should be excluded from the 7(b)(2) Case. *Id.* at 29.

The IOUs argue that BPA must not increase the combined general requirements of PF Preference rate customers in the 7(b)(2) Case by an amount equal to conservation load reduction, but rather must include all conservation costs in the section 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 27. The IOUs argue that BPA's proposed 7(b)(2) Legal Interpretation must be revised to exclude conservation as an available resource in the 7(b)(2)(D) resource stack. *Id.* at 97. The IOUs argue that BPA's proposed treatment of conservation is contrary to five provisions of the Northwest Power Act. *Id. at* 51. The IOUs contend that BPA must adopt an interpretation that comports with the five statutory provisions they describe. *Id.*

BPA Staff's Position

BPA Staff properly adjusted the loads in the 7(b)(2) Case for conservation. The proposed 2008 Section 7(b)(2) Implementation Methodology (2008 Implementation Methodology) instructs Staff to adjust the loads in the 7(b)(2) Case for conservation resources that are available for selection in the resource stack. Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, 2008 Implementation Methodology (IM), at IM-6. Adjusting the loads in the 7(b)(2) Case for conservation has been done in every rate proceeding since BPA began implementing the rate test in 1984. Doubleday, *et al.*, WP-07-E-BPA-85, at 39. The Northwest Power Act supports BPA's adjustment for conservation. Section 7(b)(2)(B), the Second Assumption, requires BPA to assume that only Federal base system (FBS) resources were used to serve preference customers in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2)(B). Conservation is not an FBS resource, so BPA cannot assume that the loads in the 7(b)(2) Case were reduced by conservation resources acquired by BPA in the Program Case. Also, the plain language of section 7(b)(2)(D) states that if the 7(b)(2) Customer loads (preference customers' load plus Within-and-Adjacent DSI Loads) exceed the available FBS resources in the 7(b)(2) Case, BPA must assume that the remaining amount of 7(b)(2) Customer load was served by other "resources," including conservation. 16 U.S.C. § 839e(b)(2)(D). Staff's position to increase loads in the 7(b)(2) Case for conservation is consistent with both the language of the Northwest Power Act and the intent underlying the 7(b)(2) rate test.

Evaluation of Positions

A. Introduction

One of the key section 7(b)(2) rate test issues in this case is whether the Administrator should assume in the 7(b)(2) Case that conservation is a resource available to meet the Administrator's contractual obligations to provide electric power in the event that the Federal base system resources are insufficient to meet public body, cooperative and Federal agency requirements. BPA's position is that the Administrator is to make that assumption. BPA's belief is in part based on its view that Congress intended the Administrator to assume that conservation would play a key role in meeting the energy needs of Pacific Northwest utilities. While many arguments are raised against BPA's position, perhaps the most fundamental difference between BPA and the parties is BPA's view that conservation is a resource that Congress intended the Administrator to utilize to meet his or her section 5(b) contractual obligations to provide electric power to public body, cooperative and Federal agency customers. Because that is a thread that runs through so many of the arguments, BPA wishes to highlight it at this initial stage of its evaluation.

While the phrase "Northwest Power Act" is often used as a convenient shorthand by BPA and other parties, it is well to remember the full title: The Pacific Northwest Electric Power Planning and Conservation Act. As evidenced by the full title, conservation is central to the Act. The Act was remarkable in that respect since at the time the Act was enacted almost 30 years ago, conservation was new and unique, a cutting-edge concept:

> This legislation makes conservation and renewable resources the top priorities for BPA acquisition, and includes the strongest conservation and renewable resource programs of any energy legislation that has been seriously considered by Congress. … I think the point here that has to be made over and over again is that for the first time in the country *we have a chance to test out the theory of conservation*. We have the answer to test out those alternatives.

126 Cong. Rec. H9859 (1980) (statement of Rep. Dicks) (emphasis added). Despite this novelty, conservation was thoroughly engrained in the Act. As Senator Jackson, Chairman of the Senate Committee on Energy and Natural Resources, remarked: "Reduced to one sentence the heart of the regional power bill is the authority for BPA to acquire from non-Federal entities additional electric power resources, including conservation, to meet the electric needs of Northwest consumers." Cong. Rec. S. 14690 (November 19, 1980). That "the electric needs of Northwest consumers" was understood to include the loads of BPA's customers is clearly borne out by the

House Committee on Interior and Insular Affairs' Report on the Act: "Section 6 of the legislation authorizes and requires the Administrator of BPA to acquire on a long-term basis sufficient resources, including conservation, to meet his section 5 contractual obligations to his customers." H. Rep. 96-976, Pt. II, at 35. The Report of the House Committee on Interstate and Foreign Commerce is to similar effect: "Section 6(a) requires the Administrator to acquire conservation, conservation measures and renewable resources installed by residential and small commercial consumers in meeting his obligations to satisfy the load of his customers." H. Rep. 96-976, Pt. I, at 64. As stated in a similar vein by Representative Foley: "The bill solves the BPA power reallocation problem by … authorizing BPA to acquire power from non-federal sources if needed to meet BPA customer loads …. The bulk of the bill consists of protections to insure that BPA's new authority is used first for conservation and renewables …" Cong. Rec. H. 9864 (Sept. 29, 1980).

Whether phrased in terms of "meeting" or "to meet" "the electric needs of Northwest consumers," the Administrator's "section 5 contractual obligations," "the load of his customers" or "BPA customer loads," it is clear that the Congressional committees considering, and the sponsors of, the Northwest Power Act repeatedly and uniformly recognized the central role of conservation under the Act to meet or satisfy the contractual demands of preference customers under section 5 of the Northwest Power Act to purchase electric power from the Administrator. Indeed, as subsequently discussed, the Northwest Power Act is precisely structured to accomplish just what its Congressional sponsors envisioned. And, in fact, meeting customer load first through conservation resources has been BPA's practice under the Act. Conservation means that power that would otherwise have been consumed without conservation can now be available to meet load that cannot be conserved. Fundamentally, reducing use of power (*i.e.*, load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load). More simply stated, reducing load through conservation is a means of meeting load.

Yet, when it comes to the role of conservation in conducting the section 7(b)(2) test under the Act, in particular determining loads and what resources would be acquired by the Administrator to "meet" those loads ("remaining general requirements"), this fundamental and commonsense understanding as to the role of conservation is nowhere to be found in the arguments of the parties. Some now strenuously object to how BPA has interpreted the test since the very first time it became "live" in 1984 and is still interpreting it in this case some 24 years later. One party argues "it is obvious that one cannot 'meet general requirements' with conservation" and even goes so far as to state "[i]t does violence to the statute to determine, as BPA proposes, that 'conservation' as a 'load reduction' 'resource' is 'serving' or 'meeting' electric power requirements." Cowlitz Br. Ex., WP-07-R-CO-1, at 5, 13. This posturing so eviscerates the Act, removing what Senator Jackson described above as "the heart of the regional power bill," that it is necessary, before turning to all the detailed and intricate provisions of the Act, to step back and ground ourselves in the fundamentals of what the Act was about. As indicated above, those fundamentals are clear when it comes to the primacy of conservation as a resource that meets customer loads on BPA. We should and will seek to remain true to those fundamentals as we examine the precise language of the Act and navigate the various arguments raised concerning the appropriate treatment of conservation in section 7(b)(2).

B. Overview of the Treatment of Conservation in the Section 7(b)(2) Rate Test

Section 7(b)(2)(D) describes the manner in which additional resources are assumed to be acquired to meet 7(b)(2) Customers' loads when available FBS resources are exhausted. Three types of additional resources are available in the 7(b)(2) Case. *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 2008 Legal Interpretation, at LI-15. The first type of resource is described in section 7(b)(2)(D)(i) as resources that were "purchased from such customers by the Administrator pursuant to section 6." *Id.* These are the resources actually acquired by BPA from 7(b)(2) Customers in the Program Case.

Conservation is defined in the Northwest Power Act as a resource. "'Resource' means … actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. § 839a(19). In addition, conservation is acquired by BPA under section 6 of the Act. "The Administrator shall acquire such resources through conservation, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load…." 16 U.S.C. § 839d(a)(1). Because conservation is acquired from 7(b)(2) Customers, BPA has historically included conservation as a non-FBS resource that is available to meet 7(b)(2) Customer load to the extent it is needed and is among the least expensive resources available. Conservation meets load as a resource because power that would otherwise have been consumed without conservation can now be available to meet load that cannot be conserved. Fundamentally, reducing load through conservation is a means of meeting load.

This treatment of conservation in the proposed Implementation Methodology is not new. In the 1984 Implementation Methodology, BPA briefly explained how conservation is treated in the 7(b)(2) Case:

> The initial loads that will be used in the 7(b)(2) case will be the same as those used in the program case, except they will not include estimates of programmatic conservation savings.

1984 Implementation Methodology, at 41. This is reiterated in Staff's testimony during the 1984 7(i) proceeding to develop the 7(b)(2) Implementation Methodology. "The loads 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 (programmatic conservation resources in the 7(b)(2) case are discretionary 'additional resources')." Melton and Armstrong, b2-84-E-BPA-02, at 9. The issue was not addressed on rebuttal.

To implement this treatment of conservation, BPA adds to the loads in the 7(b)(2) Case an amount of load equal to the conservation savings BPA assumes have been achieved in developing the Program Case. This adjustment was viewed as necessary because conservation is a resource acquired by the Administrator under section 6 of the Northwest Power Act and, therefore, must be included in the 7(b)(2) Case resource stack. Doubleday, *et al.*, WP-07-E-BPA-60, at 34. Because conservation resources are included in the resource stack to be drawn to serve remaining loads if needed, BPA believed these resources could not have already reduced the loads in the 7(b)(2) Case. *Id.* To remove the effects of conservation from the 7(b)(2) Case, the 7(b)(2) Customer loads are increased by conservation acquired by BPA. *Id*. This adjustment ensures that conservation resources may be given their full and intended effect when selected from the resource stack in section 7(b)(2)(D)(i). Staff explained that conservation resources and 7(b)(2) Customer loads have been treated this way in every rate proceeding since 1985 without significant controversy. Doubleday, *et al.*, WP-07-E-BPA-85, at 39.

In the initial WP-07 Supplemental Proposal, BPA proposed to continue this historic treatment of conservation in the section 7(b)(2) rate test. Doubleday, *et al.*, WP-07-E-BPA-60, at 34. In addition, Staff proposed to adopt additional language in the 2008 Implementation Methodology that provided further explanation regarding the adjustments made in the 7(b)(2) Case for conservation resources. Specifically, that language states:

> The initial loads that will be used in the 7(b)(2) Case will be the same General Requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA. Conservation is a resource acquired by the Administrator pursuant to section 6 and, therefore, conservation resources are required to be included in the 7(b)(2) Case resource stack. Because conservation resources must be included in the resource stack to be drawn to serve remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA. Power sales contracts that expire during the Five-Year Period, except for requirements and DSI contracts, will be recognized as expiring as scheduled. This forecast will provide the load estimates for the 7(b)(2) Case.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, 2008 Implementation Methodology, at IM 6-7. This language describes in more detail BPA's historical treatment of conservation in the 7(b)(2) Case. It in no way adjusted, modified, or changed BPA's two-decade-old method of modeling conservation in the 7(b)(2) rate test.

Several parties in this proceeding raised objections to BPA's proposal to increase the 7(b)(2) Case loads for conservation. Cowlitz Br., WP-07-B-CO-01, at 16-17; Cowlitz Br. Ex., WP-07-R-CO-1, at 3-21; APAC Br., WP-07-B-AP-01, at 37; APAC Br. Ex., WP-07-R-AP, at 16-18; PPC Br., WP-07-B-JP25-01, at 28-29; IOU Br., WP-07-B-JP6-01, at 27. Although the parties each present varying views on the appropriate way to model conservation in the 7(b)(2) Case, a common complaint was that BPA's historic treatment of conservation is inconsistent with the term "general requirements" as defined in section 7(b)(4) of the Northwest Power Act. *Id.* While technically this is not a matter of first impression, BPA has not previously described on the record in detail its interpretation of the phrase "general requirements" as defined by section 7(b)(4) and as used in the section 7(b)(2) rate test. Because this is not directly addressed in either BPA's proposed 2008 Implementation Methodology or 2008 Legal Interpretation, BPA describes here its interpretation of "general requirements" as used within the context of the section 7(b)(2) rate test.

C. Legal Analysis of the Treatment of Conservation and "General Requirements" in the Section 7(b)(2) Rate Test

When engaging in textual analysis of a statutory provision, one must "read the words of a statute in their context and with a view to their place in the overall statutory scheme." *Student Loan Fund of Idaho, Inc. v. U.S. Dep't of Educ.,* 272 F.3d 1155, 165 (9th Cir. 2001) (internal quotation marks omitted); *Camacho v. Bridgeport Fin., Inc.*, 430 F.3d 1078, 1081 (9th Cir. 2005). In so doing, it is appropriate to consider the Northwest Power Act "as a whole, giving effect to each word and making every effort not to interpret a provision in a manner that renders other provisions of the same statute inconsistent, meaningless or superfluous." *Garcia v. Brockway*, 526 F.3d 456, 463 (9th Cir. 2008) (*quoting Boise Cascade Co. v. EPA*, 942 F.2d 1427, 1432 (9th Cir. 1991)). These statutory interpretation tools are essential to understanding how the words "conservation" and "general requirements," two terms that are used throughout the Northwest Power Act, were intended to be used in context of section 7(b)(2). Not only is conservation at the heart of the Northwest Power Act, as indicated in the Introduction above, but it courses through many provisions of the Act as well.

To begin, a number of defined terms in the Northwest Power Act must be considered. First, "conservation" is defined:

> "*Conservation*" means *any reduction in electric power consumption* as a result of increases in the efficiency of energy use, production, or distribution.

16 U.S.C. § 839a(3) (emphasis added). Second, "electric power" is defined:

> "Electric power" means electric peaking capacity, or electric energy, or both.

16 U.S.C. § 839a(9). Third, "Federal base system resources" is defined:

> "Federal base system resources" means –
>
> (A) the Federal Columbia River Power System hydroelectric projects;
> (B) resources acquired by the Administrator under long term contracts in force on December 5, 1980; and
> (C) resources acquired by the Administrator in an amount necessary to replace reductions in capability of the resources referred to in subparagraphs (A) and (B) of this paragraph.

16 U.S.C. § 839a(10). Fourth, "renewable resource" is defined:

> "*Renewable resource*" means a resource which utilizes solar, wind, hydro, geothermal, biomass, or similar sources of energy and which either is *used for electric power generation or will reduce the electric power requirements* of a consumer, including by direct application.

16 U.S.C. § 839a(16) (emphasis added). Fifth, "resource" is defined:

> "*Resource*" means –
>
> > (A) *electric power*, including the actual or planned electric power capability of generating facilities, or
> >
> > (B) *actual or planned load reduction* resulting from direct application of a renewable energy resource by a consumer, or *from a conservation measure*.

16 U.S.C. § 839a(19) (emphasis added). Finally, another definition from section 7 is instructive:

> The term "*general requirements*" as used in this section means the public body, cooperative or Federal agency customer's *electric power purchased from the Administrator under section* [*5*]*(b)* of this title, exclusive of any new large single load.

16 U.S.C. § 839e(b)(4), (emphasis added). Given these definitions, groundwork can be laid for understanding the construction of sales and rates in section 7(b)(2).

To start, section 5 addresses the sale of power by the Administrator:

> Whenever requested, *the Administrator shall offer to sell* to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 [16 U.S.C. § 832, *et seq.*] and to each requesting investor owned utility *electric power to meet the firm power load* of such public body, cooperative or investor owned utility in the Region *to the extent that such firm power load exceeds* –
>
> > (A) *the capability of* such entity's firm peaking and *energy resources used* in the year prior to December 5, 1980 *to serve its firm load* in the region, and
> >
> > (B) *such other resources* as such entity determines, pursuant to contracts under this chapter, will be *used to serve its firm load* in the region.
>
> In determining the resources which are used *to serve a firm load*, for purposes of subparagraphs [5(b)(1)](A) and (B), any resources used *to serve a firm load* under such subparagraphs shall be treated as continuing to be so used, unless such use is discontinued with the consent of the Administrator, or unless such use is discontinued because of obsolescence, retirement, loss of resource, or loss of contract rights.

16 U.S.C. § 839c(b)(1) (emphasis added). In this section, it is evident that the Administrator's obligation is to offer to sell power to meet the firm power load of the requesting utility. This obligation is to the firm power load that exceeds the utility's resources used to serve its firm load. Section 5 continues by further defining the Administrator's authority:

> In addition to his authorities *to sell electric power* under paragraph [5(b)](1), the Administrator is also authorized *to sell electric power to Federal agencies* in the region.

16 U.S.C. § 839c(b)(3) (emphasis added). This section adds Federal agencies to the group of customers established in section 5(b)(1) as eligible for service, namely, public bodies, cooperatives, and investor-owned utilities. Later, section 5 speaks to the Administrator's acquisition of resources from customers being defined by the amounts specified in acquisition contracts:

> Any contractual entitlement to firm power which is based on electric power acquired from, or on behalf of, a customer pursuant to section [6] of this Title shall be in addition to any other contractual entitlement to firm power not subject to restriction that such customer may have under this section. For the purposes of this subsection, references to *amounts of power acquired by the Administrator* pursuant to section [6] of this Title shall be deemed to mean *the amounts specified in the resource acquisition contracts* exclusive of any amounts recognized in such contracts as replacement for Federal base system resources.

16 U.S.C. § 839c(e)(2) (emphasis added). (As will be seen, conservation resource acquisition contracts are a means of acquiring power.) Section 5 also provides for sales of electric power for purposes of the section 5(c) residential exchange, 16 U.S.C. § 839c(C)(1), and sales of electric power to Direct Service Industries, 16 U.S.C. § 839c(d)(1)(A). Section 5, having established the Administrator's obligations and authorities to sell electric power, then provides that the Administrator is to negotiate and offer initial long-term contracts (up to 20 years as provided in the Bonneville Project Act) to:

> (1)(A) existing public body and cooperative customers and investor-owned utility customers under subsection (b) of this section;
>
> (1)(B) Federal agency customers under subsection (b) of this section;
>
> (1)(C) electric utility customers under subsection (c) of this section; and
>
> (1)(D) direct service industrial customers under subsection (d)(1).

16 U.S.C. § 839c(g)(1)(A)-(D).

Having established the Administrator's obligation to enter contracts to sell electric power to those customers for a period up to 20 years, section 5 then concludes by stating that the Administrator "shall be *deemed to have sufficient resources* for the purpose of entering into the initial contracts specified in paragraph (1) (A) through (D)" quoted just above. 16 U.S.C. § 839c(g)(7) (emphasis added). This is very important because it represents a clear linkage between "resources" and meeting the Administrator's contractual obligations to sell electric power, consistent with the Congressional statements quoted in the Introduction to this issue. In order to make good on that deemed resource sufficiency and actually assure that the Administrator had sufficient resources for the term of the initial contracts and beyond, authority was granted for the Administrator to acquire resources to meet his or her obligations to provide electric power. The very next sentence of the Act, the first sentence of section 6, states:

> *The Administrator shall acquire such resources through conservation*, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load, as the Administrator determines are consistent with the plan, or if no plan is in effect with the criteria of section [4](e) (1) of this title and the considerations of section [4](e) (2) of this title and, in the case of major resources, in accordance with subsection (c) of this section [6]. …

16 U.S.C. § 839d(a)(1). The import of the last sentence of section 5 and this first sentence of section 6 could not be clearer: the first priority resource to be acquired by the Administrator to meet his contractual obligations to sell electric power is conservation. Fundamentally, reducing use of power (*i.e.*, load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load). Reducing load through conservation is a means of meeting load. "The bulk of the bill consists of provisions to insure that BPA's new authority is used first for conservation …" Congressman Foley, Congressional Record (Sept. 29, 1980), page H 9864. "Section 4 and 6 require conservation to be treated as the region's first priority resource, and renewable resources to be treated as the second priority resource, ahead of all other resource types." S. Rep. 96-972, at 15. The Administrator is to "rely upon conservation to the maximum extent it is feasible and cost effective, …" *Id.*

Section 6 continues by authorizing the Administrator to acquire sufficient resources to meet his contractual obligations that remain after applying any conservation that has been acquired:

> *In addition to acquiring electric power pursuant to section* [*5*]*(c)* of this title, or on a short term basis pursuant to section 11(b)(6)(i) of the Federal Columbia River Transmission System Act [16 U.S.C. § 838i(b)(6)(i)], *the Administrator shall acquire*, in accordance with this section, *sufficient resources* –
>
> > (A) *to meet his contractual obligations that remain after taking into account planned savings from measures provided for in paragraph* [*6*]*(1)* of this subsection, and
> >
> > (B) to assist in meeting the requirements of section [4](h)[13] of this title.
>
> The Administrator shall acquire such resources without considering restrictions which may apply pursuant to section [5](b) of this title.

16 U.S.C. § 839d(a)(2) (emphasis added). This clearly evinces Congress's expectation that the Administrator is to meet, and likely has met, some portion of his contractual obligation to provide electric power through savings achieved by virtue of the conservation acquisitions undertaken pursuant to the first paragraph of section 6. Later, section 6 requires that the Administrator continue to pursue the acquisition of conservation without respect to whether sufficient resources have already been acquired:

[13] Section 4(h) refers to fish and wildlife obligations.

> *Notwithstanding any acquisition of resources pursuant to this section* [*6*]*, the Administrator shall not reduce his efforts to achieve conservation* and to acquire renewable resources installed by a residential or small commercial consumer to reduce load, pursuant to subsection [6](a)(1) of this section.

16 U.S.C. § 839d(b)(5) (emphasis added). Section 6 goes on to make clear that conservation measures must conserve electric power:

> *For each proposal* under subsection [6](a), (b), (f), (h), or (l) of this section to acquire a major resource, *to implement a conservation measure which will conserve* an amount of *electric power* equivalent to that of a major resource …

16 U.S.C. § 839d(c)(1) (emphasis added). Later in section 6, the Administrator is authorized to grant billing credits for resources, including conservation, acquired by customers:

> If a customer so requests, the Administrator shall grant billing credits to such customer, and provide services to such customer at rates established for such services, for –
>
> (A) *conservation activities* independently undertaken or continued after December 5, 1980, by such customer or political subdivision served by such customer *which reduce the obligation of the Administrator that would otherwise have existed to acquire other resources under this chapter*, …

16 U.S.C. § 839d(h)(1) (emphasis added). Such billing credits are limited to those resources, including conservation, that actually reduce the Administrator's obligation to sell electric power:

> *The energy and capacity on which a credit* under this subsection to a customer *is based shall be the amount by which a conservation activity* or resource *actually changes the customer's net requirement for supply of electric power* or reserves *from the Administrator*.

16 U.S.C. § 839d(h)(2) (emphasis added). Section 6 continues its discussion of billing credits and conservation:

> The amount of *credits for conservation* under this subsection [6(h)] shall be set to credit the customer implementing or continuing the conservation activity for which the credit is granted *for the savings resulting from such activity*. The rate impact on the Administrator's other customers of granting the credit shall be equal to the rate impact such customers would have experienced had the Administrator been obligated to acquire resources in an amount equal to that actually saved by the activity for which the credit is granted.

16 U.S.C. § 839d(h)(3) (emphasis added).

Based on the above, there can be no genuine dispute that conservation is a resource that the Administrator is to acquire in order enable him to meet his contractual obligation to sell electric power to meet load. That contractual obligation is not simply a matter of making sure there is power today to meet whatever load exists today, but of forecasting the customers' needs over the length of the contracts and assuring on a planning basis that when the future arrives, BPA will be positioned to meet the customers' needs. Contracts extend over time, so load is constantly changing and is a matter of timing. Reducing use of power (*i.e.*, load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load) by assuring the power remains available for that purpose. As a temporal matter, that may mean that today's load has been met, in part, by the power conserved (not used by other load) from conservation actions that occurred in the past. Also, the conservation achieved today will reduce the power needs of tomorrow's load. Acquisition of conservation may also mean that new non-conservation resources need not be acquired to meet the Administrator's contractual obligation to provide electric power because load is or will then be less than it otherwise would have been. In all these situations, the acquisition of conservation is used to and has enabled the Administrator to <u>meet his obligation to provide electric power to meet the firm load of his customers, precisely as Congress envisioned. The cost of conservation is a cost of meeting load for firm power.</u> "Reduced to one sentence the heart of the regional power bill is the authority for BPA to acquire from non-Federal entities additional electric power resources, including conservation, to meet the electric needs of Northwest consumers." Cong. Rec. S. 14690 (November 19, 1980) (Sen. Jackson). Cowlitz could not be more off the mark when it states "[i]t does violence to the statute to determine, as BPA proposes, that 'conservation' as a 'load reduction' 'resource' is 'serving' or 'meeting' electric power requirements." Cowlitz Br. Ex., WP-07-R-CO-1, at 13.

Turning to section 7, the definition of "general requirements" becomes crucial to the meaning of section 7(b)(2). Once again, "general requirements" is defined as follows:

> The term "*general requirements*" as used in this section means the public body, cooperative or Federal agency customer's *electric power purchased from the Administrator under section* [*5*]*(b)* of this title, exclusive of any new large single load.

16 U.S.C. § 839e(b)(4) (emphasis added). The words "purchased from the Administrator under section [5](b)" are forward looking in the sense that they refer in the ratemaking context of section 7 to what is forecast to happen in the future rate period and, for purposes of section 7(b)(2), any year, plus the ensuing four years. This forward-looking perspective corresponds to the Administrator's obligation under section 5(b) to contract for periods up to 20 years "to sell … electric power to meet the firm power load" of the public body, cooperative, and Federal agency customers. 16 U.S.C. § 839c(b)(1), § 839c(g)(1)(A)-(B). Reading section 7(b)(4) in the future perfect tense, "to be purchased," comports with the full reference – "electric power [to be] purchased from the Administrator under [section 5(b)]" – because the contracts span a long period of time and the amount purchased varies over that time.

Whereas section 5 defines the Administrator's obligations and section 6 provides for sufficient resources to meet his obligations, section 7 instructs what to charge for the power sold to meet the Administrator's contractual obligations to sell electric power. This is first established by defining the costs of resources used to meet general requirements:

> 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 [5](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 [5](c) of this title and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added). Here again, the word "sold" is best read in the future perfect, "to be sold," *i.e.*, a rate that would apply once the power is sold. The phrase "electric power sold to meet the general requirements" could be rephrased, applying section 7(b)(4), as "electric power [to be] sold to meet the amount of electric power [to be] purchased." Further, note the equation of the term "general requirements" and the term "loads." The conclusion to be drawn here is if load is a matter of timing, then so are general requirements.

One more step is needed before turning to section 7(b)(2). After dealing with the allocation and recovery of costs for electric power sold (*i.e.*, power costs), section 7(g) deals with the costs of conservation:

> 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 [7], *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 [6] of this title, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g), (emphasis added). It is also notable that the costs of conservation are allocated to "power rates," not to "loads." As the language of section 7(b)(1) indicates, the rate or rates established pursuant to that section are rates "*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). Consequently, under section 7(g), conservation costs are allocated to the section 7(b)(1) rate or rates for electric power sold.

Turning to section 7(b)(2), the subsection provides as follows:

> After July 1, 1985, *the projected amounts to be charged for firm power for the combined general requirements* of public body, cooperative and Federal agency

> customers, *exclusive of amounts charged* such customers *under subsection* [7]*(g)* of this section *for the costs of conservation*, resource and conservation credits, experimental resources and uncontrollable events, *may not exceed in total*, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, *an amount equal to the power costs for general requirements* of such customers *if, the Administrator assumes that …*

16 U.S.C. § 839e(b)(2) (emphasis added). The need for the phrase "exclusive of" indicates that Congress was aware that the amounts to be charged for firm power would, or could, include conservation costs. Also, note the temporal reference to "the ensuing four years"; the phrase "during such five-year period" occurs five times in section 7(b)(2), once for each of the five assumptions.

The key question in section 7(b)(2) is whether the Administrator, in the performance of the rate test, is to solve for just "power costs" given the "combined general requirements," or to solve for "power costs" and "general requirements." If only the former, then BPA must start and, it would seem, end with the same "general requirements" as the "combined general requirements" referenced at the beginning of the paragraph. However, the language at the end of the paragraph does not refer to "such general requirements" or "those general requirements" or even "the general requirements," but to "general requirements of such customers if, the Administrator assumes" the Five Assumptions. It also makes no reference to "combined" general requirements, which is very telling since the definition of general requirements in section 7(b)(4) is in the disjunctive, not the conjunctive, using the term "or" and "customer's" rather than "customers'": "the public body, cooperative or Federal agency customer's…." The introductory language of section 7(b)(2) standing alone indicates that BPA is to look out in time – any year after July 1, 1985, plus the ensuing four years – to determine what the power costs would be *and* what general requirements (or loads) would be, given the specific assumptions of section 7(b)(2). In other words, one of the things BPA is directed to solve for in the rate test is what general requirements – the electric power purchased from the Administrator – would be in the hypothetical 7(b)(2) Case during the five-year period. Examination of the five assumptions that follow the introductory language of section 7(b)(2) quickly shows that, indeed, they directly impact not just costs but also the amount of "electric power purchased from the Administrator under" section 5(b) of the Act by the public body, cooperative, or Federal agency customer.

Section 7(b)(2) then sets forth the specific assumptions the Administrator is to make to solve for the power costs and general requirements under section 7(b)(2). The First Assumption deals with general requirements:

> (A) the public body and cooperative customers' *general requirements had included during such five year period* the direct service industrial customer loads which are—
>
> (i) served by the Administrator, and
>
> (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

16 U.S.C. § 839e(b)(2)(A) (emphasis added). Here, the temporal dimension of general requirements (and loads) is most clear: during the five years ("such five year period") assume that certain of the Administrator's future direct-service industrial (DSI) loads are included instead in the general requirements of public body and cooperative customers. In other words, assume that future loads directly served by the Administrator (DSI loads) will instead be served indirectly as a part of certain public body and cooperative customers' loads on the Administrator.

The Second Assumption provides further information that is instructive to both the "power costs" and the "general requirements" side of the 7(b)(2) question. The Second Assumption provides that the Administrator must assume that:

> public body, cooperative, and Federal agency *customers were served, during such five year period, with Federal base system resources* not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph [7(b)(2)](A) of this paragraph …

16 U.S.C. § 839e(b)(2)(B) (emphasis added). The important point to be drawn here is that the Administrator must assume that BPA is serving the customers with *only* FBS resources during the five-year test period. As noted above, FBS resources are defined as

> (A) the Federal Columbia River Power System hydroelectric projects;
>
> (B) resources acquired by the Administrator under long-term contracts in force on December 5, 1980; and
>
> (C) resources acquired by the Administrator in an amount necessary to replace reductions in capability of the resources referred to in subparagraphs (A) and (B) of this paragraph.

16 U.S.C. § 839a(10). Noticeably absent from this definition is any mention of conservation. Although conservation is a "resource," it is neither a resource that was acquired by the Administrator under contracts in effect in December 5, 1980, nor a replacement of capability from the resources mentioned in subsections (A) or (B). Also significant is the fact that in section 7(b)(2)(B) there is *no* reference to the term "general requirements." Rather, the reference is simply to "customers." This appears to be very purposeful because Congress in many places in section 7(b) refers to "general requirements," *see* 16 U.S.C. § 839e(b)(2)(A), (D), but Congress did not use "general requirements" here.

When Congress directed the Administrator in section 7(b)(2)(B) to assume that "public body, cooperative, and Federal agency customers were served, during such five year period, with Federal base system resources," it did not refer to those customers' "general requirements" or to use of conservation to serve the customers. By excluding the terms "general requirements" and "conservation" from subsection 7(b)(2)(B), Congress created an ambiguity whether, in the 7(b)(2) Case, conservation had already been used to meet load of the public body, cooperative, and Federal agency customers. Given the factors discussed below, and the omission *in the*

7(b)(2) Case of any reference to conservation, which omission is apparent and stark when compared to the prominence of conservation as the declared resource of choice under other provisions of the Act, BPA believes it is reasonable to construe subsection 7(b)(2)(B) as directing BPA to make adjustments to *both* the "power cost" and "load" sides of the section 7(b)(2) rate test. On the power cost side, section 7(b)(2)(B) plainly suggests a resource hierarchy and requires BPA to assume that FBS resources are the first resources used to "serve" the customers in the 7(b)(2) Case. In other words, the actual "electric power" produced by FBS resources (*i.e.*, the 31 federal hydroelectric dams and one nuclear plant plus replacements) is assumed to be available to "serve" the customers during the five-year period. This exclusive focus on FBS resources also has an effect on the load side of equation. By not referring to either "conservation" or "general requirements," BPA must also assume at this point in the rate test that no *other* resources but FBS resources were applied to meet the load needs of the "customers." As such, at this point, other non-FBS resources that were purchased by BPA to either serve *or* reduce the customers' loads in the real world, such as conservation, have *not been acquired* by the Administrator to serve public body, cooperative, and Federal agency customers in the 7(b)(2) Case. As a consequence, to meet the intent of Congress in having BPA use FBS resources first in the Second Assumption, BPA should remove the effects that non-FBS resources (such as conservation) have had on the loads in the 7(b)(2) Case.

If Congress had intended to direct the Administrator to assume the effects of conservation would be reflected in loads for purposes of 7(b)(2)(B), it would have included references to general requirements or stated that BPA must use conservation to first meet the customers' electric power needs. First, Congress could have included the term "general requirements" in section 7(b)(2)(B). Congress knew the importance of using this phrase, having placed it in both subsections 7(b)(2)(A) and 7(b)(2)(D). Congress must have known that if it had included this term in subsection 7(b)(2)(B) it would have conflicted with or undermined its direction to the Administrator to assume that FBS resources were used to serve the customers in the 7(b)(2) Case. This is strongly reinforced by the Fourth Assumption, in subsection 7(b)(2)(D), discussed later. Second, Congress could also have added the term "conservation" before or after referencing FBS resources. This would have made clear that the Administrator must assume that FBS *and* conservation resources were used to serve the customers during the five-year period. The fact that Congress excluded references to *both* general requirements and conservation resources from subsection 7(b)(2)(B) signifies that it intended to remove the effects of conservation from this assumption. It is an accepted principle of statutory construction that "[w]hen Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Barnhart v. Sigmon Coal Co.*, 534 U.S. 438, 452 (2002). Here, Congress specifically excluded language from 7(b)(2)(B) to ensure the priority status of FBS resources in the Second Assumption, a priority plainly at odds with the priority afforded conservation elsewhere in the Northwest Power Act. The plain language of the Act requires BPA to assume that non-FBS resources (such as conservation) were not used to "serve" the general requirements during the five-year period in the Second Assumption. To effectuate this intent, the 7(b)(2) Customer loads must logically reflect the absence of any conservation measures that were acquired by BPA.

The reason Congress excluded conservation from subsection 7(b)(2)(B) becomes more evident in the Fourth Assumption in section 7(b)(2). Section 7(b)(2)(D) describes the resources the Administrator is to assume are available to "meet remaining general requirements":

> *all resources that would have been required*, during *such five year period*, *to* ***meet*** *remaining general requirements* of the public body, cooperative and Federal agency customers (*other than requirements* ***met*** *by the available Federal base system resources* determined under subparagraph [7(b)(2)](B) of this paragraph) were –
>
> (i) purchased from such customers by the Administrator pursuant to section [6] of this title, or
>
> (ii) not committed to load pursuant to section [5](b) of this title,
>
> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; …

16 U.S.C. § 839e(b)(2)(D) (emphasis added). Following the directive from subsection 7(b)(2)(B), at this point in the temporal sequence, "remaining general requirements" have not been affected by conservation. As if it were not sufficiently clear that the only resources that were previously used to serve "public body, cooperative, and Federal agency customers" ("customers," not "general requirements") were FBS resources, section 7(b)(2)(D) includes a parenthetical reference that emphasizes that "remaining general requirements" means "(other than requirements met by the available Federal base system resources determined under subparagraph [7(b)(2)](B)…)." *Id.* This section 7(b)(2) Case hypothetical world assumption stands in stark contrast to what Congress envisioned in the Program case, where resources would be acquired as directed in the Act. As we clearly saw earlier, and as stated in the Introduction to this evaluation, whether phrased in terms of "meeting" or "to meet" "the electric needs of Northwest consumers," the Administrator's "section 5 contractual obligations," "the load of his customers" or "BPA customer loads," it is clear that the Congressional sponsors of the Northwest Power Act repeatedly and uniformly recognized the central role of conservation under the Act to meet or satisfy the contractual demands of preference customers under section 5 of the Northwest Power Act to purchase electric power from the Administrator. Yet, in the 7(b)(2) case, the central role is assigned to FBS resources. It is only at this point – the point of section 7(b)(2)(D) where we are left with general requirements "other than requirements met by the available Federal base system resources determined under subparagraph [7(b)(2)](B)" – that conservation is brought into play through the required assumptions that the next "resource" was either "purchased from such customers by the Administrator pursuant to section 6" or "not committed to load pursuant to section [5](b)" and was among "the least expensive resources owned or purchased by public bodies or cooperatives…."

The Fourth Assumption, in subsection 7(b)(2)(D), in combination with the direction given in the Second Assumption, in subsection 7(b)(2)(B), presents the crux of the issue regarding the treatment of conservation in the 7(b)(2) Case. Congress knew "general requirements" (*i.e.*, load) are a function of what resources are brought to bear, that conservation is not only a resource but a favored resource under the Pacific Northwest Electric Power Planning *and Conservation* Act, and that conservation reduces load. Consequently, Congress did not reference general requirements or conservation in subsection 7(b)(2)(B), but left the determination of what other resources "would have been required, during such five-year period, to meet remaining general requirements" to 7(b)(2)(D). As clearly evidenced earlier, section 6(a)(1) is clear that conservation is a resource to meet section 5(b) obligations, so it is at this point that conservation can be considered as the next resource *after* FBS resources have been applied to meet 7(b)(2) Case loads.

To give effect to all provisions of the Northwest Power Act based on the foregoing discussion, it is apparent BPA does not perform any conservation *before and during such five-year period* until such point as it is necessary under section 7(b)(2)(D) to meet remaining general requirements. Therefore, whereas in the Program Case conservation is assumed to have been achieved before and through the five-year period, and general requirements are reduced by application of this conservation, the reduction has not occurred in the 7(b)(2) Case unless and until the conservation resource is selected as the least-cost resource available in the 7(b)(2)(D) resource stack. As next discussed, this interpretation of the statutory language is not only consistent with the language, but also logical considering the context in which the statute was passed and the general Congressional understanding of the 7(b)(2) test as being a "with" and "without" Act rate test.

At the time the Northwest Power Act was enacted, conservation was new and unique. This sense is highlighted by the comments of House members during debate on the bill:

> This legislation makes conservation and renewable resources the top priorities for BPA acquisition, and includes the strongest conservation and renewable resource programs of any energy legislation that has been seriously considered by Congress. … I think the point here that has to be made over and over again is that for the first time in the country *we have a chance to test out the theory of conservation*. We have the answer to test out those alternatives.

126 Cong. Rec. H9859 (1980) (statement of Rep. Dicks) (emphasis added). Further:

> The bill deals with the current lack of mechanisms for achieving regional conservation with a thorough-going conservation system. *The bill treats conservation as a resource*, and requires BPA to implement it (and even "purchase" it) whenever it less costly than other resources. BPA is to use a special revolving fund of $1.25 billion (paid for by BPA customers) to make available the financing needed to help consumers achieve a level of conservation that is cost-effective for the region. Special rate credits are provided to utilities for independent conservation efforts, including voluntary implementation of retail rate structures that encourage conservation, and model conservation, and model conservation standards are to be implemented region-wide (with wholesale surcharges on BPA's sales to utilities as an incentive to achieve compliance, if necessary). Finally, with the entire financial backing of the region behind conservation and "unconventional" renewable resources, these resources can be financed more easily and more quickly: there will be no "pioneer's penalty" for the innovating utility.

Id. at H9864 (statement of Rep. Foley) (emphasis added).

The Senate Report explains the section 7(b)(2) rate test in this way:

> A rate test is provided in section 7 to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater than would occur in the absence of the regional program established in S. 885.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 20 (1979). The Report also describes the rate test as:

> The amendment would require BPA to test the estimated costs under proposed rates to preference customers under the Act against the costs which these customers would have encountered in the absence of legislation. If the estimated costs under BPA rates for any five year period exceed the estimated costs without legislation, the excess costs would be spread over all other rates of the Administrator.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 56 (1979). As Senator Jackson observed, "preference customers rates are limited by a 'rate ceiling' to no greater than what they would have been without the bill." Cong. Rec. S. 14691 (November 19, 1980). From this perspective, and the perspective that conservation was truly an untested resource, it is perfectly reasonable to proceed on the basis of assuming in the "without Act" world that, at least as an initial matter, only FBS resources were used to serve 7(b)(2) Customers. This is the logical conclusion because, absent the legislation, BPA had no authority to acquire additional resources, leaving only the FBS resources to serve preference customers. After this allocation of FBS resources, if there was still preference customer load to be met, the resources, including conservation, acquired under section 6 by the Administrator would now be assumed to be available to meet preference customers' load. If, by that time, conservation had achieved measurable savings, it would be available in the 7(b)(2)(D) resource stack; if not, it would not be available in the stack. The application of BPA-acquired conservation resources prior to FBS resources is inconsistent with intent of the rate test.

This conclusion arises from the solution to what would be the estimated costs without the legislation. In solving for the "power costs" without the legislation (the 7(b)(2) Case), preference customers cannot acquire FBS resources after having their general requirements reduced by the application of BPA-acquired conservation, because in the 7(b)(2) Case, BPA *has not yet acquired any conservation*. Rather, it is left to the Administrator to acquire additional resources *after* FBS resources are insufficient to meet customers' electric power needs. Resources acquired by the Administrator to meet those remaining general requirements would be made from the 7(b)(2)(D) resource stack.

As a result of the temporal sequence – first FBS resources, then resources from the 7(b)(2)(D) resource stack – it is clear that the loads of the preference customers, as set forth in section 7(b)(2)(B), and as further modified by section 7(b)(2)(A), must be adjusted to reflect the absence of conservation achieved before the five-year period. Otherwise, priority could not be given to the FBS resources, and the proper order of service to load, in the absence of the legislation, could not be observed. In making the adjustment to the loads of the preference customers for conservation acquired prior to the five-year period, BPA has solved for the proper amount of "general requirements" in the 7(b)(2) Case.

What remains is the solution of the "power costs" in the 7(b)(2) Case. It is evident Congress provided that preference customers would acquire resources at the same cost of those resources acquired by the Administrator from such customers, except for some financing cost differences. Should additional resources be needed, Congress provided that preference customers would acquire these additional resources, once again, "at the average cost of all other new resources acquired by the Administrator." Having set the cost of the resources available to the preference customers, BPA need only first apply the cost of FBS resources used for preference customer load (recognizing that customer-owned resources serving load pursuant to section 5(b)(1) have already been applied) and then, if needed, the 7(b)(2)(D) stack resources would be drawn in least-cost order. Having applied the resources in this order, BPA would then determine the power costs of these resources to solve for the "power costs" in the 7(b)(2) Case.

D. Analysis of Parties' Positions

While, as here addressed, BPA takes strong exception to some of the more extreme arguments made by some parties, that should not obscure the fact that – stepping back from the trees to see the forest – the parties do make a number of credible arguments for their own reading of section 7(b)(2). BPA acknowledges that there are other plausible, albeit in our view less reasonable, readings of the statutory language. BPA spent significant time evaluating and considering the parties' positions as well as Staff's interpretation before deciding upon the above textual analysis. In making this interpretation, BPA notes that the language in section 7(b)(2) rate test is not a rigid formula that directs the Administrator to do no more than input numbers to calculate the rates and loads with mathematical precision. Congress gave the difficult task of implementing the 7(b)(2) rate test to the BPA Administrator: "… the projected amounts to be charged for firm power for the combined general requirements of [COUs] … may not exceed … in total, *as determined by the Administrator*, … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes [the Five Assumptions.]" 16 U.S.C. § 839e(b)(2) (emphasis added). As this language makes clear, the rate test requires the Administrator to use his reason and judgment to create an alternative universe where the Congressionally defined Five Assumptions are given their intended effect. In creating this world, Congress recognized the complexity involved with this analysis and therefore vested the Administrator with a significant degree of discretion to effectuate the intent of the Act. This discretion is evident by the inclusion of the phrase, "as determined by the Administrator," in the body of the section 7(b)(2) rate test. Though the parties' reading of the Act is one interpretation of the statutory language, BPA believes that, in the end, its interpretation meets its primary statutory duty of implementing the rate test consistent with the language as well as the purpose and intent of section 7(b)(2).

The OPUC generally supports Staff's recommendations regarding the treatment of conservation. OPUC Br., WP-07-B-PU-02, at 29. The OPUC supports including conservation resources in the 7(b)(2)(D) resource stack and continuing to remove the effects of conservation from 7(b)(2)

Customer loads for purposes of the 7(b)(2) rate test, and supports BPA's rejection of a proposal from the IOUs to "not increase the combined general requirements of the PF Preference Rate customers in the 7(b)(2) Case."[14] *Id*.

Cowlitz, APAC, PPC, and the IOUs, however, object to Staff's treatment of conservation in the 7(b)(2) rate test. Cowlitz Br., WP-07-B-CO-01, at 16-17; Cowlitz Br. Ex., WP-07-R-CO-1, at 3-21; APAC Br., WP-07-B-AP-01, at 37; APAC Br. Ex., WP-07-R-AP, at 16-20; PPC Br., WP-07-B-JP25-01, at 28-29; IOU Br., WP-07-B-JP6-01, at 27. These parties' basic argument is that adjusting the loads in the 7(b)(2) Case for conservation is contrary to the definition of "general requirements" in section 7(b)(4) of the Northwest Power Act, and that they must be the same in both cases except where Congress has expressly directed BPA to add load, as in the case of the DSI load in section 7(b)(2)(A). *Id.* For example, Cowlitz argues that Congress defined the "general requirements" of a preference customer to constitute "electric power purchased under § 5(b) of this Act." Cowlitz Br., WP-07-B-CO-01, at 16-17. Cowlitz states that Congress did not define the "general requirements" of a preference customer to constitute "electric power purchased under § 5(b), *plus* electric power that might have been but was not purchased because of prior investments in conservation pursuant to § 6." *Id.* Thus, Cowlitz concludes that the plain language of section 7(b)(4) requires BPA to use estimates of "electric power purchased" and does not permit BPA to inflate the amounts of electric power purchased by amounts *not purchased* because of conservation. *Id.*

BPA does not disagree that in certain contexts the term "general requirements" can mean the "net" amount of load that BPA is responsible for under section 5(b) of the Act. For example, section 7(b)(1) establishes BPA's obligation to set rates that recover the costs BPA incurs to serve the loads of the preference customers. 16 U.S.C. § 839e(b)(1). There, the term "general requirements" is used to make clear that BPA must set its rates to recover the cost of the actual electric demand placed on BPA during the rate period. A similar use of the term "general requirements" occurs in the first full clause in section 7(b)(2), though the exact terminology there is "combined general requirements." In both of these contexts, "general requirements" means the expected amount of load (*i.e.,* electricity that is forecast to be purchased) of the customers that BPA forecasts it will serve during the upcoming rate period in the real world. However, in the latter part of 7(b)(2), as discussed earlier, BPA believes the term is used to mean the same concept, but with a different quantification. The final clause in the paragraph states "*an amount equal to the power costs for general requirements* of such customers *if, the Administrator assumes that* …" 16 U.S.C § 839e(b)(2). As this instruction indicates, the term "general requirements" is not simply the "combined general requirements" of the customers unchanged from the previous clauses, but general requirements of "such customers" *assuming* the Administrator were to make the Five Assumptions. What the "general requirements" of "such customers" become is therefore a product of the implementation of the Five Assumptions.

As described above, the most apparent adjustment to the term "general requirements" occurs with the application of the First Assumption. Here, BPA must assume that the "general requirements" in the 7(b)(2) Case included the "within and adjacent" DSI loads. Cowlitz, APAC

[14] The OPUC does not agree with Staff's proposal to exclude costs of conservation from the power costs of the 7(b)(2) Case prior to conducting the 7(b)(2) rate test, or BPA's proposed financing assumptions for conservation.

and PPC argue that this is the *only* load adjustment BPA may properly make in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 17; APAC Br., WP-07-B-AP-01, at 37; PPC Br., WP-07-B-JP25-01, at 28-29. BPA recognizes this is one possible reading of the Act. However, BPA believes that a more plausible reason Congress included this assumption is because *but for* this addition, BPA could not properly assume the DSIs would become part of the 7(b)(2) Customer general requirements. As stated earlier, Senator Jackson, one of the chief sponsors of the Act, observed "preference customers rates are limited by a 'rate ceiling' to no greater than what they would have been without the bill." Cong. Rec. S. 14691 (November 19, 1980). At the time the Act was being considered, DSIs constituted about one-third of BPA's firm and nonfirm energy sales. H. Rep. 96-976, Pt. II, at 28. BPA's notices of insufficiency to the DSIs that they would not renew their power sales contracts due to projected power insufficiencies was one of the primary drivers of the need for new legislation. *Id.* at 30-32. The Act, through its resource acquisition and other provisions, was intended to solve that power allocation problem, and required BPA to "offer new long-term power sale contracts to preference customers, Federal agencies, investor-owned utilities, and existing direct-service industrial customers of BPA; …" *Id.* at 32. The First Assumption in section 7(b)(2) makes clear that in a "without-legislation" world, the Administrator is to assume the DSIs would have received their service from their local utilities and not from BPA. This adjustment had to be specifically noted because it was adding the load of an independent entity to the loads of the 7(b)(2) Customers. Additionally, BPA can find no other expression in section 7(b)(2), or in the legislative history of the Northwest Power Act, that suggests that this was the only intended adjustment to the preference customers' loads in the 7(b)(2) Case. In the absence of specific statutory direction, BPA finds that the statutory language does not preclude other logical adjustments to the 7(b)(2) case loads that may occur as a result of other assumptions.

Cowlitz argues against BPA's understanding that "§ 7(b)(2) contemplates some type of 'no legislation' world in which 'BPA would have not have section 6 acquisition authority, and therefore, would have *no other* means, including conservation, of serving the loads of preference customers except through the FBS." Cowlitz Br. Ex., WP-07-R-CO-1, at 9, 14-15. It states this is "decisively refuted" by the language in section 7(b)(2)(D) referring to resources "purchased from such [preference] customers by the Administrator pursuant to section 6" of the Act and resources "obtained at the average cost of all other new resources acquired by the Administrator." *Id.* (emphasis added). Cowlitz believes this refutes any notion that BPA is to "not have section 6 acquisition authority" in the 7(b)(2) Case. As next explained, Cowlitz's statements show a misunderstanding of this provision, the temporal assumption and sequencing of resource acquisitions for purposes of only serving "remaining general requirements," and Congressional and BPA references to the "without Act" world.

With regard to the latter, Cowlitz stretches the "without Act" statements too far, positing that BPA is seeking "unbounded authority" and "Godlike power to create an alternative universe," Cowlitz Br. Ex., WP-07-R-CO-1, at 3-4, 14. Clearly, the 7(b)(2) Case test world is not completely divorced from reality, including the existence of the Act. As Cowlitz itself points out, section 7(b)(2)(D) references provisions of the Act. Definitions in the Act apply to section 7(b)(2), just as to other sections of the Act. However, the assumptions listed in section 7(b)(2) concern, and treat differently, what Congress well understood to be some of the major features of the Act: DSI service, the residential exchange, resource acquisitions. *See* H.

Rep. 96-976, Pt. II, at 32; H. Rep. 96-976, Pt. I, at 27-30; S. Rep. 906-972, at 15-16. It is in this sense, a general sense that takes major changes wrought by the Act and treats them differently, that section 7(b)(2) represents a with- and without-Act comparison. If the assumptions in 7(b)(2) replicated exactly what already occurred pursuant to the Act such that there really was nothing new to assume, there would then be nothing to compare to the Program Case other than a replica of itself. Clearly, Congress intended a comparison to be made, and the comparison is with a world where certain major features of the Act are different.

With respect to specific resource acquisitions, including conservation, that BPA makes in the 7(b)(2) Case, Cowlitz is wrong to imply that resource acquisitions would be just as they were in the Program case. As discussed earlier, BPA acquires resources to meet *all* its contractual obligations under section 5. *See, e.g.*, 16 U.S.C. §§ 839c(b)(7), 839d((a). Outside of section 7(b)(2), the Act does not direct or specify what resource is to be acquired for what customer. Outside of section 7(b)(2), the Act also does not specify a priority as to whom the Administrator is to acquire all resources from. *Id.* Outside of section 7(b)(2), the Act does not direct that the Administrator is to serve preference customers first with FBS, then with other resources, whether conservation, residential exchange or new resources. BPA provides service from all its resources managed as a whole. Rather, the Act states as a matter of ratemaking which costs of which resources are to be allocated to the rates of the various customer classes. *See, e.g.*, 16 U.S.C. § 839e(b)(1).

Under section 7(b)(2), in contrast, the Administrator is to assume the public body, cooperative and Federal agency customers are served first with the FBS. Then, under section 7(b)(2)(D), all resources that would have been required to meet remain remaining general requirements are purchased first from public bodies and cooperatives pursuant to section 6 or, with no specification as to section 6, are otherwise resources not committed to load pursuant to section 5(b). Only after that is the Administrator to assume that any still remaining general requirements are met "at the average cost of all other new resources acquired by the Administrator; …" 16 U.S.C. § 839e(b)(2(D). In this new and orderly scheme of resource service and acquisition, the reference to section 6 and later to other new resources acquired by the Administrator serves simply to provide some direction for how the Administrator is to assume resources are acquired in the 7(b)(2) Case, not to say that they all already occurred. For purposes of solving for the power costs and general requirements under section 7(b)(2), resource acquisitions would not be just as they all are under section 6 of the Northwest Power Act and as reflected in the Program Case.

BPA's approach is not inconsistent with modeling the two cases the same except where required by the five assumptions of section 7(b)(2), as argued by Cowlitz. Cowlitz Br. Ex., WP-07-R-CO-1, at 15. BPA is following the five assumptions. Cowlitz characterizes BPA's approach as subjective and contrary to one statement in the legislative history that "rate limit factors are objective in nature." Cowlitz Br. Ex., WP-07-R-CO-1, at 15, *quoting* S. Rep. No. 96-272, 96th Cong., 1st Sess. at 61 (1979), Attachment 2 to E-JP17-1-CC1. This characterization of the section 7(b)(2) rate test, however, is based simply on Cowlitz's arguments that BPA is interpreting the Act incorrectly. As shown throughout this evaluation, BPA's interpretation of the Act is correct, and follows Congressional intent regarding the role of conservation in meeting BPA's contractual 5(b) obligations to provide electric power, so there is nothing subjective about BPA's approach.

Cowlitz argues that while BPA characterizes section 7(b)(2) as complex, in the "Appendix B Numerical Analysis of Rate Directives" included as Appendix B to Senate Report 96-272, statements are made that the section 7(b)(2) factors are objective and, for the most part, fairly straightforward. Cowlitz Br. Ex., WP-07-R-CO-1, at 15, *quoting* S. Rep. No. 96-272, 96th Cong., 1st Sess. at 61 (1979); Attachment 2 to E-JP17-1-CC1. Consequently, Cowlitz crowns BPA the "Minor Estimator" and argues that BPA's concerns about interpreting the complex provisions of section 7(b)(2) are unfounded. Of course, since Cowlitz disagrees with how BPA is doing its job, it concludes BPA is exceeding its role as the Minor Estimator. Cowlitz's reliance on Appendix B goes too far. Cowlitz admits Appendix B qualifies its relevance to BPA's ratemaking because "the circumstances assumed in preparing the analysis will change over time." Cowlitz Br., WP-07-B-CO-01, at 8. What once might have been or seemed simple can change in light of changing circumstances. Cowlitz also admits that Appendix B acknowledged that notwithstanding such changes, "as a matter of law under this act rates shall be established pursuant to specific statutory provisions in section 7 and 9 …" *See* S. Rep. No. 96-272, 96th Cong., 1st Sess. 31-32 (1979). Thus, while Appendix B can be helpful when reviewing the Northwest Power Act, it is not dispositive of Congressional intent. The Ninth Circuit Court of Appeals acknowledged this fact in *Central Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1122 (9th Cir. 1984) (*citing* S. Rep. No. 96-272, 96th Cong., 1st Sess. 56-57) when it observed that "… the appendix was incorporated into the Senate Report with reservations."

Cowlitz cites the Senate Report's statement that Appendix B was "widely circulated in the region and has become an important part of the common understanding of how the costs of resources would be distributed" as meaning that anything inconsistent with it must be erroneous. Cowlitz Br. Ex., WP-07-R-CO-1, at 17. However, in the same breath, the Report states: "In full recognition that as a matter of law under this act rates shall be established pursuant to specific statutory provisions in sections 7 and 9 and that the circumstances which were assumed in preparing this analysis will change over time, the Committee has included the computer analysis and accompanying narrative in the appendix." S. Rep. No. 96-272, at 31-32. Thus, while Appendix B is some indication of Congressional intent, it is not dispositive and should be considered together with the language of the Act and other legislative history.

Also, the fact that a report attached to legislative history describes the Administrator's role as a "Minor Estimator" does not detract from the clear *statutory* language which places a much greater emphasis on the role the Administrator plays in conducting the section 7(b)(2) rate test. As noted earlier, Congress gave the difficult task of implementing the 7(b)(2) rate test to the BPA Administrator: "… the projected amounts to be charged for firm power for the combined general requirements of [COUs] … may not exceed … in total, *as determined by the Administrator*, … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes [the Five Assumptions.]" 16 U.S.C. § 839e(b)(2) (emphasis added). If Congress had intended the Administrator to apply the Five Assumptions as an automaton, as suggested by Cowlitz, there would have been no need to include the phrase "as determined by the Administrator" in section 7(b)(2). By including that phrase, Congress must have recognized that implementing the section 7(b)(2) rate test would require more than "minor estimating," but a significant degree of reason and judgment to effectuate the intent underlying the Five Assumptions. Interpreting this statutory phrase away as merely surplusage, as Cowlitz has done, is disfavored. *See TRW Inc., v. Andrews*, 534 U.S. 19, 31 (2001); *Duncan v. Walker,* 533 U.S. 167, 174 (2001).

APAC and PPC argue the term "general requirements" requires BPA to assume the 7(b)(2) Case loads must be "net" of any conservation. APAC Br., WP-07-B-AP-01, at 37-38. APAC argues the load in the Program Case already includes any reductions in load achieved by conservation programs – conservation programs that preference customers otherwise pay for. APAC Br., WP-07-B-AP-01, at 38. Therefore, the 7(b)(2) Case must also start with the net load of preference customers as reduced by conservation. *Id.* APAC claims the "net load" constitutes the "general requirements" in both the Program Case and the 7(b)(2) Case. *Id.* APAC contends this is consistent with the definition of "general requirements," which limits it to "*power purchased from BPA under section 5(b)* …" *Id.* APAC argues "general requirements" is defined in the Northwest Power Act as the demand for *power,* and the term does not include load that has been eliminated by conservation. APAC Br., WP-07-B-AP-01, at 37-38. PPC similarly argues that BPA's treatment of conservation is contrary to law because preference customers do not, and are not allowed by statute to, purchase electric power from the Administrator under section 5(b) in amounts that reflect their actual requirements, *plus* the amount of conservation BPA acquires from them. PPC Br., WP-07-B-JP25-01, at 28-29. Additionally, section 3(9) of the Northwest Power Act defines the term "electric power" to mean "electric peaking capacity, or electric energy, or both." *Id.* PPC contends this language does not permit BPA to equate electric power purchased from the Administrator as including amounts of conservation achieved. *Id.* PPC argues BPA violates the express definition provided by section 7(b)(4) by making the general requirements of preference customers in the rate test different from the amount of electric power such customers purchase from the Administrator under section 5(b). *Id.*

As noted above, BPA concurs that the parties have proffered one possible construction of the statutory language. However, BPA does not agree that this is the most consistent reading of the language when considering section 7(b)(2) as a whole. Contrary to the parties' position, section 7(b)(2) does not require that "general requirements" in the 7(b)(2) Case be the same as "the combined general requirements" in the Program Case in all of the assumptions. If this were the intent, Congress would have referred to "such general requirements" or the "combined general requirements" at the end of the introductory language to the Five Assumptions, would have included a reference to "general requirements" in section 7(b)(2)(B), would have been clear in section 7(b)(2)(B) that FBS resources are brought into play after conservation resources, would have been clear in section 7(b)(2)(B) that it was speaking of costs and not service from particular resources, and would have instructed the Administrator to utilize resources, other than conservation resources already utilized, to meet remaining general requirements in section 7(b)(2)(D). Congress did not do so, with the consequence that the Administrator is to determine general requirements as part of the implementation of the Five Assumptions.

With reference to the language differences in the introductory language to the Five Assumptions and in section 7(b)(2)(B), "[w]hen Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion." *Barnhart v. Sigmon Coal Co.*, 534 U.S. 438, 452 (2002). The fact that Congress excluded the phrase "general requirements" from subsection 7(b)(2)(B) presumes that a different treatment of 7(b)(2) Case loads was expected when implementing the Second Assumption.

Furthermore, interpreting the term "general requirements" to mean that conservation has already been acquired and applied to reduce load in the 7(b)(2) Case would create a conflict with two of the Five Assumptions. As described above, Congress explicitly instructed the Administrator to assume in the Second Assumption that BPA's role in serving the preference and Federal agency customers in the 7(b)(2) Case is limited to service with FBS resources. These resources, by definition, are confined to the 31 Federal dams and one nuclear power plant (plus any replacements). Limiting BPA's resources to these resources makes sense because the 7(b)(2) rate test is supposed to "test" the rates that BPA proposes to charge the preference customers with a hypothetical rate developed in a "no-legislation" world. The Senate Report describes the rate test as follows:

> The amendment would require BPA to test the estimated costs under proposed rates to preference customers under the Act against the costs which these customers would have encountered in the absence of legislation. If the estimated costs under BPA rates for any five year period exceed the estimated costs without legislation, the excess costs would be spread over all other rates of the Administrator.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 56 (1979). As explained in more detail earlier, in this "no-legislation" world, BPA would serve public body, cooperative and Federal agency customers first with FBS resources. If, and only if, those FBS resources were inadequate to serve the customers' needs would additional resources be used to "meet" their remaining general requirements. BPA would not have the broad section 6 acquisition authority it enjoys under the Northwest Power Act, and therefore, so long as the FBS was sufficient to serve the public body, cooperative and Federal agency customers, would have *no other* means, including conservation, of serving them except through the FBS. Again, reducing use of power (*i.e.*, load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load). Reducing load through conservation is a means of meeting load.

That all makes perfect sense when one considers that prior to passage of the Northwest Power Act, BPA was the marketing agent for the electric power generated by the Federal generating plants, augmented by limited resources. 16 U.S.C. § 838f. It was the forecasted inability of power from that limited source to meet DSI, IOU, and preference customer load that prompted passage of the Northwest Power Act. No longer would BPA simply be a marketing agent; rather, under the Act, it had a duty to serve and was given a full complement of resource acquisition authorities to effectuate that duty to serve; *e.g.*, 16 U.S.C. §§ 839c, 839d. The Act defines BPA's pre-Act resources, which did not include conservation, and their replacements as Federal Base System resources. *See* 16 U.S.C. § 839a(10). Is it any wonder then that Congress provided for a different resource paradigm, one that more closely mirrors BPA's pre-Act authorities and obligations, when it provided a rate test "to insure that the Administrator's power rates for public bodies and cooperatives entitled to preference and priority under the Bonneville Project Act [are] no greater than would occur in the absence of the regional program established in" the Act? S. Rep. No. 96-272, 96th Cong., 1st Sess. 20 (1979). It is natural and reasonable in light of this to treat BPA's conservation resource acquisitions as BPA has in conducting the 7(b)(2) rate test.

Interpreting "general requirements" in the 7(b)(2) Case to be "net" of BPA-acquired conservation, as requested by certain parties, would undermine this construct. Instead of limiting BPA's resource service in the no-legislation world to just the FBS, which Congress explicitly stated in the Second Assumption, the parties would have BPA serving the preference customers' loads with FBS *and* conservation resources. In fact, these parties would have conservation serving 7(b)(2) Case loads first, prior to the use of the FBS. That is, BPA would start with the 7(b)(2) Customers' general requirements already reduced by conservation, and then apply the FBS. If this were the intent, Congress would have included a reference to "general requirements" in section 7(b)(2)(B) and would have instructed the Administrator to compare "the general requirements" to "such general requirements" in section 7(b)(2). The fact that the Congress excluded the phrase "general requirements" in subsection 7(b)(2)(B) presumes that a different treatment of 7(b)(2) Case loads was expected when implementing the Second Assumption. Additionally, Congress could also have instructed the Administrator to serve the preference customers' loads with FBS resources and "conservation" resources in section 7(b)(2)(B). As we have seen, Congress was well aware of the key role conservation would play in meeting BPA's service obligations in the "with Act" world. The fact that the term "conservation" is not mentioned further instructs BPA that it is reasonable to assume the only resources that *BPA* may use to first serve the 7(b)(2) Case customers are the FBS resources, as specified in section 7(b)(2)(B). Arguing, as the parties do, that there was no need to specify conservation because it is already reflected in general requirements ignores the specific language of the test and Congress's purpose in creating the test.

Cowlitz takes strong exception to BPA's conclusion that because section 7(b)(2)(B) does not refer to either "conservation" or "general requirements," but speaks in terms of BPA serving public body, cooperative and Federal agency customers with FBS resources, BPA must also assume at this point in the rate test that no *other* resources but FBS resources were applied to meet the load needs of the customers. Cowlitz Br. Ex., WP-07-R-CO-1, at 7. It argues it was not necessary to reference conservation because it was already excepted in the introductory language of section 7(b)(2). *Id.* at 8. The multiple problems with that conclusion are addressed above, as are Cowlitz's arguments against the "no-legislation" approach, *id.* at 9, and its position that conservation is a not a resource that can meet general requirements, *id.* at 12-14.

Cowlitz argues that it is odd to argue that Congress meant to address an issue, conservation, in section 7(b)(2)(B) by omitting to mention it at all. It says the absence of conservation should not be assumed. *Id.* To the contrary, when X denotes the absence of Z, BPA does not believe it is necessary for Congress to state "X, but not Z." So, when Congress stated in the Second Assumption that the Administrator should assume FBS served the customers and, in the Fourth Assumption, that only then should he assume that all resources that would have been required to meet remaining general requirements were purchased as thereafter specified, that is sufficiently clear to denote the absence of conservation, unless it is chosen from the resource stack in the Fourth Assumption. That also answers Cowlitz's arguments that section 7(b)(2)(B) simply has no load significance and "Congress' care to specify the portion of low-cost FBS resources

available to be used to meet general requirements of preference customers simply has no bearing on the amount of such general requirements in the 7(b)(2) Case." *Id.* at 10-11.
Section 7(b)(2)(B), (C) and (D) deal with resources serving the customers and meeting the customers' remaining general requirements, and conservation is a resource, so the availability of conservation as a resource in section 7(b)(2)(D), *after* "requirements" (not "general requirements" but "requirements") "are met by available Federal base system resources" under section 7(b)(2)(B) denotes its absence in (B). Conservation does reduce load, so its absence until the Fourth Assumption means that when the Administrator serves public bodies, cooperative, and Federal agency customers in (B), it is serving an amount of load that is greater than would be the case had the conservation resource already been used to meet the Administrator's obligation under section 5(b) to provide electric power to firm load. *See* discussion *supra.*

Assuming conservation has already reduced the loads in the 7(b)(2) Case would cause further conflicts with the implementation of the Fourth Assumption. As noted above, the Fourth Assumption, in subsection 7(b)(2)(D), describes the manner in which additional resources are assumed to be acquired by the preference customers in the 7(b)(2) Case to meet their remaining general requirements after the FBS resources are exhausted. The first type of resource is described in section 7(b)(2)(D)(i) as being resources "purchased from such customers by the Administrator pursuant to section 6." *Id.* These are the resources actually acquired by BPA from the 7(b)(2) Customers in the Program Case. Conservation is defined in the Northwest Power Act as a resource. 16 U.S.C. § 839a(19). In addition, conservation is acquired by BPA under section 6. 16 U.S.C. § 839d(a)(1). Under the plain language of Act, conservation resources acquired by BPA are an available resource for the 7(b)(2)(D) resource stack that may be used to serve 7(b)(2) Case load to the extent it is needed and it is among the least expensive resources available.

In response, Cowlitz next states BPA is wrong in "arguing, in substance, that because § 7(b)(2)(B) does not use the term 'general requirements,' BPA is free to interpret § 7(b)(2)(D), which does expressly address 'general requirements,' as if the words 'general requirements' were not in § 7(b)(2)(D)." *Id.* at 9. Cowlitz's understanding, and its argument, is predicated on its earlier arguments that "general requirements" must already reflect the effects of conservation and that, therefore, if BPA does not similarly read "general requirements" in approaching section 7(b)(2)(D), it is reading general requirements out of section 7(b)(2)(D). *Id.* As shown earlier, that predicate argument is wrong. The introductory language of section 7(b)(2) does not require the same Program and 7(b)(2) case general requirements, conservation is a resource to meet BPA's contractual obligations to provide electric power, and that resource is first called into play in section 7(b)(2)(D) if it is the least expensive resource owned or purchased by the customers.

Cowlitz argues that "[f]ar from requiring BPA to assume that there are no non-FBS resources available to meet general requirements in the 7(b)(2) Case, § 7(b)(2)(D) requires BPA to assume that there are non-FBS resources available." BPA does not disagree with that. Cowlitz Br. Ex., WP-07-R-CO-1, at 11-12. What BPA disagrees with is Cowlitz's assumption about the timing of those resources; that is, the acquisition of conservation by the Administrator *before* he serves customers with available FBS resources. The Fourth Assumption requires the Administrator to assume that this conservation resource, if it is the least expensive resource, is acquired *after* "requirements" (not "general requirements" but "requirements") "are met by available Federal base system resources[.]" 16 U.S.C. § 7(b)(2)(D).

Adopting an interpretation of "general requirements" that is "net" of conservation, however, conflicts with this plain reading of the Act because it effectively removes conservation as a resource from selection in subsection 7(b)(2)(D). This result occurs because if the 7(b)(2) Case loads are "reduced" by conservation resources acquired by BPA before reaching the Fourth Assumption (as the preference parties suggest), then those same conservation resources cannot still be available in the 7(b)(2)(D) resource stack to "reduce" the loads even further. If the preference parties' interpretation were accepted, the net effect would be that conservation must be removed from the 7(b)(2)(D) resource stack, which is inconsistent with Congress' direction to the Administrator in 7(b)(2)(D)(i). It would also, for purposes of a test that is intended to protect customers from costs occasioned by the Act, ignore that "the heart of the regional power bill" "is the authority for BPA to acquire from non-Federal entities additional electric power resources, including conservation, to meet the electric needs of Northwest consumers." Cong. Rec. S.14690 (November 19, 1980). The customers' arguments would unreasonably put that heart into the "without-Act" side of the test, with the consequence that conservation first meets BPA's service obligations.

Excluding conservation from consideration is also inconsistent with Congress's direction to "stack" the 7(b)(2) Case resources in least-cost order. In the "no-legislation" world, as discussed above, BPA is assumed to first serve public body, cooperative, and Federal agency customers with only FBS resources. Because BPA does not have general resource acquisition authority in the 7(b)(2) Case, preference customers are presumed to have acquired any additional resources on their own. Thus, the resources are "owned or purchased" by public body and cooperative customers. Section 7(b)(2)(D) directs that after the Administrator has exhausted the capacity of the FBS to serve the public body, cooperative, and Federal agency customers, the Administrator is to assume that, among other things, remaining general requirements are met by the least expensive of those resources from such customers pursuant to section 6. Since section 6 provides first for conservation and renewable resources to meet load, Congress must have recognized that conservation could or would play an increasingly important role in a utility's overall resource mix. Therefore, Congress defined the resources available in the 7(b)(2) Case broadly to include conservation. However, in the "no-legislation" world, Congress understood that unlike under the Act where Congress had bestowed a 10 percent cost advantage on conservation, 16 U.S.C. § 839a(4)(d), preference customers would not choose conservation if it was more expensive than other means of serving load. Thus, Congress instructed BPA to assume that the first resources chosen after FBS resources to serve preference customer loads would be "the least expensive resources owned or purchased by public bodies or cooperatives." 16 U.S.C. § 839e(b)(2)(D). BPA complies with this directive by "stacking" the 7(b)(2)(D) resources from least expensive to most expensive. *See* Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, at IM-7-8. The resources at the bottom (least expensive) of the resource stack are selected and used first to serve the preference customers' remaining load needs. Consequently, conservation resources should only be used to serve the loads in the 7(b)(2) Case if they are selected as the next least-cost resource.

This Congressionally directed "ordering" of 7(b)(2)(D) resources, however, would not be followed if BPA were to presume that the 7(b)(2) Case loads are "net" of conservation. Instead of selecting conservation as the least-cost resource to serve preference customers in the 7(b)(2) Case, the preference parties' interpretation would require BPA to assume that conservation already exists and is inherent in the 7(b)(2) Case loads regardless of whether conservation resources were the least-cost option. This result is not supported by the statutory language in subsection 7(b)(2)(D). Additionally, BPA has been unable to find anything in the Northwest Power Act or its legislative history that would suggest Congress intended BPA to assume that in the "no-legislation" world the preference customers would acquire all resources *except for* conservation in least-cost order, and in advance of the FBS. BPA is also troubled by this interpretation because it leads to illogical results that are contrary to Congress's intent in designing the section 7(b)(2) rate test. In a hypothetical world where BPA could not acquire any additional resources beyond the FBS, and given that the test was created by Congress at a time when conservation was new and global warming was not a recognized concern, it is not illogical to assume that the preference customers would purchase the least expensive resources available to serve their remaining load. To be consistent with both the language and intent of the section 7(b)(2) rate test, BPA must assume that conservation resources would only be used in the 7(b)(2) Case if they are the least-cost resources.

As Cowlitz notes, when interpreting section 7(b)(2), it is important to remember that one should "not look merely to a particular clause in which general words may be used, but … take in connection with it the whole statute … and the objects and policy of the law, as indicated by its various provisions, and give to it such a construction as will carry into execution the will of the Legislature." *Id.*, at 18, *citing Azarte v. Ashcroft*, 394 F.3d 1278, 1287 (9th Cir. 2005) (*quoting Kokoszka v. Belford*, 417 U.S. 643, 650 (1974)). As the foregoing analysis of the entirety of the Northwest Power Act relating to this question shows, the Staff proposal arises not from a single subsection of the statute that is viewed in isolation, but is built on the statute in its entirety, including the stated intent from legislative history.

Cowlitz argues that BPA is *first* supposed to identify the "general requirements" of preference customers and *then* determine whether resources above and beyond FBS resources are required to "meet the remaining general requirements." Cowlitz Br., WP-07-B-CO-01, at 19. A similar argument is proffered by the PPC and the IOUs. PPC Br., WP-07-B-JP25-01, at 28-29; IOU Br., WP-07-B-JP6-01, at 53. BPA acknowledges that this is one interpretation of the language. However, as more fully discussed above, these arguments omit a number of important considerations. One of the most important is that section 7(b)(2)(B) requires BPA to assume that *only* FBS resources are to be used to serve "customers," not their "general requirements." This is an important distinction that is explained in the analysis above. The foregoing parties' argument presumes that "general requirements" is determined from the beginning. As shown above, "general requirements" must be solved in constructing the 7(b)(2) Case.

Cowlitz, PPC, APAC, and the IOUs argue that there is no conflict between their interpretation and the Second and Fourth Assumptions of the rate test because "conservation" is *not* a resource for purposes of section 7(b)(2)(D). Cowlitz Br., WP-07-B-CO-01, at 20; PPC Br., WP-07-B-JP25-01, at 28; APAC Br., WP-07-B-AP-01, at 39-40; IOU Br., WP-07-B-JP6-01, at 50-51. BPA does not find these arguments persuasive. First, the language in the Northwest

Power Act unequivocally includes conservation as a resource. 16 U.S.C. § 839a(19)(B). The parties do not seriously question that conservation is a resource in the context of the Act as a whole. The parties' main contention is that conservation is not a resource in the 7(b)(2) rate test. To determine whether conservation was intended as a resources for purposes of section 7(b)(2)(D), one must turn to the statutory language.

As shown above, conservation is a resource by definition in section 3(19)(B) of the Northwest Power Act. 16 U.S.C. § 839a(19)(B). Second, conservation is not an FBS resource, as shown both by the definition in section 3(10) of the Act and by virtue of the fact that the costs of conservation are allocated to power rates pursuant to section 7(g), not as FBS costs by section 7(b)(1). 16 U.S.C. § 839a(10). Finally, conservation may be purchased by the Administrator from customers, including the DSIs, public bodies, cooperatives, and Federal agencies. Indeed, as demonstrated in the analysis above, conservation is purchased pursuant to section 6, where it is given the highest priority among all resource types. It is therefore logical that it would be available to meet public body, cooperative, and Federal agency customers' general requirements in section 7(b)(2)(D).

Cowlitz argues that section 7(b)(2) makes no reference to any mandatory "resource stack," much less one including conservation resources. Cowlitz Br., WP-07-B-CO-01, at 19. Cowlitz is correct that the term "resource stack" is not expressly mentioned in the Northwest Power Act. However, as discussed above, the Northwest Power Act unequivocally includes conservation as a resource. 16 U.S.C. § 839a(19)(B). Furthermore, section 7(b)(2)(D) instructs BPA which resources should be used *after* FBS resources, but only if needed. Section 7(b)(2)(D) also instructs that the resources are to be "… the least expensive resources …" available. Read together, the paragraph implies there is a listing of resources, starting with the FBS and then ordered from least expensive to most expensive. BPA has used the term "resource stack" to refer to this listing since its initial Legal Interpretation. *See* Issue 6, *Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act*, 49 Fed. Reg. 23,998 (June 8, 1984). Section 7(b)(2)(D) instructs the Administrator to assume all resources that "would have been required … to meet remaining general requirements …" were acquired in a certain order. 16 U.S.C. § 839e(b)(2)(D). Congress was clear in its instruction that if the FBS resources were not sufficient to serve customers, BPA was to assume other resources were used to meet remaining general requirements. Therefore, it is clear from section 7(b)(2)(D) that the use of other resources, the "resource stack," is mandatory.

Cowlitz argues that if BPA determines FBS resources are insufficient to meet the "general requirements" of preference customers, BPA then must consider which additional resources should have their costs assigned to the preference customer rate to meet those general requirements. Cowlitz Br., WP-07-B-CO-01, at 19-20. However, section 7(b)(2)(B) does not instruct to "meet general requirements" with FBS resources, but to "serve customers" with FBS resources. Only once the FBS is fully used to serve the customers is the Administrator to assume purchase of "resources … required, during such five year period," from such public body, cooperative, and Federal agency customers. Therefore, Cowlitz has misstated the instruction of section 7(b)(2).

Cowlitz notes that the scope of the term "resource" in section 7(b)(2)(D)(i), like any statutory language, "depends on context." *Id.* at 19, *citing King v. St. Vincent's Hospital*, 502 U.S. 215, 219 (1991). Cowlitz argues that section 6 distinguishes resources, such as conservation, installed under section 6(a)(1) "to reduce load" and resources acquired under section 6(a)(2) "to meet [BPA's] contractual obligations which remain after taking into account planned saving from measures provided for in paragraph (1) of this subsection." *Id.;* Cowlitz Br. Ex., WP-07-R-CO-1, at 13. APAC raises similar issues in its brief, arguing that conservation to reduce load is distinctly different than power procured to serve load under the Northwest Power Act. APAC Br., WP-07-B-AP-01, at 39-40. BPA understands Cowlitz's and APAC's concerns, but finds that the better approach is to follow the plain language of the statute. The language of section 6(a)(1) states in no uncertain terms that "[t]he Administrator shall acquire such *resources* through conservation…" Cowlitz and APAC argue that the Northwest Power Act distinguishes resources between those "installed to reduce load" under section 6(a)(1) and those to meet contractual obligations under section 6(a)(2). As discussed in the Introduction to this issue, that acquisition was authorized to enable the Administrator to meet his contractual obligations. Fundamentally, reducing use of power (*i.e*., load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load). More simply stated, reducing load through conservation is a means of meeting load.

Cowlitz and APAC further dismiss the ability of section 6(a)(1) resources to "supply electric power," thereby disqualifying such resources from consideration as resources available in section 7(b)(2)(D) to meet general requirements. They argue that since "general requirements" refers to the "electric power purchased from the Administrator" under section 5(b), any resource to meet general requirements must be capable of generating electric power. Cowlitz Br. Ex., WP-07-R-CO-1, at 5. Cowlitz and APAC also argue that in the specific context of section 7(b)(2)(D)(i) and the overall statutory plan of section 7(b), only "electric power," not conservation, may be construed as the type of "resources" whose costs are allocated through section 7(b)(2)(D). Cowlitz Br., WP-07-B-CO-01, at 21; APAC Br., WP-07-B-AP-01, at 39-40. They argue that "electric power," defined as "electric peaking capacity, electric energy, or both" in section 3(9) of the Act, is the only type of resource that can "meet the remaining general requirements" of public customers, that is, supply power for them to purchase. Cowlitz Br., WP-07-B-CO-01, at 21; APAC Br., WP-07-B-AP-01, at 39-40. Consequently, Cowlitz argues the section 7(b)(2)(D) resources can only be section 6(a)(2) electric power resources defined in section 3(19)(A); they cannot be section 6(a)(1) conservation resources defined section 3(19)(B). *Id.* The IOUs argue a similar point. IOU Br., WP-07-B-JP6-01, at 51-52. This logic is not persuasive.

First, as fully explained above, conservation is a means of providing electric power for other customer use. "[E]lectric power purchased from the Administrator under section [5](b)" refers to the Administrator's contractual obligation to meet the customer's firm load over the contract period. 16 U.S.C. § 839e(b)(4). As demonstrated, and as stated earlier, whether phrased in terms of "meeting" or "to meet" "the electric needs of Northwest consumers," the Administrator's "section 5 contractual obligations," "the load of his customers" or "BPA customer loads," it is clear that the Congressional sponsors of the Northwest Power Act repeatedly and uniformly recognized the central role of conservation under the Act to meet or satisfy the contractual demands of preference customers under section 5 of the Northwest Power

Act to purchase electric power from the Administrator. "In acquiring necessary resources to meet the projected power demands of the region, the Administrator must pursue conservation and end user renewable resources before proceeding to other resources." H. Rep. No. 96-976, Pt. I, at 28.

Second, looking at the definition of "general requirements," 16 U.S.C. § 839e(b)(4), if "electric power purchased" were entirely in the past tense, there would be no need to acquire resources to meet general requirements since the power would have already been purchased and used by the customer. In that case, there would be no need for resources as explicitly provided for in the Fourth Assumption, 16 U.S.C. § 839e(b)(2)(D). Clearly, the reference to "electric power purchased" is one that refers to the customer's contractual commitment to purchase electric power from the Administrator under section 5 for the five years covered by the 5(b) contract. As seen, conservation is a means of the Administrator meeting his concomitant contractual commitment under section 5(b)(1) and (3) to "sell … electric power to meet the firm load" of public body and cooperative customers and to "sell electric power to Federal agencies in the region." 16 U.S.C. §§ 839c(b)(1), 839c(b)(3), 839c(g)(7), 839d.

This is also borne out by the definition of "cost-effective" in the Act, which applies to conservation and other resources:

> (A) "Cost-effective," when applied to any measure or resource referred to in this Act, means that such measure or resource must be forecast–
>
> (A)(i) to be reliable and available within the time it is needed, and
>
> (A)(ii) to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof.

16 U.S.C. § 839a(4)(a). The Senate Report explains:

> The term "cost effective" is defined to enable cost comparisons among and between alternative conservation measures and resources. A "cost-effective" conservation measure, or any resource, must be forecast to be available for and during the period when it is needed.

S. Rep. 96-972, at 21. Senator Hatfield asserted this test is "the most comprehensive ever mandated in legislation related to power plant decision making and is biased toward conservation." Cong. Rec. S. 14694 (Nov. 19, 1980). This test is forward looking ("forecast") and clearly ties the resources to meeting the Administrator's contractual obligations to supply electric power since the resource must be forecast "to meet or reduce the electric power demand[.]"

Third, the customers make too much out of the differences between section 6(a)(1) resources and section 6(a)(2) resources. Cowlitz Br. Ex., WP-07-R-CO-1, at 5, 13. Cowlitz plays a constant refrain that conservation is simply a load reduction, that it does not provide electric power, that it therefore cannot possibly meet customers' general requirements, that "power costs for general requirements" in section 7(b)(2) refers to the costs of electric power and, as such, conservation cannot be a power cost for purposes of the section 7(b)(2) cost comparison. *E.g.*, Cowlitz Br. Ex., WP-07-R-CO-1, at 5-6. The language of section 6 does differentiate between (1) acquiring conservation to meet the Administrator's obligation to provide electric power, and (2) acquiring a resource that generates electric power. While Cowlitz misquotes section 6(a)(1) as expressly stating that conservation reduces load (the reference is to renewable resources installed by residential or small commercial consumers "to reduce load," 16 U.S.C. § 839d(a)(1)), Cowlitz Br. Ex., WP-07-R-CO-1, at 13, BPA does not disagree that conservation does reduce load. However, that does not mean that BPA should ignore that reducing load through conservation is a means of meeting load; *i.e.*, meeting the Administrator's contractual obligation to "sell … electric power to meet the firm load" of public body and cooperative customers and to "sell electric power to Federal agencies in the region." 16 U.S.C. §§ 839c(b)(1), 839c(b)(3). Conservation is a resource that reduces the Administrator's obligations, which can be used in the 7(b)(2) Case when solving for "general requirements."

Indeed, while Cowlitz recites the language of section 6(a)(2), it appears oblivious to the fact that section 6(a)(2) provides for other resource acquisitions to meet the Administrator's "contractual obligations *that remain* after taking into account planned savings from measures provided for in" the first paragraph. 16 U.S.C. § 839d(a)(2). The clear and certain import of this is that conservation was used to meet the Administrator's "contractual obligations" in the first place. This is exactly what the House Interior and Insular Affairs Report on the Act states: "section 6 of S. 885 requires the Administrator to acquire on a long-term basis sufficient resources, including conservation, necessary to fulfill his contractual obligations to his customers." H. Rep. 96-976, Pt. II, at 34. Since Cowlitz openly states that it agrees that "[f]or preference customers, the 'contractual obligations' referred to in § 6(a)(2) are the same contractual obligations to sell electric power under § 5(b) that are referred to in the statutory definition of 'general requirements'" (Cowlitz Br. Ex., WP-07-R-CO-1, at 13), and since conservation is a means of meeting those general requirements (per Cowlitz, contractual obligations = general requirements), conservation is logically available to meet remaining general requirements in the Fourth Assumption of section 7(b)(2), 16 U.S.C. § 839e(b)(2)(D). Further, unlike in the Program Case where, under the Act, conservation is the resource of choice to meet load and other resources may be acquired to meet "contractual obligations that remain," that is not the case in the 7(b)(2) Case. In the 7(b)(2) Case, the language is clear that FBS resources first serve public body, cooperative, and Federal agency load, and only after that are other resources, including conservation, called into play in the Fourth Assumption to meet "remaining general requirements" (or, as accepted by Cowlitz, remaining contractual obligations). In the 7(b)(2) Case, load reductions can meet remaining general requirements, contrary to Cowlitz's arguments, Cowlitz Br. Ex., WP-07-R-CO-1, at 12-14.

Finally, at the risk of repetition, we should recall the discussion earlier regarding the interplay of section 5 and section 6. Section 5 establishes the Administrator's obligation to enter contracts to sell electric power to customers. It concludes by stating that the Administrator "shall be *deemed* *to have sufficient resources* for the purpose of entering into the initial contracts specified in paragraph (1) (A) through (D)" quoted just above. 16 U.S.C. § 839c(g)(7) (emphasis added). This clearly links "resources" and meeting the Administrator's contractual obligations to sell electric power, consistent with the Congressional statements quoted in the Introduction to this issue. In order to make good on that deemed resource sufficiency and actually assure that the Administrator had sufficient resources for the term of the initial contracts and beyond, authority was granted for the Administrator to acquire resources to meet his obligations to provide electric power. The very next sentence of the Act, the first sentence of section 6, starts out with "*The Administrator shall acquire such resources through conservation*, …" 16 U.S.C. § 839d(a)(1). The import of the last sentence of section 5 and this first sentence of section 6 could not be clearer: the first-priority resource to be acquired by the Administrator to meet his contractual obligations to sell electric power is conservation. Fundamentally, reducing use of power (*i.e.*, load) through conservation is a means of providing power for other customer use (*i.e.*, meeting load). Reducing load through conservation is a means of meeting load. No wonder then that section 6(a)(2) refers to "contractual obligations *that remain* after taking into account planned savings from measures provided for in" the first paragraph. 16 U.S.C. § 839d(a)(2). This is just as envisioned by the House Interior and Insular Affairs Committee Report:

> Section 6 of the legislation authorizes and requires the Administrator of BPA to acquire on a long-term basis sufficient resources, including conservation, to meet his section 5 contractual obligations to his customers. This resource acquisition authority, by providing the Administrator with the ability to expand the energy resource pool available to him, allows the Administrator to enter into the long-term power sale contracts with preference and investor-owned utilities, Federal agencies and existing direct-service industrial customers and obviates the need for him to administratively allocate the limited amount of Federal resources among existing and potential claimants to it. Thus, the Pacific Northwest will be able to avoid the power planning and supply uncertainties inherent in such an administrative allocation of over one-half of the region's electrical energy resources.

H. Rep. No. 96-976, Pt. II, at 34. From all this, it is reasonable to include costs of conservation resources in power costs, just like the costs of other non-conservation resources.

The parties' arguments, although representing one approach to interpreting the statute, miss the point because they approach general requirements as a given amount, not an amount that must be solved in the 7(b)(2) Case. Although it may be true that conservation cannot "meet general requirements" if one were to read "general requirements" as requiring a fixed amount of electric power that had to actually be consumed, that is not the case, as shown above. Conservation can be used to meet remaining general requirements, and it can be used to solve for "general requirements" in the 7(b)(2) Case; that is, the application of conservation to reduce load is a component of determining "general requirements." For this reason, BPA believes it is appropriate to include conservation resources in the 7(b)(2)(D) resource stack. In addition, Cowlitz's and the IOUs' arguments do not comport with the plain language of the Act. As described above in detail, 7(b)(2)(D) refers to "resources" purchased from the Administrator under section 6 of the Act. 16 U.S.C. § 839e(b)(2)(D)(i). If Congress had intended to limit the "types" of resources under section 6 to just 6(a)(2) resources, as argued by the parties, then BPA believes Congress would have expressly identified that section. Indeed, having such a pinpoint citation would have been absolutely necessary considering the prevalence of the term "conservation" in section 6. The first paragraph of section 6 states that the Administrator "shall acquire … conservation" to implement his obligations under the Act. 16 U.S.C. § 839d(a)(1). Section 6(a)(2) provides for other resource acquisitions to meet the Administrator's "contractual obligations *that remain* after taking into account planned savings from measures provided for in" the first paragraph. 16 U.S.C. § 839d(a)(2). As noted above, the clear and certain import of this is that conservation was used to meet the Administrator's "contractual obligations" in the first place. BPA does not believe it would make logical sense for Congress to cite *generally* to section 6 in 7(b)(2)(D) with the implicit intention of entirely *excluding* conservation resources. The more natural and reasonable reading is that Congress intended to include *all* resources identified in section 6 in the 7(b)(2) Case resource stack pursuant to section 7(b)(2)(D)(i).

Cowlitz argues it cannot simultaneously be true that the general and administrative and other expenses are costs of "resources" within the meaning of section 7(b)(2)(D), yet have "no measurable economic benefit beyond the year incurred." Cowlitz Br., WP-07-B-CO-01, at 22, *citing* Doubleday, *et al*., WP-07-E-BPA-85, at 115. Cowlitz argues that BPA's staff and general and administrative expenses are not "resources" owned or purchased by 7(b)(2) Customers. *Id*.

Cowlitz appears to confuse several issues. The definition of the resources included in the resource stack does not define resources by their costs; rather, the resources included in the resource stack define the costs to be considered. The magnitude of costs of these resources is a separate issue being decided in this ROD. However, the full statement was "[t]hese were *expenses* for which there was no measurable economic benefit beyond the year being incurred." Doubleday, *et al.*, WP-07-E-BPA-85, at 115 (emphasis added). This testimony was included to explain why the costs were expensed, and not to describe the resource for which they were incurred. For example, the FY 2009 conservation expenses are a cost of acquiring conservation in FY 2009. Those costs are isolated to that year's conservation program and are not borne by the FY 2010 conservation program. Expenses are a cost of a resource, whether conservation or a conventional resource. For example, if one is considering the cost of a coal plant, there are considerable (even enormous) labor costs to build the plant. Those labor expenses are legitimate costs of the coal resource. Likewise, BPA's staff and general and administrative expenses are legitimate costs of conservation resources. Just as a coal plant does not suddenly come into existence, conservation does not just happen. It is the result of human intervention, and that human intervention has a cost. That cost is legitimately included in the cost of the resource.

Cowlitz recognizes the legitimacy of the costs: "[t]here is nothing wrong with BPA incurring such costs and charging them to customers…" Cowlitz Br., WP-07-B-CO-01, at 22. However, Cowlitz states such costs must be allocated pursuant to section 7(g), not section 7(b)(2). *Id.* Cowlitz claims none of these costs are costs of "resources owned or purchased by public bodies or utilities" within the meaning of subsection 7(b)(2)(D), much less resources that supply electric power for purchase. *Id.* Cowlitz misunderstands BPA's treatment of conservation costs in the 7(b)(2) rate test in at least two respects. First, prior to performing the rate test, conservation costs have already been allocated to the preference customers' rates pursuant to section 7(g). When developing the Program Case rates, BPA uses its best projections of its rates without considering the provisions of section 7(b)(2). *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, 2008 Implementation Methodology, at IM-6. In the establishment of rates before the section 7(b)(2) rate test, BPA allocates all costs, including conservation costs, to the applicable rate pools in the Program Case rates pursuant to sections 7(b)(1), 7(c), 7(f), and 7(g) of the Northwest Power Act. Only after performing this establishment of rates does BPA then follow the subsequent rate directives in section 7(b)(2) to exclude from the Program Case rate the Applicable 7(g) Costs. *See* 16 U.S.C. § 839e(b)(2). These costs are then added back to the Program Case rate after the rate test is performed. Contrary to Cowlitz's claim, conservation costs, therefore, *are being allocated* to the preference customers through a section 7(g) allocation.

Second, BPA does not "allocate" *any* costs pursuant to section 7(b)(2) in the Program Case. Section 7(b)(2) provides for a rate test that *compares* BPA's proposed PF rates with rates developed in conformance with the Five Assumptions. The 7(b)(2) Case rate establishes only a rate "limit" that the Program Case rate cannot exceed, except for the Applicable 7(g) Costs excluded in the rate comparison. The Fourth Assumption, as described earlier, makes conservation one of the "resources" available in the resource stack to serve 7(b)(2) Case loads. If conservation is selected as a resource to serve such load, its costs are added to the 7(b)(2) Case rate in the same manner as any other resource cost from the stack. The resulting 7(b)(2) Case rate is then *compared* to the Program Case rate to determine whether the rate test has triggered. *See* 2008 Implementation Methodology, at IM-9-10. Cowlitz's statement that BPA is "allocating" conservation costs to the preference customers through section 7(b)(2) in the 7(b)(2) Case rate is, therefore, incorrect.

Cowlitz also maintains that the general and administrative costs of BPA's conservation programs are not "resources owned or purchased by public bodies or utilities" within the meaning of subsection 7(b)(2)(D), much less resources that supply electric power for purchase. Cowlitz Br., WP-07-B-CO-01, at 22. BPA believes Cowlitz's reading of section 7(b)(2)(D) is too narrow. First, BPA has already explained above that conservation is a resource and consequently is appropriately included in the section 7(b)(2)(D) resource stack to be purchased by BPA. That being the case, it logically follows that all costs of the conservation resources, whatever they may be, are properly included in the resource stack. Section 7(b)(2)(D) is not explicit on what types of costs must be considered when determining the "resources that would have been required" to meet 7(b)(2) Case loads. Absent specific statutory direction, BPA believes it reasonable to include all costs that would normally go into developing the resource. As stated above, BPA interprets section 7(b)(2)(D) to mean the preference customers would acquire the additional resources at the same cost of those resources acquired by the Administrator from such customers, except for some financing cost differences. In the case of conservation, general and administrative expenses, such as labor, are legitimate costs. *See* Doubleday, *et al.*, WP-07-E-BPA-85, at 72-73. Indeed, general and administrative costs are legitimate costs of *any* resource, not just conservation. It is therefore appropriate to include general and administrative expenses as a cost of conservation in the section 7(b)(2)(D) resource stack.

Cowlitz argues that Staff ultimately attempts to justify its interpretation of section 7(b)(2)(D)(i) on the grounds that "preference customers have not raised this issue before this time." Cowlitz Br., WP-07-B-CO-01, at 23. Cowlitz then argues that this silence was due, in part, to BPA's prior RAM model which Cowlitz claims was substantially opaque. *Id.* In addition, Cowlitz notes that BPA has been criticized in both the WP-02 case and the earlier phase of the WP-07 case because BPA's section 7(b)(2) rate test modeling was producing counterintuitive results, which the preference customers specifically identified as directly related to BPA's handling of conservation. *Id. citing* Schoenbeck and Bliven, WP-02-E-DS/AL/VN-06, at 18; Saleba, *et al.,* WP-07-E-JP1-01, at 13-14. Cowlitz further points to PPC's Brief on Exceptions of the Preference Customer Group on Section 7(b)(2), WP-07-M-79, where preference customers argued it was error for BPA "to create hypothetical loads as if savings from programmatic conservation had not been achieved" at a time when BPA was still arguing that the Mid-Columbia resources must be available to meet general requirements in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 23, *quoting* WP-07-M-79, at 12-15.

To be clear, Staff did not "ultimately attempt to justify" its implementation of section 7(b)(2)(D)(i) by relying on the fact that the preference customers have not raised this issue before. Rather, Staff made the simple statement that its treatment of conservation in the present case was based on the proposed Implementation Methodology, which, in this instance, is the same as the 1984 Section 7(b)(2) Implementation Methodology. Doubleday, *et al.*, WP-07-E-BPA-85, at 39. Staff also noted that this implementation has been used by BPA in every rate proceeding since 1985. *Id.* Staff deferred to the Draft and Final Records of Decision to elaborate on BPA's legal justification for the treatment of conservation in the 7(b)(2) rate test. *Id.* at 40.

BPA acknowledges that since it adopted the 1984 Section 7(b)(2) Implementation Methodology, there has not been a serious debate in a BPA rate proceeding regarding the adjustment to the 7(b)(2) Case loads for conservation. Cowlitz is therefore correct that it would be inappropriate for BPA to continue its longstanding practice of adjusting the loads in the 7(b)(2) Case simply because of "tradition." However, as explained above, BPA's decision to adjust the loads in the 7(b)(2) Case is not simply based on past practice but because this treatment is consistent with both the language and intent of the Northwest Power Act. This is not to say that BPA's 20-plus years of practice is immaterial to the current debate. Though not dispositive, courts will take into account the consistency of the agency's position over time when considering whether an agency interpretation of law is permissible. *See Natural Resources Defense Council v. U.S. E.P.A.*, 526 F.3d 591, 602 (9th Cir. 2008); *see also Good Samaritan Hosp. v. Shalala*, 508 U.S. 402, 417 (1993). One influencing factor in BPA's decision is the fact that since 1985, BPA has consistently implemented section 7(b)(2) in the manner Staff has proposed. Doubleday, *et al.*, WP-07-E-BPA-85, at 39. Over this 20-plus year period, BPA has conducted no fewer than eight major rate cases, none of which resulted in BPA varying or modifying its position on conservation. Furthermore, BPA is unaware of any substantive challenges, prior to the WP-07 case, where parties raised significant legal issues with the availability of conservation in the resource stack. Also, as stated above, when this treatment was raised in the original Section 7(b)(2) Implementation Methodology 7(i) proceeding in 1984, there is no mention of any issue to which BPA's rebuttal testimony needed to respond. This lack of controversy over BPA's interpretation of the Act for over two decades stands in stark contrast to Cowlitz's present-day claim that a simple "plain language" reading of section 7(b)(2) requires a contrary result.

The nature of that interpretation as contemporaneous to passage of the Act should also dispel Cowlitz's claims that BPA is seeking to manipulate the test to inflate REP benefits. Cowlitz Br. Ex., WP-07-R-CO-1, at 6. This is not some newly minted approach by BPA, but one that extends back over 25 years to a time certainly more contemporaneous with passage of the Act than now.

With regard to Cowlitz's argument that prior RAM models were "substantially opaque," Cowlitz Br., WP-07-B-CO-01, at 23, BPA does not find this argument persuasive because parties to rate proceedings have several opportunities through clarification, discovery, and cross-examination to request additional information from BPA. The fact that Cowlitz did not take adequate advantage of these tools in prior rate proceedings to better understand the rate case does not diminish the value of BPA's 20-plus-year practice of including conservation as a resource in the section 7(b)(2) rate test. Also, Mr. Schoenbeck's firm, the firm that now consults in this case for APAC, was able to manipulate the RAM2002 model in the 2002 rate case to run scenario analyses. Cowlitz next attempts to argue that "criticisms" were made in the WP-02 case and the WP-07 case regarding BPA's treatment of conservation. *Id.* Cowlitz cites to testimony filed by the DSIs in the WP-02 case as support. *Id.* This reference, however, is inapposite. The cited testimony criticizes BPA for certain alleged modeling errors, but does not otherwise object to BPA's decision to include conservation as a resource in the 7(b)(2)(D) resource stack or to adjust the 7(b)(2) Customer loads for conservation. Schoenbeck and Bliven, WP-07-E-DS/AL/VN-06, at 17-19.

Cowlitz labels the amount of the difference in loads between the two Cases as "phantom load." But the use of a deprecatory term does not change the instruction of the statute. BPA properly reflects a difference between the Cases of 500 to 700 aMW because that is the amount of conservation the Administrator has acquired pursuant to section 6. Doubleday, *et al.,* WP-07-E-BPA-85, Attachment 6-7, at 92. Therefore, these conservation resources are added to the 7(b)(2)(D) stack to be available to apply to load *after* the use of the available FBS resources.

Cowlitz refers to the costs of the conservation selected from the 7(b)(2)(D) stack as exaggerating the rate effects. However, it appears Cowlitz believes conservation should be free in the 7(b)(2) Case. Cowlitz argues that acquired conservation be used to reduce load, but that the costs of that conservation not be added to the revenue requirement of the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-2, at 9; Tr. at 655, *citing* to Mr. Kari at 639. The PPC reaches a similar conclusion, arguing that "BPA should afford conservation appropriate treatment by excluding its costs from the rate test and leaving the general requirements of preference customers as defined by the Act." PPC Br., WP-07-B-JP25-01, at 29. The IOUs, on the other hand, argue that all of the costs BPA incurred to acquire conservation must be included in the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 51.

BPA notes that both the preference customers and the IOUs avidly present arguments supporting their respective positions. BPA understands the parties made their arguments based on specific words and phrases used in section 7(b)(2). However, BPA believes that the best interpretation is one that gives effect to all provisions of the Act. *Garcia v. Brockway*, 526 F.3d 456, 463 (9th Cir. 2008), *quoting Boise Cascade Co. v. EPA*, 942 F.2d 1427, 1432 (9th Cir. 1991). BPA's decision to adopt an interpretation must be guided by its statutory duty to avoid conflicts and reach the intent of the statute as envisioned by Congress. In light of this direction, BPA finds that the interpretations proffered by the preference customers and IOUs are wanting in several respects.

First, BPA is puzzled by the treatment of conservation advocated by Cowlitz and PPC. These parties ask BPA to assume conservation occurred in the 7(b)(2) Case, but at *no cost.* In other words, BPA would assume that the loads in the 7(b)(2) Case would be reduced by the effects of conservation that had been purchased by BPA (in apparent contravention of 7(b)(2)(B)), remove conservation as a resource from 7(b)(2)(D) (in apparent contravention of 7(b)(2)(D)), and at the same time assume that these reductions in load came at *no cost* to preference customers. PPC does not articulate what legal or policy objective is met by treating conservation in this odd way in the section 7(b)(2) rate test. BPA is equally unable to explain what legal or policy objective is achieved by assuming conservation exists in the 7(b)(2) Case at no cost. It further seems improbable that Congress would ever have thought that in a "no-legislation" world, preference customers would have obtained conservation savings for free. For these reasons, BPA cannot agree with Cowlitz and PPC to assume no conservation costs in the 7(b)(2) Case.

The opening language to section 7(b)(2) states:

> After July 1, 1985, *the projected amounts to be charged for firm power for the combined general requirements* of public body, cooperative and Federal agency customers, *exclusive of amounts charged* such customers *under subsection* [*7*]*(g)* of this section *for the costs of conservation*, resource and conservation credits, experimental resources and uncontrollable events, *may not exceed in total*, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, *an amount equal to the power costs for general requirements* of such customers *if, the Administrator assumes that …*

16 U.S.C. § 839e(b)(2), (emphasis added). Congress did not at the end of this language refer to "an amount equal to the power costs for general requirements of such customers, *exclusive of amounts charged* such customers under subsection [7](g) of this section for the costs of conservation …, if, the Administrator assumes that, …" As discussed earlier, the Four Assumptions call for the Administrator to solve for power costs. Absent a direction like that in the first part of the language quoted above, it is not reasonable to read that direction into the latter part of the language. When Cowlitz argues that the language is "unmistakably clear that conservation costs are to be excluded entirely from the § 7(b)(2) rate test," Cowlitz Br. Ex., WP-07-R-CO-1, at 4, it draws a conclusion that unreasonably reads language into the latter part of the language that is simply not there.

Cowlitz does attempt to support its reading by stating that, under Cowlitz's reading of the language, "Congress assured that BPA's conservation costs would be recovered in full under all circumstances" and that it is "consistent with the extraordinarily-favored position and highest priority of conservation under the NWPA." Cowlitz Br. Ex., WP-07-R-CO-1, at 4-5. If this imagined reason for the exclusion of conservation costs were correct, precisely the opposite position from Cowlitz should be taken. By excluding conservation costs from the Program Case (lowering Program Case costs) while including conservation costs in the 7(b)(2) Case when, under the Fourth Assumption, conservation is the least expensive resource (increasing 7(b)(2) Case costs), conservation costs are, under Cowlitz's logic, more assured of recovery. However, Cowlitz's logic is faulty in any case. The rate test does not in any way preclude conservation cost recovery. It simply compares the Program Case and 7(b)(2) Case costs and, when the Program Case costs are higher than the 7(b)(2) Case costs, allocates the difference to other rates for recovery. In addition, the paramount rate directive in section 7(a)(1) is to establish rates to recover BPA's total costs of the "acquisition, conservation, and transmission of electric power," 16 U.S.C. § 839e(a)(1). The rate directives for particular customer classes are "[s]ubject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs." H.R. Rep. No. 976, Part II, at 36; *see also* S. Rep. No. 96-272, 96th Cong., 1st Sess. 32 (1979).

BPA similarly does not find the IOUs' position reasonable, which goes to the other extreme. The IOUs contend that BPA must assume that *all* conservation costs are included in the 7(b)(2) Case regardless of whether conservation resources are selected from the resource stack. The OPUC appears to argue for this treatment also. *Cf*. OPUC Br., WP-07-B-PU-02, at 21-23 with 29-30. This approach to conservation resources would violate a clear Congressional directive to bring resources into the 7(b)(2) Case on a "least expensive" basis. *See* 16 U.S.C. § 839e(b)(2)(D). Allowing all conservation costs into the 7(b)(2) Case irrespective of whether those resources were the least expensive undermines the resource stack concept. BPA must follow the directives of the 7(b)(2) rate test in a manner consistent with Congressional intent. BPA believes it would be contrary to both the language and Congress's intent in including the words "least expensive" in section 7(b)(2)(D) to assume all conservation costs would be automatically in the 7(b)(2) Case. BPA, therefore, cannot accept the IOUs' position that all conservation costs must be included in the 7(b)(2) Case.

As indicated earlier in connection with Cowlitz's argument that conservation should not be presumed left out in section 7(b)(2)(B), BPA does not believe that when X denotes the absence of Z, it is necessary for Congress to state "X, but not Z." On the other hand, when X *does* denote the presence of Z, it is necessary or appropriate for Congress to state "X, but not Z" when it intends to include Z. That is precisely what it did in the opening language of section 7(b)(2):

> After July 1, 1985, *the projected amounts to be charged for firm power for the combined general requirements* of public body, cooperative and Federal agency customers, *exclusive of amounts charged* such customers *under subsection* [7]*(g)* of this section *for the costs of conservation*, resource and conservation credits, experimental resources and uncontrollable events, *may not exceed in total*, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, *an amount equal to the power costs for general requirements* of such customers *if, the Administrator assumes that …*

16 U.S.C. § 839e(b)(2) (emphasis added). The phrase "exclusive of" indicates that Congress was aware that the amounts to be charged for firm power would, or could, include conservation costs. Based on this and the other reasons discussed above, it is reasonable to include conservation costs in "the power costs for general requirements of such customers" when, but only when,

conservation resources are purchased from public body, cooperative, and Federal agency customers pursuant to the requirements of the Fourth Assumption, 16 U.S.C. § 839e(b)(2)(D).

Cowlitz argues that adding significant load to the 7(b)(2) Case in ways not specified in the Northwest Power Act manifestly alters the rate protection provided by section 7(b)(2) because it draws into the 7(b)(2) Case additional costs of serving alleged non-existent loads. Cowlitz Br., WP-07-B-CO-01, at 17-18. Cowlitz contends that using conservation as the resource to meet "phantom loads" further exaggerates the rate effects because significant costs (roughly $271 million a year (*citing* Doubleday, *et al*., WP-07-E-BPA-85, at 51)) are added, while significant loads are subtracted. *Id.* Cowlitz claims that BPA admits that the "inevitable effect" of this process is to increase the 7(b)(2) Case rate. *Id., citing* Tr. 395-96.

Having already described above how BPA's over 20-year treatment of conservation in the section 7(b)(2) rate test conforms to the instructions of Congress in the Northwest Power Act, BPA cannot now agree with Cowlitz's characterization of such treatment as altering the rate protection provided in section 7(b)(2). Simply labeling the effects as "phantom loads" does not change the instruction of Congress. Furthermore, whether the costs are significant is a matter of whether the least-cost resources are being selected from the 7(b)(2)(D) resource stack. This last issue is dealt with elsewhere in this ROD. Finally, admitting to an "inevitable effect" does not mean that was the causal factor in its implementation, nor does it mean it is wrong.

Cowlitz cites language in Appendix B out of context to state "[t]he Appendix B narrative specifically confirms that the 'cost of conservation' is a 'general cost' allocated under 7(g) as 'an overall rate adjustment applied to all firm power sales under any rate.'" Cowlitz Br. Ex., WP-07-R-CO-1, at 17-18, *citing* S. Rep. No. 96-272, at 60. However, Appendix B covers all of the rate directives, and this statement concerns not the rate test, but is a general statement concerning section 7(g) of the proposed legislation. S. Rep. No. 96-272, at 60. This statement does not deal with how the rate test is to be performed. In any case, by excluding conservation costs from the Program Case (lowering Program Case costs) while including conservation costs in the 7(b)(2) Case when, under the Fourth Assumption, conservation is the least expensive resource (increasing 7(b)(2) Case costs), the conservation costs that BPA has incurred in real life under the Act are recovered through the PF and, if the Rate Test triggers, PF Exchange rates.

Cowlitz also states that Appendix B includes load forecasts from two sources, the Pacific Northwest Conference Committee (PNUCC) and the Northwest Energy Policy Project (NEPP), with the later denominated a "conservation load forecast," but the scenarios in Appendix B show no difference between Program Case loads and 7(b)(2) Case loads. Cowlitz Br. Ex., WP-07-R-CO-1, at 17-18. According to Cowlitz, "In other words, even though future conservation was assumed to exist in at least the scenarios based on the NEPP forecast (half of the scenarios analyzed), no adjustment was made in any scenario to back out the effects of conservation in the 7(b)(2) Case." *Id.* at 18. Cowlitz erroneously extrapolates the description of the NEPP forecast as a "conservation load forecast" to mean that it is one that reflects application of conservation resources. However, nothing in Appendix B indicates that is the case. The only thing that is indicated is that the PNUCC load forecast is "taken from the 1978 Bluebook," which predated passage of the Act, and that the NEPP load forecast is based on different load growth assumptions:

> By a cursory evaluation of some typical utility systems, the domestic and rural or residential component of load was found to approximate 40 percent of the utility class total load. Therefore, we assumed that 40 percent of the public agency PNUCC 1979-80 load was domestic and rural, and the remaining 60 percent was commercial and industrial. NEPP forecasts were derived by applying a 3.90 percent growth rate per year to the domestic and rural base load for 1979-80 of 2742 megawatts and a 2.53 percent growth rate per year to the commercial and industrial base load of 4112 megawatts.

S. Rep. 96-272, at 64. There is nothing in this statement to indicate anything about acquisition of conservation resources. Inasmuch as the base case assumed a 90 percent rate increase, *see* S. Rep. 96-272, at 69, it may well be that the NEPP was forecasting a lower percent growth rate in response to the higher costs. It may be as well that the NEPP was assuming a form of rate to induce conservation. As indicated elsewhere in the Appendix regarding various rate forms, "The rate forms (energy, capacity, time differential, *conservation*, etc.) and levels for each of these rate forms will be determined by the Administrator as presently done through public participation programs in the region and then filed for confirmation and approval with the Federal Energy Regulatory Commission." *Id.* at 57. Similarly, the fact that the scenarios in Appendix show no differences in loads between the Program and 7(b)(2) Cases does not mean conservation resources were considered in the analysis. There is no indication of that, which may well be due to the untried and then uncertain aspect of the "theory of conservation," 126 Cong. Rec. H9859 (1980) (statement of Rep. Dicks).

The decision here is a difficult choice for BPA. BPA was presented with a number of forceful arguments and with options on how to resolve the treatment of conservation in the section 7(b)(2) rate test. Most importantly, BPA wants to act in a manner consistent with law. After an extremely thorough review of the statute, the legislative history, Staff's proposal, and parties' positions, BPA believes that its longstanding position remains the most reasonable interpretation of the Northwest Power Act and the most reasonable implementation of the section 7(b)(2) rate test.

Decision

Conservation is properly a resource within the scope of section 7(b)(2)(D), should be included in the 7(b)(2)(D) resource stack, and should modify the amount of preference customer loads in the solution of general requirements in the 7(b)(2) Case.

16.4 Conservation's Accounting and Financing Treatments in the 7(b)(2) Case

Issue 1

Whether BPA applied the correct accounting and financing treatment for conservation costs contained in the 7(b)(2) Case resource stack.

Parties' Positions

PPC argues that Staff errs in its treatment of financing conservation resources available to serve preference customer load in the 7(b)(2) Case. PPC Br., WP-07-B-JP25-01, at 24. PPC notes the Supplemental Proposal used historical BPA financing assumptions to finance conservation programs in any given year. *Id.*, *citing* Keep, *et al.*, WP-07-E-BPA-68, at 14-15. PPC contends the manner in which conservation is acquired in the 7(b)(2) Case is fundamentally different than the Program Case. *Id.* PPC states it is important to consider that conservation is treated by BPA exactly the same as any other resource available to meet load. PPC Br., WP-07-B-JP25-01, at 25. BPA must determine how the JOA in the 7(b)(2) Case would finance a very large resource (over 500 aMW) brought on to meet load. *Id.* Standard industry practice for financing such a resource is to capitalize the cost of such a resource and amortize those costs over the useful life of the resource. *Id.*

Cowlitz argues it is inappropriate to select conservation resources from the resource stack using a cost comparison based on the levelized cost measured over the useful life and then assign large amounts of first-year conservation program expensed costs for multiple years' worth of conservation investments. Cowlitz Br., WP-07-B-CO-01, at 34-37. Cowlitz argues the Joint Operating Agency that such customers would use would not expense such a high proportion of conservation expenditures. *Id.* Cowlitz argues that Staff would replace the section 7(b)(2) directives with a standardless morass of asserted discretion to provide any particular level of REP benefits funded by preference customers that BPA may desire. *Id.*

APAC argues that BPA's treatment of conservation in the proposed Implementation Methodology continues an improper penalty on conservation that defeats a prime purpose of the Northwest Power Act and results in an improper subsidy to IOUs. APAC Br., WP-07-B-AP-01, at 40.

The OPUC argues that the new proposed approach of deferring the historical expensed portions of BPA's conservation programs and financing these costs over five years that was advanced by BPA's rebuttal testimony should be rejected. OPUC Br., WP-07-B-PU-02, at 30. The OPUC argues that proposals that avoid the front-loading of costs differ from current utility practice. *Id.*

BPA Staff's Position

In the Supplemental Proposal, BPA Staff modeled conservation costs in the 7(b)(2) Case using the same method BPA has used in all prior rate cases. This method follows the classification of expensed and capitalized costs used in the Program Case. Expensed costs are expensed in the first year, the year incurred. Capitalized costs are amortized and financed over a 15-year period for assets acquired after FY 2001, and over a 20-year period for assets acquired prior to FY 2002. This was the first rate case where such a large number of programmatic conservation investments were selected in the first year of the rate test period with the cumulative amount of first-year expensed costs being included in the 7(b)(2) Case revenue requirement. As a result, Staff indicated that some financing assumption other than BPA's actual historical practice may be reasonable in the 7(b)(2) Case. Keep, *et al.,* WP-07-E-BPA-68, at 15.

In rebuttal testimony, Staff proposed a modified conservation accounting and financing treatment when compared to the traditional 7(b)(2) Case cost treatment. Doubleday, *et al.,* WP-07-E-BPA-85, at 103-116. This alternative continued to follow the classification of expensed and capitalized costs used in the Program Case. However, instead of expensing all first-year expensed costs in the first year, these costs were deferred and amortized over a five-year period. This alternative was proposed to address the large cumulative amount of first-year expensed conservation costs associated with a large (approximately 500 MW) conservation program and the resulting first-year rate shock of the traditional cost treatment approach that was present in the Initial Proposal.

Evaluation of Positions

In order to understand the proposed treatment of conservation costs in the 7(b)(2) Case, one must understand the nature of conservation program resource costs, how utilities account for and finance conservation expenditures, and how utilities recover these costs in rates.

A. The Nature of Conservation

Conservation is any reduction in electric power consumption as a result of increases in the efficiency of energy use, production, or distribution. 16 U.S.C. § 839a(3). Large utilities' conservation programs involve substantial expenditures of staff time to develop individual programs that target different sectors of the economy to reduce the amount of energy required to accomplish a given objective or task. Programs are specially designed to achieve energy savings in the residential, commercial, agricultural, industrial, and multi-sector areas of the economy. In addition, specific programs have been developed to address energy efficiency opportunities through improved building codes and market transformation efforts. Market transformation programs cause new technologies to be built and then become accepted as standard practice. Examples include efforts to promote the manufacture and marketing of more energy-efficient appliances, such as electric lighting through compact fluorescent lights. Individual sector programs can use a number of approaches to acquire energy savings. Direct acquisition programs pay for energy efficiency measures through direct actions, as opposed to programs that cause conservation to occur through indirect means. An example of a direct acquisition is the installation of a more energy efficient motor in an industrial application. Direct acquisitions are capitalized when the energy savings are quantifiable as occurring over a defined period of years and the conservation measures have been documented and inspected upon installation. Indirect conservation programs use education, advertising, and related efforts to encourage consumers, businesses, and other entities to adopt energy-efficient practices or devices. Most conservation programs require or involve the evaluation and verification of conservation savings to help ensure the cost effectiveness of conservation measures and programs.

B. Accounting for Conservation Programs

A basic tenet of accounting theory is that the expenses of the operating year are matched against the revenues generated in that year. The methods/criteria that are used to determine revenues and expenses for the period are consistently applied over time so there is comparability of financial results from one period to the next. Expenditures that are not operating expenses of the year are either capitalized expenditures or deferred assets that are amortized over the period of time they provide benefits. Capital expenditures are those that provide value beyond one year. The cost of the asset is depreciated (expensed) over its estimated useful life using various methods of depreciation (*e.g.*, accelerated (DDB, SYD), straight-line). Depreciation is the process of allocating an asset's cost to the periods of time over which the asset provides economic value. Capitalized assets that are not "fixed assets" (buildings and equipment) are intangible assets. The most common examples include good will, patents, copyrights, and trademarks. Amortization is the term that refers to the allocation of the cost of intangible assets to current period operations. Conservation expenditures that are capitalized are intangible assets amortized over their estimated periods of benefit.

1. Rate Regulation Created Assets

The utility industry is unique in having an additional class of assets that are termed "Rate Regulation Created Assets." The Statement on Financial Accounting Standards No. 71 (Accounting for the Effects of Certain Types of Regulation) (SFAS No. 71) came into being during a tumultuous period in the utility industry. During this period, interest rates on the money used to invest in utility assets were very high, cost overruns on power projects were the norm (not the exception), and as a result, utility rates were higher than recent historical averages. Regulators faced tremendous pressure to ease the "rate shocks" that were being experienced. Regulatory tools developed in this period created "phase-in plans" for "rolling-in" the costs of new utility plants. Many nuclear plants were terminated and written down to the amount that regulators were going to allow in rate base to be recovered over future periods. The basic tenets of SFAS No. 71 allowed for the capitalization or deferral of costs that would have been expensed under generally accepted accounting principles (GAAP) if it were a nonregulated entity, and the postponement of the recovery of these costs from current rates. Before these costs can be capitalized and deferred, it must be probable that the regulator will allow their recovery in the future, and that the clear intent is to recover these costs through rates rather than to provide for recovery of similar future costs. In general, SFAS No. 71 is used to account for the effects of independent regulator decisions concerning the allocation of costs or the disallowance of costs from current periods to future periods.

2. Accounting's Conservatism Principle

A basic tenet of accounting is the "conservatism principle," which prescribes that assets should be conservatively valued, that all contingent liabilities should be fully disclosed, that revenues are only recorded when all the elements of revenue recognition have taken place, and all expenses attributable to the period are recognized in the period. SFAS 71 has not been used by most utilities to capitalize and defer conservation costs. Most utilities follow a conservative treatment of expensing conservation expenditures as incurred. *See* OPUC Br., WP-07-B-PU-02, at 30.

3. Quality of Financial Statement Assets

There is a difference between the quality of assets that can be bought and sold due to their ability to generate future earnings and those assets that cannot be sold because they have no value other than the value prescribed by the regulatory treatment of allowing their costs (or a portion of their costs) to be recovered in the rates of future periods. Stated differently, it is unlikely that an investor purchasing utility assets would be willing to pay the book value for past deferred conservation investments. Most utilities try to "work off" their nonperforming regulated assets as soon as possible due to the time value of money (a dollar today is worth more than a dollar tomorrow), the risk that a firm's operating costs could rise above prevailing market rates, jeopardizing cost recovery, and increased deregulation of utility markets could result in stranded costs. Most assets have the common distinction that there is a "property right" that can be bought and sold. Conservation investments (resource acquisitions) are unique in that there is no property right that can be bought and sold. Economically these investments are closer to being recognized as "public goods" that benefit society by causing energy to be used more efficiently.

4. Intergenerational Rate Equity Considerations

In the utility industry there is another cost allocation concept that comes into play concerning intergenerational equity. This term concerns ratepayer equity over when utility investments are made and how the resulting costs and benefits are allocated over the generations of ratepayers that receive the benefits of those investments. Due to intergenerational equity concerns and also due to the long lives of most utility assets, the periods of time over which assets are depreciated or amortized are very long when compared to periods used in other industries, where technological change has dictated shorter cost recovery periods. Although this is generally true for large generation investments with high capitalized costs (nuclear and coal plants where the frequency of investments might be decades depending on the size of the utility), it is less of a factor with utility conservation programs that make regular annual investments in conservation. Because most regional utilities plan to invest in conservation continuously, conservation costs will be borne by all generations of the region's customers for the foreseeable future. Conservation expenditures can be viewed as being similar to annual advertising expenditures in that they preserve the competitive position of the region's electric utility infrastructure by decreasing the need to invest in more expensive generation resources, just as advertising promotes and maintains the demand for a company's products. Intergenerational rate equity considerations, when viewed from this perspective, should not have a large influence over the choice of conservation amortization and financing policies.

5. Conservation Accounting Treatments by Utilities in the Region

Staff reviewed conservation accounting treatments of utilities in the region in 2007, when BPA adopted its current policy of amortizing capitalized conservation investments over five years. Staff observed that, through the years, BPA has used a wide range of accounting treatments for its own conservation program. Staff's review of these policies indicated that IOUs predominantly expense conservation expenses as incurred. *See* OPUC Br., WP-07-B-PU-02, at 30. Regional COUs' accounting treatment for conservation varies from utility to utility. Some COUs, like Grant County PUD, Eugene Water and Electric Board (EWEB), and Seattle City Light, capitalize a large portion of their conservation expenditures and amortize them over periods that range from 5 to 20 years. Grant County PUD currently expenses all overhead and administrative costs of its conservation programs and capitalizes and amortizes conservation acquisition expenditures over a range of 10-15 years. Seattle City Light also expenses all overhead and administrative costs associated with conservation programs and amortizes conservation acquisition expenditures over a composite useful life of 20 years. EWEB currently expenses all overhead and administrative costs of running conservation programs and amortizes conservation acquisition expenditures over a period of five years. Other COUs in the region, such as Chelan County PUD and Tacoma City Light, expense all conservation costs as incurred.

C. Statutory Guidelines for BPA's Treatment of Conservation Costs

Conservation activities operated or supported by BPA are sanctioned in large part by the Northwest Power Act. The following describes some of the guidance found under the Northwest Power Act:

(1) The Power and Conservation Planning Council is charged with preparing a plan for meeting the electrical needs of the region that must give highest priority to cost-effective conservation, treating it as a resource preferable to all other means of responding to demand for electricity. 16 U.S.C. §§ 839b(d); 839b(e)(1).

(2) "Cost-effective" means the measure or resource is forecast to be reliable and available within the time needed and would meet or reduce power demand at an estimated incremental system cost no greater than that of the least cost similarly reliable and available alternative resource or measure. 16 U.S.C. § 839a(4)(A). "System cost" means an estimate of all direct costs of a measure over its effective life. 16 U.S.C. § 839a(4)(B).

(3) "Resource" means, in part, actual or planned load reduction resulting from a conservation measure. 16 U.S.C. § 839a(19).

(4) In order to effectuate the priority given to conservation measures and renewable resources under the Northwest Power Act, the Administrator must, to the maximum extent practicable, make use of his authorities under the Act to acquire conservation measures and renewable resources, to implement conservation measures, and to provide credits and technical and financial assistance for the development and implementation of such resources and measures (including the funding of, and the securing of debt for, expenses incurred during the investigation and preconstruction of resources …). 16 U.S.C. § 839d(e)(1).

(5) The Federal Columbia River Transmission System Act was amended to increase borrowing authority by $1.25 billion for the purpose of providing funds for conservation and renewable resource loans and grants pursuant to the Administrator's authorities under the Act. 16 U.S.C. § 838k.

(6) The Administrator equitably allocates to power rates, in accordance with generally accepted ratemaking principles and the provisions of the Northwest

Power Act, all costs and benefits not otherwise allocated under section 7 of the Act, including conservation. 16 U.S.C. § 839e(g).

D. The Impact of the Northwest Power Act on BPA's Conservation Accounting and Financial Policies

The Act states nothing directly and implies very little concerning the nature of BPA's accounting and financing policies for conservation expenditures, although it does require that the Administrator implement the Act in a sound and businesslike manner. 16 U.S.C. § 839f(b). Although the Act regards conservation as the resource of first priority, resources can be constructed (capital-oriented), the output can be purchased annually (expense), or the output can be contracted for over a period of time (also an expense). The Act clearly anticipates capitalized conservation expenditures through the establishment of borrowing authority for conservation measures. In determining that measures are cost-effective, the Act requires that direct costs be viewed over the effective life of the measure, which is part of the nature of distinguishing capital costs from annual conservation expenditures that are expensed. The equitable allocation to power rates may argue for following the effective life for expenditures that are capitalized and treating costs that are normally expenses of the period as being expensed as incurred.

E. BPA's Conservation Accounting Treatment in the Program Case

BPA treats conservation expenses fundamentally differently than most utilities because the Northwest Power Act gave BPA the authority to borrow from the U.S. Treasury to finance conservation investments. Borrowing for conservation investments requires that conservation investments be capitalized. Cost-effective conservation measures provide value to BPA and its ratepayers in that they postpone the need to invest in more expensive generating assets and thus keep BPA's rates lower than they would have been had the investments not been made, assuming conservation is the least-cost resource. Conservation resource acquisitions meet BPA's obligation to invest in cost-effective conservation measures that are outlined in the Council's Power and Conservation Plan. BPA's capitalized conservation investments during the years 1982-2001 followed a consistent accounting treatment of amortizing these expenditures over their composite service lives of 20 years. This estimate was based on engineering estimates of the service lives of the individual conservation measures, and then a "weighting" of the measures was calculated based on the estimated mix of conservation investments that were being acquired. Later, the Council provided an estimate of 15 years for the composite service lives of the measures contained in the Fifth NW Power and Conservation Plan (conservation acquired after 2001). In 2002, BPA entered a period of using conservation to augment its required resources in addition to the past practice of acquiring conservation to mitigate the need to acquire more expensive resources. BPA adopted a second conservation amortization policy that addressed ConAug activities. The ConAug policy linked the term of amortization to the remaining number of years in the power contracts (2002-2011). Conservation augmentation investments made in the first year of the contract would be amortized over 10 years, while identical investments made in the last year of the contract would be expensed. BPA adopted a third conservation amortization policy in FY 2007 that amortizes capitalized conservation costs for FY 2007 and future years over a five-year period. A significant factor in making this change in amortization and financing periods was based on the need to increase BPA's available U.S. Treasury borrowing capability. Because the total amount of BPA's borrowing authority is capped, the adoption of a shorter bond maturity period maturity period "replenishes" the available borrowing sooner than longer maturity and amortization periods. In the 7(b)(2) Case, access to borrowing is not a limitation, and such concerns would not drive borrowing and amortization decisions.

Historical and projected conservation expenditures for Energy Efficiency staff salaries, indirect and overhead costs, general and administrative costs, market transformation funding costs, expense agreement and grant costs, and C&RD power bill credit costs have been treated as operating expenses of the period by BPA. BPA has consistently capitalized and amortized the costs of direct conservation acquisition expenditures.

BPA maintains the consolidated accounts of the Federal Columbia River Power System (FCRPS) in accordance with generally accepted accounting principles (GAAP) and the uniform system of accounts prescribed for electric utilities by the Federal Energy Regulatory Commission. In connection with the ratemaking process, certain costs may be included in rates for recovery over a future period. Under those circumstances, regulatory assets or liabilities are recorded; such costs or credits are amortized over the periods they are included in rates in accordance with GAAP, specifically Statement of Financial Accounting Standards 71, Accounting for the Effects of Certain Types of Regulation. BPA rates staff relied on their professional knowledge of GAAP in preparing this testimony on accounting and financing treatment in both the Program Case and the 7(b)(2) Case. BPA takes official notice of such of such documents. BPA also takes notice of Accounting for Public Utilities, Hahne and Aliff, Matthew Bender & Company, Inc. (2007).

PPC and Cowlitz argue that Staff's proposed treatment of conservation resource financing in the 7(b)(2) Case is incorrect. PPC Br., WP-07-B-JP25-01, at 24-26; Cowlitz Br., WP-07-B-CO-01, at 34-37. They note that Staff's Supplemental Proposal uses the historical BPA financing assumptions used to finance annual conservation programs in any given year. *Id*. They argue that the manner in which conservation is acquired in the 7(b)(2) Case is fundamentally different than in the Program Case. *Id*. In the 7(b)(2) Case, many years of annual programmatic conservation can be acquired to meet load in a single year. *Id*. In Staff's modeling of the FY 2009 section 7(b)(2) rate test, 15 years of annual programmatic conservation are brought on to meet load in 2009. *Id*. PPC and Cowlitz argue it is unreasonable to assume that the same financing arrangements used for each of the 15 historical years would be used if all the programs are brought on-line in a single year. *Id*. They state it is inappropriate to assume that utilities would finance conservation in this manner in the absence of BPA's ongoing conservation program. *Id*. They assert that BPA's determination that in the 7(b)(2) Case the JOA would expense over half of the costs of a several-hundred-megawatt resource is not supported. *Id*.

PPC's and Cowlitz's arguments describe one possible approach to address conservation financing, but ultimately their arguments are not persuasive. Under PPC's and Cowlitz's approach, the JOA and COUs would act in a manner inconsistent with established accounting principles and choose to defer and capitalize all conservation costs over the useful life of the capitalized portion of costs in order to shift costs to future years and keep current rates lower than they would be under normal operating practices. Taking into account concerns for sound business practices of matching current operating costs against current revenues, establishing adequate debt coverage ratios to meet bond covenants, and maintaining high credit ratings to ensure access to capital should be given more weight and deference by the parties in developing their proposal on how conservation costs should be accounted and financed in the 7(b)(2) Case. BPA believes the JOA and its member COUs would adopt a more balanced approach in dealing with the upward rate pressures associated with the high first-year costs of conducting a large 500 aMW conservation program and concerns over accumulating substantial balances of deferred regulatory assets that would be have to be recovered from future rate periods. Doubleday, *et al.*, WP-07-E-BPA-85, at 103-104.

BPA is also concerned about the comparability of the cost treatments used in the 7(b)(2) Case with the comparability of the cost treatment in the Program Case. BPA realizes the financing of resources can be different between the two Cases. However, it is still important that the cost treatment of individual conservation resources in the two Cases be more similar than dissimilar.

F. BPA's Past Treatment of Conservation in the 7(b)(2) Case

BPA has consistently treated past and planned conservation acquisitions covering the Five-Year Period as being available to meet 7(b)(2) Customer loads during the Five-Year Period. BPA has consistently assumed that the historical BPA costs for past conservation acquisitions adjusted for inflation comprise a reasonable cost projection of acquiring these conservation resources during the Five-Year Period. *See* Section 16.6 – Costs of Resources Contained in the 7(b)(2) Resource Stack – Resource Cost Escalation.

Although section 7(b)(2) is generally silent as to the cost basis for additional needed resources, it is reasonable for BPA to use the actual cost to BPA of the resources designated by subsection 7(b)(2)(D)(i). Although not specified, it can be reasoned that the resources acquired by the Administrator that fall under section 7(b)(2)(D)(i) would be at the cost of the specific resource acquired by the Administrator. However, because section 7(b)(2)(D) specifies that subsection 7(b)(2)(D)(i) and (ii) resources must be stacked in least cost order, it does not make sense to use the average costs of all resources acquired. Therefore, the most reasonable interpretation of section 7(b)(2)(D) is that BPA should assume that 7(b)(2)(D)(i) resources are acquired at BPA's cost of each specific resource. The historical and projected costs of acquiring conservation resources through BPA's customers has been equivalent to BPA's annual programmatic conservation costs that it undertakes on behalf and in partnership with 7(b)(2) Customers. It is reasonable for BPA to use the actual historical and projected costs associated with these annual programmatic conservation expenditures, adjusted for differences in savings and costs, to ensure the 7(b)(2)(D) resources have the capability to reduce BPA's load obligations (these adjustments are outlined in Appendix D to WP-07-FS-BPA-14), and for price level changes as described in Section 16.6 - Costs of Resources Contained in the 7(b)(2) Resource Stack – Resource Cost Escalation.

While section 7(b)(2)(D)(i) addresses the types of resources that are used to meet preference customer loads, section 7(b)(2)(E) addresses the differences in financing costs between the Program Case and the 7(b)(2) Case. Here Congress prescribed that the costs of financing (interest rates) were to be different between the two Cases, stating "the quantifiable monetary savings … resulting from reduced public body and cooperative financing costs as applied to the total amount of resources … were not achieved." 16 U.S.C. § 839e(b)(2)(E). Appendix B to the

Senate Report explains: "preference customers would construct new generating resources to meet their loads in excess of the Federal Base System Resources using tax exempt bonds and REA/CFC loans to finance such construction[.]" S. Rep. No. 96-272, 96th Cong., 1st Sess. 61 (1979). Here, Congress clearly allowed for different financing methods of the resources in the 7(b)(2)(D) resource stack.

As explained in subsection D above, the Act states nothing directly and implies very little concerning the nature of BPA's accounting and financing policies for conservation expenditures. BPA's accounting treatment of the amount of annual conservation expenditures that are expensed and the amount that are capitalized is consistent between the two Cases. The accounting treatment of conservation costs in the 7(b)(2)(D) resource stack follows BPA's historical and projected costs of conservation resources. The determination of which costs are capitalized and which are expensed is consistent with BPA's financial statement treatment of these costs. BPA's past accounting treatment for these costs has been similar to a number of COUs in the region of expensing all overhead and administration costs of running the programs and capitalizing and amortizing the direct costs of conservation acquisition expenditures.

BPA has consistently followed an amortization policy for capitalized conservation expenditures that has followed the Council's estimates of the useful life of conservation measures contained in the Council's power plans. BPA's capitalized conservation investments during the years 1982-2001 have followed a consistent accounting treatment of amortizing these expenditures over their composite service lives of 20 years in the resource stack. Capitalized conservation expenditures occurring after 2001 have been amortized over a period of 15 years, based on the composite useful life estimate of the measures contained in the Council's Fifth Power Plan. BPA has consistently adopted a financing period (maturity of the debt) in the 7(b)(2) Case that matches the amortization period. As noted above, these amortization and debt maturity periods are different from those used in the Program Case for periods after FY 2001.

This Supplemental Proposal is the first rate case where Staff has proposed that obsolete conservation (those years of conservation investments that have exceeded their useful life before the end of the Five-Year Period) is not available to meet 7(b)(2) Customer loads during the Five-Year Period.

The revised Appendix D to WP-07-FS-BPA-14, which describes the costs of conservation resources and the related savings for the final Supplemental Proposal, will follow the same consistent methodology presented in the original Appendix D included in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, in presenting the individual years of historical and projected conservation investments available to the resource stack. This Appendix will summarize the historical and projected cost treatment of conservation expenditures into the classifications of expensed conservation expenditures and those portions associated with conservation acquisition programs that were or are projected to be capitalized. Historical and projected expenditures that were treated as operating expenses of the year incurred include Energy Efficiency staff salaries, indirect and overhead costs, general and administrative costs, market transformation funding costs, expense agreement and grant costs, and C&RD power bill credit costs. Capitalized costs include expenditures for direct conservation acquisition programs. For the final proposal, BPA will amortize and finance capitalized conservation costs over a term of 15 years using the projected financing cost that is included in the financing study. This decision on the accounting and financing treatment for conservation costs is discussed in Section 16.4.O below, The Hybrid Approach.

The composition of conservation programs has changed over the years, and the cost of obtaining annual conservation savings (in $/MWh) has varied between years. BPA's historical and projected conservation costs and savings are presented in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D, at D-22. This table presents the subtotal for historical conservation costs as adjusted for the 7(b)(2) Case for FY 1982-2004. The total conservation expenditures stated in the nominal dollars for the year in which they were acquired for this period is $1,933.2 million. Of this amount, $571.8 million was expensed (29.6%) and $1,361.4 million was capitalized (70.4%). In contrast, the projected conservation expenditures stated in nominal dollars for the respective years as adjusted for the 7(b)(2) Case for the years FY 2005-2013 total $1,006.6 million (subsequently revised and updated for the Final Studies). Of this amount, $684.1 million was expensed (68.0%) and $322.5 million was capitalized (32.0%). Recent conservation efforts such as market transformation are expensed in the period incurred. Thus, the current composite amount of conservation expenditures acquired since FY 2004 has a significantly higher amount of conservation costs that are properly expensed as compared to prior periods.

G. Comparing the Cost and Financing Treatment of Conservation to the Cost and Financing Treatment of Other Resources in the Resource Stack

PPC and Cowlitz argue that conservation should be treated by BPA exactly the same as any other resource available to meet load. PPC Br., WP-07-B-JP25-01, at 25; Cowlitz Br., WP-07-B-CO-01, at 37. They argue that in modeling the 7(b)(2) Case, there should be no difference between a conservation resource (or group thereof) and a combustion turbine, or any other type of resource, with respect to how it meets load. *Id*. They argue how utilities, JOAs, or BPA actually financed or have previously financed conservation is less relevant than how the JOA in the 7(b)(2) Case would finance a very large resource (over 500 aMW) brought on to meet load. *Id*. They state the standard industry practice for financing such a resource is to capitalize the cost of such a resource and amortize those costs over the useful life of the resource. *Id*.

The PPC states that in the 7(b)(2) Case BPA assumes conservation is acquired from a JOA formed of regional consumer-owned utilities. PPC Br., WP-07-B-JP25-01, at 25. The PPC claims the hypothetical JOA would have an interest in acquiring resources in a manner so as to sustain power rates at the lowest and most stable levels possible, and spread costs to customers that benefit from those costs. *Id*. The PPC argues that BPA's traditional approach to how conservation is financed in the 7(b)(2) Case is not consistent with the interests of the JOA and the member utilities. *Id*. In Staff's modeling of the FY 2009 section 7(b)(2) rate test, 15 years of annual programmatic conservation are brought on to meet load in 2009. *Id*. The PPC argues it is unreasonable to assume that the same financing arrangements used for each of the 15 historical years would be used if all the programs are brought online in a single year. *Id*. The PPC contends it is inappropriate to assume that utilities would finance conservation in this manner in the absence of BPA's ongoing conservation program. *Id*. The PPC claims that BPA's determination that in the 7(b)(2) Case the JOA would expense over half of the costs of a several-hundred-megawatt resource are not supported. *Id*.

Again, PPC's and Cowlitz's arguments describe one possible approach to address conservation financing, but ultimately their arguments are not persuasive. Under PPC's and Cowlitz's approach, the JOA and COUs would act in a manner inconsistent with established accounting principles and choose to defer and capitalize all conservation costs over the useful life of the resource in order to shift costs to future years and keep current rates lower than they would be under normal operating practices. Taking into account concerns for sound business practices of matching current operating costs against current revenues, establishing adequate debt coverage ratios to meet bond covenants, and maintaining high credit ratings to ensure access to capital should be acknowledged by the parties in developing their proposal on how conservation costs should be accounted and financed in the 7(b)(2) Case. BPA believes that the JOA and its member COUs would adopt a more balanced approach in dealing with the upward rate pressures associated with the high first-year costs of conducting a large 500 aMW conservation program and concerns over accumulating substantial balances of deferred regulatory assets that would be have to be recovered from future rate periods.

The nature of conservation resource costs is fundamentally different than the cost structure of generating resources. The standard utility practice by a number of COUs that operate large utility conservation programs is to expense conservation staff salaries and related overhead and administrative costs in the year incurred, while capitalizing conservation direct acquisition costs. The current practice of COUs is a better indicator of how the JOA and member COUs would choose to finance a large 500 aMW conservation program in the 7(b)(2) Case. PPC's and Cowlitz's argument focuses on keeping current rates low, but does not adequately consider the potential negative impacts of capitalizing costs of the operating period and postponing their recovery over a 15-year period. However, BPA agrees with PPC and Cowlitz that BPA's historical practice of financing conservation resources is less important in the 7(b)(2) Case. BPA agrees that the manner in which the JOA in the 7(b)(2) Case would finance conservation resources is a more appropriate focus.

The OPUC argues that Staff's rebuttal proposal to defer the historically expensed portions of BPA's conservation programs and finance these costs over five years should be rejected. OPUC Br., WP-07-B-PU-02, at 30. The OPUC states this proposal would be a departure from how utilities in Oregon recover conservation costs. *Id*. The OPUC notes that prior to the creation of the Energy Trust of Oregon, utilities in Oregon expensed 100 percent of conservation costs. *Id*. The OPUC argues that the Energy Trust of Oregon continues this treatment by paying for conservation resources upfront and thus incurs significant front-loaded costs when acquiring conservation. *Id*. The OPUC argues that proposals avoiding the front-loading of costs, including the PPC proposal, differ from current utility practice. *Id*.

The OPUC assumes there is a narrow range of acceptable conservation costs that should be present in the 7(b)(2) Case. Unlike Cowlitz, which advocates capitalizing all conservation costs in the 7(b)(2) resource stack, the OPUC would require that the majority of, if not all, conservation costs should be expensed in the resource stack. These arguments are at opposite ends of possible approaches to financing conservation resources. As discussed above, utilities can choose different conservation accounting and financing treatments, and all of the different treatments would be in accordance with GAAP due to the latitude afforded by SFAS 71.

Further, the OPUC argument is based on the standard treatment by IOUs in Oregon. IOU treatment of costs is not necessarily the same as COU treatment of costs. IOU treatment, however, is not the accounting basis to be assumed in the 7(b)(2) Case. Here Congress is clear that the COUs are assumed to acquire the resources in the 7(b)(2)(D) resource stack.

H. Least-Cost Selection

The PPC and Cowlitz argue that Staff's proposed treatment of conservation financing in the 7(b)(2) Case creates a problem with the "least-cost" selection methodology. PPC Br., WP-07-B-JP25-01, at 26; Cowlitz Br., WP-07-B-CO-01, at 35. They argue if some portion of conservation is expensed, then the cost of a conservation resource in the year it is brought on to serve load in the 7(b)(2) Case may not correspond to its position in the resource stack. *Id*. They argue it is inappropriate to select conservation resources from the resource stack based on a cost comparison using their levelized costs measured over their useful lives but to recover through rates based on large amounts of first-year conservation program expensed costs for multiple years' worth of conservation investments. *Id*. They argue the highly front-loaded costing of conservation is inconsistent with section 7(b)(2)(E)'s requirement that BPA evaluate resource costs as if financed by preference customers themselves without BPA assistance. *Id*. The JOA that such customers would use would not expense such a high proportion of conservation expenditures, meaning that resources are not brought on in a "least-cost" order. *Id*. They argue that to the extent that BPA does not adopt the PPC's proposal to fully capitalize the cost of conservation resources in the 7(b)(2) Case (which would resolve this issue), BPA needs to ensure that resources are actually brought on to serve load in least-cost order as dictated by the Northwest Power Act. *Id*.

BPA agrees with PPC and Cowlitz it must ensure that resources are brought on to serve load in least-cost order. In rebuttal testimony, however, Staff disagreed with PPC's and Cowlitz's argument. Doubleday, *et al.*, WP-07-E-BPA-85, at 111-113. Within the utility industry, a high proportion of annual conservation expenditures is expensed. *Id*. The higher first-year cost of conservation resources is an industry norm due to the nature of the resource, and it is not tied to the number of conservation resources brought on from the 7(b)(2) Case resource stack in any one year. *Id*. The first-year conservation expense that is present during the Five-Year Period is higher than the levelized cost of the resource over its projected lifetime. *Id*. Because the first-year cost of conservation resources actually purchased in the Program Case is as high as those available in the 7(b)(2)(D) resource stack, the decision as to whether a conservation resource was cost-effective was made on the basis of the useful life cost rather than the first-year cost. *Id*. The higher first-year costs of conservation resources reflect the "true nature" of conservation programs and treat costs that are normally expensed in the year that they are incurred. *Id*. The PPC's and Cowlitz's proposal to capitalize all conservation costs does not properly reflect how conservation costs are accounted for and financed in the utility industry. *Id*.

BPA understands PPC's and Cowlitz's case. Section 7(b)(2)(D) specifies that resources be drawn from the resource stack in least-cost order. The costs used to stack the resources should reflect the costs that are included in the 7(b)(2) Case rates if the resource is selected from the stack. In the case of modeling the Staff proposal, the first-year costs are significantly different than the second-year costs. It is incongruous to model the year-to-year costs separately because the second-year costs cannot be realized independent of the first-year costs. Therefore, a method needs to be developed to properly stack resources that have significantly different year-to-year costs. Because the model changes necessary to implement a proper stacking of resources has not been developed by either BPA or any party, and such model changes are a significant task, it was not possible for BPA to develop the necessary model changes before the conclusion of this proceeding. BPA will make its best efforts to accomplish such model changes in the next rate proceeding.

I. General and Administrative Costs

Cowlitz argues that instead of identifying "conservation resources," BPA uses conservation year costs, which contain an allocation of general and administrative (G&A) costs for the vintage year in which BPA acquired the conservation savings. Cowlitz Br., WP-07-B-CO-01, at 35. Cowlitz states in FY 2009 alone, BPA assumes that 15 years of annual programmatic conservation spring into existence, thus front-loading the 7(b)(2) Case with 15 times the normal allocation of G&A to conservation, and with no reduction to the allocation of G&A costs to other programs. *Id*.

In response, the annual costs of conservation resources in the resource stack contain an adequate allocation of G&A costs that reflects the total cost of acquiring the conservation savings for the individual year. Other non-conservation resources in the resource stack also contain adequate allocations of G&A costs. In order to conduct the ranking of resources in the resource stack on a "least-cost" basis, the costs of resources need to be stated on a comparable basis. The inclusion of an adequate allocation of G&A costs to the individual resources in the 7(b)(2) Case is also necessary to ensure that the costs contained in the 7(b)(2) Case are comparable to the costs in the Program Case.

Cowlitz's argument raises concerns with the scale of the cumulative amount of G&A costs reflected in the first-year costs of the 7(b)(2) Case. BPA has not had to address this issue before because this is the first rate case where the number of individual years of conservation investments selected in the 7(b)(2) Case has been so great. To resolve this issue would require significant analysis, and neither BPA nor the parties have performed any analysis of what reductions, if any, should be made to the cumulative conservation resource costs that have been added to the 7(b)(2) Case, assuming that in fact economies of scale would be present. It is just as plausible, however, that the impacts of the first-year startup costs associated with conducting this large conservation program by the JOA, COUs and contractors should also be accounted for in the 7(b)(2) Case. Again, neither BPA nor the parties have conducted any analysis to quantify the magnitude of the startup costs associated with undertaking such a large conservation program.

The allocation of G&A costs to the individual years of conservation costs is based on a proportionate share of BPA's total staffing costs. Projected G&A costs included in the conservation costs inventoried in the resource stack for FY 2009-2013 range between $9 million and $11 million per year. Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A, at 53-55. The amount of G&A allocated costs represents approximately 7 percent of the total annual conservation costs. The total cumulative amount of conservation G&A costs, assuming 15 years of conservation costs being drawn from the resource stack, would thus range between $135 million and $165 million in the 7(b)(2) Case revenue requirement, which totals approximately $2.3 billion. The cumulative amount of conservation G&A costs associated with 15 years of conservation investments comprise less than 8 percent of the total revenue requirement. Thus, the reduction in 7(b)(2) costs due to the economy of scale argument that would be attributable to G&A costs would in all likelihood be less than 2-3 percent of the total 7(b)(2) Case revenue requirement.

In summary, BPA will not adjust the costs in the 7(b)(2) revenue requirement for either any potential reduction in G&A costs due to economies of scale or additional first-year startup costs associated with conducting a large conservation program. The starting total costs of each resource in the 7(b)(2) Case should be based on the historical and projected costs of conservation resources in the Program Case, as adjusted for the 7(b)(2) Case as provided in Appendix D to WP-07-FS-BPA-14, and for the time value of money based on when they are selected from the resource stack in the 7(b)(2) Case.

J. Range of Acceptable Conservation Costs

Cowlitz argues that Staff takes the position that various alternatives are available with differences of hundreds of millions of dollars in cost impacts on the 7(b)(2) Case, and this shows that the proposed Implementation Methodology destroys the specific and objective rate protection crafted by Congress. Cowlitz Br., WP-07-B-CO-01, at 36-37. Cowlitz claims Staff would replace the section 7(b)(2) directives with a standardless morass of asserted discretion to provide any particular level of REP benefits funded by preference customers that BPA may desire. *Id*. Cowlitz grants that Staff is correct to observe that "there may be modeling and accounting changes that can be adopted that would make the acquisition of conservation resources from the stack comport with industry practice of capitalizing and deferring costs," but Congress did not empower BPA to wander far beyond the Five Assumptions to manipulate the level of section 7(b)(2) protection in the first place. *Id*.

Cowlitz's argument, however, implies there should be a narrow range of acceptable conservation financing options in the 7(b)(2) Case. Its argument oversimplifies the complexity of determining a reasonable cost and financing approach to conservation costs included in the 7(b)(2) Case revenue requirement. As explained above, utilities can and do choose different conservation accounting and financing treatments, and all of the different treatments could be in accordance with GAAP. To help ensure that the same entities' financial statements are comparable from year to year, GAAP relies on the consistency principle, which requires entities to use a set of consistent accounting principles and methods over successive periods of time.

As to Cowlitz's claims that Staff would replace the section 7(b)(2) directives with a standardless morass of asserted discretion, BPA disagrees. BPA is not replacing the rate directives; it is implementing them. The fact that an implementation issue involves the exercise of discretion that Congress vested in BPA does not mean BPA is replacing the directives. The current discussion involves conservation financing, which is only one of many issues regarding the implementation of the section 7(b)(2) rate test. The instant issue involves the difficult question of the manner in which BPA should treat conservation financing given an existing environment in which there are many alternative financing approaches being used by regional utilities. As seen from review of the manner in which BPA generally conducts the rate test, there are many standards BPA applies for the respective 7(b)(2) issues. BPA notes, however, that Congress recognized the difficulty of implementing section 7(b)(2) and left the determination of the "power costs for general requirements of such customers" to BPA. Section 7(b)(2) states that this is to be "as determined by the Administrator" assuming the Five Assumptions. Financing costs associated with resources are not prescribed by section 7(b)(2), but are a matter to be determined based on the record and the exercise of the Administrator's sound discretion. As discussed here, BPA believes its approach is consistent with the record and the reasonable exercise of such discretion.

Appendix B to the Senate Report describes the construction of the "power costs" in the 7(b)(2) Case:

> The specific rate limit factors are objective in nature. The first, the size and cost of the Federal Base System Resources, will be determinable in much the same way that BPA applies in its current power marketing operations and ratemaking. The size and location of DSI loads with respect to preference customer service areas are also easily identified. *The amount of new resources needed* to meet preference customer load growth, including the applicable DSI load, and its cost *may require some minor estimating*. This is principally because preference customer resource construction probably will never exactly match preference customer load growth (high or low). *The monetary benefits which would not be available to preference customers without the program will be the* <u>*hardest to determine*</u>*.* This analysis limits its consideration to two specific areas, lower financing costs and lower system planning and operating reserve costs. Consideration of other savings may be appropriate if they can be stated and quantified in an objective manner and they are not recognized in A.5. All these items will be fully reviewed in the normal rate setting process.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 61 (1979). It is clear that Congress thought that the amount of resources needed to meet additional 7(b)(2) Customer load required some minor estimating. However, the costs of the resources, and the benefits due to financing the resources, would be the "hardest to determine." Rather than setting specific rules for determining the costs of resources in the 7(b)(2)(D) resource stack, Congress left the details to BPA. BPA has set forth its principles in determining such costs.

The PPC and Cowlitz argue that a different cost and financing treatment for conservation resources should be adopted in the final proposal due to the large number of conservation resources being selected, with the cumulative first-year conservation costs being added to the 7(b)(2) Case revenue requirement. PPC Br., WP-07-B-JP25-01, at 24-26; Cowlitz Br., WP-07-B-CO-01, at 34-37. Their approach of capitalizing all conservation costs, including costs that are normally expensed in the year incurred, along with financing them over a period of 15 years is not consistent with how the majority of COUs in the region account for and finance conservation expenditures.

Although Staff repeatedly emphasized that the amortization cost and financing treatments are different between the two Cases, Staff also recognized the desirability of the cost of conservation resources being more similar between the two Cases when it advocated that "some financing assumption other than the actual historical practice may be reasonable in the 7(b)(2) Case." Keep, *et al.*, WP-07-E-BPA-68, at 15. As discussed below, the consistency in resource cost treatment between the Program Case and the 7(b)(2) Case is measured by the total costs recovered for a single conservation resource over the Five-Year Period. The PPC and Cowlitz alternative, which would capitalize all conservation costs and amortize and finance them over a 15-year period, would recover only one-third of the conservation costs in the 7(b)(2) Case during the Five-Year Period. In contrast, the Initial Proposal recovered 100 percent of those costs in the 7(b)(2) Case which was similar to the level of recovery in the Program Case. The Staff proposal introduced in rebuttal testimony (WP-07-E-BPA-85 at 98-116) recovered 75.4% of the conservation costs in the 7(b)(2) Case during the Five-Year Period (*see* the table in subsection N. below, Alternative 3A). Although the PPC and Cowlitz have presented one possible approach to financing conservation, the Staff proposal produces a greater level of cost recovery that is more comparable to the Program Case than the PPC and Cowlitz proposal.

Cowlitz's approach to the cost and financing treatment for conservation resources also appears inconsistent with Cowlitz's position on the comparability of non-conservation resource costs between the two Cases. Cowlitz argues there should be no changes in resource costs between the Program and 7(b)(2) Cases other than changes in financing costs for particular resources arising under the fifth assumption in section 7(b)(2)(E) (no benefit from Northwest Power Act-reduced financing costs). Cowlitz Br., WP-07-B-CO-01, at 32. Yet when it comes to conservation resources, Cowlitz and the PPC propose to adopt a 100 percent capitalization cost treatment, which is inconsistent with the cost treatment used in the Program Case and by a significant number of COUs in the region and by BPA. Cowlitz's and the PPC's proposed accounting and financing treatment in the 7(b)(2) Case is drastically different than the treatment in the Program Case and produces a much lower level of cost recovery for a single conservation resource over the Five-Year Period compared to the Staff proposal, which is demonstrated by the table in sub-section N below that compares the cost recovery amounts of different accounting/financing alternatives.

K. Conservation Penalty

APAC argues that BPA's treatment of conservation in the proposed Implementation Methodology continues an improper penalty on conservation that defeats a prime purpose of the Northwest Power Act and results in an improper subsidy to IOUs. APAC Br., WP-07-B-AP-01, at 40.

Cowlitz's comments support APAC's argument that it makes no sense that every time BPA spends a million dollars on conservation it has to turn around and give another million REP dollars to the IOUs out of the pockets of the preference customers. Tr. at 662.

Staff stated the proposed Implementation Methodology provides that conservation resources are to be included in the 7(b)(2)(D) resource stack and, as a consequence, the effects of conservation resources are to be removed from 7(b)(2) Customer loads. Doubleday, *et al.*, WP-07-E-BPA-85, at 85. The proposed Implementation Methodology is in conformance with the proposed Legal Interpretation. *Id.*

APAC argues that because conservation resources are in the resource stack, the REP net benefits are higher than under an Implementation Methodology that omits the conservation resources from the resource stack. APAC Br., WP-07-B-AP-01, at 40. However, under APAC's scenario, the benefits of conservation in the 7(b)(2) Case would be achieved at little or no cost because the costs of both past and projected conservation savings are not included in the 7(b)(2) revenue requirement. This approach makes little sense because conservation savings cannot be achieved at little or no cost. Building on this faulty logic, APAC then concludes that this approach makes the actual cost of conservation programs more or less cost-effective, and concludes this constitutes an improper penalty on conservation.

It is true that if the load/resource balance is changed at a near-zero cost in the 7(b)(2) Case, and the cost of the resources is removed from the resource stack, the level of REP benefits would be reduced. However, this approach is not consistent with BPA's interpretation of section 7(b)(2). *See* Section 16.2 - General Section 7(b)(2) Legal Issues.

APAC argues that when selected as a resource, BPA discards the information on the historical costs of conservation. APAC Br. Ex., WP-07-R-AP-01, at 17-18. APAC claims the substitution of current prices for historical conservation costs creates an impermissible penalty on conservation. *Id.* APAC argues BPA assumes unreasonably that a significant percentage of the costs of a very large amount of conservation is financed out of current rates. *Id.* APAC states BPA's assumptions require that 20 times more conservation is financed in the first year than the historical average of 32 aMW. *Id.* APAC claims the result is that BPA's treatment of conservation unlawfully increases the Preference rate and provides an improper subsidy to REP customers. *Id.*

In response, BPA's 2008 Legal Interpretation assumes that BPA's historical and projected conservation program efforts are not present in the 7(b)(2) Case unless they are the least-cost resources available to serve 7(b)(2) Customer loads. BPA Staff has modeled resource costs in the 7(b)(2) resource stack using a consistent methodology since the first section 7(b)(2) rate test was conducted in FY 1985. Doubleday, *et al.*, WP-07-E-BPA-85, at 43. BPA has consistently maintained that the costs of the Program Case and the 7(b)(2) Case are different as provided by the exclusions from the Program Case, the five specific assumptions that outline changes from the Program Case to the 7(b)(2) Case, and the consequences that follow from applying the Five Assumptions. *Id.* BPA's practice in modeling the 7(b)(2) Case resource costs has properly recognized and given effect to the time value of money. *Id.* In order to perform the "least-cost ordering" prescribed in section 7(b)(2)(D) of the Act, it is necessary that all resource costs are stated in a common base year of purchasing power dollars. *Id.* Because resources are selected in different years of the rate test period, it is equally clear and well recognized in performing rate analyses that costs escalate throughout the rate test period. *Id.*

BPA does not discard past historical information on each vintage year's conservation program costs. Such information includes the amount of those costs that were classified as being capital in nature and financed over their respective useful life/amortization period, and the amount of conservation costs that are first-year conservation expenses that have been expensed as incurred in the Program Case. BPA has an objective accounting policy of classifying conservation costs in the Program Case as either (1) costs that are expensed in the year incurred or (2) capitalized costs that are capitalized and financed over a period of years. BPA has consistently followed this policy for more than 25 years. Staff's treatment of conservation resource costs adjusts the historical resource costs (maintaining the relationship of capitalized and first-year expensed costs) for purchasing power cost changes so that a resource's costs reflect its operation in the year it is selected from the resource stack.

There have been several past rate cases where the augmented FBS resources were adequate to meet the 7(b)(2) Customers' loads with very few or no conservation resources being selected from the 7(b)(2) Case resource stack. Each rate case has unique loads, resource costs, and operating costs that present different circumstances, thus requiring different approaches to how the 7(b)(2) conservation resources are modeled in the subject rate case. This is the first rate case where such a large number of conservation resources were selected in the first year of the rate test period to meet the loads in the 7(b)(2) Case. In the Program Case, conservation is acquired in annual program increments one year at a time. In the present 7(b)(2) Case, multiple years of vintage conservation programs have been selected to meet 7(b)(2) loads. The multiple years of conservation investments and their cumulative first-year costs increased the costs of the first year of the rate test period by a significant amount. In response to Cowlitz's and PPC's arguments that the Joint Operating Agency that would be coordinating and financing the conservation programs for 7(b)(2) Customers in the 7(b)(2) Case would not choose to account for and finance conservation costs in the same manner that was used historically in the Program Case, BPA proposed a policy of deferring these costs under SFAS No. 71 and amortizing and financing them over a period of 1 to 15 years (the capitalized conservation costs are amortized and financed over a period of 15 years in the 7(b)(2) Case). BPA's approach provides a considerable reduction in first-year conservation costs, and thus a reduction in the preference customers' PF Preference rate, when compared to the historical treatment used in BPA's Initial Proposal.

In the Initial Proposal, 15 years of conservation resources were selected in the first year of the rate test period with a total amount of first-year (FY 2009) conservation costs of $759 million. (If 10 years of conservation investments were selected, the total first-year costs would have been $362 million in the Initial Proposal.) In the Final Proposal, 10 years of conservation investments were selected in the first year of the Five-Year Period with the total conservation cost in the first year of the rate test period amounting to $65 million. Thus, the first-year rate impact of selecting multiple conservation investments has been reduced by more than ninety-percent by adopting the deferred expense approach and by adopting a single 15-year life for all conservation investments. (Adopting a standard 15-year life reduced the 7(b)(2) loads in the Final Proposal, which in turn reduced the amount of resources required to serve 7(b)(2) loads.) In the Final Proposal, 258 aMW of vintage conservation investments are selected in FY 2009, the first year of the rate test period, compared to the single-year average in the Program Case of approximately 30aMW. The amount of conservation selected in the first year of the rate test period is 8.6 times the historical amount as outlined in page B-4 of Appendix B to the FY 2009 Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14. As noted above, BPA's decision to defer the first-year conservation expenses has greatly reduced the amount of conservation costs contained the first year (FY 2009) of the rate test period. APAC's argument that 20 times more conservation is financed in the first year of the 7(b)(2) Case than the average single-year amount in the Program Case does not reflect BPA's treatment in the Final Rate Proposal. APAC's argument also fails to take into account that, in addition to the current year's programmatic conservation investments, the Program Case also includes the amortization costs of prior year conservation investments in all years of the rate test period.

APAC's argument that BPA unreasonably assumes that a significant percentage of the costs of a very large amount of conservation is financed out of current rates ignores the manner in which conservation costs are accounted for and treated by regional COUs. BPA's capitalization and expense policy for conservation is similar to a large number of COUs that have large conservation programs. These COUs and BPA expense a substantial portion of conservation program costs that relate to staff salaries and all overhead and administrative costs ("first-year" conservation expenses) connected with running their conservation programs. A large number of regional COUs expense a significant amount of first-year expense costs in the year incurred. Due to the large cumulative number of vintage years of conservation resources that were selected in the first year in the 7(b)(2) Case, BPA has reasonably chosen to defer these costs over a period of 7 years in the current rate case. The historical and projected amounts of conservation costs that were capitalized continue to be amortized and financed over a period of 15 years, which recovers these costs over a period of years that is three times the period of time that they are recovered in the Program Case.

APAC's claim that the treatment of conservation costs in the 7(b)(2) Case unlawfully increases the PF Preference rate and provides an improper subsidy to REP benefit recipients is simply wrong. In the table (*see* sub-section N) that provides a comparison of alternative conservation cost treatments for a single year of conservation costs, the 7(b)(2) cost treatment for the final proposal (Alternative 3B) recovers approximately 57 percent of the total costs over the rate test period as compared to 100 percent for the Program Case. Thus, the rate of cost recovery for a single year of conservation investment in the 7(b)(2) Case is almost half of the rate of recovery in the Program Case. The comparison of conservation costs in total between the two Cases is not comparable because they are comprised of different populations of conservation investments and cost streams, consistent with BPA's Legal Interpretation regarding the Five Assumptions. Doubleday, *et al.*, WP-07-E-BPA-85, at 51-54. While recognizing that the conservation costs in the two Cases are different and not comparable, it is useful to look at the total first-year costs in the two Cases to gauge the reasonableness of APAC's claim that conservation costs are unreasonably being increased and provide a subsidy to REP benefit recipients. In the Program Case for FY 2009, the total amount of conservation costs for FY 2009 conservation programs and the amortization of prior year conservation efforts totals $174.5 million. In the 7(b)(2) Case, the total conservation costs associated with selecting 10 years of conservation resources from the resource stack totals $65.0 million. Thus, the amount of total conservation costs in the Program Case for FY 2009 is 2.7 times the amount of total conservation costs present in the 7(b)(2) Case for the same year.

L. Useful Life of Conservation in the 7(b)(2) Case

Staff proposed to consider conservation resources that were installed in years earlier than the prevailing useful life of conservation programs to be obsolete resources, and no longer capable of reducing loads in the Program Case, and no longer available in the 7(b)(2)(D) resource stack in the 7(b)(2) Case. This is first rate case that has addressed the obsolescence of conservation resources.

No parties raised an objection to this proposal.

For the final Supplemental Proposal, all conservation resources contained in the 7(b)(2) Case resource stack will have a useful life of 15 years. This useful period is consistent with Council's estimate of the composite useful life of the measures that are included in its Fifth NW Power and Conservation Plan. As mentioned above, PPC proposed that the useful life for all conservation resources should be 15 years. O'Meara, *et al.*, WP-07-E-PP-09, at 28.

M. Alternative 7(b)(2) Case Conservation Financing Treatments

In general, the PPC and Cowlitz argue for the capitalization of all conservation expenditures and their amortization and financing over their useful life. PPC Br., WP-07-B-JP25-01, at 24-26; Cowlitz Br., WP-07-B-CO-01, at 34-37. This proposal would amortize and finance the historical capitalized conservation costs over 15 years. O'Meara, *et al.*, WP-07-E-PP-9, at 28.

In the Supplemental Proposal, Staff proposed to continue to use BPA's past 7(b)(2) Case conservation treatment. Keep, *et al.*, WP-07-E-BPA-68, at 14-15. This proposal would continue to amortize and finance the historical capitalized conservation costs over 15 years (post-2001 conservation investments) and 20 years (pre-2002 conservation investments) and continue to treat the first-year historically expensed costs as costs that are fully expensed in the year the conservation resource is selected from the resource stack. *Id*.

In rebuttal testimony, Staff presented a hybrid approach. Doubleday, *et al.*, WP-07-E-BPA-85, at 103-116. This proposal amortizes and finances the historical and projected capitalized conservation costs over 15 to 20 years in the resource stack, depending on the then-determined useful life of the resource. Thus, there is a capitalization policy for items that are appropriately capitalized and borrowed for 15 to 20 years, which is consistent with the Council's estimate of the composite useful life for conservation measures included in the Council's then-effective NW Power and Conservation Plan. The first-year historically expensed costs, however, would be treated as deferred charges under SFAS 71, and these costs would be amortized and financed over a five-year period. This approach spreads the high amount of first-year expensed costs ratably over the first five years, thus mitigating the first-year "rate shock." This hybrid approach was further refined in the Final Rate proposal as discussed in sub-section O. below.

The OPUC states that utilities in Oregon recovered conservation costs, prior to the creation of the Energy Trust of Oregon, by expensing 100 percent of conservation costs. OPUC Br., WP-07-E-PU-02, at 30. The OPUC further states that the Energy Trust of Oregon continues this treatment by paying for conservation resources up front and thus incurs significant front-loaded costs when acquiring conservation. *Id*. A logical argument can be drawn from the OPUC's statements that conservation could be entirely expensed in the 7(b)(2) Case. The OPUC raised no argument on conservation financing.

N. Decision Considerations

1. Multiple Years of Conservation Investments

This is the first BPA rate case where as many as 15 years of conservation investments are being selected in the first year of the Five-Year Period as the least-cost resources to meet 7(b)(2) Customer loads. Following BPA's past practice of accounting for and financing conservation costs in the 7(b)(2) Case would result in substantial amounts of "first-year" conservation costs being expensed. This approach would produce a substantial rate increase in 7(b)(2) Case rates. This outcome would produce a "super-sized" conservation program whose scale begs the question of whether BPA should continue its historic treatment of conservation expenditures in the section 7(b)(2) rate test.

The PPC and Cowlitz argue that Staff's proposed treatment of conservation resource financing in the 7(b)(2) Case is incorrect. PPC Br., WP-07-B-JP25-01, at 24-26; Cowlitz Br., WP-07-B-CO-01, at 34-37. They note that Staff's Supplemental Proposal uses the historical BPA financing assumptions used to finance annual conservation programs in any given year. *Id*. They argue that the manner in which conservation is acquired in the 7(b)(2) Case is fundamentally different than in the Program Case. *Id*. In the 7(b)(2) Case, many years of annual programmatic conservation can be acquired to meet load in a single year. *Id*. In Staff's modeling of the FY 2009 section 7(b)(2) rate test, 15 years of annual programmatic conservation are brought on to meet load in 2009. *Id*. They claim it is unreasonable to assume that the same financing arrangements used for each of the 15 historical years would be used if all the programs are brought online in a single year. *Id*.

The PPC and Cowlitz argue that BPA's historical cost treatment for conservation acquired in the 7(b)(2) Case should be changed to reflect the multiple years of conservation investments that are being selected. PPC Br., WP-07-B-JP25-01, at 24-26; Cowlitz Br., WP-07-B-CO-01, at 34-37. They argue that the 7(b)(2) Customers using the JOA to procure and finance conservation would not finance conservation costs in the historical manner BPA has followed in conducting the section 7(b)(2) rate test. *Id*. PPC argues it is inappropriate to assume that utilities would have financed conservation in the same manner as BPA's annual programmatic conservation. PPC Br., WP-07-B-JP25-01, at 24-26. The PPC contends BPA's determination that in the 7(b)(2) Case the JOA would expense over half of the costs of a several-hundred-megawatt resource is not supported. *Id*. The PPC and Cowlitz argue that BPA should capitalize all conservation costs and amortize and finance the costs over their useful life. *Id*. The PPC proposes that a useful life of no more than 15 years for all of BPA's annual programmatic conservation investments should be used. O'Meara, *et al.*, WP-07-E-PP-09, at 28. The PPC argues that the hypothetical JOA would have an interest in acquiring resources in a manner so as to sustain power rates at the lowest and most stable levels possible while spreading costs to customers that benefit from those costs. PPC Br., WP-07-B-JP25-01, at 25.

One reasonable approach would be to assume that if the JOA were to contract for the administration and acquisition of a super-sized conservation program, the distinctions between costs that have been historically expensed by regional utilities and those that have been capitalized would not occur. Under a turnkey concept there could be greater justification for treating these costs as annualized expenses spread over the useful life of the resource based on the amortization and debt maturity of the conservation investments. This treatment produces the same result as capitalizing the costs over the useful life of the resource similar to the PPC and Cowlitz proposal.

2. Levelized Cost Selection Methodology

The high level of first-year conservation expensed costs reflects the true nature of conservation programs' costs. Most, if not all, utilities in the region treat expenses associated with overhead and administrative costs of their conservation programs as expenses that are properly expensed in the period in which they are incurred. As noted previously, the treatment of conservation acquisition expenditures varies from utility to utility, with some utilities choosing to capitalize these expenditures and other utilities choosing to expense these costs.

Resources are placed in the resource stack using a standard levelized cost methodology that is commonly used in the utility industry. The costs of conservation programs are different from generating resources in that the only operating expenses associated with conservation programs are the first-year costs. The cost of debt service occurs over the debt maturity period, which matches the useful life of the portion of capitalized conservation expenditures. In contrast, generating resources have a level of operating expenses in all years of their operation, along with the debt service costs associated with costs of financing the capitalized fixed costs. As noted in the arguments of the PPC, Cowlitz, and APAC, under the method used in the Supplemental Proposal, the selection of conservation resources using the standard levelized cost methodology is based on the discounted costs of all years of a resource's operation over its useful life, and the levelized cost ranking for the useful life period is different from a ranking or evaluation of just the costs that would be incurred during the Five-Year Period.

PPC, Cowlitz, and APAC argue that the levelized cost methodology BPA uses should reflect just the costs that are incurred during the Five-Year Period. They propose to fix this problem by capitalizing all conservation costs with the only costs for conservation resources being the debt service that would be spread over the useful life of the conservation investment. Capitalizing all conservation costs would fix the levelized cost selection procedure that the PPC, Cowlitz, and APAC cite. Staff's rebuttal proposal to defer the first-year conservation expense over five years somewhat mitigates the differences from the levelized cost calculation that is based on (1) all conservation being capitalized and financed over 15 years under PPC's proposal, and (2) Staff's approach of treating capitalized costs as being amortized and financed over the useful life and having the expensed costs deferred and amortized and financed over a period of five years. The OPUC argues that an approach of capitalizing all conservation costs ignores the true nature of acquiring conservation. OPUC Br., WP-07-B-PU-02, at 30. OPUC argues that BPA's historical practice avoids the front-loading of costs and differs from current utility practices. *Id*.

PPC previously argued that BPA's assumptions regarding the financing and costs of conservation in the rate test result in BPA bringing on conservation resources to serve load in the 7(b)(2) Case in an order other than least-cost, and that BPA should remedy this problem to ensure that resources are brought on in least-cost order. PPC Br. Ex., WP-07-R-PP-01, at 17. PPC notes that in the Draft ROD BPA indicated partial agreement, stating that in order to correct for problems that occur now in the modeling of the order in which resources are brought on in the 7(b)(2) Case resource stack, "a method needs to be developed to properly stack resources that have significantly different year-to-year costs." *Id*. BPA then explained that creating a model in time for this proceeding may prove difficult. *Id*. PPC states that it appreciates BPA's moves to be responsive to the problems identified by parties, but it is inappropriate to identify an error in this proceeding and not provide certainty that the parties will be afforded a rate based on a correction of that error. *Id*. PPC states that, to the extent BPA is unable to develop a model in time for the Final ROD, it must provide a way for FY 2009 rates to be corrected, and parties made whole for any errors that persisted into the rate period, once the error can be corrected. *Id*. PPC states that otherwise, BPA's establishment of its rates would be arbitrary and capricious due to their being based on known errors that were not corrected, and which could have a material impact on the level of the rates. *Id*.

First, BPA does not agree with PPC's characterization that the current least-cost resource selection methodology constitutes an error. In addition to PPC's selected references to the Draft ROD, BPA also stated in that "[w]ith regard to the levelized cost arguments, BPA did not find merit in the parties' arguments that the traditional 'least-cost' selection process that ranks resources based on the average of the discounted cash flows over the resource's useful life should be changed for a selection process that would evaluate the cost of the resources based on the costs that occur during the Five-Year Period. This would be an imprudent way to approach resource acquisitions, so it is not one that BPA can select consistent with sound business principles." Draft ROD, WP-07-A-03, at 397. The Draft ROD also notes that "BPA will make its best effort to revise the modeling of the 7(b)(2)(D) resource stack to more closely stack the resources in a way that relates to the cost of the resource that would be included in 7(b)(2) Case rates, if the resource is selected, so that resources are drawn in least-cost order." *Id*. at 398. The levelized cost methodology contained in the rates model has been used for over 20 years without objection. The methodology used is the standard resource costing tool that is still used in the utility industry today. Considering BPA's decision to amortize the first-year cost of conservation over 7 years, the currently-used levelization method to sort by least-cost first could be retained. PPC's and Cowlitz's position on the least-cost ranking methodology is one view. The OPUC expressed a different view on this issue and, undoubtedly, if there were a workshop convened to discuss alternative approaches to improving the least cost methodology, there would be many different alternatives presented. This issue is a complex issue from the perspective of the many different approaches that could be used to give more effect to the resource costs that occur during the Five-year period. BPA is being responsive to this issue, but parties must understand the amount of work required to address this issue and make the required rate model changes. There was not sufficient time to address this issue adequately prior to the conclusion of this rate proceeding.

Second, BPA is establishing the instant power rates for only a one-year period, FY 2009, and will promptly begin a rate adjustment proceeding for the development of its post-FY 2009 rates.

This ensures that even if there were an instance where a particular matter could not be determined or modeled, it can be promptly addressed and resolved for immediately succeeding rates.

3. Consistency of Resource Cost Treatment Between the Program Case and the 7(b)(2) Case

Generally, the cost of resources in the Program Case and the 7(b)(2) Case should be similar, with the main differences attributable to the mix of resources used in the two Cases, the timing of when they are selected to serve loads, and the differences in financing costs attributable to modeling the provisions of section 7(b)(2)(E). The costs of non-conservation resources that are common to both cases consist of the "new resource costs" of Cowlitz Falls Hydro Project, Idaho Falls Hydro Project, and Wauna Cogeneration, and, in addition, billing credit resources. The costs of these resources are similar between the Program Case and the 7(b)(2) Case.

The costs of individual conservation resource investments, consisting of the historical and projected capitalized and expensed costs, are nearly identical in the two Cases. These historical costs of conservation resources are then escalated for changes in the time value of money, as discussed in Section 16.6, Issue 1 below, so they are stated in comparable Five-Year Period costs.

The amortization and debt maturity time periods of capitalized conservation costs have differed between the two Cases starting with BPA's WP-02 rate case. Prior to that time, the financing period for the capitalized costs was 20 years in both the Program Case and the 7(b)(2) Case. Starting in FY 2002, BPA has followed two different amortization and financing periods for capitalized conservation costs in its financial statements (reflected in the Program Case) as outlined above, while updating to adhere to the Council's estimate of conservation useful lives to set the amortization and financing period at 15 years in the 7(b)(2) Case for conservation resources acquired after 2001. Because a smaller proportion of historical and projected BPA conservation costs are being capitalized in recent time periods as compared to annual programmatic conservation investments occurring before FY 2002, the impact of the difference in the amortization and debt maturity time periods between the two Cases has not been as large or material as it would have been had higher percentages of annual costs been capitalized. Should a higher proportion of annual programmatic expenditures be capitalized in the future, the difference in amortization periods between the Program Case and the 7(b)(2) Case could cause a greater difference in the level of conservation costs present in the two Cases.

A comparison of the amount of conservation costs that are present in the Program Case with the amount of costs contained in and the 7(b)(2) Case for a single conservation resource is informative in gauging the level of comparability in the alternative cost treatments of conservation costs between the two Cases.

As the table below shows, under Alternative 1 (PPC's and Cowlitz's proposal), capitalizing all the conservation costs in the 7(b)(2) Case would recover only 33.3 percent of the conservation costs in the 7(b)(2) Case during the Five-Year Period, while 100 percent of these costs would be recovered in the Program Case during the same period. Alternative 2 (Staff's Initial Proposal) recovers 75.4 percent of the conservation costs in the 7(b)(2) Case during the Five-Year Period, compared to 100 percent for the Program Case during the same period. Alternative 3A, Staff's rebuttal hybrid proposal recommendation also recovered 75.4 percent of conservation costs in the 7(b)(2) Case during the Five-year period, but the timing of when costs occur over the Five-year period differs. Alternative 3B refines the hybrid approach and moves closer to the PPC and Cowlitz proposal that proposed capitalizing all conservation costs. The hybrid approach for the Final Proposal produces a level of conservation cost recovery in the 7(b)(2) Case of 57.4 percent that is more comparable to the level of costs that is present in the Program Case when compared to Alternative 1 that was advanced by the PPC and Cowlitz.

Comparison of the Amount of Conservation Costs Recovered Under Three Alternatives

	Program Case Costs[15]			**7(b)(2) Case Costs**[1]		
	Expensed Costs-%	Capital Costs-%	Total Cost-%	Expensed Costs-%	Capital Costs-%	Total Cost-%
Alternative 1[16]						
FY 2009 Rate Period	63.0%	7.4%	70.4%	00.0%	6.7%	6.7%
FY 2010-2013 Periods	00.0%	29.6%	29.6%	00.0%	26.6%	26.6%
Total Costs Recovered	**63.0%**	**37.0%**	**100.0%**		**33.3%**	**33.3%**
Alternative 2[17]						
FY 2009 Rate Period	63.0%	7.4%	70.4%	63.0%	2.5%	65.5%
FY 2010-2013 Periods	00.0%	29.6%	29.6%	00.0%	9.9%	9.9%
Total Costs Recovered	**63.0%**	**37.0%**	**100.0%**	**63.0%**	**12.4%**	**75.4%**
Alternative 3A[18]						
FY 2009 Rate Period	63.0%	7.4%	70.4%	12.6%	2.5%	15.1%
FY 2010-2013 Periods	00.0%	29.6%	29.6%	50.4%	9.9%	60.3%
	63.0%	**37.0%**	**100.0%**	**63.0%**	**12.4%**	**75.4%**

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15 This hypothetical example assumes the historical average of 63 percent of the total investment costs are costs that are appropriately expensed in the first year and 37 percent of the costs are capitalized costs in the Program Case for conservation investments occurring after during FY 1999-2013 per Appendix B to WP-07-FS-BPA-14. The conservation investment is selected from the resource stack in FY 2009 and the actual investment is projected to occur in FY 2009 in the Program Case. The Program Case amortizes capitalized conservation investments over five years.

16 Alternative 1 - Capitalize all 7(b)(2) Case Costs. This alternative ignores the distinction between costs that have been expensed and capitalized in the Program Case and capitalizes all conservation costs. The capitalized costs would be amortized and financed over a 15-year period. This alternative is advocated by PPC and Cowlitz.

17 Alternative 2 - Traditional 7(b)(2) Case Cost Treatment. This alternative follows the classification of expensed and capitalized costs used in the Program Case. Expensed costs are expensed in the first year, the year incurred. Capitalized costs are amortized and financed over a 15-year period for assets acquired after FY 2001. This alternative has been used in all prior rate cases in modeling conservation costs in the 7(b)(2) Case.

18 Alternative 3A – Modified/Traditional 7(b)(2) Case Cost Treatment. This alternative follows the classification of expensed and capitalized costs used in the Program Case. Instead of expensing all first year expensed costs in the first year, these costs are deferred and amortized and financed over a five-year period. This alternative mitigates the first-year rate shock of the traditional cost treatment approach. This alternative was advanced by Staff in rebuttal testimony (WP-07-E-BPA-85 page 105).

Alternative 3B[19]							
	FY 2009 Rate Period	63.0%	7.4%	70.4%	9.0%	2.5%	11.5%
	FY 2010-2013 Periods	00.0%	29.6%	29.6%	36.0%	9.9%	45.9%
		63.0%	**37.0%**	**100.0%**	**45.0%**	**12.4%**	**57.4%**

4. The Hypothetical Operating Environment of the Joint Operating Agency (JOA) and the Consumer-Owned Utilities in the 7(b)(2) Case

The PPC argues the hypothetical JOA would have an interest in acquiring resources in a manner that would sustain power rates at the lowest and most stable levels. PPC Br., WP-07-B-JP25-01, at 24-26. The PPC states this interest conflicts with expense financing a massive amount of conservation resources through rates in a single year. *Id*. The PPC proposed that the JOA would fully capitalize the costs of all conservation resources in the 7(b)(2) Case and amortize these costs over the useful lives of the resources, which the PPC proposed to be 15 years. O'Meara, *et al.*, WP-07-E-PP-09, at 28. The PPC stated it is unreasonable to assume that the same financing choices to achieve an amount of conservation over 15 years would be used to achieve the same amount in a single year. *Id*. The PPC claims that under cross-examination, the PPC's questioning supported a financing treatment for conservation that was similar to any other resource available to meet load. Tr. at 224. The PPC contends, in other words, in the modeling of the 7(b)(2) Case, there is no difference between a conservation resource (or group thereof) and a combustion turbine, or any other type of resource, with respect to how it meets load. PPC Br., WP-07-B-JP25-01, at 24-26. The PPC argues, for this reason, how actual utilities, JOAs, or BPA actually finance or have previously financed conservation is less relevant than the specific question BPA must determine: how the JOA in the 7(b)(2) Case would finance a very large resource (over 500 aMW) brought on to meet load. Tr. at 224-225. PPC argues that standard industry practice for financing such a resource is to capitalize the cost of such a resource and amortize those costs over the useful life of the resource. PPC Br., WP-07-B-JP25-01, at 24-26. This approach is also supported by Cowlitz. Cowlitz Br., WP-07-B-CO-01, at 34-37. These positions favor Alternative 1.

In rebuttal testimony, Staff presented a number of arguments establishing that the operating and financial environment of the JOA and member COUs would still face some of the same facts and circumstances that are present today and, for those reasons, the treatment of conservation costs would not be much different than it is today. Doubleday, *et al.*, WP-07-E-BPA-85, at 98-116. Additional arguments in support of Alternative 3B are as follows:

(a) The JOA and its member COUs would want to operate in a manner that is consistent with sound business principles. Conducting their operations under sound business principles would require the JOA to: (1) be cognizant of matching the current costs of operations and current rates; (2) adopt

[19] Alternative 3B – Modified/Traditional 7(b)(2) Case Cost Treatment. This alternative follows the classification of expensed and capitalized costs used in the Program Case. Instead of expensing all first year expensed costs in the first year, these costs are deferred and amortized and financed over a seven-year period. This alternative mitigates the first-year rate shock of the traditional cost treatment approach.

accounting policies consistent with GASB and FASB pronouncements; (3) maintain high credit ratings so the cost of financing their operations would be low; and (4) maintain adequate financial reserves for operations and to meet or exceed debt coverage ratio requirements associated with bond covenants and operating lines of credit.

(b) The financial pressures on the hypothetical JOA would be similar to the financial pressures faced by BPA; that is, it would have debt covenants that would have minimum required debt coverage ratios that would have to be maintained. The individual utility boards would probably mandate a coverage level above the minimum level specified in the debt issues. The boards would have to follow GASB pronouncements if they wanted a clean annual audit opinion. In addition, they would likely elect to implement FASB statements and interpretations, especially SFAS No. 71. BPA and the JOA would be governmental entities operating in the electric utility industry. Financially, the JOA and member COUs would be more like BPA.

(c) The JOA and the member utilities would be able to capitalize and defer conservation expenditures as intangible regulatory assets as long as they could demonstrate the expenditures were recoverable in future rates. These deferred regulatory assets have value only if they can be recovered in rates over future time periods. Under deregulation of utility rates, auditors and rating agencies have expressed concerns that deferred costs such as intangible conservation expenses could become stranded utility costs; that is, costs that are not recoverable in rates and are thus written off as a loss. Sound business practices and prudent utility practices would temper the accumulated amount of deferred regulatory assets that are present in a utility's balance sheet.

(d) The composition of conservation programs has changed since 2001. A greater percentage of expenditures are classified as operating expenses of the period. Market transformation expenditures are expenses of the period, along with staffing costs and general and administrative costs of running the program. As pointed out above, most COUs in the region currently expense all overhead and administrative costs of their conservation programs while capitalizing and amortizing conservation acquisition expenditures. Although the argument can be made that a large turnkey conservation contract could be fully capitalized, it is just as, if not more, plausible that the portions of the contracted costs that were not associated with direct conservation acquisition activities would be expensed. As noted above, conservation expenditures could be viewed as similar to annual advertising expenditures in that they preserve the competitive position of the region's electric utility infrastructure by decreasing the need to invest in more expensive generation resources, just as advertising promotes and maintains the demand for a company's products.

(e) From a ratemaking perspective, the JOA and its member COUs would adopt a balanced approach in dealing with the upward rate pressures associated with

> the high first-year costs of conducting a large (approximately 500 aMW) conservation program and concerns over accumulating substantial balances of deferred regulatory assets that would be have to be recovered from future rate periods. A balanced and prudent approach would be to capitalize and finance the smaller portion of direct acquisition costs (approximately 37 percent of total costs) of the conservation program over their useful life (15 years), while spreading the large amount of first-year expensed costs (63 percent of costs) over a one-year to useful-life period based on the conservation resources selected from the resource stack and their relationship to the total package of resources selected to meet 7(b)(2) Customer loads in the prospective rate case. Alternative 3B would decrease the level of rate impacts as compared to the rate impacts associated with Alternative 2 the Initial Proposal, while providing a level of costs in the 7(b)(2) Case that is more comparable to the level of costs in the Program Case when compared to Alternative 1.

O. The Hybrid Approach

A decision in this Supplemental Proceeding to defer the first-year expensed costs of conservation could change in future rate cases to address changes in the composition of resources from the resource stack. As noted previously, the composition of annual conservation investments between the portions that have been capitalized and the portions that have been expensed has changed over the years. If future years of conservation investment have higher levels of direct acquisition expenditures that are capitalized, then a higher proportion of that year's investments will be capitalized. This would mitigate the amount of first-year expensed costs, which in turn would reduce the need to defer these expenditures over a longer period of time to reduce the cumulative rate shock associated with multiple years of conservation investments. In addition, other non-conservation resources in the resource stack might prove to be the least-cost resources in a future rate case so the number of conservation investments selected to meet 7(b)(2) Customer loads could be reduced in a future rate case. This also would mitigate the need in future rate cases to defer the first-year expensed costs of conservation. The JOA and its member COUs would not want a rigid policy covering the deferral of first-year expensed costs that could not be changed to address the dynamics of the package of resources that are selected from the resource stack to meet the loads of 7(b)(2) Customers in those respective time periods.

BPA will amortize and finance the historical and projected capitalized conservation costs in the resource stack over 15 years. The first-year historically expensed costs in the resource stack will be treated as deferred charges under SFAS No. 71 and will be amortized and financed over a 7-year period in this rate case. The period over which conservation first-year expense costs are deferred/amortized and financed could change in future rate cases (between 1 year to the useful life) to address the conservation resources selected from the resource stack and their relationship to the total package of resources selected to meet 7(b)(2) Customer loads in the prospective rate case.

BPA arrived at this decision by carefully considering the facts contained in the background information along with the decision factors pertinent to this issue. The best indicator of how the JOA and member COUs would finance a large (approximately 500 aMW) conservation program would be more aligned with the current practices of the region's COUs. As stated previously, most COUs with large conservation programs in the region currently expense all overhead and administrative costs of their conservation programs and capitalize and amortize conservation acquisition expenditures over their useful lives. BPA found merit in PPC's and Cowlitz's arguments that the same traditional approach of financing conservation in the past would need to be modified to address the cumulative amount of first-year conservation expensed costs. First-year expensed costs would be treated as regulatory assets (deferred charges) and amortized and financed over a 7-year period in the Final Supplemental Proposal.

Parties' arguments that the JOA and COUs would ignore established accounting principles and choose to defer and capitalize all conservation costs over the useful life of the capitalized portion of costs in order to shift costs to future years and keep current rates low were one approach to this issue, but ultimately they were not convincing. Concerns for sound business practices of matching current operating costs against current revenues, establishing adequate debt coverage ratios to meet bond covenants, and maintaining high credit ratings to ensure access to capital should have been given more weight and consideration by PPC and Cowlitz in developing their proposal on how conservation costs should be accounted for and financed in the 7(b)(2) Case. BPA's decision provides a more balanced approach to addressing the high level of first-year expensed costs by deferring these expenses and financing them over a one-year to useful-life period as opposed to the 15-year period that would result from adopting PPC's and Cowlitz's recommendation of capitalizing all conservation costs. BPA adopted a first-year expense deferral period of 7 years for this rate case.

With regard to the levelized cost arguments, BPA did not find merit in the parties' arguments that the traditional "least-cost" selection process that ranks resources based on the average of the discounted annual cash flows over the resource's useful life should be changed for a selection process that would evaluate the cost of resources based on the costs that occur during the Five-Year Period. This would be an imprudent way to approach resource acquisitions, so it is not one that BPA can select consistent with sound business principles. BPA was not convinced of the appropriateness of "solving" the "least-cost" selection process by capitalizing all conservation costs and ignoring the "true nature" of how conservation programs are conducted and financed with a substantial amount of up-front expenses paid for in current rates. Although the total capitalization approach is viewed as a solution by PPC and Cowlitz, it capitalizes current operating expenses that are generally matched against the income of the year in which the expenses are incurred. BPA's decision to retain the identity of these costs as being costs that are expensed, but choosing to defer these first-year conservation expenses over a 7-year period in this rate case, substantially mitigates the difference in the levelized cost calculation that is based on all conservation being capitalized and financed over 15 years in PPC's approach.

The comparability of resource cost treatment between the Program Case and the 7(b)(2) Case, as measured by the amount of the total resource costs that are recovered during the five-year period, demonstrated that BPA's proposal provides a more comparable cost treatment between the two Cases compared to the PPC and Cowlitz recommendation.

PPC's and Cowlitz's proposed cost treatment for conservation investments focused too much on keeping rates low in the short run without addressing the long-term business and financial needs of the JOA and its member COUs. Their proposal does not take into account concerns for sound business practices that advocate the matching of current operating costs against current revenues, establishing adequate debt coverage ratios to meet bond covenants, and maintaining high credit ratings to ensure access to capital. BPA's proposal provides a more balanced and prudent approach for capitalizing and financing the smaller portion of direct acquisition costs (approximately 37 percent of total costs) of the conservation programs over their useful lives (15 years), while spreading the larger amount of first-year expensed costs (63 percent of costs) over a 7-year period in this rate case as opposed to the 15-year period that would result from adopting the PPC's and Cowlitz's recommendation.

BPA's decision, then, is to defer the first-year expensed costs and finance them over a 7-year period in this rate case. This is a reasonable approach for dealing with the cumulative first-year expense costs that result from multiple years of conservation investment being selected in the first year of the rate test. BPA's approach reflects the wide range of accounting treatments that BPA has used throughout the years and that are in use by other utilities throughout the region. BPA's approach of capitalizing the historical and projected amounts of conservation expenditures for the direct acquisition of conservation savings and amortizing and financing them over their useful life of 15 years, based on estimates independently determined by the Council, is appropriate. BPA's proposal is more comparable to the present treatment of conservation by a number of COUs with large conservation programs in the region. The current treatment of conservation expenditures by these entities is more indicative of how the JOA and its member COU entities would treat conservation costs in the 7(b)(2) Case.

BPA will consider alternative "least cost" ranking methods that give more effect to the cost of the resources selected for the five-year period that are included in 7(b)(2) Case rates during the next rate case.

In its Brief on Exceptions, PPC notes that it previously argued that BPA improperly used historical financing assumptions for conservation. PPC Br. Ex., WP-07-R-PP-01, at 14. PPC notes that BPA responded in the Draft ROD and agreed with PPC and Cowlitz that the manner in which the JOA in the 7(b)(2) Case would finance conservation is a more appropriate focus than BPA's historical practice of financing conservation resources. *Id.* PPC states that BPA now proposes to treat first-year historically expensed conservation costs as deferred charges under SFAS No. 71, and to assume a financing of these costs and amortization "over a one-year to useful life period." *Id*. PPC states that it appreciates BPA's consideration and response to its argument that historical conservation financing should not be determinative of how a JOA is assumed to finance conservation in the 7(b)(2) Case because the Draft ROD's approach is more appropriate than the Initial Proposal's approach to this issue, and PPC supports it over the Initial Proposal approach. *Id*. PPC, however, reasserts that, for all of the reasons described in its Initial Brief, BPA should capitalize all, or at least the major portion of, the costs of conservation that it deems to be a resource that is able to meet load in the 7(b)(2) Case. *Id*.

BPA Staff has consistently disagreed with PPC's argument that BPA should capitalize all conservation costs and ignore the fundamental character of the first-year expensed conservation costs as being costs that are generally properly expensed in the year incurred. In rebuttal testimony, Staff advocated that a more balanced approach was needed to give consideration to the large number of conservation resources that are chosen in the first year of the rate test period from the resource stack. Doubleday, *et al*., WP-07-E-BPA-85, at 98-116. Staff's rebuttal testimony outlined a number of reasons for why the JOA in the 7(b)(2) Case would have adopted the balanced approach that BPA advanced in its such testimony. *Id*. Staff introduced its proposal to defer first-year expensed costs pursuant to SFAS No. 71 and to amortize these expenses over a period of 5 years. Staff indicated it was open to considering other alternatives for dealing with the large amount of first-year conservation costs that addressed: (1) the SFAS No. 71 accounting treatment for such costs; (2) concerns over accumulating an excessive amount of deferred costs/regulatory assets; (3) a financing treatment for the deferred costs/regulatory assets that is supported by current financing practices; and (4) a levelized cost selection metric for conservation resources. *Id*. at 106. Rather than consider different cost and financing treatments for conservation costs, PPC has consistently advanced a single approach to the financing of conservation resources, which proposes to ignore the true nature of these first-year conservation costs as costs that are generally expensed in the year incurred.

The Draft ROD refuted PPC's claim that "the standard industry practice for financing such a [conservation] resource is to capitalize the costs of the resource and amortize them over the useful life of the resource." Draft ROD, at 372-398. The Draft ROD established that the majority of utilities with large conservation programs expense the overhead and administrative costs of operating their conservation programs in the year incurred. *Id*. at 376. The Draft ROD also explained why a more balanced approach to financing the large amount of conservation resources during the rate test period was necessary. One of the factors presented in the Draft ROD was the desire to have greater consistency in the cost treatment for conservation resources between the Program Case and the 7(b)(2) Case.

The Draft ROD contained a comparison table presenting different cost treatment alternatives and the percentage of total conservation costs for a single year's investment (FY 2009) that were recovered in the Program Case compared to the 7(b)(2) Case. *Id*. at 393. This table contained in subsection N. 3 above was revised for the Final ROD to reflect the revised conservation costs outlined in Appendix D of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14, and for BPA's decision to amortize the first-year expensed costs over 7 years. As provided in the table, Alternative 1 (the PPC and Cowlitz proposal), which capitalizes all conservation costs, results in 33 percent of the total costs from a single year of conservation investment being recovered in the 7(b)(2) Case. For the Final Proposal (revised Alternative 3B in the table), all capitalized conservation resource costs are amortized and financed over a fifteen-year period and the first-year expensed costs are deferred and amortized and financed over a seven-year period in the 7(b)(2) Case. BPA's treatment in the Final Proposal recovers 57 percent of the total costs from a single year of conservation investment during the rate test period. In the Program Case, 100 percent of the conservation costs from this single year of conservation investment are recovered during the five-year period. BPA's proposal provides greater consistency and comparability in the treatment of conservation costs between the two Cases when compared to the PPC and Cowlitz proposal.

BPA's approach not only presents a more consistent and comparable treatment of conservation costs between the two Cases, but it also provides a considerable reduction in first-year conservation costs when compared to the historical treatment used in the Initial Proposal. In the

Initial Proposal, 15 years of conservation resources were selected in the first year of the rate test period with a total amount of first-year conservation costs of $759 million (if 10 years of conservation investments were selected, the total first-year costs would have been $362 million in the Initial Proposal). In the Final Proposal, 10 years of conservation investments were selected with total first year costs of $65 million. Thus, the first-year rate impact of selecting multiple conservation investments has been reduced by more than ninety-percent by adopting the deferred expense approach and by adopting a single 15-year life for all conservation investments (adopting a standard 15-year life reduced the 7(b)(2) loads in the Final Proposal, which in turn reduced the amount of resources needed to serve these loads).

Nevertheless, PPC argues the Draft ROD does not make clear exactly what BPA is proposing to do. PPC Br. Ex., WP-07-R-PP-01, at 16. PPC states the proposed range of years over which first-year conservation costs will be spread is "one to fifteen," which is unhelpful in evaluating the reasonableness of BPA's proposed application of its new proposed approach. *Id*. PPC argues that under the Northwest Power Act, it is assured of an adequate opportunity to refute or rebut the materials submitted by BPA. *Id*. However, based on the Draft ROD, PPC is unable to do so. *Id*. PPC claims that, as it stands, it will only be able to evaluate BPA's proposed approach upon review of the Final ROD, after the record has closed in the proceeding. *Id*. PPC requests that it be given a chance to at least review and offer comment on BPA's proposed decisions regarding conservation financing. *Id*. PPC expects that BPA has at least preliminary information on its proposal, but BPA has not shared that information with the parties. *Id*.

In response, although parties must be provided an adequate opportunity to refute or rebut materials submitted by the litigants, this is generally achieved through the filing of direct and rebuttal testimony, not the review of conclusions reached in decision documents that were based upon such testimony. Even assuming *arguendo* this principle applied to the Administrator's decisions, the Draft ROD provided that the proposed range of years over which first-year conservation costs would be amortized and financed is one to fifteen. This is a limited range and allows PPC to consider any of the limited numbers within this range when preparing its Brief on Exceptions. PPC therefore has had the opportunity to review and offer comment on BPA's proposed decisions regarding conservation financing. Also, the Draft ROD does not establish rates and the fact that BPA, as a courtesy to the parties, provided the parties with rough estimates of what rates would be under the Draft ROD does not mean BPA is required to provide documentation regarding such preliminary non-record calculations. Nevertheless, although the Draft ROD provided a range that would be applied in making this determination, BPA must identify a particular period over which first-year conservation costs would be amortized and financed over in order to develop rates.

PPC argues the Draft ROD does not clearly specify the criteria that BPA will use in making its determinations about conservation financing in the rate test for FY 2009 or for subsequent rate cases. PPC Br. Ex., WP-07-R-PP-01, at 16. PPC states that although BPA offers some discussion about the trade-offs that it may face in future rate periods, this does not constitute the criteria BPA will use. *Id*. PPC argues this information is inadequate to ascertain BPA's proposal, and the parties are thus denied an opportunity to comment on the proposal or evaluate it. *Id*. As noted previously, however, the Draft ROD is not the same as a rate proposal, but rather a statement of draft decisions. Regardless, given that parties knew the range of years for spreading first-year conservation costs, they could advocate the criteria they believe are most appropriate for BPA to use. Furthermore, the parties were free to argue, as PPC has done, that using a range is an inappropriate methodology. Given such comments, BPA can determine whether a range is appropriate or whether BPA should identify a specific number of years for amortizing and financing first-year conservation costs. BPA's decision on the number of years over which to defer the first-year conservation expenses is outlined below.

After reviewing the record, BPA has determined that first-year conservation costs should be amortized and financed over 7 years in this rate case. The Draft ROD described BPA's "hybrid approach," and that the decision on the number of years over which the first-year conservation costs are deferred, amortized, and financed could change in relation to the amount and composition of resources contained in the 7(b)(2) resource stack of the subject rate case. Draft ROD, at 395. In arriving at the choice of amortizing and financing the first-year expensed costs over 7 years in the current case, BPA took into account the following factors:

1. <u>Resource Stack Composition:</u> The resource stack consists of 15 years of conservation resources that total 451 aMW. Their historical and projected cost structure (nominal dollars of the year incurred or projected) is composed of $689.3 million in first-year expensed costs (63 percent) and $402.1 million in capitalized and financed costs (37 percent). In addition to conservation resources, there were eight non-conservation resources in the resource stack. Ten of the conservation resources were selected in the first year of the rate test period and four more were chosen in the remaining four years of the rate test period. Of the eight non-conservation resources, five were selected in the first year of the rate test period. The fact that a large number of conservation resources were chosen in the first year (10) favors the adoption of a longer amortization period as compared to a shorter period. The fact that 37 percent of the conservation costs were already capitalized and financed over 15 years partially mitigates the need for a longer amortization period for the first-year expensed costs. The fact that five non-conservation resources were chosen in the first year of the rate test period also partially mitigates the need for a longer deferral period for the first-year expensed costs.

2. <u>Additional Financing Costs Associated with Financing the Deferred First-Year Expensed Costs</u>: The annual interest rate associated with financing the deferred first-year conservation expensed costs for 7 years was 3.95 percent. This short-term interest rate was a favorable cost of money when viewed historically for similar rates of interest over recent time periods. This interest rate was interpolated based on Table F and Table G (page 16) of the August 21, 2008, Financing Study Report prepared by Public Financial Management at Appendix A of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14. The total cumulative amount of interest expense associated with financing the deferred first-year expense costs over the FY 2009-2018 period totaled $103.6 million (fourteen of fifteen conservation resources were selected in rate test period years FY 2009-2012 and financed for 7 years), and the total amount of first-year operating expenses associated with the fourteen conservation resources inflated to the rate test period year of selection totaled $630.5 million, so the financing of these costs increased their cost by approximately 16.4 percent. This increased cost of acquiring conservation resources of $103.6 million in relation to the first year (FY 2009) revenue requirement cost savings of

approximately $297 million ($362 million for the first ten conservation resources in the Initial Proposal less $65 million for the ten conservation resources selected in FY 2009 in the Final Proposal) in conservation costs (savings attributable to deferral of first-year costs) was a fairly high cost to pay to reduce the first-year rate shock of investing in multiple years of conservation investments by the JOA and to help provide rate stability for its member utilities and their ratepayers. Financing the deferred first-year expense costs over a period as long as 15 years would have increased the first-year expense cost by approximately 34 percent over a 15-year financing period. This level of increased cost in relation to the first-year rate savings is not as reasonable as the choice to defer the first-year expenses over a 7-year period.

3. Number of Years Required to Recover Conservation Costs: The weighted average cost recovery period of conservation assets is 9.96 years under BPA's accounting and financing treatment for the 7(b)(2) Case in the Final Proposal. This is compared to a weighted average cost recovery period of 6.18 years under the traditional historical cost treatment of conservation assets where no deferral of first year costs occurs under SFAS No. 71. BPA viewed this rate of recovery, which was approximately 150 percent of the traditional recovery period, as being reasonable. This level of recovery should not compromise other financial measures such as debt coverage ratios and overall financial health and flexibility of the JOA in the 7(b)(2) Case. BPA viewed a deferral recovery period that was greater than 200 percent of the traditional recovery period as being too negative in terms of the period of time over which borrowed funds would have to be used to finance costs that normally would have been recovered in rates in the year incurred.

4. Cost Treatment Comparability Between the Two Cases: As noted above, it is important that the cost treatment of resources be more alike and similar in the two Cases as opposed to being dramatically different. As provided in the Draft ROD in subsections E and F of Section 16.4, the amortization and financing periods covering capitalized conservation costs are different between the two Cases. Draft ROD, at 377-381. The amortization period for the 7(b)(2) Case is 15 years (consistent with the weighted average life of conservation measures in the NWPPC's Fifth Power Plan) while the Program Case uses a period of 5 years to replenish the amount of unused Treasury borrowing authority more quickly so that a greater level of capitalized conservation investments can occur over time. Thus, the 7(b)(2) Case already receives more favorable cost treatment concerning capitalized expenditures in amortizing and financing them over a period that is three times as long as the period used in the Program Case.

   In the Program Case, first-year expensed costs are expensed in the year incurred. In the 7(b)(2) Case, due to the cumulative number of conservation programs and their associated costs that are being selected, a different approach than the traditional historical approach is being adopted for the Final Proposal. BPA is making the assumption that the JOA in the 7(b)(2) Case would adopt the balanced approach that BPA is using to defer first-year expensed costs pursuant to SFAS No. 71 over a period of 1 to 15 years in each respective rate case. This treatment in the 7(b)(2) Case greatly reduces the amount of first-year expensed costs present in the 7(b)(2) Case revenue requirement for the first year of the rate test period. In the Initial Proposal, which used the traditional approach of expensing first-year expense costs as incurred, 15 years of conservation resources were selected in the first year of the rate test period with a total amount of costs for FY 2009 of $759 million.

In the Final Proposal, 10 years of conservation investments were selected with total conservation costs of $65 million for FY 2009. Thus, the first year rate impact of selecting multiple conservation investments has been reduced by more than ninety-percent by adopting the deferred expense approach and by adopting a single 15-year life for all conservation. As noted in the table in this chapter, Alternative 1, the PPC and Cowlitz proposal that capitalizes all conservation costs results in 33 percent of the total costs from a single year of conservation investment being recovered in the 7(b)(2) Case during the rate test period. For the Final Proposal (revised Alternative 3B in the table), all capitalized conservation resource costs are amortized and financed over a 15-year period and the first-year expensed costs are deferred and amortized and financed over a 7-year period in the 7(b)(2) Case. BPA's treatment in the Final Proposal recovers 57 percent of the total costs from a single year of conservation investment being recovered during the rate test period. In the Program Case, 100 percent of the conservation costs from this single year of conservation investment are recovered during the 5-year period. BPA's proposal of deferring the first-year expensed costs over 7 years provides greater consistency and comparability in the treatment of conservation costs between the two Cases when compared to the PPC and Cowlitz alternative of capitalizing all expenditures and deferring and financing them over 15 years. This criterion of comparability of cost treatment for the same resource between the Program Case and the 7(b)(2) Case was also advanced and supported by Cowlitz in its discussion of the comparability of the costs of the Idaho Falls resource between the two Cases. *See* Cowlitz Br., WP-07-B-CO-1, at 33.

BPA has determined for rate development in the instant case that an amortization and financing period of 7 years should be used. As noted above, the decision on the number of years over which the first-year conservation costs are deferred, amortized, and financed can change in relation to the amount and composition of resources contained in the 7(b)(2) Case resource stack of the particular rate case. For example, if the composition of conservation resources discussed in point number 1 above were comprised of resources whose capitalized costs constituted more than 60 percent of the total conservation costs in the resource stack, the need to defer the first-year conservation costs would be much lower than the present case, where 37 percent of the conservation costs in the resource stack are capitalized and financed over 15 years. If the resource stack in future rate cases contained a large amount of less expensive non-conservation resources that were selected first, and if very few conservation resources were selected to serve the 7(b)(2) loads during the rate test period, the need to defer the first-year conservation costs would probably not be present in that rate case. With regard to decision criterion number 2, the cost of financing the deferred first-year costs, the interest rate spread between generally less expensive short-term financing and the cost of more expensive longer-term financing that exists in future rate cases would have to be taken into account in deciding the period of time over which to defer and finance the first-year conservation expenses. The decision criteria listed in points 3 (Number of Years Required to Recover Conservation Costs) and 4 (Cost Treatment Comparability Between the Two Cases) would also need to be factored into the relevant rate case. Additional decision criteria could also be identified in future rate cases. The amount of weight given to various decision criteria could also change in the subject rate case.

Cowlitz argues that the Administrator's "one year to useful life" amortization approach for conservation resources (*i.e.,* that BPA may choose in its discretion any amortization period from as short as one year to as long as the useful life of the conservation measure based entirely on factors nowhere mentioned in section 7(b)(2)) exemplifies the lack of any statutory basis for the discretion BPA claims. Cowlitz Br. Ex., WP-07-R-CO-01, at 23. As noted previously, however, simply because a statute does not expressly contain all of the detailed instructions needed to implement the statute does not mean that an agency is precluded from doing what is necessary to implement the statute in a sound and reasonable manner. For example, section 7(b)(2) does not prescribe the manner in which BPA is to determine least expensive resources, yet BPA must do so. *See* 16 U.S.C. § 839e(b)(2)(D). Furthermore, Cowlitz fails to present the full facts regarding the arguments it presented with PPC that conservation should be accounted for and financed differently in the 7(b)(2) Case. BPA necessarily must exercise judgment in order to address Cowlitz's concerns over the large amount of first-year conservation costs that are present in the 7(b)(2) Case revenue requirement in the first year of the rate test period (FY2009 in the Five-Year period; FY2009-2013 used to revise FY 2009 rates). BPA has an objective accounting policy that it has consistently followed for more than twenty-five years for classifying conservation costs in the Program Case as either costs that are expensed in the year incurred or capitalized costs that are financed over a period of years. As BPA noted in the Draft ROD, BPA's capitalization and expense policy for conservation is similar to a large number of COUs in the region that have large conservation programs. These COUs, and BPA, expense a substantial portion of conservation program costs that relate to staff salaries and all overhead and administrative costs ("first-year" conservation expenses) connected with running their conservation programs. In conducting past 7(b)(2) rate tests, BPA has followed the same accounting policy used in the Program Case of expensing first-year expense costs in the year incurred. It was Cowlitz and PPC that argued for the adoption of a different accounting and financing treatment for conservation in the 7(b)(2) Case from what was used in the Program Case. Cowlitz and PPC argued that the Joint Operating Agency that would be coordinating and financing the conservation programs for 7(b)(2) Customers in the 7(b)(2) Case would not choose to account for and finance conservation costs in the same manner that was used historically in the Program Case. Cowlitz Br., WP-07-B-CO-01, at 37; PPC Br., WP-07-B-JP25-01, at 25. Cowlitz and the PPC proposed to capitalize all conservation costs in the 7(b)(2) Case, even though approximately 63 percent of these costs were historically or projected to be expensed in the Program Case. In the Program Case, conservation is acquired in annual program increments one year at a time. In the present 7(b)(2) Case, multiple years of vintage conservation programs have been selected to meet 7(b)(2) loads. The multiple years of conservation investments and their cumulative first-year costs increased the costs of the first year of the rate test period by a significant amount. To be responsive to Cowlitz's and the PPC's concerns concerning the significant amount of first-year expensed costs, BPA proposed a policy of deferring these costs under SFAS No. 71 and to amortize them and finance them over a period of 1 to 15 years (the capitalized conservation costs are amortized and financed over a period of 15 years in the 7(b)(2) Case). BPA believes this range of years is necessary to address the following circumstances:

1. In prior rate cases there have been instances where no resources or very few resources were selected from the 7(b)(2) resource stack to meet the loads in the 7(b)(2) Case. In those instances there would be no need to defer the first-year expense costs. Thus, such prior circumstances argue for the ability of the Administrator to choose a period of one year or the traditional approach of expensing the first-year expenses as incurred.

2. There have been periods of time where the amount of conservation costs that were capitalized for the year (large conservation direct acquisition programs were in effect) have approached 80 percent and the expensed portion was 20 percent, where the need to defer the first-year expensed costs would be very slight or not present. Should the composition of historic or projected conservation programs again contain this high a portion of capitalized expenditures, the Administrator should have the ability to choose the traditional approach of expensing the costs as incurred.

3. In the event there were dramatic regional load growth and BPA increased the size of its conservation programs commensurately for a number of years, the amount of first-year expensed costs would be very significant. BPA would be very concerned over the rate impacts associated with the conservation effort on the regional economy and could choose to defer the first-year expensed costs in the Program Case over a long period of time that approached the useful life of the conservation measures. BPA would want to adopt a similar accounting and financing approach in the 7(b)(2) Case. Thus, this circumstance would argue for the Administrator to have the discretion to choose an accounting and financing period that approached 15 years.

The utility industry is a very dynamic industry that has experienced dramatic changes in both the rate of load growth over time, the cost of new resources, and the cost of fuel stocks to operate resources. To meet the accounting and regulatory environment of the utility industry, the Financial Accounting Standards Board adopted SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," which allows utility companies to defer costs that would normally be expensed, and to treat them as "Rate Regulated Created Assets." As BPA pointed out in the Draft ROD, utilities can choose different conservation accounting and financing treatments, all of which would be in conformance with Generally Accepted Accounting Principles due to the wide latitude afforded by SFAS No. 71. The Draft ROD also pointed out the wide range of different accounting practices that are being followed by COUs and IOUs in the region, which range from expensing all conservation costs as incurred to amortizing the capitalized costs of conservation programs over 20 years. To help ensure consistency in BPA's 7(b)(2) accounting policy for first-year conservation costs from rate case to rate case, BPA has proposed a set of criteria that it will use to determine the appropriate deferral period that these costs should be amortized and financed over. BPA requires reasonable flexibility regarding the treatment of first-year conservation expenses that BPA is proposing, which is necessary to address the different circumstances that can be present in future rate cases.

Decision

For the 7(b)(2) Case resource stack, historical and projected capitalized conservation costs will be amortized and financed over a 15-year period. The first-year historically expensed costs will be treated as deferred charges under SFAS No. 71, and these costs will be amortized and financed over a one-year to useful-life period. In this rate case, the decision was made to defer the first year expense cost over seven years. This approach mitigates the first-year rate shock associated with the large number of programmatic conservation resources being selected from the resource stack in the first year of the Five-year period. The financing parameters will be assessed in each case depending on the number of conservation resources drawn from the stack and the then-current accounting practices for conservation costs. Conservation investments that have been fully amortized (FY 1998 and prior years) will be considered obsolete resources that are not available to serve 7(b)(2) Customer loads in the 7(b)(2) Case.

16.5 Costs of Other Resources Contained in the 7(b)(2) Resource Stack: Verification of Resource Costs

Issue 1

Whether BPA has properly determined resource costs for the resources contained in the 7(b)(2) resource stack.

Parties' Positions

The IOUs argue that BPA must develop a full and complete justification for the resources to be included in the 7(b)(2) resource stack, information regarding these resources, and the appropriate costs attributable to those resources to be included in determining the 7(b)(2) Case costs. IOU Br., WP-07-B-JP6-01, at 27-32. The IOUs claim BPA must demonstrate that (1) any resource included in the 7(b)(2)(D) resource stack for any portion of the Five-Year Period is, in fact, a resource that is projected to operate (*e.g.*, not obsolete) during such Five-Year period, and (2) the costs in the 7(b)(2) Case resource stack of any such resource are, in fact, the projected costs of such resource. *Id*. The IOUs argue that BPA must include realistic resource costs for resources in the 7(b)(2) Case resource stack, claiming that just using historical costs of resources adjusted by general rates of inflation (by using a GDP deflator) was arbitrary and capricious. *Id*. They claim the current costs for such items as the price of materials and fuel can greatly exceed the historical costs adjusted for the rate of inflation. *Id*.

The IOUs also argue that Administrative and General Costs allocable to a resource must be included in resource costs reflected in the 7(b)(2) Case resource stack. *Id*. at 31. The IOUs suggest that the Nine Canyon Wind Project should include charges for within-hour balancing transmission costs that become effective in October 2008. *Id*.

BPA Staff's Position

BPA Staff agreed with most of the IOUs' arguments. Doubleday, *et al.,* WP-07-E-BPA-85, at 67-70. Staff agreed it should provide a full and complete justification for including resources in the resource stack along with the documentation used to determine the cost of the resources in the stack. *Id.* Staff agreed the resources contained in the resource stack must be available and capable of meeting the 7(b)(2) Customer loads in all years of the Five-Year Period. *Id.*

Staff obtained a sufficient body of information and documentation for the operation of the non-conservation resources in the resource stack to make a reasonable projection of the operating costs for those resources during the Five-Year Period. Staff has determined that these resources are currently projected by the resource owners to operate during the respective Five-Year Periods. BPA is confident that the documentation of resource costs in the final study for non-conservation resources will adequately document the operating costs of those resources.

Evaluation of Positions

The IOUs argue BPA must verify resource costs in the 7(b)(2) Case resource stack. IOU Br., WP-07-B-JP6-01, at 27-32. They argue BPA must develop a full and complete justification for the resources to be included in the 7(b)(2)(D) resource stack, information regarding these resources, and the appropriate costs attributable to those resources to be included in determining the 7(b)(2) Case costs. *Id*.

Staff agreed it should provide a full and complete justification for including resources in the resource stack along with the documentation used to determine the cost of the resources in the stack. Doubleday, *et al.,* WP-07-E-BPA-85, at 67-70. Staff obtained a sufficient body of information and documentation for the operation of the non-conservation resources in the resource stack to make a reasonable projection of the operating costs of those resources during the Five-Year Period. *Id.* Staff has determined that these resources are currently projected by the resource owners to operate during the respective Five-Year Periods.

In the case of Type 1 resources, the current practice of using the actual financing costs adjusted for refinancing savings is correct. Doubleday, *et al.,* WP-07-E-BPA-85, at 67-70. This practice is also correct for Type 2 resources that have already been built, where the financing is already in place. *Id*. The current practice of relying on the operating costs reflected in current financial reports, FERC Form 1 information, or the projected operating budgets by the resource owner/operator to project the costs that will be incurred during the Five-Year Period provides a reasonable approximation of the costs that will be incurred during such period. *Id*.

BPA has acquired all or a portion of the output from four Type 1 resources: four small billing credit resources, which are represented as a combined single resource in the resource stack for modeling simplicity; the Idaho Falls Hydro Project; the Cowlitz Falls Hydro Project; and the Wauna Cogeneration resource. The projected resource costs for these resources for the Five-Year Period are based on the purchase power contract costs BPA is projected to pay during the Five-Year Period. The costs for these resources, with the exception of the Cowlitz Falls Hydro Project, are limited to the projected purchase power contract costs. The IOUs' resource cost concerns outlined above are not germane to purchase power contracts. The costs of these resources are determined contractually, and one can reasonably assume the seller of the resource is recovering its costs along with an adequate rate of return on its investment. The updated FY 2009 cost projections for these resources developed in the Integrated Program Review (IPR) process will be included in the final study and will closely follow the format of the documentation for these resources provided in Staff's rebuttal testimony. *See* Doubleday, *et al.*, WP-07-E-BPA-85, Attachment 6, Subpart 3 (Idaho Falls), at 85; Attachment 6, Subpart 4 (Wauna Cogen), at 86; and Attachment 6, Subpart 6 (Billing Credits), at 89-91. The out-year costs (FY 2010-2013) for these resources are the escalated costs for the year the resources are chosen from the resource stack as adjusted by the GDP price deflator series.

The Cowlitz Falls Hydro resource is the only Type 1 resource that is subject to BPA's financial backing. Due to BPA's financial backing, it achieved a lower financing cost, which is reflected in the costs for this resource contained in the Program Case. The purchase power contract for this resource requires BPA to pay the debt service on the bonds used to finance the project, along with the operations and maintenance costs of the project and the cost of transmission service to integrate and transmit the power generated from the project. In the 7(b)(2) Case, the debt service costs associated with the refinanced debt are "re-priced" in the 7(b)(2) Case to reflect the higher financing costs of this resource. The increased financing cost spread is based on the revised financing study report prepared by Public Financial Management. The O&M costs and the transmission costs for this resource are based on the projected purchase power contract provisions reflected in the Program Case. The updated IPR FY 2009 cost projections for this resource (consistent with IPR FY 2009 cost projections) will be included in the final study and will closely follow the format of the documentation for this resource that was provided in Staff rebuttal testimony.

The Type 2 resources owned or purchased by a COU with a section 5(b) contract, but not committed to load, include: the Nine Canyon Wind Project, the 10 percent share of the Boardman coal plant owned by COUs through their interests in the Power Resources Cooperative; and a small portion of Grant PUD's Priest Rapids and Wanapum Hydro project resources output purchased by COUs in the region but not dedicated to regional loads.

The non-dedicated portion of Phases 1 and 2 of the Nine Canyon Wind Project that were available to meet 7(b)(2) Customer loads during the FY 2007-2008 Lookback period was 26.9 MW. The costs for that resource in the WP-07 Final Proposal resource stack were documented. *See* Doubleday, *et al.*, WP-07-E-BPA-85, Attachment 6, Subpart 5, at 88. The projected operating costs for this period were based on Energy Northwest's FY 2006 budget projections, which were escalated to FY 2007 operating costs. These budget costs contained General and Administrative costs and all of the reasonably projected operating costs of this resource for the Five-Year Period. These costs are not being updated for the results of actual operations in keeping with the Lookback methodology of using the information available at the time BPA's WP-07 Final Proposal was prepared.

The costs of the Nine Canyon Wind Project have been updated for the revision of FY 2009 based on additional information obtained from Energy Northwest, the entity that manages and operates the project. This additional information consists of the actual operating results for the years

2006, 2007, and 2008, along with the operating budget for this project for 2009. Phase 3 of the project became operational in May 2008 and is available to serve 7(b)(2) Customer loads during the Five-Year Period. The total non-dedicated capacity of the project that is available to meet 7(b)(2) Customer loads during this period is 46 MW. In addition to the projected 2009 operating budget costs that were prepared by Energy Northwest, BPA will include the operating costs for control area reserves and within-hour balancing charges, based on the rates established by BPA's 2009 Wind Integration Rate Case, which will become effective October 1, 2008. BPA has revised the costs of this resource for this new information to ensure that the projected operating costs during the Five-Year Period are a reasonable projection of the costs that will be incurred. The FY 2009 operating cost estimates from Energy Northwest were not available at the time the initial Supplemental Proposal was developed. The documentation for the revised projected operating costs will be contained in the final study. These revised projected operating costs for FY 2009 address all of the IOUs' cost-of-resource concerns described above.

Ten percent of the Boardman coal plant is owned by COUs through their interests in Power Resources Cooperative. This 10 percent share has been sold to the Turlock Irrigation District in California and therefore is not dedicated to regional loads and is available in the resource stack to meet additional 7(b)(2) Customer loads. Staff is revising the projected operating costs for Boardman based on past historical operating cost information contained in Portland General Electric's FERC Form 1 report for 2007 along with the plant's operating budget for 2008 that was obtained through a data request to PGE. The FERC Form 1 information has been audited and reviewed by an independent certified public accounting firm, which helps to ensure the accuracy of the information. The revised operating cost projections for the resource will include a reasonable allocation of General and Administrative expenses that need to be included to reflect the complete costs of operating the coal plant. BPA's fuel cost projection for the Five-Year Period will be informed by projected coal cost information obtained from the Energy Information Administration. The documentation for the revised operating cost projections for the Boardman resource will be contained in the final study. These revised projected operating costs for the FY 2007-2008 Lookback period and the FY 2009 rate period should address the IOUs' cost-of-resource concerns described above.

Projected cost information for the Priest Rapids and Wanapum Hydro project resources (approximately 25 aMW of these resources have been purchased by COUs and are not dedicated to their native loads) is documented in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix C, at C-6 through C-17. This information will be updated for more recent operating cost information contained in Grant County PUD's annual operating reports for the final study. These revised projected operating costs for the FY 2007-2008 Lookback period and the FY 2009 rate period should address the IOUs' cost-of-resource concerns described above.

The IOUs argue BPA must demonstrate that (1) any resource included in the 7(b)(2)(D) resource stack for any portion of the Five-Year Period is, in fact, a resource that is projected to operate during such Five-Year period, and (2) the costs in the 7(b)(2)(D) resource stack of any such resource are, in fact, the projected costs of such resource. IOU Br., WP-07-B-JP6-01, at 28. Staff agreed the resources contained in the resource stack must be available and capable of meeting additional 7(b)(2) Customer loads in all years of the Five-Year Period. Doubleday, *et al.,* WP-07-E-BPA-85, at 67-70. Also, the costs in the 7(b)(2)(D) resource stack should be the projected costs of such resources. *Id*. The resources in the resource stack satisfy these requirements.

The IOUs argue General and Administrative (G&A) Costs allocable to a resource must be included in resource costs reflected in the 7(b)(2)(D) resource stack. IOU Br., WP-07-B-JP6-01, at 28. Staff believes the methods used to develop resource costs result in G&A costs being included in the cost of resources contained in the resource stack. Doubleday, *et al.,* WP-07-E-BPA-85, at 72-73. Conservation resources in the resource stack contain an allocation of G&A costs. BPA assumes the resource costs associated with BPA's Type 1 resources purchased from COUs and based on the seller's projection of market prices in the power purchase contract implicitly contain an allocation of G&A costs. The costs of other resources in the stack (Type 2 resources) are developed based on financial statement data, FERC Form 1 information, and projected operating budgets explicitly contain a reasonable allocation of G&A costs. Thus, all the necessary and reasonable costs required for the resources to operate are contained in the resource stack costs, including G&A costs.

The IOUs argue the Nine Canyon Wind Project should include the charges for within-hour balancing transmission costs that become effective in October 2008. IOU Br., WP-07-B-JP6-01, at 28. The IOUs note that BPA has indicated that the within-hour balancing costs may increase in the future, as wind penetration levels increase. *Id*. As described above, Staff has included within-hour balancing charges in the operating costs for this resource, based on the rates established by BPA's 2009 Wind Integration Rate Case that will become effective October 1, 2008. BPA will revise the costs of this resource with this new information to ensure that the projected operating costs for the resource during the rate test period are a reasonable projection of the costs that will be incurred during the rate test period.

The IOUs argue BPA must include realistic resource costs for resources in the 7(b)(2)(D) resource stack. IOU Br., WP-07-B-JP6-01, at 28. They state that just using historical costs of resources adjusted by general rates of inflation (by using a GDP deflator) is arbitrary and capricious. *Id*. They claim the current costs for such items as the price of materials and fuel can greatly exceed the historical costs adjusted for the rate of inflation. *Id*. Staff indicated that it did not agree with the IOUs' position insofar as it implies that a "replacement value" approach was required to reflect the costs of resources that already exist and are operating in the region. Doubleday, *et al.,* WP-07-E-BPA-85, at 71-72. Type 1 and Type 2 resources contained in the resource stack are resources that exist and have already been built, or planned resources that are expected to be built and acquired by BPA. *Id*. Thus, it is not necessary to revise the historical costs associated with these resources using a "replacement value" approach in developing the resource costs contained in the resource stack. *Id*. The current modeling approach of reflecting the actual historical construction costs for these resources, adjusted for changes in general price levels, is correct. BPA's approach of using recent historical operating cost information and/or projected operating cost budgets provided by the resource owners/operators for non-conservation resources is responsive to the IOUs' concerns that the operating costs for resource stack resources should be realistic projections of the actual operating costs that would be incurred over the rate test period.

The IOUs argue that BPA must include realistic resource costs for resources in the 7(b)(2) Case resource stack, claiming that just using historical costs of resources adjusted by general rates of inflation (by using a GDP deflator) was arbitrary and capricious. IOU Br., WP-07-B-JP6-01, at 27-32.

BPA disagrees. It is reasonable for BPA to use the escalated actual cost to BPA of the resources designated by subsection 7(b)(2)(D)(i). Although not specified in section 7(b)(2), it can be reasoned that the resources acquired by the Administrator that fall under section 7(b)(2)(D)(i) would be at the cost of the specific resource acquired by the Administrator. Section 7(b)(2)(D) specifies that Type 3 resources are to be assumed to cost the "average cost of all other new resources acquired by the Administrator." Therefore, the most reasonable interpretation of section 7(b)(2)(D) is that BPA should assume that 7(b)(2)(D)(i) resources are acquired at BPA's cost of each specific resource.

Decision

BPA has properly determined resource costs for the resources contained in the 7(b)(2)(D) resource stack for the final Supplemental Proposal.

16.6 Cost of Resources Contained in the 7(b)(2) Resource Stack – Resource Cost Escalation

Issue 1

Whether BPA has properly escalated resource costs in the resource stack.

Parties' Positions

Cowlitz argues nothing in the Northwest Power Act permits BPA to assume that resources cost more in the 7(b)(2) Case than BPA's actual costs for the very same resource. Cowlitz Br., WP-07-B-CO-01, at 32-33. Cowlitz argues it is unlikely that Staff's escalation method will replicate BPA's actual cost of the resources because BPA's section 7(b)(2) method has the effect of escalating the fixed capital cost from the date of actual commercial operation to a later date. *Id.* Cowlitz argues that Staff's escalation of resource costs in the 7(b)(2) Case exaggerates resource costs. *Id.*

APAC argues that when conservation resources are chosen to satisfy load, Staff compounds the error by pricing them at current prices with unreasonable financing assumptions, rather than the historical prices at which they were actually procured. APAC Br., WP-07-B-AP-01, at 36. APAC argues the substitution of current prices for historical conservation costs creates an impermissible penalty on conservation. *Id.*

The IOUs argue BPA must include realistic resource costs for resources in the 7(b)(2) Case resource stack. IOU Br., WP-07-B-JP6-01, at 27-32. The IOUs argue that just using historical costs of resources adjusted by general rates of inflation (using a GNP deflator) is arbitrary and capricious. *Id*. The IOUs note that the current costs for such items as the price of materials and fuel can greatly exceed the historical costs adjusted for the rate of inflation. *Id*.

<u>BPA Staff's Position</u>

BPA Staff has modeled resource costs in the 7(b)(2) resource stack using a consistent methodology since the first section 7(b)(2) rate test was conducted in FY 1985. Doubleday, *et al.*, WP-07-E-BPA-85, at 43. BPA has consistently maintained that the costs of the Program Case and the 7(b)(2) Case are different, as provided by the exclusions from the Program Case, the five specific assumptions that outline changes from the Program Case to the 7(b)(2) Case, and the consequences that follow from applying the Five Assumptions. *Id*. BPA's practice in modeling the 7(b)(2) Case resource costs has properly recognized and given effect to the time value of money. *Id*. In order to perform the "least-cost ordering" prescribed in section 7(b)(2)(D) of the Act, it is necessary that all resource costs be stated in a common base year of purchasing power dollars. *Id*. Because resources are selected in different years of the rate test period, it is equally clear and well recognized in performing rate analyses that costs escalate throughout the rate test period. *Id*. Staff's treatment of Type 1 resource costs adjusts the historical resource costs for purchasing power cost changes so that a resource's costs reflect its cost and operation in the year it is selected from the resource stack. *Id*. Adjusting Type 1 resource costs for changes in purchasing power is necessary to make resources comparable to other operating expenses represented in the revenue requirement for the respective rate test period year. *Id*. It would be illogical to assume one could produce a meaningful rate test result using a comparison of different inputs that were stated in different units of purchasing power dollars. *Id*. Giving effect to the changes in the time value of money is a necessary consequence of implementing the 7(b)(2)(D) rate test assumptions. *Id*. Conservation resources are assumed not to have been acquired at the outset of the 7(b)(2) Case, and thus the historical and projected costs of conservation resources from the Program Case, both capital and first-year operating expense, are adjusted for changes in the purchasing power of the dollar. *Id*. Staff's treatment of Type 2 resource costs uses 7(b)(2) Customers' costs for the historical capitalized costs and related debt service, taking into account the refinancing of such debt along with the current projected costs of operating the resource during the Five-Year Period. Adjusting Type 2 resource operating costs for changes in purchasing power is necessary to make these resources comparable to other operating expenses represented in the revenue requirement for the respective rate test period year. *Id*.

<u>Evaluation of Positions</u>

A. Background

Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' general requirements when FBS resources are exhausted. 16 U.S.C. § 839e(b)(2)(D). Type 1 resources are those resources not included in the FBS that are acquired by BPA from 7(b)(2) Customers in the Program Case. Conservation resources are a Type 1 resource. Type 2 resources are those resources owned or purchased by 7(b)(2) Customers that are not dedicated to load by COUs or IOUs pursuant to section 5(b) of the Northwest Power Act. Type 1 and Type 2 resources are stacked in least-cost order and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least cost first. Type 3 resources are additional acquired resources, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the rate test period. Section 7(b)(2)(E)(i) requires an assessment of the "quantifiable monetary savings" that are realized by public body financing of resources in the resource stack.

BPA selects resources to meet 7(b)(2) Customer loads in the 7(b)(2) Case based upon a "least-cost" selection methodology. The treatment of historical fixed costs and variable operating costs associated with different resources varies is explained herein. The selection methodology for conservation resources starts by obtaining the nominal costs of the resources in the year they were acquired. For conservation resources acquired in FY 1991-2013, the costs used are the historical and projected resource costs, adjusted as detailed in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D, at D-22.

For the FY 2002-2006 Lookback period, the conservation resources used are the historical conservation resources for FY 1991-2001, and projected and planned conservation resources for FY 2002-2010. For the FY 2007-2008 Lookback period, the conservation resources used are the historical conservation resources for FY 1994-2006, and the projected and planned conservation resources for FY 2007-2013. For the FY 2009 rate period, the conservation resources used are the historical conservation resources for FY 1999-2007, and the projected and planned conservation resources for FY 2008-2013. The selection methodology for non-conservation resources starts by obtaining recent operating cost information and projected operating budget information to develop an accurate projection of the operating and financing costs associated with the applicable Type 1 and Type 2 resources during the rate period.

The nominal historical costs of conservation resources, along with the projected operating and financing costs of non-conservation resources, are discounted to a common base year period's dollars (the RAM model uses a 1980 base year) so that a "rank ordering" of resources can be made using a consistent levelized cost methodology denominated in a common dollar. When resources are selected from the resource stack to meet the remaining general requirements of preference customers in the 7(b)(2) Case, the costs of resources are then escalated using GDP price deflator series to inflate the costs to the purchasing power dollars of the year in which the resource was selected from the resource stack.

Fixed and variable costs vary among resources and are treated differently depending on the resource type; for example, whether or not the resource is a Type 1 resource with or without BPA financial backing, whether the resource has a fuel stock component that could escalate at a rate different than inflation, and additional other factors. The resource stack consists of various vintage years of historical conservation resources that have been acquired or are planned and projected as noted above along with seven other Type 1 or Type 2 resources for the FY 2009 Five-Year Period. Because these resources are sufficient to meet the remaining general requirements of 7(b)(2) Customers in the 7(b)(2) Case, it is not necessary to use Type 3 resources, and therefore their cost treatment is moot. The cost treatment of different resources is discussed at Issue 16.5 – Costs of Other Resources Contained in the 7(b)(2) Resource Stack – Verification of Resource Costs, and generally follows Staff's rebuttal testimony. Doubleday, *et al.*, WP-07-E-BPA-85, at 60-82.

As explained in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D, the individual years of historical and projected conservation resources have a portion of costs that have been capitalized and debt-financed along with a portion of historical and projected expenditures that were treated as first-year operating expenses. The composition of conservation programs has changed over the years, and the cost of obtaining annual conservation savings (expressed in $/MWh) has varied between years. In the current rate case and in past rate cases, Staff has assumed that using historical costs for past BPA conservation programs, adjusted for inflation, is a reasonable cost projection for acquiring these conservation resources during the Five-Year Period. Because the composition of conservation programs has changed over the years, it is not possible or practical to "cost out" individual components of past conservation programs (*e.g.*, water heater wraps and energy-efficient shower heads) to establish what it would cost to buy these individual components during the Five-Year Period in order to address the change in material and commodity costs that have increased or decreased at rates different than the general rate of inflation.

The historical and projected costs of conservation resources are contained in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D, and at Doubleday, *et al.*, WP-07-E-BPA-85, Attachment 6 – Subpart 7, at 92-96. The cost of conservation investments for the vintage years of FY 2005-2007 are based on the projections made for the WP-07 rate case (July 2006). These projected costs will be revised for the FY 2009 final Supplemental Proposal to reflect the actual historical costs and savings that are stated in the Fiscal Year 2007 Conservation Resource Energy Data (The Red Book, published June 2008), as amended for the adjustments described in Appendix D. These updated historical costs and savings for FY 2005-2007 will be contained in the final study, as stated in Staff's rebuttal testimony. Doubleday, *et al.*, WP-07-E-BPA-85, at 61-62. Updated projected costs and savings for conservation for the years FY 2008-2013 for the final Supplemental Proposal will be contained in the final study, as noted in Staff's rebuttal testimony. *Id*. Updating these conservation cost projections is necessary to ensure comparability of costs with the Program Case because these updated costs are reflected in the Program Case revenue requirements for the final Supplemental Proposal. Conservation costs and savings for FY 2009-2013 have been revised to be consistent with the recent results reached in the Integrated Program Review (IPR) process.

B. Resource Cost Escalation

Staff previously agreed with Cowlitz that fixed costs (capitalized costs funded by mortgage-type financing), once inflated to the year of selection, should be fixed from that time forward, and the related debt service amounts should remain fixed for all subsequent years of the rate test period. Doubleday, *et al.*, WP-07-E-BPA-85, at 81. The rate model used for the final Supplemental Proposal has corrected this problem.

Staff also acknowledged there were problems with the GDP deflator series used to restate the actual nominal costs of conservation investments from the year in which they were incurred to be stated in 1980 dollars. Doubleday, *et al.*, WP-07-E-BPA-85, at 66. A revised set of GDP deflator series provided in Attachment 6, Subpart 8 of Staff's rebuttal testimony was used to revise the statement of conservation costs in the tables provided in Attachment 6, Subpart 7, which display conservation costs in the actual nominal dollars of the year incurred, and in 1980 and 2007 dollars. *Id*. In addition to using these restated 1980 dollar values for conservation resources, BPA intends to also revise the GDP deflator series used to escalate the conservation resources from 1980 dollars to the dollars for the year that the conservation resource is selected from the resource stack. *Id*. These changes will address these problems in all versions of the rate models. *Id*.

As noted above, the costs of non-conservation resources reflect the cost of operating those resources based on recent historical operating cost information and/or projected operating cost budgets provided by the resource owners/operators. Thus, the costs in the resource stack reflect the anticipated operating costs for the resources that are projected to occur during the rate test period. *See* Section 16.5 – Costs of Other Resources Contained in the 7(b)(2) Resource Stack – Verification of Resource Costs for a more detailed discussion on the projection of costs in the resource stack for non-conservation resources.

Cowlitz argues nothing in the Northwest Power Act permits BPA to assume that resources cost more in the 7(b)(2) Case than BPA's actual costs for the very same resource. Cowlitz Br., WP-07-B-CO-01, at 32-33. Even if escalation of costs were permitted based on a hypothetical future date at which the resources were needed to meet general requirements of preference customers, nothing in the Act permits BPA to assign fictitiously higher costs by escalating costs that do not escalate. *Id*. Cowlitz argues, "[a]ctual resources should be assigned actual costs, just as happens in the Program Case." *Id*. at 33.

Cowlitz's arguments are flawed for a number of reasons. The Northwest Power Act allows the cost of resources to be different between the two Cases. *See* 16 U.S.C. § 839e(b)(2)(E). There are many reasons why the cost of a resource in the 7(b)(2) Case may be different than the cost of that resource in the Program Case. First, the population of resources serving the 7(b)(2) Case loads is different than the population of resources serving Program Case loads, so in the aggregate the resource costs will be different between the two Cases. In BPA's WP-96 rate case, no resources from the resource stack were used to perform the section 7(b)(2) rate test. In the WP-02 rate case, there were very few resources from the resource stack used during the later years of the Five-Year Period. Thus, because the resource stack resources were not used in those two rate cases, the cumulative costs of resources were less in the 7(b)(2) Case than in the Program Case. Second, resources are generally selected to serve the loads in the 7(b)(2) Case in a different time period than in the Program Case. This gives rise to changes in the cost of acquiring and operating the resource generally associated with price changes between time periods. Third, the provisions of section 7(b)(2) give rise to changes in the costs of resources between the two Cases. Section 7(b)(2)(E)(i) instructs that the rate test is to be performed assuming that "reduced public body and cooperative financing costs … were not achieved." 16 U.S.C. § 839e(b)(2)(E)(i). Section 7(b)(2)(D) provides that Type 3 resources are to be priced at the average cost of all such resources, whereas such resources in the Program Case are discretely priced. Thus, there are numerous justifiable reasons why resource costs in the 7(b)(2) Case will be different than in the Program Case.

Cowlitz states BPA draws resources into the 7(b)(2) Case based on a "least cost" selection methodology comparing actual costs discounted to 1980 dollars, and then escalates those discounted costs to the year the resource is required to be "added" to the 7(b)(2) Case to meet the general requirements of preference customers. Cowlitz Br., WP-07-B-CO-01, at 32. Cowlitz argues it is unlikely this method will replicate BPA's actual cost of the resources because Staff's selection method has the effect of escalating the fixed capital cost from the date of actual commercial operation to a later date. *Id.* For example, BPA has acquired the Idaho Falls resource under circumstances where no financial benefits need be considered under section 7(b)(2)(E). *Id.* Thus, none of the Five Assumptions should alter the cost of Idaho Falls. *Id.* Yet BPA uses a higher cost for Idaho Falls in the 7(b)(2) Case than the actual cost incurred by BPA. *Id.* Cowlitz argues that even resources with *zero* current cost to BPA (*i.e.*, completely paid off) will have a very substantial cost in the 7(b)(2) Case, based on escalated historical costs. *Id.*, *citing* Tr. 386-87.

Cowlitz's argument is incorrect for all of the non-conservation resources in the resource stack. The final study documentation will present a comparison of the non-conservation resource costs included in the Program Case revenue requirement for FY 2009 and the 7(b)(2) Case cost of these same resources as if they were selected from the resource stack in the that same year. This will demonstrate that the cost differences between the Program Case and the 7(b)(2) Case are solely due to financing. Cowlitz cites the Idaho Falls resource and asserts that the cost of this resource is higher in the 7(b)(2) Case than in the Program Case. Cowlitz's assertion is incorrect. The projected costs for the Idaho Falls resource are based solely on the power purchase contract with the City of Idaho Falls, where the price estimated to be charged is at the contract cap of $39.05/MWh and the generation is based on the final Load Resource Study's generation amount of 162,060 MW hours for FY 2009. The operating cost assumptions for the 7(b)(2) Case and the Program Case are identical.

Cowlitz argues that having inflated FBS costs by assuming away non-FBS costs in the 7(b)(2) Case for repayment study purposes (this issue is discussed in Section 16.9 - 7(b)(2) Case Repayment Study), Staff then brings such costs back into the 7(b)(2) Case through modeling assumptions that grossly exaggerate them, so that the very same resource has far higher costs in the 7(b)(2) Case than in the Program Case. Cowlitz Br., WP-07-B-CO-01, at 32. Cowlitz claims the Program Case and the 7(b)(2) Case constitute two alternative methods of setting the power cost component of rates by allocating (not changing) the costs of certain resources to certain customers. *Id*. Cowlitz argues there should be no changes in costs between the Program and 7(b)(2) Cases other than changes in financing costs for particular resources arising under the fifth of the Five Assumptions in section 7(b)(2)(E) (no benefit from Northwest Power Act-reduced financing costs). *Id*. In addition, Cowlitz argues, it is not a necessary or permissible consequence of any of the Five Assumptions that BPA exaggerate the fixed costs of resources over and above Program Case levels, so that the very same resource can cost twice as much in the 7(b)(2) Case, and it is contrary to Congressional intent for BPA to overstate the costs of the same resources in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 34.

In its Brief on Exceptions, Cowlitz notes BPA offers lengthy arguments for its different accounting treatment of resources in the 7(b)(2) Case than in the Program Case, but never offers an adequate statutory basis for changing the costs. Cowlitz Br. Ex., WP-07-R-CO-01, at 22. Cowlitz's argument is incorrect and is refuted by Cowlitz itself. Cowlitz admits that BPA "argue[s] that "'least-cost ordering' prescribed in section 7(b)(2)(D)" makes it "necessary that all resource costs are stated in a common base year of purchasing period dollars." *Id*. Furthermore, BPA Staff has modeled resource costs in the 7(b)(2) resource stack using a consistent methodology since the first section 7(b)(2) rate test was conducted in FY 1985. Doubleday, *et al*., WP-07-E-BPA-85, at 43. BPA has consistently maintained that the costs of the Program Case and the 7(b)(2) Case are different as provided by the exclusions from the Program Case, the five specific assumptions that outline changes from the Program Case to the 7(b)(2) Case, and the consequences that follow from applying the Five Assumptions. BPA's practice in modeling the 7(b)(2) Case resource costs has properly recognized and given effect to the time value of money. In order to perform the "least-cost ordering" prescribed in section 7(b)(2)(D) of the Act, it is necessary that all resource costs are stated in a common base year of purchasing power dollars. Because resources are selected in different years of the rate test period, it is equally clear and well-recognized in performing rate analyses that costs escalate throughout the rate test period. Staff's treatment of Type 1 resource costs adjusts the historical resource costs for purchasing power cost changes so that a resource's costs reflect its cost and operation in the year it is selected from the resource stack. Type 1 resources that have been purchased from COUs to serve loads in the Program Case (Idaho Falls Hydro Project, Cowlitz Falls Hydro Project, Wauna Co-Generation resource, and billing credit resources) have been modeled to have nearly identical costs in the 7(b)(2) Case with the following exceptions. The Cowlitz Falls Hydro Project, whose financing costs were reduced due to BPA's financial backing in the Program Case, has had its debt service costs repriced in the 7(b)(2) Case to give effect to section 7(b)(2)(E)(i) to reflect the higher debt service costs in the 7(b)(2) Case. In addition, the Program Case has a higher level of costs and greater resource capability from billing credit resources when compared to the costs and resource capabilities that are contained in the 7(b)(2) Case. One of the four billing credit resources, Smith Creek Hydro Project's power purchase contract, expires on September 30, 2011. Because this resource is not available to meet 7(b)(2) Case loads in all years of the rate test period, it has been excluded from the amount of billing credit resources present in the resource stack. Just like FBS resource costs that escalate during the rate test period in both the Program Case and 7(b)(2) Case for increased maintenance, operating, and general and administrative costs, it is necessary to adjust Type 1 resource costs for changes in purchasing power to make the costs for these resources comparable to other operating expenses represented in the revenue requirement for the respective rate test period year. It would be illogical to assume one could produce a meaningful rate test result using a comparison of different inputs that were stated in different units of purchasing power dollars. Giving effect to the changes in the time value of money is a necessary consequence of implementing the 7(b)(2)(D) rate test assumptions. Conservation resources are assumed to not have yet been acquired at the outset of the 7(b)(2) Case and thus the historical and projected costs of conservation resources from the Program Case, both capital and first year operating expense, are adjusted for changes in the purchasing power of the dollar. Type 2 resources that are owned by COUs but not committed to meeting section 5(b) loads in the region are not present in the Program Case, but are included in the 7(b)(2) resource stack. Thus, contrary to Cowlitz's assertion that "it's a simple task to require the Administrator to take the loads and resource costs already assembled for the Program Case, and make a limited set of specific assumptions to change those loads and resource costs" for the 7(b)(2) Case, BPA currently has a difficult time procuring the necessary resource cost and power capability information for these resources from COUs in the region. Staff's treatment of Type 2 resource costs uses 7(b)(2) Customers' costs for the historical capitalized costs and related debt service, taking into account the refinancing of such debt along with the current projected costs of operating the resource during the Five-Year Period. Adjusting Type 2 resource operating costs for changes in purchasing power is necessary to make these resources comparable to other operating expenses represented in the revenue requirement for the respective rate test period year.

Cowlitz notes BPA's statement that BPA is implementing the least-cost ordering prescribed in section 7(b)(2)(D) because it is necessary that all resource costs are stated in a common base year of purchasing period dollars. Cowlitz Br. Ex., WP-07-R-CO-01, at 22. Cowlitz argues section 7(b)(2)(D) merely says that in meeting remaining general requirements, the Administrator is to select the resources, and the costs thereof, which were "the least expensive resources owned or purchased by public bodies or cooperatives." *Id*. Cowlitz argues that picking the least expensive resources to meet preference customer general requirements in the 7(b)(2) Case does not require the Administrator to do more than review the lists of costs in $/MWh already assembled for the Program Case and simply add the costs of the resource from the Program Case into the 7(b)(2) Case. *Id*. As outlined above, Type 2 resource cost and capabilities are not present in the Program Case, BPA has to procure this information from COUs in the region, analyze it, and make necessary adjustments to the data so it can be input into the rates model in a manner that is consistent with other resource information contained in the 7(b)(2) Case resource stack. BPA has also previously explained why this simplistic approach is incorrect under fundamental ratemaking principles. Because resources are selected in different years of the Five-Year Period, it is equally clear and well recognized in performing rate analyses that costs escalate throughout the Five-Year Period. BPA's treatment of resource costs adjusts the historical resource costs for purchasing power cost changes so that a resource's costs reflect its cost and operation in the year it is selected from the resource stack. Adjusting resource costs for changes in purchasing power is necessary to make them comparable to other operating expenses represented in the revenue requirement for the respective Five-Year Period year. It would be illogical to assume one could produce a meaningful rate test result using a comparison of different inputs that were stated in different units of purchasing power dollars. Giving effect to the changes in the time value of money requires that the cost of resources be stated in comparable purchasing power dollar units. The escalation of resource costs is a necessary consequence of implementing the 7(b)(2)(D) rate test assumptions.

Cowlitz argues BPA misses the mark in its lengthy explanation of the multitude of different ways it could have accounted for resource costs other than the way it did account for them in developing its revenue requirement (*i.e.*, the actual costs BPA determined it must recover with its rates). Cowlitz Br. Ex., WP-07-R-CO-01, at 22. Cowlitz contends the basic problem is the disparate treatment of the costs of identical resources in the Program Case and the 7(b)(2) Case. *Id*. Cowlitz argues BPA does not and cannot identify any statutory language that requires or permits the Administrator to change costs between the two Cases based on accounting considerations, considerations relating to the time value of money, "alternative universe" considerations, or any other extra-statutory considerations. *Id*. Cowlitz's argument is not persuasive. Cowlitz proposes a hyper-restrictive interpretation of the Northwest Power Act, which fails for a number of reasons. First, Cowlitz's advocacy for a hyper-restrictive reading of section 7(b)(2) was previously rejected in 1984 when BPA established the 1984 Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology. In the development of these seminal guides to the implementation of section 7(b)(2), the issue arose of whether section 7(b)(2) should be limited to a hyper-restrictive interpretation or whether BPA should recognize that, in implementing the Five Assumptions for the 7(b)(2) Case, BPA should recognize that there are natural consequences that result from the implementation of the Five Assumptions. In 1984, nearly 25 years ago, after reviewing the parties' arguments in the administrative proceedings that established the Legal Interpretation and Implementation Methodology, BPA concluded that it should recognize the natural consequences of the Five Assumptions in conducting the 7(b)(2) rate test. If Cowlitz believes BPA should not recognize the natural consequences of the Five Assumptions, Cowlitz should have challenged the Legal Interpretation and Implementation Methodology when they were developed in 1984 or in a subsequent rate case, that is, at least some time in the last 24 years. BPA has consistently recognized the time value of money as a necessary consequence of the Five Assumptions when conducting the 7(b)(2) rate test in every single power rate case since 1984. As explained previously, failure to reflect the time value of money and normal accounting considerations would defy common sense and pervert the section 7(b)(2) rate test. Although this might provide additional benefits to preference customers, it would not properly implement the rate test.

Cowlitz argues BPA cannot identify any statutory language that permits the Administrator to reflect different costs between the two Cases based on the time value of money, accounting, or similar considerations. Cowlitz Br. Ex., WP-07-R-CO-01, at 22. To the contrary, section 7(a)(1) of the Northwest Power Act requires BPA's rates to be "established and, as appropriate, revised to recover, *in accordance with sound business principles*, [BPA's total costs]." 16 U.S.C. § 839e(a)(1) (emphasis added). Similarly, the Federal Columbia River Transmission System Act provides that BPA's "*rate schedules* may be modified from time to time by the Secretary of Energy, acting by and through the Administrator, subject to confirmation and approval by the Secretary of Energy, and *shall be fixed and established* (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers *consistent with sound business principles* …" 16 U.S.C. § 838g (emphasis added). *See also* 16 U.S.C. § 835s. It would be directly inconsistent with sound business principles to ignore the time value of money and standard accounting principles in BPA's ratemaking analyses. Furthermore, reversing Cowlitz's argument, Cowlitz cannot identify any statutory language that says BPA should ignore some of the most fundamental requirements of economics and accounting when conducting its rate analyses. BPA reflects the time value of money in the Program Case and therefore should reflect the same principles in the 7(b)(2) Case and in the comparison of such cases. Finally, simply because a statute does not expressly contain all of the detailed instructions needed to implement the statute does not mean that an agency is precluded from doing what is necessary to implement the statute in a sound and reasonable manner.

Cowlitz argues that BPA's proposal attempts to create a standardless mass of asserted discretion untethered to the Northwest Power Act. Cowlitz Br. Ex., WP-07-R-CO-01, at 23. Cowlitz ignores, however, that BPA's rate proposal is not a new creation, but instead is based on the agency's decades-long recognition of the natural consequences of the Five Assumptions in section 7(b)(2). Instead of being untethered to the Northwest Power Act, BPA's proposal *is derived from BPA's original interpretation of the Act* in developing the 1984 Legal Interpretation and the 1984 Implementation Methodology. These longstanding principles did not somehow suddenly appear in BPA's Supplemental Proposal. Although Cowlitz attributes a colorful (albeit predictably negative) motivation to BPA, the motivation is untrue. Instead, BPA attempts to properly interpret and implement section 7(b)(2) of the Act in order that it function properly. BPA does not benefit from the establishment of rates other than to recover its costs as required by law, and therefore objectively reviews the statute and legislative history. BPA's common sense recognition of factors such as the time value of money does not establish "a standardless mass of asserted discretion." The time value of money, for example, is a straightforward issue on which all parties can file testimony based on objective data. Although Cowlitz advocates hyper-restrictive interpretations of the Act that would reverse nearly 25 years of BPA ratemaking precedent and eliminate any possible circumstance where the Administrator might exercise lawful discretion, BPA will interpret the law based on statutory language, legislative intent, and common sense.

As explained in the discussion of the Legal Interpretation and Implementation Methodology at Section 16.2 – General Section 7(b)(2) Legal Issues, Staff correctly assumed that both past and projected and planned conservation resources are contained in the resource stack. Because resources are selected in different years of the Five-Year Period, it is equally clear and well recognized in performing rate analyses that costs escalate throughout the Five-Year Period. BPA's treatment of resource costs adjusts the historical resource costs for purchasing power cost changes so that a resource's costs reflect its cost and operation in the year it is selected from the resource stack. Adjusting resource costs for changes in purchasing power is necessary to make them comparable to other operating expenses represented in the revenue requirement for the respective Five-Year Period year. It would be illogical to assume one could produce a meaningful rate test result using a comparison of different inputs that were stated in different units of purchasing power dollars. Giving effect to the changes in the time value of money requires that the cost of resources be stated in comparable purchasing power dollar units. The escalation of resource costs is a necessary consequence of implementing the 7(b)(2)(D) rate test assumptions.

APAC argues that when conservation resources are chosen to meet remaining general requirements, Staff compounds the error by pricing them at current prices with unreasonable financing assumptions, rather than the historical prices at which they were actually procured. APAC Br., WP-07-B-AP-01, at 36. APAC argues the substitution of current prices for historical conservation costs creates an impermissible penalty on conservation. *Id*.

APAC's argument is not persuasive. As noted at Section 16.2 – General Section 7(b)(2) Legal Issues (BPA's legal interpretation concerning the solving for general requirements in the 7(b)(2) Case), BPA's position is that conservation resources both past and proposed (through the rate test period) are to be included in the 7(b)(2)(D) resource stack. Because conservation resources are available to serve additional 7(b)(2) Customer loads after FBS resources are exhausted, the starting 7(b)(2) load forecast cannot already have been reduced by these same conservation resources. The effects of conservation resources have to be removed from 7(b)(2) Customer loads. This same treatment of including conservation resources in the resource stack and increasing the 7(b)(2) Case loads has been followed since 1985, and BPA's preference customers have not raised this issue before this time. Doubleday, *et al.*, WP-07-E-BPA-85, at 38-44.

In all prior rate cases going back to 1985, BPA has consistently adjusted historical conservation resource costs for purchasing power so the costs of the resources reflect their cost and operation in the year they are selected from the resource stack. Doubleday, *et al.*, WP-07-E-BPA-85, at 43. Adjusting resource costs for changes in purchasing power is necessary to make them comparable to other operating expenses represented in the revenue requirement for the respective rate test period year. It is illogical to assume BPA could produce a meaningful rate test result using a comparison of different inputs stated in different units of purchasing power dollars. Giving effect to the changes in the time value of money is a necessary consequence of implementing the 7(b)(2)(D) rate test assumption.

The IOUs argue BPA must include realistic resource costs for resources in the 7(b)(2)(D) resource stack. IOU Br., WP-07-B-JP6-01, at 27-32. The IOUs contend that just using historical costs of resources adjusted by general rates of inflation (by using a GDP deflator) is arbitrary and capricious. *Id*. They note that the current costs for such items as the price of materials and fuel can greatly exceed the historical costs adjusted for the rate of inflation. *Id*. The IOUs argue that resource costs included in the resource stack should include an allocation of Administrative and General costs. *Id*.

The IOUs' argument is not accurate in describing how Staff has determined the costs of the resources contained in the resource stack. As explained above, BPA uses a simplifying modeling assumption in modeling conservation costs. BPA assumes that vintage conservation can be acquired during the rate test period for its historical or projected costs adjusted for inflation. The number of separate conservation components within a year, and the fact that the population of components changes over the years, does not lend itself to using other cost indices to separately re-price the costs of all of the individual components for every vintage year of conservation investment. Conservation costs include a reasonable allocation of Administrative and General Overhead costs. *See* Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D, at D-20.

As explained in Section 16.5 – Costs of Other Resources Contained in the 7(b)(2) Resource Stack – Verification of Resource Costs, BPA uses recent operating results and projected operating budgets from resource owners/operators to reasonably project the operating costs for non-conservation resources during the rate test period. In the case of the 10 percent portion of the Boardman coal plant owned by COUs that is not dedicated to regional loads, the cost of coal in the final study will be projected using Energy Information Administration projected prices for delivered coal. Once the operating costs have been projected for the rate period, they are then escalated using the standard GDP Deflator series for the remaining years of the Five-Year Period.

In addition, the IOUs' argument misses the point of establishing the cost of resources included in the 7(b)(2)(D) resource stack. BPA is not trying to establish an entirely new cost of a resource, but to use the cost of a Type 1 resource as established in the Program Case, or to establish a comparable cost for a Type 2 resource. In this instance, the Cowlitz argument is correct; BPA should use the same cost of a particular resource in both Cases. *See also* Section 16.5 – Costs of Other Resources Contained in the 7(b)(2) Resource Stack – Verification of Resource Costs. What Cowlitz misses, and the IOUs try to expand, is that the cost of the resource must be restated in dollars of the year in which the resource is selected from the resource stack.

Decision

BPA properly projects the operating costs of non-conservation resources in the resource stack using recent historical operating results and projected budgets provided by resource owners/operators or the projected amounts to be paid by BPA under power purchase contracts. These costs are reasonable approximations of the cost of operating and financing these resources during the rate test period. These projected operating costs for the rate period are escalated using standard GDP deflator series to arrive at the Five-Year Period costs. BPA's assumption that vintage conservation resources can be acquired based on their historical costs escalated for the time value of money is a reasonable assumption that is consistent with the Implementation Methodology. BPA has properly projected and escalated resource costs in the resource stack.

16.7 Costs of Resources Contained in the 7(b)(2) Resource Stack: Financing Analysis

Issue 1

Whether BPA has properly conducted its financing analysis of the financing costs of resources contained in the 7(b)(2) resource stack.

Parties' Positions

The OPUC argues that BPA underestimates the financing benefits associated with the section 7(b)(2) rate test and the Administrator should update BPA's financing benefits analysis to recognize a more realistic spread for differences in borrowing costs. OPUC Br., WP-07-B-PU-02, at 31-32.

BPA Staff's Position

BPA Staff's rebuttal testimony stated that a decision to update the study would be based on the opinion of BPA's financial advisor that fundamental changes have occurred in credit markets that have impacted credit spreads from the time the final Supplemental Proposal's financing cost study was prepared and whether the initial financing study still represents a reasonable projection of the spreads that will occur over the rate test period. Doubleday, *et al.*, WP-07-E-BPA-85, at 95. Staff stated the update to the financing cost study would rely on historical averages of the difference in credit spreads, with more weight given to recent bond issuances. *Id*.

Evaluation of Positions

The OPUC argues that Staff underestimates the financing benefits associated with the section 7(b)(2) rate test and BPA should update the financing benefits analysis to recognize a more realistic spread for differences in borrowing costs. OPUC Br., WP-07-B-PU-02, at 31-32. The OPUC claims Staff does not give sufficient consideration to today's troubled financial markets and the increased spreads currently present. *Id*. Staff assumes a single rating category difference between Joint Operating Agency (JOA) borrowing costs (A credit rating) and BPA-backed financing (AA credit rating). *Id*. Staff then assumes that the difference in the rates for A-rated debt and AA-rated debt for FY 2009-2013 is best represented by the period FY 1998-2007. *Id*. The OPUC does not take issue with Staff's proposal to use a single category rating difference. *Id*. The OPUC also does not take issue with the concept of using long historical averages in most circumstances. *Id*. This general practice espoused by Staff is well-founded. *Id*. However, because spreads (*i.e.*, the difference between actual borrowing costs and Treasury rates) have increased considerably, Staff's use of the FY 1998-2007 period as a proxy for FY 2009-2013 is unreasonable. *Id*. OPUC argues BPA should prepare an updated financing study that places more reliance on recent history. *Id*. In the alternative, BPA should simply re-determine the spread between A and AA-rated debt giving more weight to the last three, five, or seven-year time period. *See* Hellman and McGovern, WP-07-E-PU-01, at 28-30.

BPA agrees with OPUC's argument that the financing study should be updated for the final Supplemental Proposal. Staff's rebuttal testimony left open the possibility of updating the financing study for the final Supplemental Proposal based on how credit markets appear at the time the final rate proposal is prepared. Doubleday, *et al.*, WP-07-E-BPA-85, at 95. Staff's rebuttal testimony stated that a decision to update the study would be based on the opinion of BPA's financial advisor that fundamental changes have occurred in credit markets that have impacted credit spreads from the time the Supplemental Proposal's financing cost study was prepared and whether the initial financing study still represents a reasonable projection of the spreads that will occur over the rate test period. *Id*. Staff stated that the update to the financing cost study would rely on historical averages of the difference in credit spreads, with more weight given to recent bond issuances. *Id*.

Staff's rebuttal testimony noted that credit markets have been in disarray since the fall of 2007. *Id*. at 94. In the latter part of 2007, these developments began to affect credit spread relationships, which are central to the financing cost study. *Id*. Credit spread relationships have continued to deteriorate since the time the financing analysis was completed. *Id*. It is also evident that experts in the credit markets have not yet developed a consensus on whether the spread among credit ratings will continue to increase, or whether the current spread will decrease in the near future before finding stability at a new equilibrium point. *Id*. A significant factor in the current increase in the true cost spread (net interest rate differential after taking into account any cost related to bond insurance or other credit enhancement fees) among credit ratings has been the changes that have occurred in bond insurance. *Id*. Bond insurance is not as widely available as it was before the fall of 2007, and it is more expensive. *Id*. The change in bond insurance cost and availability has increased the true cost spread between credit ratings in the current period. *Id*. The current premiums for bond insurance have attracted new entrants into this market, and it could continue to attract new entrants that could decrease the cost of bond insurance from current levels and thus decrease the true cost differential in credit spreads. *Id*. Current legislative developments could have the Federal government assume some of the risks and costs that have historically been borne by private banks. *Id*. Additional capital infusions into private banks to improve their financial stability, should additional loan loss reserves be required, could increase the overall cost of credit. *Id*. These factors, along with other current changes taking place in credit markets, could change the expectation of credit spreads between the initial Supplemental Proposal and the time when the final Supplemental Proposal is published. *Id*.

During cross-examination on this issue, BPA's Financial Advisor, Michael Mace of Public Financial Management, responded to a question posed by the OPUC concerning how the revised financing study could be performed:

> [Mr. Mace:] As [BPA witness Paul Brodie] point[s] out, there are a lot of possibilities, and I think to arrive at a reasonable assumed future financing cost, we could either take a shorter historical period with which to average, which would by definition give more weight to current or more recent rates, or we could just increase the weighting and take the average of a longer period of time.
>
> Either one of those might be a reasonable way to arrive at some measure that does give more weight to what's been going on recently in the markets.

Tr. 239-240.

Since the time of Staff's rebuttal testimony, investor confidence in the creditworthiness of financial institutions has continued to decline. The investment banking firm Bear Stearns was acquired in an arranged acquisition with the facilitation of the U.S. Treasury by the investment banking firm JPMorgan Chase & Co. The Federal government has had to prepare plans to ensure the creditworthiness of the nation's two largest holders of mortgage-backed debt, Fannie Mae and Freddie Mac, and a number of mid-sized regional banks have been declared insolvent and their assets taken over by the Federal Deposit Insurance Corporation. The decline in the stock price of financial institutions has made it harder for these entities to raise additional capital to restore their regulatory lending requirements, which has deceased the supply of available credit. In addition, companies that issue both municipal bond insurance policies and mortgage-backed insurance have suffered considerable additional losses, which has decreased the availability of municipal bond insurance and has continued to raise the cost of such insurance. The impact of these events has been to increase interest rate differentials between credit rating categories, which in turn has increased the credit spreads between bonds rated A and those rated AA.

The degree of the current disruption in credit markets has not occurred in prior rate cases. Since the time the initial Supplemental Proposal's financing study was prepared, the spread between bonds that are rated A and those that are rated AA has continued to increase to the point where they no longer represent a reasonable projection of the spread in interest rates that is projected to occur over the rate test period. This fact provides the justification for revising the financing study analysis. In order to correctly perform the section 7(b)(2) rate test, giving effect to the financing cost differences between the Program Case and the 7(b)(2) Case as directed in section 7(b)(2)(E)(i), it is necessary that a revised financing study be used for the final Supplemental Proposal.

In its Brief on Exceptions, the OPUC supports both of the approaches suggested by BPA's financial advisor to account for the unusual spreads and financial conditions that have been recently experienced in financial markets. OPUC Br. Ex., WP-07-R-PU-01, at 1-2. The first method is to use a shorter time period with the spreads in that shorter time period averaged to calculate the one-rating step differential. *Id*. The second method would be to increase the weighting of the near-term rate spreads while keeping the length of the study period the same. *Id*. The Draft ROD does not identify which method BPA will use. *Id*. The OPUC recommends that BPA identify in its Final ROD which approach BPA used as well as provide work papers or tables showing its calculations and all relevant data. *Id*. In response, BPA's financial advisor Public Financial Management (PFM) has chosen to use the first approach. The interest rate assumptions in the financing study were derived from historical interest rates averaged over the 3-year period starting July 15, 2005, through July 15, 2008. PFM's financing study report provides historical tables of the annual average interest rates for AA and A-rated bonds for the last 3 years for various bond maturity terms. The interest rate averages for the last 3 years in the financing study tables serve as the source documentation for the interest rates used to finance applicable resources contained in the 7(b)(2) Case resource stack in revising FY 2009 rates. The financing study is contained in Appendix A to the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-14.

Decision

BPA will revise its financing study to reflect the financing cost of resources contained in the 7(b)(2)(D) resource stack in performing the section 7(b)(2) rate test.

16.8 Conservation and the PF Exchange Rate

Issue 1

Whether BPA's treatment of conservation costs unfairly burdens the PF Exchange rate.

Parties' Positions

The IOUs argue BPA's treatment of conservation costs may unfairly burden the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 66-70.

BPA Staff's Position

BPA Staff states that because BPA's actual conservation costs are excluded from the section 7(b)(2) rate test, they cannot disproportionately burden, or burden in any way, those rates that are affected by a section 7(b)(3) reallocation made necessary by a non-zero section 7(b)(2) rate test trigger. Doubleday, *et al.*, WP-07-E-BPA-85, at 50.

Evaluation of Positions

The IOUs argue that BPA's conservation costs may unfairly burden the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 66-70. First, in the section 7(b)(2) rate test, only conservation costs allocated to the PF rate are subtracted from the Program Case as Applicable 7(g) Costs, whereas all conservation costs are excluded from the 7(b)(2) Case by BPA. *Id*. at 66. BPA allocates about 9 percent of conservation costs to surplus firm power and about 91 percent of conservation costs to the PF rate. *Id*., *citing* Supplemental Section 7(b)(2) Rate Test Documentation, WP-07-E-BPA-50A, at 17. BPA's allocation of 9 percent of conservation costs to surplus firm power increases the revenue shortfall from the FPS rate, all of which is allocated to the unbifurcated PF rate. *Id*. at 19. Nevertheless, the Applicable 7(g) Costs of conservation subtracted from the Program Case by BPA only consist of the 91 percent of conservation costs initially allocated to the unbifurcated PF rate. IOU Br., WP-07-B-JP6-01, at 67. The IOUs provide a calculation to determine the amount of Applicable 7(g) Costs of conservation subtracted by BPA for FY 2009, which they contend is 1.26 mills/kWh. *Id*. The IOUs argue that, by contrast, BPA erroneously excludes all of the conservation costs from the 7(b)(2) Case. *Id*. To avoid unfairly burdening the PF Exchange rate, the IOUs state BPA must subtract all conservation costs allocated to the unbifurcated PF rate or the FPS rate from the Program Case as Applicable 7(g) Costs. *Id*.

The IOUs account for all conservation costs allocated to rate pools. Ninety-one percent is allocated to the 7(b) rate pool (PF rates), and 9 percent is allocated to the 7(f) rate pool (FPS rates). The IOUs are basically correct that for FY 2009, 1.26 mill/kWh is subtracted from the Program Case rate as Applicable 7(g) Costs. (There is actually a small amount of billing credit costs included in the 1.26 mills/kWh, but this does not detract from the IOUs' argument.) The IOUs argue that BPA must subtract *all* conservation costs allocated to 7(b) *or* 7(f) rate pools as Applicable 7(g) Costs. The IOUs fail to state by what authority BPA should make such a change. The IOUs cite their rationale as "avoid[ing] unfairly burdening the PF Exchange rate," but BPA's treatment of subtracting only the costs allocated to the 7(b) rate pool is taken from section 7(b)(2). There, Congress directs that:

> … the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged *such customers* under subsection (g) of this section for the costs of conservation, resource and conservation credits …

16 U.S.C. § 839e(b)(2) (emphasis added). Congress clearly directs that the amount to be excluded from the Program Case, prior to the comparison with the 7(b)(2) Case, is the amount charged "such customers," not "all customers." As a result, BPA does not need to reach whether BPA's treatment unfairly burdens the PF Exchange rate or not. The IOUs' proposed treatment does not comport with statutory direction.

Further, the IOUs argue BPA's Implementation Methodology may cause conservation costs to disproportionately burden the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 67. Under BPA's Implementation Methodology, BPA subtracts conservation costs from the Program Case as an Applicable 7(g) Cost, yielding "net Program Case costs," and excludes conservation costs in the 7(b)(2) Case, and the loads are increased by the amount of the conservation. *Id*. at 68. At this point, all other things being equal, the 7(b)(2) Case rate is lower than the net Program Case rate: the costs are the same (ignoring the issue discussed in the preceding paragraph), but the loads are higher in the 7(b)(2) Case. *Id*. As resources are drawn from the 7(b)(2) Case resource stack, the costs are added to the 7(b)(2) Case. *Id*. When conservation resources are drawn from the 7(b)(2) Case resource stack, BPA reduces loads in the 7(b)(2) Case to reflect such conservation. *Id*. When output from generating facilities is drawn from the 7(b)(2) Case resource stack, the loads in the 7(b)(2) Case are not reduced. *Id*. Thus, depending on the nature of the resources drawn and their costs, the added costs in the numerator of the 7(b)(2) Case rate calculation may not be enough to overcome the effect of the higher loads in the denominator. *Id*. This is particularly true if the resources drawn are output from generating facilities, which will tend to result in a 7(b)(2) Case rate that is lower than the net Program Case rate. *Id*. In other words, the drawing of output from generating facilities in particular to serve the increased load due to conservation in the 7(b)(2) Case artificially lowers the 7(b)(2) Case rate because of the artificially increased loads used in the denominator of the calculation of that rate. *Id*. The IOUs provide an example to illustrate this effect. IOU Br., WP-07-B-JP6-01, at 69. In this example, BPA's treatment of conservation in the section 7(b)(2) rate test causes a trigger amount of 0.6 mills/kWh, which equals $0.60/MWh. *Id*. To avoid disproportionately burdening the PF Exchange rate, the IOUs argue BPA should not increase the loads in the 7(b)(2) Case for conservation savings and should not exclude conservation costs from the 7(b)(2) Case. *Id*.

Again, the IOUs appeal to avoiding a disproportionate burden on the PF Exchange rate to argue for a change in BPA's treatment of conservation resources. BPA addressed the proper treatment of conservation in the 7(b)(2) Case earlier in this ROD, *see* Section 16.2 – General Section 7(b)(2) Legal Issues, and Section 16.3 – Conservation Load Adjustment, and the IOUs' direct arguments about the treatment of conservation in the 7(b)(2) Case are addressed in those sections. BPA has laid out the statutory direction in the Northwest Power Act for why loads in the 7(b)(2) Case are increased and why conservation costs are excluded from the 7(b)(2) Case unless and until conservation resources are selected from the 7(b)(2)(D) resource stack. As a result, BPA does not need to reach whether BPA's treatment unfairly burdens the PF Exchange rate. The IOUs' proposed treatment does not comport with statutory direction. It would also have BPA disregard the immutable fact that conservation acts to reduce load.

Also, the IOUs miss the point that resources brought on from the resource stack may cost more or may cost less than the resources applied to 7(b) load in the Program Case. If, as is the case in the Supplemental Proposal, 7(b) loads exceed the size of the FBS and Exchange resource pools, then new resources are applied to 7(b) loads pursuant to section 7(b)(1). Such application of new resources is at the average cost of all new resources. However, in the 7(b)(2) Case, resources are applied in least-cost order, not average cost. This would be true even if the resources in the resource stack included only the very same collection of new resources from the Program Case. Section 7(b)(2)(D) is clear that resources are to be applied in a different order in the 7(b)(2) Case. Section 7(b)(2)(E) is clear that the cost of resources is different in the 7(b)(2) Case. Thus, there is no nexus between the cost of resources in the Program Case and the 7(b)(2) Case.

Further, the IOUs' technical argument has flaws. At the beginning of the IOUs' construction, they state that "[a]t this point, all other things being equal, the 7(b)(2) Case rate is lower than the net Program Case rate: the costs are the same … but the loads are higher in the 7(b)(2) Case." Here, the IOUs begin with a false premise; the costs are not the same in the two Cases. Most notably, there are no section 5(c) exchange costs in the 7(b)(2) Case rate. Although other differences exist due to the Five Assumptions, it is the exclusion of section 5(c) exchange costs from the 7(b)(2) Case rate that is the primary cause of the 7(b)(2) Case rate being lower than the

Program Case rate, not the treatment of conservation. Building on their false premise, the IOUs state that "depending on the nature of the resources drawn and their costs, the added costs in the numerator of the 7(b)(2) Case rate calculation may not be enough to overcome the effect of the higher loads in the denominator." Although the IOUs are correct that generating resources and conservation resources have a different effect when applied against load, it is not clear why they believe that such differential treatment must "overcome the effect on the higher loads." The IOUs state that "[i]n other words, the drawing of output from generating facilities in particular to serve the increased load due to conservation in the 7(b)(2) Case artificially lowers the 7(b)(2) Case rate because of the artificially increased loads used in the denominator of the calculation of that rate." Now the IOUs' argument collapses. The IOUs surmise that adding resource costs to a rate "artificially lowers" the rate. Ignoring the hyperbole regarding the "artificially" increased load, it should be evident that if the load is not increased due to the removal of conservation, the additional resources would not be added to serve the load. Therefore, it does not follow that an additional resource cost *lowers* the rate. If the load were not there, the resource would not be needed, and its costs would not be added. Thus, the rate is not lowered due to the added generation.

Staff states the IOUs misunderstand the treatment of conservation costs in the 7(b)(2) rate test. Doubleday, *et al.*, WP-07-E-BPA-85, at 50. The IOUs seem to be arguing that if the conservation resources taken from the resource stack in a given rate proceeding are cheaper than the actual conservation costs of that rate proceeding, the section 7(b)(2) rate test trigger may increase. *Id*. The fact is that conservation costs are removed from the adjusted Program Case PF rate that is compared with the 7(b)(2) Case PF rate in the rate test. *Id*. Therefore, the zero conservation costs in the adjusted Program Case rate can never be greater than the conservation costs in the 7(b)(2) Case PF rate. *Id*. Because BPA's actual conservation costs are excluded from the section 7(b)(2) rate test, they cannot disproportionately burden, or burden in any way, those rates that are affected by a section 7(b)(3) reallocation made necessary by a non-zero 7(b)(2) rate test trigger. *Id*.

The IOUs note that Staff's rebuttal testimony argues that conservation costs cannot burden rates such as the PF Exchange rate, because whatever conservation costs are included in the 7(b)(2) Case will be greater than the zero conservation costs in the adjusted Program Case. IOU Br., WP-07-B-JP6-01, at 70, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 50. The IOUs argue this argument overlooks the scenario discussed above, in which output from generating facilities in particular is drawn to serve the increased load due to conservation in the 7(b)(2) Case, which artificially lowers the 7(b)(2) Case rate because of the artificially increased loads used in the denominator of the calculation of that rate. IOU Br., WP-07-B-JP6-01, at 70. In short, in this scenario overlooked by BPA, conservation in the Program Case is effectively replaced not with conservation, but with relatively inexpensive output from generating facilities in the 7(b)(2) Case. *Id*. In that scenario, conservation may well increase the 7(b)(2) trigger amount. *Id.*

However, as explained above, the IOUs miss the point. If the 7(b)(2) Case loads were not higher, then resources would not be added from the 7(b)(2)(D) resource stack, and the costs of those resources would not be added to the 7(b)(2) Case rate. It is irrelevant whether it is conservation or another resource, relatively inexpensive or not, that is drawn from the resource stack. Section 7(b)(2)(D) clearly states that resources are to be drawn from the stack in least-cost order. Ultimately, the IOUs' argument fails because they are arguing against the section 7(b)(2) instruction to apply the Five Assumptions. BPA has no choice in how resources are applied to load in the 7(b)(2) Case. BPA is to first use FBS resources. If FBS resources are insufficient, BPA is then, in order to serve the public body, cooperative, and Federal agency customers, to draw resources from the 7(b)(2)(D) resource stack in least-cost order. Whether doing so unfairly burdens the PF Exchange rate or not is not a criterion contained in section 7(b)(2).

The IOUs argue BPA's conservation costs are not borne solely by the PF Preference rate and may disproportionately burden the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 101. The IOUs claim Cowlitz and Clark erroneously assert BPA's conservation costs, which are the only Applicable 7(g) Costs in this case, are fully recovered from preference customers irrespective of what happens in the 7(b)(2) Case. *Id., citing* Schoenbeck and Beck, WP-07-E-JP17-01, at 17. The IOUs state this assertion is incorrect for several reasons. IOU Br., WP-07-B-JP6-01, at 101. The IOUs note conservation costs in BPA's rates as adopted are reflected in not only the PF Preference rate but also in other rates, including, notably, the PF Exchange rate. *Id*. at 101-102, *citing* Supplemental WPRDS, WP-07-E-BPA-49A, at 21, Table 2.4.2. For FY 2009, BPA allocates about 9 percent of the conservation costs to Surplus Firm power and about 91 percent of the conservation costs to the PF rate, which, at this point of the cost allocation process, is unbifurcated and includes both the PF Preference rate and the PF Exchange rate. IOU Br., WP-07-B-JP6-01, at 102, *citing* Supplemental Section 7(b)(2) Rate Test Documentation, WP-07-E-BPA-50A, at 17. The IOUs conclude the assertion that BPA's conservation costs are fully recovered from preference customers is erroneous. *Id*. Conservation costs are allocated not only to the PF Preference rate but also to other rates as well, including, notably, the PF Exchange rate. *Id*.

The IOUs continue to miss the point in their argument. As they state, 9 percent of conservation costs are allocated to FPS rates. The other 91 percent are allocated to the PF rate, both PF Preference and PF Exchange. Those rates share *pro rata* in the 91 percent of the conservation costs. The share of conservation costs attributed to the PF Preference rate, slightly lower than 1.26 mills/kWh, is then subtracted from the PF Preference rate in the Program Case prior to comparison with the 7(b)(2) Case rate. After the comparison, if the section 7(b)(2) rate test has triggered, the rate protection amount is removed from the PF Preference rate. Finally, the conservation costs removed from the PF Preference rate before the rate test comparison are added back in to the PF Preference rate (again slightly less than 1.26 mills/kWh). Thus, the PF Preference rate is fully recovering its *pro rata* share, about 1.26 mills/kWh, of conservation costs. There is no transfer of conservation costs to the PF Exchange rate. The PF Exchange rate recovery of conservation costs remains as it was before the PF rate was bifurcated, about 1.26 mills/kWh. As a result, the PF Exchange rate is not "unfairly burdened" with conservation costs.

<u>Decision</u>

BPA's treatment of conservation comports with statutory requirements. It does not unfairly burden the PF Exchange rate.

16.9 7(b)(2) Case Repayment Study

Issue 1

Whether BPA properly establishes a repayment study in the 7(b)(2) Case.

Parties' Positions

Cowlitz argues an alternative repayment study is contrary to the 1984 Legal Interpretation and the 1984 Implementation Methodology, which provide that only changes required by the Five Assumptions may be reflected in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 30. An alternative repayment study is best understood as a secondary consequence of the improper additional assumptions that BPA no longer need repay monies it actually borrowed, and that BPA need not account for alternative borrowings it hypothetically substituted for the actual borrowings. *Id*. Assuming that BPA might lawfully create an alternative 7(b)(2) repayment study, BPA cannot as a matter of law base that study on an arbitrarily truncated set of revenue requirements. *Id*. BPA must base any alternative repayment study on the full revenue requirements of the 7(b)(2) Case, including the revenue requirements of all resources necessary to meet the general requirements of preference customers. *Id*.

BPA Staff's Position

BPA develops different revenue requirements, based on different repayment studies, for the Program Case and the 7(b)(2) Case. Doubleday, *et al.*, WP-07-E-BPA-85, at 17. One is derived (allocated) from the total Program Case revenue requirement, and the other is derived from the total revenue requirement developed specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective Cases. *Id*.

Evaluation of Positions

A. BPA's Repayment Studies in the 7(b)(2) Rate Test

The purpose of the repayment study is to establish, as the first step in the development of revenue requirements, the schedule of annual amortization payments to the U.S. Treasury for the rate test period and the resulting interest payments. Revenue Requirement Study, WP-07-FS-BPA-10, at 18. Because these costs are the last to be paid after BPA has met all of its other cost obligations, the adequacy of rates to pay the Federal investment means that rates can assure recovery of all costs and amortization of the Federal investment over a reasonable number of years. Thus, the overarching purpose of the repayment study is to assure rates are adequate to satisfy cost recovery requirements. The content requirements for repayment studies and for demonstrating the sufficiency of revenues from current or proposed rates are contained in Department of Energy Order RA 6120.2. *Id.* at Chapter 5.3. Outstanding and projected Treasury bonds and Congressional appropriations of the FCRPS must be repaid within the average service life of the associated asset or 50 years, whichever is less. The repayment study also takes into account the fixed debt service payments associated with BPA's capitalized purchase power contracts and long-term energy resource acquisition payments. It is also based on all other costs and revenues. "Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all generation obligations within the required repayment period." *Id.* at 19. For the section 7(b)(2) rate test, "the Program Case repayment study [is] performed without the excluded costs to determine the interest and amortization applicable to the 7(b)(2) case." Section 7(b)(2) Rate Test Study and Documentation, WP-07-FS-BPA-14, Attachment B, at IM-8.

B. How BPA's Repayment Studies Respond to Changes in Resource Cost Assumptions

Cowlitz notes BPA must develop rates "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 …." Cowlitz Br., WP-07-B-CO-01, at 26, *citing* 16 U.S.C. § 839e(a)(2). Cowlitz notes that, pursuant to Order RA 6120.2, BPA conducts repayment studies which portray "… the annual repayment of power production and transmission costs of a power system through the application of revenues over the repayment period of the power system. The study shows, among other items, estimated revenues and expenses, year by year, over the remainder of the power system's repayment period …, the estimated amount of Federal investment amortized during such year, and the total estimated amount of Federal investment remaining to be amortized." RA 6120.2, § 7(f).

Cowlitz states that, pursuant to RA 6120.2, "[t]he study does not deal with rate design." *Id.* Cowlitz argues there is no provision in RA 6120.2 for alternative repayment studies based on rate design issues. *Id.* Cowlitz fails to note, however, that RA 6120.2 was established on September 20, 1979 to apply to *all* Federal power marketing administrations (PMA), not just BPA. Supplemental Revenue Requirement Study, WP-07-E-BPA-46, at 47-48. Furthermore, at the time RA 6120.2 was adopted, Federal PMAs developed a single set of wholesale power rates for each rate period using a particular rate design. Therefore, there was no need for RA 6120.2 to address more than one repayment study for a Federal PMA. Yet today, pursuant to FERC requirements, BPA prepares two repayments studies, one for generation costs and one for transmission costs. Furthermore, RA 6120.2 was developed *before* enactment of the Northwest Power Act. RA 6120.2 therefore had no opportunity to address a circumstance in which BPA was required to develop alternative rates (costs) for two ratemaking worlds that were based on different assumptions, such as the section 7(b)(2) rate test. Therefore, RA 6120.2 does not limit the number of repayment studies that BPA must provide.

In any case, Cowlitz's argument is a red herring. The issue is what BPA's power costs are in the 7(b)(2) Case, and how they are to be determined. BPA's obligation to repay the United States Treasury for the Federal investment in the FCRPS is not a fixed schedule. Rather, BPA is to establish rates to assure repayment of the Federal investment over a reasonable number of years. 16 U.S.C. 839e(a)(1). This "assurance" is provided by running repayment studies. Repayment studies are always used by BPA to determine the amount of (amortization of) repayment of the Federal investment to the U.S. Treasury in each year of the rate period. The amount of amortization is, in part, a function of BPA's other debt costs. Because those costs differ in the Program and 7(b)(2) Cases, it is necessary for BPA to determine what amount of the Federal investment will be repaid in each year of the 7(b)(2) rate period. This is the function of a repayment study and rerunning the repayment study.

Cowlitz notes BPA is to prepare an annual study that "use[s] sound *and consistent* forecasting techniques." *Id.,* § 10(a) (emphasis added). Cowlitz argues BPA's invention of an alternative repayment study for the 7(b)(2) Case represents a failure to conform to the requirements of RA 6120.2, quite apart from its undermining of section 7(b)(2) rate protection. Cowlitz Br., WP-07-B-CO-01, at 26. Cowlitz's argument, however, cannot legitimately be based on RA 6120.2. The direction to use "sound and consistent forecasting techniques" applies to the development of a single repayment study and thus to the use of sound and consistent forecasting techniques *within* that repayment study. It does not address the consistency of two separate repayment studies. Furthermore, RA 6120.2 says nothing about preparing separate repayment studies for generation and transmission based on their unique characteristics, but BPA prepares them in compliance with FERC requirements. Similarly, the requirements of section 7(b)(2) of the Northwest Power Act and the different assumptions for the Program Case and 7(b)(2) Case likewise call for separate studies. In any event, BPA has used sound and consistent forecasting techniques for both the Program Case repayment study and the 7(b)(2) Case repayment study. The fact that the results of the repayment studies may be different is a result of the different assumptions BPA is required to use in establishing the two Cases.

Cowlitz cites its direct testimony, which states:

> A repayment study essentially determines what level of interest and amortization payments are required to pay off BPA's debt obligations over a 50-year term. The interest and amortization amount is controlled by a "pinch year" or "critical year" arising from the required due date of the largest debt repayment obligations. This critical year (or years) is usually determined by the obligations associated with the Energy Northwest ("ENW") debt.

Id. at 26, *quoting* Schoenbeck and Beck, WP-07-E-JP17-01-CC1, at 22. Cowlitz notes the Program Case "reflects BPA's actual accounting and financing policies," which include certain "debt management" and "debt optimization" practices. Cowlitz Br., WP-07-B-CO-01, at 26, *citing* Keep, *et al.*, WP-07-E-BPA-68, at 14. Pursuant to these policies, if certain resource costs prior to the "pinch year" are assumed not to exist in the 7(b)(2) Case, "there is 'more room' for pre-paying FBS obligations." Cowlitz Br., WP-07-B-CO-01, at 27, *citing* Schoenbeck and Beck, WP-07-E-JP17-1-CC1, at 22. Cowlitz states that, in other words, if costs other than FBS costs are assumed to decrease in the 7(b)(2) Case, then a new repayment study will automatically increase FBS costs in the 7(b)(2) Case. *Id*. Cowlitz states that BPA acknowledges that "[i]n general, Cowlitz/Clark have correctly characterized the operation of the repayment study" as just described. *Id*. *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 16-17; *see also Id.* at 19 ("the repayment study did respond in its operation essentially as stated by Cowlitz/Clark"). Cowlitz, however, omits the entire statement of BPA's witnesses, which presents a different and more accurate and complete picture than Cowlitz's characterization:

> In general, Cowlitz/Clark have correctly characterized the operation of the repayment study. However, based on the data they present, they appear to

> confuse the results of the repayment study with the allocation of the components to the resource pools, specifically the FBS. Although they have focused primarily on the net interest and net revenues from the total revenue requirement that have been allocated to Hydro, the more appropriate comparison, given the operation of the section 7(b)(2) rate test, would be between the full FBS in the two Cases. BPA's Fish & Wildlife program is also part of the FBS and receives allocations of net interest and net revenues. However, more importantly, the comparisons of capital-related costs are quite different between repayment studies and the revenue requirements allocated to the FBS.

Doubleday, *et al.*, WP-07-E-BPA-85, at 17-18. In addition, Cowlitz's quotation that "the repayment study did respond in its operation essentially as stated by Cowlitz/Clark," is misleading unless viewed in context:

> Using the data for the 2009 portion of the rate tests (FY 2009-2013) as an example, Cowlitz/Clark first show a total difference of net interest between the two Cases of negative $2,650 (all $ in thousands herein) when the Program Case data are subtracted from the 7(b)(2) Case data for the costs allocated to Hydro. Directly from the repayment study, however, the gross interest between the Cases is negative $128,404. (*See* Attachment 1 for source data used here.) The amortization scheduled by the studies differs by [negative $60,577], for a total difference between the Program Case and 7(b)(2) Case repayment study results of negative [$188,981]. Compare that figure to the total difference cited by Cowlitz/Clark of positive $215,832. This is quite disparate data and Cowlitz/Clark's conclusions cannot, then, be attributed solely to repayment study results. Although the repayment study did respond in its operation essentially as stated by Cowlitz/Clark, one of the most noteworthy differences between the two Cases is from revenue requirement development. Because BPA's conservation investments are not present at the outset in the 7(b)(2) Case, the revenue requirement for that Case excludes $279,657 of conservation amortization (non-cash annual write-down of the investment) that is in the Program Case revenue requirement. The Planned Net Revenues difference of positive $218,482 Cowlitz/Clark cites is directly affected by the exclusion of the conservation amortization because Planned Net Revenues, specifically the Minimum Required Net Revenues component, is calculated as the positive difference of scheduled Federal principal repayment and irrigation assistance payments less the non-cash expenses in the revenue requirement. Consequently, it is not really the repayment study that creates such a difference between the allocated costs in the two Cases, but it is a consequence of the different assumptions in the revenue requirements of each Case pertaining to the annual costs associated with conservation investments.

Doubleday, *et al.*, WP-07-E-BPA-85, at 18-19; Doubleday, *et al.*, WP-07-E-BPA-85-E2. Thus, the results from the 7(b)(2) repayment study are substantially less than those of the Program Case, and the differences that Cowlitz cites actually stem directly from the different assumptions in the 7(b)(2) Case revenue requirements that are required by the Five Assumptions.

C. BPA Correctly Assumes that Certain Non-FBS Costs and Conservation Costs Are Not Included in the 7(b)(2) Case Repayment Study, Thereby Correctly Stating FBS Costs

Cowlitz argues BPA improperly creates an uncalled-for and internally inconsistent repayment study in the 7(b)(2) Case that exaggerates FBS costs. Cowlitz Br., WP-07-B-CO-01, at 26. Cowlitz claims the proposed Implementation Methodology exploits BPA's debt management policies by declaring that BPA must run an alternative repayment study for the section 7(b)(2) Case (different than that employed in the Program Case) by excluding three categories of costs from the repayment study: (1) Residential Exchange Program costs; (2) all costs of any acquisition of new resources; and (3) Applicable 7(g) Costs, including, most importantly, all conservation costs. *Id*., *citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, Implementation Methodology, at IM-8. In the Program Case, however, BPA subtracts from the pool of Program Case costs the Applicable 7(g) Costs of conservation that are allocated to all loads pursuant to section 7(g), not just general requirements of preference customers, *and does not attempt to run a repayment study as if BPA's obligation to pay those costs had simply disappeared*. *Id*., *citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, at 15. Cowlitz misinterprets the basic premise of section 7(b)(2)(D)(i) concerning the resources that are available to meet 7(b)(2) Customer loads after available FBS resources have been exhausted, which reads "purchased from such customers by the Administrator pursuant to section 6." Staff's proposed Implementation Methodology is correct in excluding these costs because in the hypothetical 7(b)(2) Case world (the "without the Act" world), conservation resources are acquired and financed by the 7(b)(2) Customers themselves. Because the financial repayment obligation for these resources rests with the 7(b)(2) Customers (coming together jointly through the JOA), they are not BPA's obligations. This is made even more clear by section 7(b)(2)(E)(i) of the Act, which provides that the resources would not have received BPA's financial backing and the financing cost is different between the two Cases. If the financial obligations rest with the 7(b)(2) Customers, then they are not BPA's financial obligations, and the only logical conclusion is that the 7(b)(2) Case repayment study should not reflect these obligations. The proper repayment study is one that is modeled to levelize the repayment obligations of the FBS over the 50-year period without conservation or new resource obligations present. Thus, there is no need to rerun the 7(b)(2) Case repayment study to incorporate the effect of the conservation resources that are chosen from the resource stack.

In addition, the language of section 7(b)(2) is consistent with BPA's approach. For the Program Case, BPA is to determine the "projected amounts to be charged … exclusive of" specified 7(g) costs. It is fair to read this as stating BPA should first determine the projected amounts, then exclude certain costs. The projected costs are, in the first instance, determined in part by the repayment study results. Only after this are the specified 7(g) costs excluded.

In its Brief on Exceptions, Cowlitz opposes BPA's development of a repayment study in the 7(b)(2) Case and cites BPA's recognition that conservation costs brought into the 7(b)(2) Case to meet remaining general requirements through section 7(b)(2)(D) "are not BPA's obligations" to repay. Cowlitz Br. Ex., WP-07-R-CO-01, at 26. Cowlitz argues BPA's recognition of the "hypothetical 7(b)(2) Case world (the world without the Act) [wherein] conservation costs are acquired and financed by the customers themselves" departs from the Five Assumptions. *Id.* Cowlitz notes BPA's statement that "the financial repayment obligation for these resources rests with the 7(b)(2) Customers (coming together jointly through the JOA [Joint Operating Agency]), they are not BPA's obligations." *Id.* Cowlitz states that section 7(b)(2) does not call for BPA to create a "world without the Act." *Id*. BPA generally agrees, with the qualifications noted in the evaluation of the issue of whether to adjust loads for conservation. Instead, BPA interprets section 7(b)(2), including, as BPA has recognized since 1984, the natural consequences of the Five Assumptions in the 7(b)(2) Case.

In conducting the 7(b)(2) rate test, BPA implements the Five Assumptions, including sections 7(b)(2)(D)(i) and 7(b)(2)(E)(i), which are relevant to this issue. Cowlitz argues one will search section 7(b)(2) in vain for any mention of a JOA or any suggestion that the section 7(b)(2)(D)(i) resources are anything other than real power resources that actually exist and that are "*purchased*" by the *Administrator*. Cowlitz Br. Ex., WP-07-R-CO-01, at 27. Cowlitz's argument is not persuasive. The fact that section 7(b)(2) does not mention a JOA does not mean the assumption of a JOA is incorrect in implementing section 7(b)(2). As Cowlitz notes elsewhere in its Brief on Exceptions, where the Act does not specify how BPA is to determine the magnitude of the financing benefit, BPA is free to use any reasonable means to estimate that benefit. *Id*. at 28. Indeed, there are numerous assumptions that are not *expressly* mentioned in section 7(b)(2), but which must be assumed in order to properly implement the rate test. With regard to a JOA, one must review the statutory language, legislative intent and sound business principles regarding whether such an assumption is consistent with section 7(b)(2). The fact that additional resources to serve regional public load are brought on from the resource stack means that resources have been acquired by customers. BPA believes that in certain cases it is reasonable to assume that it is a regional entity acquiring the resources. Otherwise, individual public body customers would acquire resources in all instances. Given the financing and other matters involved in resource acquisitions, it is a reasonable conclusion that a JOA would be formed to most efficiently and cost-effectively acquire the resources. This was initially done in 1984 in the development of BPA's Section 7(b)(2) Implementation Methodology.

In 1984, BPA conducted a section 7(i) hearing in order to establish a Section 7(b)(2) Implementation Methodology to guide BPA in subsequent power rate cases when implementing section 7(b)(2) of the Northwest Power Act. All parties had the opportunity to participate in the development of the Implementation Methodology. During the hearing, the PPC proposed that the conservation funded by BPA in the Program Case should be assumed to be performed, for financing benefit analyses, by the individual utility serving the geographical area where BPA's conservation investment was made. 1984 Implementation Methodology ROD, at 13. BPA disagreed and decided to treat Type 3 and conservation resources as owned and sponsored by a group of 7(b)(2) Customers to avoid speculation and additional complicating assumptions about financing arrangements in the 7(b)(2) Case. *Id*. BPA recognized that financing benefits should logically be quantified for only the 7(b)(2) Customers in order to properly determine their power costs in the 7(b)(2) Case. *Id*.

Cowlitz states that under section 7(b)(2)(D)(i), BPA is directed to "meet remaining requirements" through, among other things, resources "purchased from [preference] customers by the Administrator pursuant to section 6." Cowlitz Br. Ex., WP-07-R-CO-01, at 27. Cowlitz argues that, in other words, the assumptions required in section 7(b)(2) expressly recognize BPA's statutory acquisition authority under the Northwest Power Act. *Id*. Cowlitz argues the fact that the cost of BPA conservation resources are not properly part of differences to be analyzed in the section 7(b)(2) rate test, and that conservation costs are to be allocated under section 7(g) irrespective of section 7(b)(2), cannot and does not warrant BPA pretending those costs do not exist. These arguments are addressed above in the discussion of adjusting loads for conservation. BPA, however, does not pretend conservation costs do not exist. Instead, they are not part of the FBS resources, which are the only "Federal" resources in the 7(b)(2) Case. It is not that the resources "disappear"; the premise of section 7(b)(2)(D) is that the ownership changes from BPA to COUs. This is supported by the Senate Report, which states that "*preference customers* would construct new generating resources to meet their loads in excess of the Federal Base System Resources." S. Rep. No. 96-272, 96th Cong., 1st Sess. 61 (1979) (emphasis added). Section 7(b)(2) recognizes BPA's statutory acquisition authority under the Northwest Power Act, but only to the extent of identifying the regional resources that can be included in the 7(b)(2) resource stack. In the 7(b)(2) Case these resources, once identified as eligible to be in the resource stack, may or may not be called upon to serve load. The fact that they were used in the Program Case is not sufficient to determine that they will be used to serve load in the 7(b)(2) Case. Further, because of this uncertainty of service, conservation costs will likely be different in the Program and 7(b)(2) Cases. Pursuant to RA 6120.2, the purpose of the repayment study is to determine the adequacy of BPA's rates to assure recovery of BPA's costs over the 50-year power repayment period. In the process, the amount and timing of amortization of the Federal investment is determined. So, if BPA's costs change or are different than those assumed in conducting the repayment study, rates that were once adequate to assure cost recovery may no longer be sufficient. Because costs are different between the Program and 7(b)(2) Cases, it is necessary to run repayment studies to determine the timing and amount of amortization of the Federal investment, and the adequacy of rates to assure total cost recovery over the repayment period.

Cowlitz argues the JOA is merely a device BPA uses to implement the Fifth Assumption in section 7(b)(2)(E)(i). Cowlitz Br. Ex., WP-07-R-CO-01, at 27. Cowlitz notes that Assumption Five calls upon BPA to assume that:

> quantifiable monetary savings, during such five-year period, to [preference] customers resulting from … reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) … were not achieved.

Id. Cowlitz argues that passage of the Northwest Power Act was expected to reduce financing costs by giving public agencies the ability to sell the output of their resource projects to an especially creditworthy customer: BPA. *Id*. Cowlitz states that although section 7(b)(2)(D)(i) makes clear that BPA is still to be assumed to acquire resources from preference customers under the Act, section 7(b)(2)(E)(i) directs BPA to assume that BPA's acquisition of such resources does not result in "reduced public body and cooperative financing costs." *Id*. In order to assess the reduced financing costs in the Program Case that must be adjusted for in the 7(b)(2) Case, BPA "concluded that a reasonable assumption for the most favorable [alternative] 'financing vehicle' … would be the formation of a Joint Operating Agency (JOA) …" *Id*.

Cowlitz argues that, in short, the JOA is merely a conceptual tool to quantify the "monetary savings" to be eliminated in the 7(b)(2) Case. *Id.* In response, the assumed JOA a logical choice to acquire regional resources to serve a regional load and is more than a conceptual tool to quantify monetary savings. For example, Energy Northwest (formerly the Washington Public Power Supply System (WPPS)) is an operating JOA. Formed by public bodies, a JOA's purpose is to construct and acquire resources for meeting the supply needs of such utilities. *See* RCW 43.52.360. It is illogical that, in the 7(b)(2) Case, individual utilities would acquire individual resources to serve only their own load.

Cowlitz argues that because the Act does not specify how BPA was to determine the magnitude of the financing benefit, BPA was free to use any reasonable means to estimate that benefit. Cowlitz Br. Ex., WP-07-R-CO-01, at 28. Cowlitz states that nothing, however, authorizes BPA to pretend that the FBS resources cost more in the 7(b)(2) Case than they really cost in the Program Case. *Id.* Cowlitz argues that section 7(b)(2)(E)(i) expressly exempts "Federal base system resources" costs from any adjustment due to the financing benefit. *Id.* As stated in the legislative history, when performing the rate test:

> The specific rate limit factors are objective in nature. The first, the size and cost of the Federal Base System Resources, will be determined in much the same way that BPA applies it in its current power marketing operations and ratemaking.

S. Rep. No. 96-272, 96th Cong., 1st Sess. at 61 (1979); Attachment 2 to E-JP17-1-CC1. Cowlitz forgets, however, that the costs (interest and amortization) are determined by the repayment study and that they are a function of the timing of repayment, which is determined in part by BPA's other costs. Cowlitz also states that the statutory test for which resources may be used to "meet remaining general requirements" of preference customers in the 7(b)(2) Case is set forth in section 7(b)(2)(D), which includes resources that "were purchased from such customers by the Administrator pursuant to section 6" and other "resources [that] were obtained at the average cost of all other new resources acquired by the Administrator." Cowlitz Br. Ex., WP-07-R-CO-01, at 28. Cowlitz states that when the Administrator purchases something, it is BPA's obligation to pay for what has been purchased. *Id.* However, in the 7(b)(2) Case, the Administrator is to determine the resources that may be chosen to serve the remaining public load after the FBS is exhausted. The fact that those resources have already been purchased in the Program Case does not mean they have been purchased in the 7(b)(2) Case, but only that they are *available* to serve load in the 7(b)(2) Case. It does not mean they would actually be selected to serve load.

Cowlitz argues nothing in section 7(b)(2)(D) suggests that BPA is to assume it has not acquired conservation resources it has actually acquired or that it has been excused from paying for them. Cowlitz Br. Ex., WP-07-R-CO-01, at 28. However, Cowlitz fails to recognize the differences between the Program and 7(b)(2) Cases. Non-FBS resources purchased and used to serve load in the Program Case may or may not be used to serve load in the 7(b)(2) Case. Cowlitz contends BPA recovers those costs under section 7(g) irrespective of whether the power costs are higher or lower in the Program Case than in the 7(b)(2) Case. *Id.* Cowlitz argues that for this reason BPA must account for the costs of such resources on its own account and specifically account for their costs in the repayment study. *Id.* This issue is dealt with in the evaluation of whether to adjust load for conservation. Cowlitz assumes that the Program and 7(b)(2) Cases are more similar than they really are. Conservation resource costs are section 7(g) costs in the Program Case. Those forecasts of the agency's conservation costs reflect spending level decisions from a public cost review process and are incorporated in the development of generation revenue requirements that are allocated to the resource pools in the COSA tables for the ratemaking process. In the 7(b)(2) Case, conservation resource costs, rather than being included in the revenue requirement, are in the 7(b)(2) resource stack from which a very different mix of conservation programs may be selected than was reflected in the Program Case. Because the amount and the associated cost of conservation that *may be selected* in any given year of the 7(b)(2) Case is unknown at the outset of the rate development process, a repayment study performed before the 7(b)(2) rate test is conducted could not include these unknown amounts and costs of conservation. Cowlitz claims running a separate repayment study that excludes such costs is contrary to law because it adds an additional assumption to the 7(b)(2) Case: higher FBS costs. *Id*. Cowlitz states it cannot be defended as a necessary consequence of any of the Five Assumptions, because no assumption excuses BPA to substitute new and exaggerated conservation costs in the 7(b)(2) Case and simultaneously to assume that it has not acquired and need not pay for such conservation. *Id*. In the 7(b)(2) rate test, however, conservation resources belong in the 7(b)(2) resource stack to be selected to serve load in a least-cost-first manner. A consequence of being in the stack is that they may very likely come on-line to serve load in the 7(b)(2) Case in quite a different manner than how they actually served load in the Program Case. Because of this, it is inappropriate to include them in a repayment study as if they were identical to the Program Case conservation costs.

Cowlitz states BPA recognizes for purposes of the Program Case (but not the 7(b)(2) Case) that the fact that a specific resource, or class of resources, is not assigned to a particular class of load for ratemaking purposes does not make the resource or its costs disappear. Cowlitz Br., WP-07-B-CO-01, at 28. BPA still must pay the cost of the resource, and it is available to serve other loads. *Id*., *citing* Schoenbeck and Beck, WP-07-E-JP17-01-CC1, at 23; *see also* Tr. 434. In particular, BPA makes no changes in the Program Case to the FBS revenue requirement on account of conservation excluded from the power cost comparison required by section 7(b)(2). *Id*., *citing* Tr. 430.

Cowlitz's argument, however, compares apples and oranges and ignores that the test is expressly about costs and loads being different in the two Cases. Naturally, the assignment of a resource to a particular class of load does not make the resource or its costs disappear. However, as explained in more detail below, resources and resource costs do not "disappear" in the 7(b)(2) Case either. Instead, they are not part of the FBS resources, which are the only "Federal" resources in the 7(b)(2) Case, and thus the only resources BPA develops a repayment study for. That is because, as noted earlier, the purpose of the repayment study is to determine how much of the Federal investment is repaid to the U.S. Treasury during the rate period, which assures repayment of the Federal investment in the FCRPS over a reasonable number of years. It is not that the resources "disappear"; the premise of Section 7(b)(2)(D) is that the ownership changes from BPA to COUs. This is supported by the Senate Report, which stated that "*preference customers* would construct new generating resources to meet their loads in excess of the Federal Base System Resources." S. Rep. No. 96-272, 96th Cong., 1st Sess. 61 (1979) (emphasis added).

Cowlitz argues that, despite the same underlying reality of debt repayment, BPA assumes in the 7(b)(2) Case that its obligation to repay the cost of non-FBS obligations simply disappears. Cowlitz Br., WP-07-B-CO-01, at 28, *citing* Schoenbeck and Beck, WP-07-E-JP17-1-CC1, at 22; *cf.* Doubleday, *et al.*, WP-07-E-BPA-85, at 20; Tr. 435.

In response, however, first, there is not the same underlying debt repayment in the Program Case and the 7(b)(2) Case. The Program Case includes debt repayment for Federal resources, which include the FBS and conservation, as well as for non-Federal resources associated with the FBS, conservation and new resources. In contrast, the 7(b)(2) Case contains repayment associated with only FBS resources, both Federal and non-Federal.

Cowlitz argues the net effect, as BPA acknowledges, is to substantially increase the financing costs associated with FBS resources by effectively adopting a special 7(b)(2) Case assumption that the costs of the FBS resources can be paid much more rapidly now that BPA is assumed (for purposes of the 7(b)(2) Case repayment study only) to be free from its obligation to make other debt payments. Cowlitz Br., WP-07-B-CO-01, at 28, *citing* Schoenbeck and Beck, WP-07-E-JP17-1-CC1, at 22-24; *see also* Brodie, *et al.*, WP-07-E-BPA-58, at 12; Tr. 418-19. Cowlitz argues the costs have not vanished, and BPA remains obligated by contract and other authority to pay them. *Id*.

Once again, these arguments lack merit because they fail to capture the basic ownership and financial arrangements that are outlined in the 7(b)(2) Case by the Five Assumptions, which specify the resource owner(s) and parties that are responsible for the financial obligation of the resources being used to serve 7(b)(2) Customer loads as explained above.

Cowlitz argues the net effect of the 7(b)(2) Case repayment study is to inflate FBS costs by more than $1.1 billion over the FY 2002-2009 time frame. Cowlitz Br., WP-07-B-CO-01, at 28, *citing* Schoenbeck and Beck, WP-07- E-JP17-01-CC1, at 22. Cowlitz notes that Staff complains of "disparate data" in the individual year calculations presented by Cowlitz and Clark and notes that much of the additional cost "is a consequence of different assumptions in the revenue requirements of each Case pertaining to the annual costs associated with conservation investments." *Id*. at 28-29 *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 18-19. Cowlitz then makes the remarkable statement that BPA Staff "does not dispute the $1.1 billion bottom line." *Id*. at 29.

To the contrary, although Staff did not dispute there were differences between the Program Case and the 7(b)(2) Case hydro costs as characterized by Cowlitz, Staff's statements were the reason they did not accept the $1.1 billion "bottom line" as being a product of the 7(b)(2) Case repayment study. As cited earlier, Staff clearly demonstrated that the differences were not attributable to the repayment study, but instead to other factors pertinent to the different assumptions required of the 7(b)(2) Case.

Cowlitz argues Congress specifically addressed the question of how BPA was supposed to assign financing costs in the 7(b)(2) Case because the only different assumption BPA is supposed to make in the 7(b)(2) Case concerning financing costs is that certain "reduced public body and cooperative financing costs" did not occur. Cowlitz Br., WP-07-B-CO-01, at 29, *citing* 16 U.S.C. § 839e 7(b)(2)(E)(i).

Again, Cowlitz's argument is inconsistent with the rate test's basic assumptions concerning the owner of the resources and the parties who are responsible for the financial obligations for these resources in the 7(b)(2) Case. Section 7(b)(2)(E)(i) clearly indicates that these financial obligations are not BPA's obligations because the resources did not enjoy BPA's financial backing; the "reduced public body and cooperative financing costs as a result of the Administrator's actions [ ] were not achieved." 16 U.S.C. § 839e 7(b)(2)(E)(i). Thus, the 7(b)(2) Customers' separate financial obligations are added to the 7(b)(2) Case revenue requirement only if the resources are in fact the "least-cost" resources available to meet the remaining loads, and the separate FBS repayment obligations are modeled independently in the 7(b)(2) Case repayment study, subject to the provisions of RA 6120.2.

Cowlitz states that BPA staff acknowledges that it might be reasonable not to perform a different repayment study for the 7(b)(2) Case than the Program Case, and it acknowledges that a "lay reader may not find a reference to such a requirement [a 7(b)(2) Case repayment study] in the Act," but argues that it has done one since 1985. Cowlitz Br., WP-07-B-CO-01, at 29, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 19, 21. Cowlitz argues BPA is without power to add additional assumptions to the Five Assumptions in this rate case merely because it has done so before.

BPA agrees. However, a longstanding Legal Interpretation that has been consistently applied for over 20 years is quite significant in determining the deference to be given BPA's interpretation. Staff reasoned that:

> [i]f there were only one view of the FBS, once the FBS revenue requirement was determined in the Program Case, it might not be necessary to start over and establish another revenue requirement for the 7(b)(2) Case. However, throughout the history of the rate test BPA has approached the cost development as a "bottoms up" approach in which repayment requirements and resulting revenue requirements are determined by starting over from the Program Case and independently developing revenue requirements that only include those costs that are known at the outset of the analysis to be present in the 7(b)(2) Case. Only when resources are brought on from the 7(b)(2)(D) resource stack are the associated costs brought on in proportion to the amount of the resources needed, which may be entirely different from what is projected in the Program Case.

Doubleday, *et al.*, WP-07-E-BPA-85, at 21-22. This is consistent with the requirements of the Act. A central function of the 7(b)(2) rate test is to determine what the "power costs" would be if the Administrator made the five load, resource, and financing cost assumptions. Nothing in those assumptions changes the statutory ratemaking requirement that has existed since passage of the Bonneville Project Act that BPA must establish rates to assure repayment of the Federal investment over a reasonable number of years. *See, e.g.,* 16 U.S.C. 839e(a)(1) and acts cited therein. Because BPA must continue to do so in the 7(b)(2) Case, and the repayment study is run to determine the amount of rate period repayment that will assure amortization of the Federal investment over a reasonable number of years, the repayment study is appropriately run.

Cowlitz notes the Legal Interpretation's statement that "only the assumptions specified in section 7(b)(2) and any unavoidable consequences or secondary effects of those assumptions will be considered to determine 7(b)(2) customers' power costs in the 7(b)(2) case." Cowlitz Br., WP-07-B-CO-01, at 29, *citing* 49 Fed. Reg. 23,998 (June 8, 1984) and Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Legal Interpretation, at LI-4 to LI-5 (reiteration of this principle). Cowlitz argues BPA cannot demonstrate than an alternative repayment study that selectively modifies costs is an unavoidable consequence or secondary effect of one of the statutory assumptions. *Id*. Indeed, in the 1984 Implementation Methodology, BPA identified only "three natural consequences" of the statutory assumptions that would be considered in the 7(b)(2) Case (beyond the statutory assumptions), none of which had to do with changes in financing costs associated with alternative repayment studies. *Id*. at 29-30.

In response, however, Cowlitz ignores the statutory assumptions of section 7(b)(2). Section 7(b)(2) establishes that different resources are used to serve preference customer loads in the Program and 7(b)(2) Cases. 16 U.S.C. § 839e(b)(2). Cowlitz's arguments ignore the basic premise surrounding the owner of the resources and the parties who are responsible for the financial obligations for these resources in the 7(b)(2) Case. This is not due to a "secondary effect," but is based on the literal meaning and direct implications of sections 7(b)(2)(D) and 7(b)(2)(E), and is supported by the Senate Report. 16 U.S.C. § 839e(b)(2)(D), § 839e(b)(2)(E).

Cowlitz argues that, in short, an alternative repayment study is contrary to the longstanding 1984 Legal Interpretation and the initial 1984 Implementation Methodology, which provide that only changes required by the Five Assumptions may be reflected in the 7(b)(2) Case and is best understood as a secondary consequence of the improper additional assumptions that BPA no longer need repay monies it actually borrowed, and that BPA need not account for alternative borrowings it hypothetically substituted for the actual borrowings. Cowlitz Br., WP-07-B-CO-01, at 30.

As outlined previously: (1) BPA has consistently conducted a separate repayment study in all prior rate cases over the last 23 years and parties to the rate case have not objected to the separate 7(b)(2) Case repayment study before this rate case; (2) a separate repayment study is required because BPA is not the owner of the resource nor the party responsible for the conservation or "new resource" obligations in the 7(b)(2) Case; thus, the population of obligations that are being modeled subject to RA 6120.2 is different between the two Cases; and (3) BPA's action to perform a separate repayment study is not based on secondary effects or a natural consequences of the Five Assumptions, but rather is due to the direct meaning and application of sections 7(b)(2)(D) and 7(b)(2)(E)(i), and the statutory requirement to timely repay the U.S. Treasury.

Cowlitz argues that through section 7(b)(2)(E)(i), "Congress has directly spoken to the precise question at issue, [and] that is the end of the matter; for the … agency must give effect to the unambiguously expressed intent of Congress." Cowlitz Br., WP-07-B-CO-01, at 30, *citing*

Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc., 476 U.S. 837, 842-43 (1984). This argument, however, supports BPA's position.

BPA believes its interpretations of sections 7(b)(2)(D) and 7(b)(2)(E)(i) are correct, and the need for a separate repayment study for the 7(b)(2) Case is required and consistent with BPA's interpretation.

D. A New Repayment Study in the 7(b)(2) Case Properly Does Not Include Certain Costs in the 7(b)(2) Case

Cowlitz states that Staff attempts to justify the revised repayment study for the 7(b)(2) Case on the ground that it cannot simply subtract the conservation costs as it does in the Program Case, because it does not know before it runs the 7(b)(2) Case how much conservation cost it will add back to the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 31, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 21-22. Cowlitz argues that once it runs the 7(b)(2) Case, Staff does know how much conservation it has drawn from the section 7(b)(2)(D) resource stack, and the revenue requirement it has arbitrarily assigned to such conservation, yet it does *not* run a repayment study reflecting these costs. Tr. 439.

However, the cited characterization of the role of the repayment study "is to establish*, as the first step in the development of revenue requirements*, the schedule of annual amortization payments to the U.S. Treasury for the rate test period and the resulting interest payments." Revenue Requirement Study, WP-07-E-BPA-46, at 20 (emphasis added).

Cowlitz states removing the conservation costs from the initial 7(b)(2) Case repayment study for FY 2009 increased the FBS costs in the 7(b)(2) Case by at least $186 million. Cowlitz Br., WP-07-B-CO-01, at 31, *citing* Tr. 418-19. Cowlitz states that if BPA had rerun the 7(b)(2) Case repayment study with what BPA claims are the conservation costs that must be included in the 7(b)(2) Case, FBS costs assigned to preference customers by virtue of the alternative repayment study would have actually *decreased*. Cowlitz Br., WP-07-B-CO-01, at 31. Cowlitz claims the larger amount of conservation costs added by the end of the 7(b)(2) Case would have reduced the FBS costs more than subtracting conservation costs at the onset of the 7(b)(2) Case increased the FBS costs. *Id. citing* Tr. 435-36, 438-39. In addition, Cowlitz argues that even assuming BPA might lawfully create an alternative section 7(b)(2) repayment study, BPA cannot as a matter of law base that study on an arbitrarily truncated set of revenue requirements. Cowlitz Br., WP-07-B-CO-01, at 31. BPA must base any alternative repayment study on the full revenue requirements of the 7(b)(2) Case, including the revenue requirements of all resources necessary to meet the general requirements of preference customers. *Id*.

As BPA established in its foregoing arguments, BPA does not own conservation resources or other resources in the 7(b)(2)(D) resource stack, nor does it have the financial obligation for these resources in the 7(b)(2) Case. Instead, those obligations are the separate obligations of the 7(b)(2) Customers. Those obligations are only added to the 7(b)(2) Case revenue requirement if these resources are selected from the resource stack and become part of the power costs in the 7(b)(2) Case. The 7(b)(2) repayment study appropriately models the remaining FBS obligations in the 7(b)(2) Case.

Decision

BPA properly establishes a repayment study in the 7(b)(2) Case.

16.10 Preference Customer-Owned Resources and the Resource Stack

Issue 1

Whether and, if so, to what extent preference customer-owned resources should be included in the 7(b)(2) Case resource stack.

Parties' Positions

CUB states that Staff's proposal to exclude the Mid-Columbia resources from the resource stack in the 7(b)(2) Case is supported by the plain meaning of the Northwest Power Act. CUB Br., WP-07-B-CU-01, at 14-15.

The IOUs argue that BPA should exclude from the 7(b)(2) Case resource stack the portion of the output of the Mid-Columbia dams sold to non-preference purchasers. IOU Br., WP-07-B-JP6-01, at 95.

The IOUs and CUB argue BPA must not include in the 7(b)(2) Case resource stack the portion of the output from the Mid-Columbia dams sold to non-preference purchasers because such output is not a resource "owned or purchased by public bodies or cooperatives." *Id.*; CUB Br., WP-07-B-CU-01, at 14-15.

PPC argues that one of the required 7(b)(2) assumptions is that the Administrator assume that resources owned or purchased by public body utilities that are needed to serve the preference customers' remaining general requirements (after the FBS is exhausted), are either (1) "purchased from such customers by the Administrator" or (2) "not committed to load pursuant to section 5(b)." PPC Br., WP-07-B-JP25-01, at 16-17.

WPAG cites BPA's 1984 Legal Interpretation and states that the interpretation correctly concludes that section 7(b)(2)(D) should be read as providing that resources eligible for the resource stack should include "resources owned or purchased by 7(b)(2) customers that are not dedicated to their own loads." WPAG Br., WP-07-B-WA-01, at 13.

APAC argues BPA cannot change its 1984 Legal Interpretation now and apply it to prior decisions, which APAC characterizes as retroactive ratemaking. APAC Br., WP-07-B-AP-01, at 46.

Cowlitz argues that because the firm power requirements contracts attached to the REP Settlement Agreements are inextricably intertwined with the REP Settlement Agreements, and therefore no longer valid, the additional Mid-Columbia resources must be made available for purposes of meeting general requirements in the 7(b)(2) Case pursuant to section 7(b)(2)(D)(ii). Cowlitz Br., WP-07-B-CO-01, at 58, fn. 28.

<u>BPA Staff's Position</u>

The proposed Implementation Methodology instructs BPA to exclude all resources committed to load pursuant to section 5(b) (which applies to preference customers and IOUs) from the 7(b)(2) Case resource stack. Doubleday, *et al.*, WP-07-E-BPA-85, at 28. This exclusion is in conformance with the proposed Legal Interpretation. *Id*. Therefore, it must be determined that two conditions exist. *Id*. BPA must have access to the resource in the 7(b)(2) Case. *Id*. To establish this, the resource must be owned or purchased by a customer with a section 5(b) contract with BPA. *Id*. If the owner has a 5(b) contract, BPA must determine if the resource has been dedicated to load. *Id*.

If BPA were establishing revised base rates in the WP-02 rate case in 2001, the changed load and market price conditions would have required BPA to address the Mid-Columbia issue, which was moot under the initial load and market price assumptions. *Id*. In addressing that issue, BPA would have had to address the DSIs' legal argument that the plain language of the Northwest Power Act stating "not committed to load pursuant to section 5(b)" refers to both preference customers and IOUs. *Id*. To accommodate this correct interpretation, BPA properly would have amended the 1984 Legal Interpretation on this one issue. *Id*.

<u>Evaluation of Positions</u>

A. The History of BPA's Treatment of Mid-Columbia Resources in the Section 7(b)(2) Rate Test

Section 7(b)(2) of the Northwest Power Act prescribes revised rate directives for BPA to implement in developing its wholesale power rates after July 1, 1985. 16 U.S.C. § 839e(b)(2). Section 7(b)(2) provides:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that" –
>
> **§ 7(b)(2)(A)** the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are –
>
> > (i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

§ 7(b)(2)(B) public body, cooperative, and Federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

§ 7(b)(2)(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

§ 7(b)(2)(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b)

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

§ 7(b)(2)(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from –

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this chapter

were not achieved.

16 U.S.C. § 839e(b)(2).

Pursuant to section 7(b)(2), BPA was required to implement the section 7(b)(2) rate test for the first time in BPA's 1985 rate case. Prior to the 1985 rate case, on January 23, 1984, BPA published in the Federal Register a notice of a proposed "Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act" (1984 Legal Interpretation), 49 Fed. Reg. 2,811 (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. Because of the importance and complexity of the section 7(b)(2) rate test, and in order to provide customers certainty as to how section 7(b)(2) would be applied, BPA conducted a special evidentiary hearing in 1984 to establish a Section 7(b)(2) Implementation Methodology, 49 Fed. Reg. 23,998 (1984 Implementation Methodology).

In the 1984 Legal Interpretation, BPA addressed the issue of which resources BPA should use to serve 7(b)(2) Customers' loads in the 7(b)(2) Case. The Act provides that all resources that would have been required to meet preference customers' general requirements, after serving such loads with FBS resources, are required to be (i) purchased from such customers by the Administrator pursuant to section 6 of the Act, or (ii) "not committed to *load pursuant to section 5(b)*" of the Act. 16 U.S.C. § 839e(b)(2)(D) (emphasis added). These resources are required to be the least expensive resources owned or purchased by public bodies or cooperatives. *Id*. The 1984 Legal Interpretation stated that among the resources to be considered pursuant to section 7(b)(2)(D)(ii) are "… resources owned or purchased by the 7(b)(2) customers, and not dedicated to *their own loads*." 1984 Legal Interpretation, 49 Fed. Reg. 2,811, 2,815 (1984) (emphasis added). In the 1984 Legal Interpretation ROD, BPA's supporting legal analysis of this issue was superficial. The full analysis upon which BPA based its interpretation was the following:

> Section 7(b)(2)(D)(ii) describes the second type of resource as those "not committed to load pursuant to section 5(b)." These are resources owned or purchased by the 7(b)(2) customers that are not dedicated to their own loads.

This terse and conclusory analysis shows BPA did not review the plain language of the statute, which references "committed to load pursuant to section 5(b)" and which is a statutory provision that applies equally to BPA's preference customers *and IOU* customers.

The 1984 Legal Interpretation and ROD showed that no party raised, and BPA did not address, the fact that BPA's conclusion was inconsistent with the plain language of the Act. Although section 7(b)(2) refers to resources "not committed to load pursuant to section 5(b)" of the Act, section 5(b) provides that both preference customers *and* IOUs dedicate resources to meet their own loads in their section 5(b) requirements contracts. BPA's 1984 Implementation Methodology incorporated the same language used in the 1984 Legal Interpretation. Once again, in the development of the 1984 Implementation Methodology and its ROD, no party raised, and BPA did not address, the fact that BPA's conclusion was inconsistent with the plain language of the Act.

In BPA's 1996 rate case, BPA's *initial* proposal assumed that FBS resources would be insufficient to meet preference customer loads in the 7(b)(2) Case. Therefore, the litigants prepared cases addressing the issue of whether Mid-Columbia resources should be included in the 7(b)(2) Case resource stack. Because neither BPA nor the parties knew whether BPA's final Section 7(b)(2) Rate Test Study would need to use resources from the resource stack, the parties addressed the issue in their briefs. In the Administrator's Final WP-96 ROD, BPA responded to the parties' arguments. Relying on the 1984 Legal Interpretation and Implementation Methodology, BPA concluded:

> The 1312 aMW of the Mid-Columbia resources owned by §7(b)(2) customers but not dedicated to their loads is properly included in the §7(b)(2) case resource stack and used to meet §7(b)(2) customers' loads when the FBS is exhausted.

Although BPA stated this conclusion in the WP-96 ROD, the issue was moot. When BPA developed its *final* Section 7(b)(2) Rate Test Study, the FBS was sufficient to meet preference customer loads in the 7(b)(2) Case. Therefore, BPA did not have to use resources from the resource stack, including any Mid-Columbia resources, to serve preference customer loads. Thus, the Mid-Columbia issue was moot, and BPA's Mid-Columbia legal analysis was not used to establish BPA's WP-96 power rates. BPA's statement in the WP-96 ROD therefore was not necessary to BPA's decision in the case and merely comprised dicta. More significantly, in the WP-96 proceeding, no party raised, and BPA did not address, that BPA's Mid-Columbia legal conclusion was inconsistent with the plain language of the Act.

In its Initial Brief, APAC states that "[i]n reaching this [Mid-Columbia] decision [in the WP-96 rate case], BPA specifically considered, <u>and rejected</u>, the claim that Mid-C resources sold to IOUs under power contracts should be excluded from the §7(b)(2)(D) case resource stack." APAC Br., WP-07-B-AP-01, at 44 (emphasis in original). This statement is factually incorrect. APAC's argument is based on BPA's WP-96 ROD's statement that "[t]he 1312 aMW of the Mid-Columbia resources owned by §7(b)(2) customers but not dedicated to their loads is properly included in the §7(b)(2) case resource stack and used to meet §7(b)(2) customers' loads when the FBS is exhausted." *Id*. at 44. APAC argues that because this statement includes the words "owned by §7(b)(2) customers but not dedicated to their loads," BPA considered whether Mid-Columbia resources sold to IOUs and dedicated to their loads under section 5(b) contracts should be excluded from the resource stack. In fact, however, there is no evidence to support this assertion. Instead, the record shows BPA simply relied on the prior interpretation of the statutory language as applying to preference customers' resources dedicated to meeting preference customers' own loads. There is no evidence BPA considered whether there might be other utilities that have section 5(b) contracts and dedicated resources. BPA simply did not identify or consider the argument. Indeed, the record shows the argument was never made. As noted above, no party made the argument in developing the 1984 Legal Interpretation or the 1984 Implementation Methodology. Similarly, the WP-96 ROD simply relied on the 1984 Legal Interpretation and 1984 Implementation Methodology. In the WP-96 administrative record, no party argued that "not committed to load pursuant to section 5(b)" of the Act referred to the IOUs, even though the plain language of the Act provided so. Therefore, no party had ever raised, and BPA had never addressed, this issue. This was about to change.

In its WP-02 Initial Proposal, BPA forecast that FBS resources would be insufficient to meet 7(b)(2) Customers' loads in the 7(b)(2) Case. BPA concluded it would therefore have to use resources from the 7(b)(2)(D) resource stack in order to serve such loads. *See* WP-02 Final ROD, WP-02-A-02, at 13·49-13·50, *citing* Kaptur, *et al.*, WP-02-E-BPA-34, at 12. One issue that arose in the WP-02 rate case was whether power from the Mid-Columbia dams owned by preference customers but sold to IOUs constituted a "Type 2" resource that should be included in the resource stack. (The 1984 Implementation Methodology used the term "Type 2" to designate 7(b)(2)(D)(ii) resources.) As noted above, although BPA discussed this issue in the WP-96 ROD, BPA did not have to decide or incorporate any Mid-Columbia decision in rates because the FBS turned out to be sufficient to meet the 7(b)(2) Customers' loads and the issue was moot. As in the WP-96 rate case, BPA developed its WP-02 Initial Proposal using BPA's 1984 Legal Interpretation and 1984 Implementation Methodology. BPA's WP-02 Initial Proposal therefore assumed that the test for inclusion of Mid-Columbia resources in the resource stack was whether such resources were dedicated by preference customers to their own loads.

In rebuttal testimony, BPA recognized that additional resources in excess of the FBS were not expected to be needed to meet 7(b)(2) Customers' loads; therefore, it was unnecessary to use any resources from the 7(b)(2) Case resource stack in conducting the section 7(b)(2) rate test. *See* WP-02 Final ROD, WP-02-A-02, at 13·49-13·50, *citing* Kaptur, *et al.*, WP-02-E-BPA-56, at 18-19. Although this is what BPA expected to happen in the development of BPA's final WP-02 proposed rates, this was not certain until BPA ran its final studies. Therefore, BPA's DSI customers raised arguments on the Mid-Columbia issue in their Initial Brief. These arguments included an argument that had not previously been raised in the development of BPA's 1984 Legal Interpretation and 1984 Implementation Methodology or in subsequent rate cases, including the WP-96 rate case. The DSIs argued that BPA cannot lawfully include Mid-Columbia resources dedicated to serving regional loads by *either* preference customers <u>*or IOUs*</u> in the 7(b)(2) Case resource stack. DSI Brief, WP-02-B-DS-01, at 72-75. The DSIs' Initial Brief stated:

> It is unreasonable to read "committed to load pursuant to section 5(b)" in section 7(b)(2)(D)(ii) to mean "committed *to the facility owner's own load* pursuant to section 5(b)." The plain language of the Northwest Power Act forecloses such a reading of section 7(b)(2)(D)(ii). Section 5(b) sets forth a clear methodology for determining whether resources are to load "committed" thereunder. <u>Specifically, section 5(b) requires BPA to offer power to any preference customer or IOU to meet its net requirements</u>, being specifically defined as the difference between the utility's "firm power load … in the Region" and the sum of "the capability of such entity's firm peaking and energy resources …" and "such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region." Thus for purposes of section 5(b), resources, **no matter who owns them**, are committed to load if they must be used to decrement <u>any utility's</u> firm load in the region to establish its net requirements. Section 5(b) makes plain that, whether or not the physical generating facilities are owned by the utility, resources consisting of power acquired by contract are specifically included as committed to load. *See* section 5(b)(1), 16 U.S.C. § 839c(b)(1) (referring to "loss of contract rights").

DSI Initial Brief, WP-02-B-DS-01, at 73 (emphasis added by DSIs; underlining added by BPA).

Thus, the DSIs in the WP-02 rate case presented an argument based on the plain language of section 7(b)(2) that conflicted with BPA's 1984 Legal Interpretation and 1984 Implementation Methodology. When BPA ran its final WP-02 studies, however, the Mid-Columbia resources owned by 7(b)(2) Customers but sold to IOUs were not used to develop BPA's WP-02 rates because the augmented FBS resource pool was large enough to serve the 7(b)(2) Case loads without need for resources from the stack. The increased size of the FBS was due to increased system augmentation in the Program Case that was necessary to serve the total PF, IP, RL, and FPS loads. BPA's WP-02 Record of Decision stated:

> **Evaluation of Positions**
> In the initial proposal, BPA proposed to use resources from the resource stack in the 7(b)(2) Case, which included Mid-Columbia resources, to meet specified loads. Kaptur, *et al.*, WP-02-E-BPA-34, at 12. In BPA's rebuttal testimony, however, BPA recognized that additional resources in excess of the FBS were not needed to meet 7(b)(2) customers' loads; therefore, it was unnecessary to use any resources from the 7(b)(2) Case resource stack in conducting the 7(b)(2) rate test. Kaptur, *et al.*, WP-02-E-BPA-56, at 18-19. Because BPA did not propose to use resources from the 7(b)(2) Case resource stack, including the *Mid-Columbia resources*, in conducting the 7(b)(2) rate test, this issue would not affect the development of BPA's wholesale power rates in this proceeding and *need not be addressed at this time*.
>
> *Decision*
>
> *The issue of whether BPA should include Mid-Columbia resources in the 7(b)(2) Case resource stack is moot, because BPA will not use any resources from the resource stack, including Mid-C resources, to meet 7(b)(2) customers' loads.*

WP-02 Final ROD, WP-02-A-02, at 13·49-13·50 (emphasis added).

In the WP-02 ROD, BPA did not have to address the DSIs' new legal argument because the issue was moot. BPA acknowledged that the Mid-Columbia issue was moot because it had no bearing on the rate calculation, but it was clear that a different treatment (excluding the Mid-Columbia resources from the resource stack) was possible if the issue became ripe in subsequent rate cases. BPA expected the DSIs to reiterate their argument in BPA's WP-07 rate case, and they did so. Tr. 490 (2006 hearings).

When BPA developed its initial proposal for the WP-07 rate case, BPA knew it had not addressed the DSIs' WP-02 argument that Mid-Columbia resources dedicated by the IOUs under their section 5(b) requirements contracts should be excluded from the resource stack. BPA therefore filed an Initial Proposal that reflected BPA's still-effective 1984 Legal Interpretation and 1984 Implementation Methodology. BPA expected the DSIs' legal argument to be raised again and, if not rendered moot, the argument would have to be directly addressed by BPA and the parties. *See* Tr. 490 (2006 hearings). In the WP-07 rate proceeding, however, the litigants entered into a Partial Resolution of Issues that once again rendered the issue moot:

> … 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 agreement, BPA did not fully litigate all issues regarding the Mid-Columbia resources in the WP-07 rate proceeding. Because the DSI argument was based on the plain language of the Act, however, BPA was aware that if the proceeding had continued, BPA could have been forced to revise its Legal Interpretation in order to comply with the Northwest Power Act. This was expressly recognized in the WP-07 Final ROD, which noted:

> *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.

WP-07 Administrator's Record of Decision, WP-07-A-02, at 10·4-10·5 (emphasis added). Thus, BPA acknowledged that it might have changed its treatment of the Mid-Columbia resources in BPA's final WP-07 rates if the issue had been litigated and not been moot.

Then came the *PGE* and *Golden NW* decisions of the Court. Because the Court found that the WP-02 rates were not set in accordance with the Northwest Power Act, and the WP-07 rates were based on the same faulty premise, BPA chose to respond to the Court by modifying both sets of rates. The Court held that any construction of the REP must fall within the confines of sections 5(c) and 7(b). *PGE*, 501 F.3d at 1030. To reconstitute the REP that has lain dormant for over 10 years, BPA began work on all aspects of the REP: new RPSAs, revisions to the 1984 ASC Methodology, and revisions to the 1984 Legal Interpretation and 1984 Implementation Methodology. Rather than continue with the existing Legal Interpretation and the two Methodologies, which BPA knew had many issues with regional parties, BPA believed it would work better to engage parties to identify issues and receive comments. In the Fall of 2007, BPA held a series of workshops to identify issues with the Interpretation and the two Methodologies. Based on comments received, BPA crafted proposed changes to each of the documents. The ASC Methodology was dealt with through a regional consultation process, and the final product is now before the FERC for approval. The Legal Interpretation and Implementation Methodology are undergoing review by parties in this proceeding. Parties have raised several issues regarding the proposed documents, this Mid-Columbia issue being one of them.

Staff's FY 2002-06 Lookback analysis used a load/resource balance as of June 2001, assuming no REP settlements, and it is significantly different from the WP-02 Final Proposal load/resource balance. This difference is due to removing RL sales to reflect the absence of the REP Settlement Agreements and using what was assumed to be FPS sales to serve increased PF Preference loads. As a result of this changed load/resource balance, resources from the 7(b)(2) resource stack are required during some of the Five-Year Period. Thus, the Mid-Columbia issue would have been a ripe issue in the WP-02 rate case in the absence of the REP Settlement Agreements and is ripe for the Lookback analysis.

Although BPA previously discussed including or not the Mid-Columbia resources in the resource stack in its WP-96 and WP-02 rate cases, BPA never had to formally decide the issue in a manner that affected BPA's rates because FBS resources were sufficient to serve 7(b)(2) Customer loads in both Cases. Similarly, due to the Partial Resolution of Issues in BPA's WP-07 Final Proposal, BPA did not have to address the issue at that time. After reviewing the issue more thoroughly, BPA has proposed a revised Legal Interpretation and a revised Implementation Methodology. *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B. If BPA had been required to decide the Mid-Columbia issue in BPA's WP-02 Final Proposal, it would have come to the same conclusions reached in the proposed Legal Interpretation and proposed Implementation Methodology: dedicated preference customer and IOU Mid-Columbia resources should not be included in the resource stack for the section 7(b)(2) rate test in the WP-02 and WP-07 Lookback analysis, or for the Supplemental Proposal calculation of FY 2009 rates. Keep, *et al.*, WP-07-E-BPA-68, at 25-26.

APAC argues that BPA has mischaracterized the record on the Mid-Columbia determination by contending that BPA never made the Mid-Columbia determination. APAC Br., WP-07-B-AP-01, at 45. To the contrary, however, it is APAC that has mischaracterized the record. BPA has not denied that its 1984 Legal Interpretation and 1984 Implementation Methodology provided that BPA's approach to the Mid-Columbia issue was to be based on reading section 7(b)(2) as referring to 7(b)(2) Customers' dedication of resources to meet their own loads (despite that such interpretation conflicts with the plain language of section 7(b)(2)). BPA also has not denied that in developing its Initial Proposals for the WP-96, WP-02, and WP-07 rate cases, BPA relied on the then-applicable 1984 Legal Interpretation and 1984 Implementation Methodology. However, BPA has established that the incorrect statement in the 1984 Legal Interpretation has not been used to develop BPA's past rates because the FBS has always been sufficient to meet proposed customers' loads in the 7(b)(2) Case. In the WP-96 proceeding, the Mid-Columbia issue was moot and did not affect BPA's rates. In the WP-02 rate proceeding, the Mid-Columbia issue was moot and did not affect BPA's rates. In the WP-07 rate proceeding, there was a Partial Resolution of Issues, and the Mid-Columbia issue was never litigated. BPA also has established that the DSIs raised a new legal argument in BPA's WP-02 rate case that was consistent with the statutory language (unlike BPA's 1984 Interpretation), and the DSIs' interpretation could not be reasonably refuted, but the issue was not addressed when the Mid-Columbia issue became moot. BPA has also established that it recognized the DSIs' argument would have been raised in its WP-07 rate case and, after all litigants had the opportunity to address the issue, BPA would have changed its legal interpretation to be consistent with the plain language of section 7(b)(2). Thus, the record shows BPA, in the absence of the REP settlements, reasonably concluded that it would have revised its 1984 Legal Interpretation to comply with the plain language of section 7(b)(2) in the WP-02 proceeding. There is thus a *strong* legal basis supporting BPA's testimony:

> If BPA had been required to decide the Mid-Columbia issue in BPA's WP-02 rate case, we assume it would have come to the same conclusions reached in the proposed Legal Interpretation and Implementation Methodology. We propose that the Mid-Columbia resources should not be included in the resource stack for the §7(b)(2) rate test in the WP-02 and WP-07 Lookback analysis, nor for BPA's WP-07 Supplemental calculation of FY 2009 rates.

Doubleday, *et al.*, WP-07-E-BPA-60, at 22. Even assuming *arguendo* that BPA previously addressed the issue, it would not require BPA to perpetuate a plain legal error. This is especially true when legal argument is raised for the first time.

In its Brief on Exceptions, WPAG notes that BPA's 1984 Legal Interpretation addressed the resources referenced in section 7(b)(2)(D)(ii) of the Northwest Power Act, that is, those "not committed to load pursuant to section 5(b)." WPAG Br. Ex., WP-07-R-WA-01, at 20. WPAG states the 1984 Legal Interpretation stated that "[t]hese are resources owned or purchased by 7(b)(2) customers that are not dedicated to their own loads." *Id*. WPAG argues this interpretation was used in BPA's 1996 rate case. *Id*. citing WP-02 Final ROD, WP-96-A-02, at 254. As BPA previously explained, although this interpretation was included in BPA's 1984 Legal Interpretation and therefore was used in the preliminary review of this issue in BPA's 1996 rate case, BPA did not have to address this issue because it became moot when FBS resources proved sufficient to serve preference loads in the 7(b)(2) Case and BPA did not need to use resources from the resource stack. Therefore, BPA never had to implement this interpretation. When BPA conducted its next rate case, however, certain parties in the rate case noted that BPA's interpretation was directly inconsistent with the language of the Act, which referred to resources "not committed to load pursuant to section 5(b)." The plain meaning of this provision is that it applies to all utilities' resources that are committed to load pursuant to section 5(b) of the Act. Section 5(b) of the Act expressly applies to preference utilities and IOUs. Thus, section 7(b)(2)(ii) must be read as applying to the dedicated resources of preference utilities and IOUs.

B. Section 7(b)(2)(D) Requires BPA to Exclude from the Resource Stack Mid-Columbia Resources Dedicated to Load Under the Section 5(b) Contracts of Preference Customers and Investor-Owned Utilities

Whether Mid-Columbia resources should be included in the 7(b)(2) Case resource stack is, in the first instance, a legal issue. Section 7(b)(2) of the Northwest Power Act provides that:

> [a]fter July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that –
>
> * * * *
>
> **§7(b)(2)(D)** *all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –*
>
> > *(i) purchased from such customers by the Administrator pursuant to section 6, or*
> >
> > *(ii) not committed to load pursuant to section 5(b)*
>
> *and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator …*

16 U.S.C. § 839e(b)(2) (emphasis added). As noted above, section 7(b)(2)(D) identifies three types of additional resources assumed to be acquired to meet 7(b)(2) Customers' general requirements when Federal base system (FBS) resources are exhausted. First, the statute identifies those resources purchased by BPA from preference customers pursuant to section 6 of the Northwest Power Act. Second, the Act lists those resources not committed to load pursuant to section 5(b). These two types of resources must be added from least expensive to most expensive of the resources owned or purchased by public bodies or cooperatives. Therefore, these two types of resources are stacked in order of cost and then the least expensive resources needed are acquired from the stack to meet 7(b)(2) Customer loads. The third resource category consists of any additional resources required to meet any remaining load, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

Mid-Columbia resources are not Type 1 resources; that is, resources acquired by BPA from preference customers pursuant to section 6 of the Northwest Power Act. Mid-Columbia resources are not Type 3 resources; that is, additional resources required to meet any remaining load, because these additional resources are nonspecific. Mid-Columbia resources are therefore potential Type 2 resources. BPA must conduct an analysis of the Mid-Columbia resources to determine whether any such resource satisfies the statutory criteria and is properly included in the resource stack. It is helpful, however, to review the criteria of section 7(b)(2)(D) in their statutory order.

Section 7(b)(2)(D) first prescribes what the subsection is establishing: "the resources required to meet the remaining general requirements of public body, cooperative and Federal agency customers other than requirements met by FBS resources." 16 U.S.C. § 839e(b)(2)(D). The first type of resource that can be used to meet these remaining requirements is resources "purchased from such customers by the Administrator pursuant to section 6 …" 16 U.S.C. § 839e(b)(2)(D)(i). Section 6 prescribes the rules governing BPA's acquisition of conservation and other resources. Thus, under section 6, BPA can acquire such resources from its public agency customers for inclusion in the 7(b)(2) Case resource stack.

The second type of resource that can be used to meet remaining requirements is resources "not committed to load pursuant to section 5(b) [of the Northwest Power Act] …" 16 U.S.C. § 839e(b)(2)(D)(ii). Section 5(b)(1) of the Northwest Power Act provides:

> Whenever requested, the Administrator shall offer to sell *to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and* <u>to each requesting investor-owned utility electric power</u> *to meet the firm power load of such public body, cooperative or investor-owned utility in the Region* to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1) (emphasis added). As noted in section 3(19) of the Northwest Power Act, the term "resource" includes "electric power." 16 U.S.C. § 839a(19). Because section 5(b) applies to requirements determinations for both preference customers *and* investor-owned utilities, section 7(b)(2)(D)(ii) precludes BPA from including resources owned or purchased by 7(b)(2) Customers in the 7(b)(2) Case resource stack if such resources are committed to load by preference customers *or* investor-owned utilities. This is the plain meaning of the statutory language. It is a logical conclusion that resources already reducing the Administrator's obligation are not available to meet that obligation.

Once the foregoing resources have been identified, section 7(b)(2)(D) prescribes additional requirements for resources to be included in the resource stack. The foregoing resources must be "the least expensive resources owned or purchased by public bodies or cooperatives." 16 U.S.C. § 839e(b)(2)(D). This describes the two methods by which a preference customer may have rights to power. The preference customer may be the owner of a resource with the rights to the power generated, or the preference customer may have purchased the power. In either case, if the Administrator has acquired the resource from the preference customer under section 6 of the Act and the resource is not included in FBS resources, the resource must be included in the resource stack. Also, in either case, if the preference customer has not dedicated the resource under its section 5(b) contract, the resource must be included in the resource stack. Further, if a preference customer owns or has purchased a resource and sells it to a utility with a section 5(b) contract, BPA must determine if the purchasing utility has dedicated the resource to load (*i.e.*, reduce the Administrator's obligation) under its contract. If so, the resource must not be included in the resource stack. For the same reason, if a preference customer sells the resource to an entity that has no section 5(b) contract, the resource must be included in the resource stack. The apparent logic of this approach in the statutory "what if" 7(b)(2) world is that, absent BPA acquisition authority and a limited amount of FBS resources, the preference customer would have used the resource to serve its own load (or another regional load that otherwise would have purchased from BPA).

If the resources from the resource stack are insufficient to serve such loads, then "any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator …" *Id*.

C. Responses to Parties' Arguments

1. Section 7(b)(2) Substantive Issues

CUB states that Staff's proposal to exclude the Mid-Columbia resources from the resource stack in the 7(b)(2) Case is supported by the plain meaning of the Northwest Power Act. CUB Br., WP-07-B-CU-01, at 14. Where the Northwest Power Act defines "resource" as electric power, as opposed to the resource itself, 16 U.S.C. § 839a(19), the plain meaning of section 7(b)(2)(D) requires exclusion of the Mid-Columbia hydro resources that are sold to IOUs to meet firm load. *Id*. The resources sold by preference customers to the region's IOUs are already "committed to load pursuant to section 839c(b)" and thus cannot be included in the resource stack. *Id*. Thus, Staff's proposed clarification excluding those portions of the Mid-Columbia hydro resources contracted to regional IOUs from the 7(b)(2)(D) resource stack is not only justified, but is required by the plain language of section 7(b)(2)(D). *Id*.

The IOUs argue that BPA should exclude from the 7(b)(2) Case resource stack the portion of the output of the Mid-Columbia dams sold to non-preference purchasers. IOU Br., WP-07-B-JP6-01, at 95. The IOUs and CUB argue BPA must not include in the 7(b)(2) Case resource stack the portion of the output from the Mid-Columbia dams sold to non-preference purchasers because such output is not a resource "owned or purchased by public bodies or cooperatives." *Id*., CUB Br., WP-07-B-CU-01, at 15. The IOUs argue that power from Mid-Columbia dams purchased by non-preference purchasers cannot be classified as "owned or purchased" for purposes of the 7(b)(2) Case by the preference customers that own the Mid-Columbia dams because such preference customers have sold, and therefore do not own, such power. IOU Br., WP-07-B-JP6-01, at 95. The IOUs note section 3(19) of the Northwest Power Act defines "resource" as the "electric power, including the actual or planned electric power capability of generating facilities" and not as the physical generating facilities that generate such electric power. *Id*., *citing* 16 U.S.C. § 839a(19)(A). Therefore, the "resource" with respect to physical generating facilities owned by public bodies or cooperatives, such as the

Mid-Columbia dams, is, for purposes of the Northwest Power Act, the *power* from those projects, rather than the *projects* themselves. *Id*.

The IOUs argue Staff has taken the illogical position that a preference customer that owns the physical generating facility continues to own the output (resource) even after it sells the output (resource) to a non-preference customer. *Id*. They claim Staff's reasoning is based on a fundamental flaw that treats the resource as the physical generating facilities rather than the electric power produced by those facilities. *Id*. Based on Staff's incorrect treatment of the physical generating facilities as the "resource," Staff erroneously concludes that the preference customer that owns the physical generating facilities continues to own the "resource" even after such customer sells the output of the physical generating facility. *Id*. at 96, *citing* Tr. 341, lines 3-7. The IOUs argue this position – treating the physical generating facilities as the resource – is contrary to the plain language of the Northwest Power Act, which expressly defines the "resource" as the "electric power, including the actual or planned electric power capability of generating facilities[.]" *Id*., *citing* 16 U.S.C. § 839a(19)(A). The IOUs state Staff also appears to erroneously treat the preference customer as the owner of the output (resource) even after it has sold that output (resource) to a non-preference customer. *Id*., *citing* Tr. 347, lines 10-14, and 361, line 24, through page 362, line 16. Simply stated, when the owner of the physical generating facilities sells the output (resource) to a non-preference customer, the output (resource) is neither "owned [n]or purchased by public bodies or cooperatives" and, therefore, such resources are not properly included in the 7(b)(2) resource stack. *Id*., *citing* 16 U.S.C. § 839e(b)(2)(D). The IOUs argue that, correctly interpreted, "owned or purchased" simply describes the two methods by which a preference customer may have rights to power during the relevant time period in the Five-Year Period: (i) it is the owner of the generator and retains (*i.e.*, has not sold) rights to the power generated by the generator for the relevant time in the Five-Year Period; or (ii) it has purchased the power for the relevant time in the Five-Year Period. *Id*. at 96-97. In either case, it is the preference customer's power and may be eligible for inclusion under the "owned or purchased" standard. *Id*. at 97.

The IOUs argue that Staff's interpretation – allowing a resource (or portion thereof) to be "owned or purchased" simultaneously by two entities – leads to complications and counterintuitive results. *Id*. In order to determine whether a resource is eligible for inclusion in the 7(b)(2) resource stack, Staff must under its interpretation define a new term ("7(b)(2) Customer") and construct a decision tree with 5 rows, as many as 6 columns in a single row, and 9 potential outcomes. *Id*. In contrast, the appropriate test is simple and straightforward: a resource (power or output) is eligible to be included in the resource stack if (i) a preference customer is forecast to have the rights to the power or output for the relevant time in the Five-Year Period; and (ii) the preference customer is forecast to have not dedicated the power or output to load for the relevant time in the Five-Year Period. *Id*.

The IOUs' legal argument is partially persuasive. The inquiry pursuant to section 7(b)(2)(D) should focus on the power owned or purchased by the preference customer and not on the generating facility. When a preference customer sells power, it necessarily owns the power at the time of sale. If the sale is made to the Administrator under section 6 of the Northwest Power Act, the power must be included in the resource stack if it is not a replacement of an FBS resource. Significantly, the power can be included in the resource stack even though the preference customer no longer, under the IOUs' interpretation, owns the resource once it has been sold to the Administrator. The language "owned or purchased by public bodies or cooperatives" therefore is satisfied by the ownership *prior* to the sale by the preference customer.

Similarly, if the power has not been dedicated to its load by the preference customer under its section 5(b) contract, it is presumably sold to another entity. BPA must then determine whether the power has been sold to a regional utility and dedicated by that utility under that utility's section 5(b) contract. This is because section 7(b)(2)(D) permits the power to be included in the resource stack only if it has not been dedicated to load under a section 5(b) contract, regardless of whether it is a preference customer's *or an IOU's* section 5(b) contract. If the power is dedicated in the purchaser's section 5(b) contract, it cannot be included in the resource stack. If the power is not dedicated in the purchaser's section 5(b) contract, it must be included in the resource stack. If the power is sold by a preference customer to a purchaser without a section 5(b) contract, the power must be included in the resource stack. This is because the "owned or purchased" language applies to the preference customer's ownership of the power prior to its sale to another entity, including the Administrator. As indicated earlier, the apparent logic of this approach in the statutory "what if" 7(b)(2) world is that the preference customer would have used the resource to serve its own load when faced with limited access to FBS resources.

Holding to the IOUs' interpretation, in addition to being in conflict with section 7(b)(2)(D)(i), would restrict eligible resources under section 7(b)(2)(D)(ii) to those resources owned by preference customers that are otherwise idle resources; that is, resources not used to meet preference customer load and not sold to any other entity. This is an extremely limiting interpretation of section 7(b)(2)(D)(ii). Resources are not usually built and then left idle. If there is any economic value in the resource, the owner would attempt to sell power to capture the economic value. Thus, the only resources that would be available under the IOUs' interpretation would be very expensive, noneconomic resources. Further, the IOUs' interpretation would exclude resources exported from the region under the reading that the extraregional purchaser now "owns" the resource. Given the concern in section 9(c) about resources being sold outside of the region, it is unreasonable to believe that Congress would place hurdles in the way of the export of 5(b) resources and allow a loophole through section 7(b)(2)(D).

PPC argues that one of the required 7(b)(2) assumptions is that the Administrator assume that resources owned or purchased by public body utilities that are needed to serve the preference customers' remaining general requirements (after the FBS is exhausted), are either (1) "purchased from such customers by the Administrator" or (2) "not committed to load pursuant to section 5(b)." PPC Br., WP-07-B-JP25-01, at 17-18; PPC Br. Ex., WP-07-R-PP-01, at 5. PPC claims that under either assumption, the result is the same: those resources owned or purchased by public body or cooperatives are available to serve preference customer loads in the 7(b)(2) Case. *Id*. at 18. PPC argues that section 7(b)(2) requires a simple assumption by the Administrator: he or she is directed to assume that resources owned by public bodies are available to serve preference customer load in the 7(b)(2) Case, regardless of whether or not they are available under current arrangements. *Id*. PPC claims this provision of the Act effects an unsurprising outcome that aligns with the purpose of section 7(b)(2) to protect preference customers from the costs imposed by the Act; it assumes that public body or cooperatives would have used their least-cost resources to meet their own loads in the absence of the Northwest Power Act. *Id*. PPC's interpretation, however, is inconsistent with section 7(b)(2).

Section 7(b)(2) provides that the adjusted Program Case rate "may not exceed … an amount equal to the power costs for general requirements of such customers *if, the Administrator assumes that*" –

* * * *

> **§7(b)(2)(D)** *<u>all resources that would have been required</u>*, during such five year period, *<u>to meet remaining general requirements of the public body, cooperative and Federal agency customers</u>* (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) *<u>were</u>* –
>
> > (i) purchased from such customers by the Administrator pursuant to section 6, or
> >
> > *(ii) <u>not committed to load pursuant to section 5(b)</u>*
>
> and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator …

16 U.S.C. § 839e(b)(2) (emphasis added). Under PPC's argument, if subsection 7(b)(2)(D) were simply a required assumption, it would require BPA to make two nonsensical assumptions. The first would be that "all resources … were purchased … pursuant to section 6." If that were the case, then there would be no need for any other resources, because all resources were purchased under section 6. The second would be the nonsensical assumption that the resources required to meet preference customers' general requirements (after using the FBS) were not committed to load pursuant to section 5(b), even though the preference customers' resources had to be committed to their loads in order to determine their general requirements. Clearly, the fair and plain-sense reading of section 7(b)(2)(D) means all resources that would have been required to meet remaining general requirements were either those resources that were purchased under section 6 or not committed to load pursuant to section 5(b).

While not dispositive, the sense of Congressional direction can be gained from an earlier version of what became the Northwest Power Act. The part of Senate Bill No. 885 corresponding to section 7(b)(2)(D) stated:

> all resources that would have been required to meet remaining general requirements of the public body, cooperative and Federal agency customers not met by the available Federal base system resources determined under [section 7(b)(2)(B)] above were *resources* purchased from such customers by the Administrator pursuant to section 6 or *resources* not committed to load pursuant to section [5(b)] and were the least expensive resources owned or purchased by public bodies or cooperatives with any additional needed resources having been

> obtained at the average cost of all other new resources acquired by the Administrator …

Section 7(b)(4) of S. 885, reprinted in S. Rep. No. 96-272, 96th Cong., 1st Sess. 10 (1979) (emphasis added). Here we see that the two added words ("resources") assist in reading section 7(b)(2)(D). The two added "resources" point back to "all resources" at the beginning of the thought. The thought conveyed in section 7(b)(2)(D) can best be read as the resources that would have been required are those resources that are not committed to load pursuant to section 5(b).

As noted previously, section 7(b)(2) establishes a Program Case, which represents the amounts charged for the preference customers' "general requirements." The Program Case is compared with the 7(b)(2) Case, which is "the power costs for general requirements of such customers," based on the Five Assumptions. The comparison of the two Cases focuses on the costs of serving preference customers' "general requirements" in each Case. Section 7(b)(4) defines "general requirements" as a preference customer's "electric power purchased from the Administrator under section 5(b) of this [Northwest Power] Act, exclusive of any new large single load." 16 U.S.C. § 839e(b)(4). Section 5(b) of the Act provides:

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) *such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region*.

16 U.S.C. § 839c(b)(1) (emphasis added). Thus, by statutory definition and under Staff's interpretation, "general requirements" is an amount of firm power load BPA must serve *after preference customers have committed their own resources to meeting their own loads*. 16 U.S.C. §§ 839e(b)(4); 839c(b)(1). Under PPC's interpretation, Congress said that after preference customers committed their resources to load under section 5(b) to determine their general requirements (and the FBS is then used to meet part of the requirements), the resources that would have been required to meet their remaining general requirements must be assumed not to have already been committed to load under section 5(b). In other words, under PPC's interpretation, Congress directed how to determine preference customers' general requirements by first using the customers' own dedicated resources. This established the amount of additional resources that would have to be acquired to satisfy the remaining requirements after using any FBS resources. Tr. 703-709. Then, however, Congress required the Administrator to assume that the very resources *that were already used to meet preference customers' loads to establish the remaining requirements* would become magically available to be used *again* to meet the remaining requirements. This double counting simply makes no sense and renders PPC's interpretation unreasonable. This situation is clearly different than the one involving resources not dedicated to section 5(b) load because in that case the preference customer would use the

resource to meet load rather than to sell to another party. Deferring a sale would make no sense in the case of a resource already used to meet general requirements, as discussed in more detail below.

PPC argues that Staff's proposed Implementation Methodology seeks to reverse its 1984 approach by directing that public bodies' resources be deemed available in the rate test only if they are "not dedicated to regional load by preference customers *or IOUs*." PPC Br., WP-07-B-JP25-01, at 20, *citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, IM-7 (emphasis added). PPC notes Staff's explanation that its current methodology "overlooks" the statutory language of section 7(b)(2)(D)(ii), which reads "not committed to load pursuant to section 5(b)," rather than "not committed to *their own* load pursuant to 5(b)," as the current methodology provides. PPC Br., WP-07-B-JP25-01, at 20, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 26 (emphasis added).

WPAG similarly cites BPA's 1984 Legal Interpretation and states the interpretation correctly concludes that section 7(b)(2)(D) should be read as providing that resources eligible for the resource stack should include "resources owned or purchased by 7(b)(2) customers that are not dedicated to their own loads." WPAG Br., WP-07-B-WA-01, at 13; WPAG Ex. Br., WP-07-R-WA-01, at 20. PPC and WPAG argue that instead of correcting an oversight in the prior methodology, Staff's proposed methodology erroneously dispenses with two words that are required to make the statutory phrase, when quoted alone, accurately represent the context in which it appears. PPC Br., WP-07-B-JP25-01, at 21; WPAG Br., WP-07-B-WA-01, at 13. PPC and WPAG's argument, however, implicitly invites its refutation. PPC and WPAG argue that section 7(b)(2)(D)(ii) should be read as "not committed to *their own* load pursuant to 5(b)." This, however, is the fundamental flaw of BPA's 1984 interpretation. Section 7(b)(2)(D)(ii) *does not include* the words "their own." Section 7(b)(2)(D)(ii) simply states "not committed to load pursuant to 5(b)." 16 U.S.C. § 839e(b)(2)(D)(i). Section 5(b)(1) expressly refers to resources committed to load by preference customers ("each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937") *and IOUs* ("to each requesting investor-owned utility"). As explained previously, the plain meaning of this provision is that the resource is not committed to load under section 5(b), and section 5(b) includes resource dedications *both by preference customers and IOUs*. 16 U.S.C. § 839c(b)(1). Staff's interpretation is consistent with the plain language of the Act. PPC and WPAG's is not. Their interpretation also ignores the fact that IOUs' ASCs are reduced because of the dedication of these resources to the IOUs' load, and that this reduction serves to reduce costs in the Program Case. PPC's and WPAG's reach for this kind of double benefit – first in reduced program costs, and then again in reduced resource stack costs – is not reasonable.

PPC notes that with respect to PPC and WPAG's argument that a portion of the Rocky Reach dam (owned by Chelan PUD, a public body utility) that is purchased by Alcoa (a non-5(b) customer) is not dedicated to load pursuant to 5(b), Staff responded that Rocky Reach is not eligible to be included in the 7(b)(2) Case because Chelan PUD does not currently have a 5(b) contract with BPA and is therefore not a "7(b)(2) Customer" under BPA's proposed Implementation Methodology. PPC Br., WP-07-B-JP25-01, at 22, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 28-29; PPC Br. Ex., WP-07-R-PP-01, at 13. PPC states Staff based its decision regarding the Rocky Reach resource on a "decision tree" it proposed to include in the

Implementation Methodology. PPC Br., WP-07-B-JP25-01, at 22. PPC argues the decision tree set out an analysis based on rules that Staff had never articulated. *Id*. In response, PPC's characterization of the decision tree is misleading. As BPA has noted, this case is the first case in which BPA must interpret section 7(b)(2) with regard to the Mid-Columbia resources *and actually use that interpretation in establishing rates.* The decision tree was founded on Staff's proposed Implementation Methodology, which was founded upon Staff's proposed Legal Interpretation. Both the proposed Implementation Methodology and the proposed Legal Interpretation were included in BPA Staff's initial Supplemental Proposal at the very beginning of this proceeding. The decision tree reflects the legal determinations contained in the initial Legal Interpretation, with which parties have been familiar for some time. The decision tree was introduced in rebuttal testimony based on arguments that Staff's earlier Legal Interpretation and Implementation Methodology were deficient in analyzing the complexity of Mid-Columbia contractual relationships. BPA provided the decision tree to make it easy for the parties to walk through Staff's proposed Legal Interpretation, as it was refined by that time in response to legal arguments presented during the hearing. It is important to recognize that the decision tree reflects legal arguments and legal requirements and is not a factual construct; that is, the decision tree was not developed based on technical evidence, it is based on legal interpretations of the Northwest Power Act. Therefore, parties have been able to address the legal issues comprising the decision tree in their Initial Briefs and Briefs on Exceptions in this proceeding. The fact that Staff refined legal arguments during the course of the rate case did not deprive the parties of an opportunity to address the legal arguments upon which the decision tree is based in their legal briefs.

PPC appears to characterize the decision tree as something that should have been provided earlier in the proceeding. PPC Br. Ex., WP-07-R-PP-01, at 13. To support its argument, PPC cites a portion of the cross-examination transcript:

> *Q. And is it fair to say this [decision tree] represents a new analysis of which resources are available to serve load in the 7(b)(2) case?*
>
> A. New compared to our initial supplemental proposal, that is correct.
>
> *Q. Is it -- has it been offered before in some other context?*
>
> A. No.
>
> * * *
>
> *Q. And the reasons for which you exclude all but 25 megawatts or so of the Mid-C resources from the 7(b)(2) case resource stack, under this methodology, those are different reasons than the ones for which you propose[d] [sic] to exclude them from the resource stack in your initial proposal; is that correct?*
>
> A. They are.

Tr. 325-26. To summarize the foregoing testimony, the decision tree represented a new analysis compared to BPA's initial Supplemental Proposal because, although nearly all of the elements of the decision tree were based on the Legal Interpretation provided in the initial Supplemental Proposal, the decision tree also addressed the requirement of a section 5(b) contract. This element was new at that time. The decision tree had not been offered before in any other context because this was a new format for describing the implementation of BPA's initial Legal Interpretation. In addition, as noted, the section 5(b) contract portion of the decision tree was developed in response to legal arguments raised during the course of the proceeding up to that time. Finally, the reasons BPA proposed to exclude all but 28 megawatts of Mid-Columbia resources from the resource stack in its rebuttal case were different from the reasons for the exclusion of Mid-Columbia resources in the initial Supplemental Proposal because: (1) BPA had incorrectly excluded *all* Mid-Columbia resources from the resource stack in BPA's initial Supplemental Proposal due to a lack of information regarding certain resources, which BPA has corrected; and (2) although the decision tree is based on the initial Legal Interpretation, BPA's interpretation was refined to reflect the requirement of a section 5(b) contract, which arose in response to parties' arguments during the proceeding. In summary, the decision tree, which reflects BPA's legal interpretation of section 7(b)(2)(D) of the Northwest Power Act, was readily available to all parties in order that such parties could present their opposing legal interpretations in their legal briefs.

In its Brief on Exceptions, PPC notes that BPA's proposed Implementation Methodology seeks to correct an error in its current approach by directing that public bodies' resources be deemed available in the rate test only if they are "not dedicated to regional load by preference customers *or IOUs*." PPC Br. Ex., WP-07-R-PP-01, at 8. PPC notes that as justification for this change, BPA recognizes that its current methodology "overlooks" the statutory language of section 7(b)(2)(D)(ii), which reads "not committed to load pursuant to section 5(b)," rather than "not committed to *their own* load pursuant to 5(b)" as the current methodology provides. *Id*. PPC argues the statutory phrase BPA refers to provides a definition of the *assumption* BPA must make about the resources owned by public bodies. *Id*. PPC argues BPA erroneously interprets that phrase as describing the *actual circumstances* that must surround a resource before it can be deemed available in the rate test. *Id*. PPC contends that instead of correcting an oversight in the prior methodology, BPA's proposed methodology erroneously dispenses with two words that are required to make the statutory phrase, when quoted alone, accurately represent the context in which it appears. *Id*. To the contrary, however, as noted previously, the "two words" BPA has removed from its Implementation Methodology are two words *that are not included in the language of section 7(b)(2)(D)*. It is the retention of such words that would preclude the proper interpretation of section 7(b)(2)(D). PPC's proposed "assumption" argument is refuted below.

PPC states that in the Draft ROD, BPA rejected PPC's argument that section 7(b)(2) directs the Administrator to categorically assume that all resources that would be required to meet remaining general requirements of the preference customers in the 7(b)(2) Case were either purchased by the Administrator or not committed to load. PPC Br. Ex., WP-07-R-PP-01, at 9. The Draft ROD noted that if PPC's argument were accepted, section 7(b)(2)(D) would "require BPA to make two nonsensical assumptions." *Id*. The first nonsensical assumption is that if the Administrator were directed to assume that all required resources were acquired by him or her, then there would be no need to assume that any of the required resources were not committed to load. *Id*. PPC claims BPA's argument overlooks the fact that the statute directs the Administrator to make one of two assumptions with regard to required resources, not both. *Id*. The statute directs an assumption that the resource is purchased by the Administrator *or* not dedicated to load. *Id*. BPA must determine in which instances each assumption would be appropriate (*i.e.,* whether an assumption of a non-dedication of a specific resource would be more reasonable than an assumption of an acquisition by BPA of that resource, or vice-versa). *Id*. In response, however, it makes no sense for BPA to make such determinations if, as claimed by PPC, all resources owned or purchased by preference customers are available to serve preference requirements loads in the 7(b)(2) Case.

Under PPC's proposed interpretation, section 7(b)(2)(D) would require BPA to categorically assume that all resources that are required to meet remaining general requirements of the preference customers in the 7(b)(2) Case were either (1) purchased by the Administrator from public body, cooperative and Federal agency customers pursuant to section 6, or (2) not committed to load pursuant to section 5(b). If PPC's interpretation were correct, Congress would have simply stated in section 7(b)(2)(D) that all resources owned or purchased by preference customers would be available in least cost order to serve preference customers' requirements in the 7(b)(2) Case. There would be no need to mention whether the resources were acquired from preference customers by the Administrator under section 6 or whether the resources were not dedicated to load. Statutory interpretations that render language surplusage are disfavored. *See TRW Inc., v. Andrews*, 534 U.S. 19, 31 (2001); *Duncan v. Walker,* 533 U.S. 167, 174 (2001).

Furthermore, section 7(b)(2)(D) describes the resources that are to be used in the 7(b)(2) Case to meet preference customers' requirements. Under BPA's interpretation, BPA looks to see which resources were "purchased from such customers by the Administrator pursuant to section 6." This makes sense because the rate test assumes that, in the general "without Act" 7(b)(2) Case, preference customers would not have sold such resources to BPA but would have retained them to serve their own loads. It is therefore logical to identify which preference customer resources were *actually purchased by the Administrator under section 6*. Similarly, section 7(b)(2)(D) addresses "all resources that would have been required, during such five-year period, to meet remaining general requirements of [preference customers] … not committed to load under section 5(b)." The only way to know whether utilities have dedicated resources under section 5(b) is to look at the section 5(b) power sales contracts and see which resources *have actually been dedicated to load*.

PPC also argues that its interpretation would not require the Administrator to assume "that the very resources that were already used to meet preference customers' loads to establish the remaining requirements would become magically available to be used again to meet the remaining requirements." PPC Br. Ex., WP-07-R-PP-01, at 10. That is, PPC contends that its interpretation would not compel a double-counting of resources' ability to meet load. *Id.* PPC asserts that BPA has mischaracterized its argument. *Id*. PPC argues that section 7(b)(2)(D) speaks to an assumption the Administrator is to make regarding resources owned or purchased by public body or cooperative utilities that would be required to meet the "remaining general requirements" of preference customers. *Id*. The remaining general requirements are preference customers' electric power needs after application of their own resources, and after service with the power available from the FBS. *Id*. Portions of public body and cooperative-owned resources that have been used by preference customers to meet their own loads are no longer even available to meet additional load, and therefore not among the resources that would be "required to meet remaining general requirements." *Id*.

Although PPC may quibble with BPA's recitation of PPC's position, BPA has earlier addressed the fact that "remaining general requirements" refers to requirements not met by the FBS. BPA has not mischaracterized it. PPC's basic argument, as repeatedly stated by PPC in its Initial Brief and now Brief on Exceptions, is that section 7(b)(2)(D) is simply an instruction that the Administrator assume that resources owned or purchased by public body utilities that are needed to serve the preference customers' remaining general requirements (after the FBS is exhausted), are either (1) "purchased from such customers by the Administrator pursuant to section 6" or (2) "not committed to load pursuant to section 5(b)." PPC Br., WP-07-B-JP25-01, at 17-18. The problem with this argument is that PPC seeks to rely on the language of section 7(b)(2)(D) as a *directive*, but disavows what this interpretation of the language would actually require. If section 7(b)(2)(D) were simply a directive to assume specified assumptions, then in developing the 7(b)(2) Case, the Administrator would have to assume that *all* resources that would have been required to meet remaining general requirements of the preference customers were, if not purchased from such customers by the Administrator pursuant to section 6, "not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D). If the Administrator were required to assume that resources that would have been required to meet remaining general requirements were not committed to load, this would mean that such resources would be available to meet load, which is nonsensical, and leads to the very "double-counting" issue BPA addressed in the Draft ROD.

PPC's proffered interpretation is even less reasonable when considering that PPC previously agreed that BPA *should* use, in the 7(b)(2) Case, the resources *actually acquired by BPA from preference customers pursuant to section 6* of the Act in the Program Case. In 1984, nearly 25 years ago, after reviewing the parties' arguments in the administrative proceedings that established the 1984 Legal Interpretation, BPA stated:

> In the Notice of Proposed Interpretation, BPA proposed that section 7(b)(2)(D) identified three additional resources assumed to be acquired to meet the 7(b)(2) customers' general requirements when FBS resources are exhausted. The first type was identified as those *resources actually acquired by BPA from the 7(b)(2) customers* in the program case. The second type are those resources owned or purchased by the 7(b)(2) customers, and not dedicated to their own loads. These two resources were proposed to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) customers' loads, least expensive first. …

1984 Legal Interpretation ROD at 31. The ROD notes that most of the commenters, *including the PPC*, "support Bonneville's interpretation of section 7(b)(2)(D)." *Id*. at 32. Thus, PPC's original interpretation of section 7(b)(2)(D) was the same as BPA's longstanding interpretation. This demonstrates that BPA's longstanding interpretation is reasonable.

PPC also mischaracterizes statements made in the Draft ROD that demonstrated legislative history supports BPA's interpretation. In the Draft ROD, BPA cites to the Senate Report accompanying Senate Bill No. 885 corresponding to section 7(b)(2)(D), which contained a version of section 7(b)(2)(D) that included the word "resources" before the clause "purchased from such customers" and before the clause "not committed to load." PPC Br. Ex., WP-07-R-PP-01, at 11. PPC asserts that BPA uses this legislative history to justify inserting the words "those resources that are" in front of subsections (i) and (ii) of section 7(b)(2)(D). *Id.* PPC has mischaracterized BPA's position. BPA never stated that *any* additional words need be inserted into section 7(b)(2)(D). Instead, BPA was stating the language of the previous bill, which included such words, may provide some assistance in understanding this issue. Similarly, BPA never argued that the word "resources" was accidentally removed from the Act, as PPC alleges. It is most likely the word "resources" was removed because it was redundant given the use of the word "resources" earlier in the subsection, although no party has been able to document Congress' motivation. Also, a natural reading of the language is one that implies "those resources that are." PPC argues that Senate Bill No. 885's inclusion of the word "resource" in the legislative history clarifies only that subsections (i) and (ii) refer to resources—a point with which PPC does not contend. *Id*. BPA, however, believes that the word "resources" used in the bill supports the review of actual resources that meet the stated criteria. As BPA acknowledged in the Draft ROD, however, the cited legislative history is certainly not dispositive.

BPA also agrees with PPC that the statutory language itself is the best guidance on this issue. Where, as here, the statute is ambiguous, the Administrator must interpret the language. The Supreme Court has recognized that:

> Under established administrative law principles, it is clear that the Administrator's interpretation of the Regional Act is to be given great weight. "We have often noted that the interpretation of an agency charged with the administration of a statute is entitled to substantial deference." *Blum v. Bacon*, 457 U.S. 132, 141, 102 S. Ct. 2355, 2361, 72 L.Ed.2d 728 (1982). "To uphold [the agency's interpretation] 'we need not find that [its] construction is the only reasonable one, or even that it is the result we would have reached had the question arisen in the first instance in judicial proceedings.' … We need only conclude that it is a reasonable interpretation of the relevant provisions." *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402, 422423, 103 S. Ct. 1921, 1933, 76 L.Ed.2d 22 (1983), *quoting Unemployment Compensation Comm'n v. Aragon*, 329 U.S. 143, 153, 67 S. Ct. 245, 250, 91 L. Ed. 136 (1946).
>
> These principles of deference have particular force in the context of this case. The subject under regulation is technical and complex. BPA has longstanding expertise in the area, and was intimately involved in the drafting and consideration of the statute by Congress. Following enactment of the statute, the agency immediately interpreted the statute in the manner now under challenge. Thus, BPA's interpretation represents " 'a contemporaneous construction of a statute by the men charged with the responsibility of setting its machinery in motion, of making the parts work efficiently and smoothly while they are yet untried and new.' " *Udall v. Tallman*, 380 U.S. 1, 16, 85 S. Ct. 792, 801, 13

L.Ed.2d 616 (1965), *quoting Power Reactor Co. v. Electricians*, 367 U.S. 396, 408, 81 S. Ct. 1529, 1535, 6 L.Ed.2d 924 (1961).

Aluminum Co. v. Central Lincoln Util. Dist., 467 U.S. 380, 389-90 (1984). BPA's interpretation is consistent with the language of the Act and is a reasonable interpretation. BPA concludes that "the Administrator [will] assume[ ] that all resources that would have been required … to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—purchased from such customers by the Administrator pursuant to section 6, or not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D). To effectuate this assumption, BPA will determine the resources that were purchased from such customers by the Administrator under section 6, and the resources not committed to load by regional utilities pursuant to section 7(b), and will include such resources in a resource stack to serve 7(b)(2) Case loads using least-cost resources first.

PPC argues that Staff's decision tree, and particularly its determination that under the decision tree the Alcoa-purchased portion of Rocky Reach is to be excluded from the 7(b)(2) Case, does not comply with the Northwest Power Act. PPC Br., WP-07-B-JP25-01, at 23; PPC Br. Ex., WP-07-R-PP-01, _. PPC argues section 7(b)(2) expressly describes the resources that are eligible for inclusion in the list of resources assumed to serve preference customers' loads in the rate test. *Id*. PPC claims section 7(b)(2)(D) states that resources must be deemed available if they are "owned or purchased by public bodies or cooperatives." 16 U.S.C. § 839e(b)(2)(D). This argument, however, was previously refuted. As explained previously, section 7(b)(2)(D) does not make all resources available in the 7(b)(2) Case solely if they are "owned or purchased by public bodies or cooperatives."

Staff acknowledges that Rocky Reach is owned by Chelan PUD and that Chelan PUD is a public body. Doubleday, *et al.*, WP-07-E-BPA-85, at 27. Chelan, however, does not have a section 5(b) contract with BPA and is therefore not a 7(b)(2) Customer. *Id*. Therefore, according to the proposed Implementation Methodology and Legal Interpretation, Rocky Reach can be included in the 7(b)(2)(D) resource stack only if it was purchased by a customer with a 5(b) contract and not dedicated to load. *Id*. All other portions of Rocky Reach would not be available to be considered for inclusion in the resource stack. *Id*.

The proposed Implementation Methodology, consistent with the proposed Legal Interpretation, instructs BPA to exclude all resources committed to load pursuant to section 5(b) from the 7(b)(2)(D) resource stack. *Id*. Therefore, it must be determined that two conditions exist. *Id*. First, BPA must have access to the resource in the 7(b)(2) Case. *Id*. To establish this, the resource must be owned or purchased by a customer with a section 5(b) contract with BPA. *Id*. If the owner does not have a 5(b) contract and the resource output is for the owner's own use, then BPA cannot use the resource in the 7(b)(2) Case. *Id*. If the owner without a 5(b) contract sells the output to a purchaser without a 5(b) contract, then BPA cannot use the resource in the 7(b)(2) Case. *Id*. However, if the owner without a 5(b) contract sells the output to a purchaser with a 5(b) contract, and that purchaser has not dedicated the output to load, then BPA can use the resource in the 7(b)(2) Case. *Id*. This is not because the original preference utility was a customer, but because the purchaser is a customer and the resource it has purchased is not dedicated to load under section 5(b).

If the owner has a 5(b) contract, BPA must determine if the resource has been dedicated to load. *Id*. This resolution requires another set of questions. *Id*. First, BPA must examine the owner's own use of the resource to see if the "own use" portion is dedicated to load. *Id*. If it is, then it will be excluded from the resource stack; if not, then it will be included. *Id*. Second, if the owner has a 5(b) contract and has sold the resource, the portion that is sold is obviously not dedicated to the owner's load. *Id*. In this case, BPA must determine whether the purchaser has a 5(b) contract. *Id*. If it does, and the purchaser has dedicated the resource to load, then it will be excluded from the resource stack; if it is not dedicated to load, it will be included. If the purchaser does not have a 5(b) contract, the resource will be included in the resource stack. *Id*.

PPC argues there is no dispute that Chelan PUD, which owns Rocky Reach, is a public body utility, but Staff now relies on its proposed Implementation Methodology and Legal Interpretation, and specifically its new decision tree, to impose a new test on whether a public body's resources are to be considered available in the rate test: they must belong to a "7(b)(2) Customer" purchasing power from BPA. PPC Br., WP-07-B-JP25-01, at 23. As noted above, however, parties have had a full opportunity to respond to the legal arguments that comprise the decision tree. Furthermore, the "test" is not exactly a new test, but rather a test that would have had to be addressed under any thorough examination of section 7(b)(2) in any rate case where BPA actually had to determine the manner in which resources are included in the resource stack. As noted previously, BPA simply has never had to apply its 1984 Implementation Methodology to facts that would be used to actually establish rates. In the instant case, BPA has proposed a Legal Interpretation, as refined during the hearing in response to parties' arguments, and parties have been free to address BPA's legal arguments.

For example, PPC argues the Act does not define "7(b)(2) Customer," or require that a public body must have a contract for purchasing power from BPA before its resource can be considered "owned or purchased by public bodies or cooperatives." *Id*. Although the Act does not define "7(b)(2) Customer," BPA defined "7(b)(2) Customer" in its 1984 Legal Interpretation and Implementation Methodology. BPA has thus used the term for 24 years. BPA's 1984 Methodology and Staff's proposed Methodology define 7(b)(2) Customers as "those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test." Also, although the Act does not define "7(b)(2) Customers," it does establish the utilities subject to the section 7(b)(2) rate test. As noted previously, section 7(b)(2) is founded on the concept of general requirements; that is, the amount of power BPA provides to its preference customers *under contracts executed in accordance with section 5(b) of the Northwest Power Act in which customers have dedicated resources to meet their own loads.*
Section 7(b)(2) is a comparison of the Program Case, the amounts charged for the "general requirements of public body, cooperative and Federal agency customers," with the 7(b)(2) Case, the "amount equal to the power costs for general requirements of such [public body, cooperative and Federal agency] customers." 16 U.S.C. § 839e(b)(2). The preference (7(b)(2)) Customers' "general requirements" are assumed to include DSI loads. 16 U.S.C. § 839e(b)(2)(A). All resources that would have been required to serve the "general requirements of public body, cooperative and Federal agency customers," after using the FBS to serve the preference

customers, are prescribed in section 7(b)(2)(D). 16 U.S.C. § 839e(b)(2)(D). If a preference customer does not have a "requirement," it is not subject to section 7(b)(2). Thus, Staff does not reword the Northwest Power Act as alleged by PPC, but instead applies it based on its terms. In addition, it is clear from the focus in section 7(b)(2)(D) on "general requirements," the focus in section 7(b)(2)(D)(i) on "customers," and in section 7(b)(2)(D)(ii) on section 5(b), that the focus of section 7(b)(2)(D) is on resources owned or purchased by public body or cooperative customers.

WPAG argues that Staff asserts that either the owner of the resource, or the purchaser of the output from a non-Federal resource, must hold a section 5(b) contract with BPA in order for such resource to be considered available under the section 7(b)(2) rate test. WPAG Br., WP-07-B-WA-01, at 17, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 24-26; WPAG Br. Ex., WP-07-R-WA-01, at 24. WPAG argues this condition does not square with the facts or the law. *Id*. WPAG argues that in order for a non-Federal resource to qualify for use in serving the general requirements of public bodies and cooperatives in the 7(b)(2) Case, it must be "… the least expensive resources owned or purchased by *public bodies or cooperatives* …" and must be either "… not committed to load …" or "… purchased from such customers by the Administrator …" The term "public body" is defined in the Bonneville Project Act to mean "… states, public power districts, counties and municipalities, including agencies or subdivisions thereof." *Id., citing* 16 U.S.C. § 832b. The same statute defines cooperative as "… any form of nonprofit-making organization or organizations of citizens supplying, or which may be created to supply, members with any kind of goods, commodities, or services, as nearly as possible at cost." *Id.* WPAG argues there is no requirement that a consumer-owned utility have a section 5(b) contract with BPA to qualify as a public body or cooperative, and section 7(b)(2)(D) does not impose such a requirement. *Id*. As a consequence, any non-Federal resource owned by a public body or cooperative that has either been acquired by BPA or has not been dedicated to the resource owner's load under section 5(b) is available to serve load in the 7(b)(2) Case, regardless of the presence or absence of a section 5(b) contract with BPA. *Id*. WPAG's legal analysis, however, selectively quotes a small portion of section 7(b)(2)(D) and omits the portions of section 7(b)(2) that refute its argument.

Section 7(b)(2)(D) of the Northwest Power Act prescribes the resources that can be used to serve load in the 7(b)(2) Case. Section 7(b)(2)(D) prefaces the "owned or purchased" requirement by providing that "all resources that would have been required … to meet remaining *general requirements* of the public body, cooperative and Federal agency customers … *were purchased from such customers* by the Administrator pursuant to section 6, *or not committed to load pursuant to section 5(b)* …" 16 U.S.C. § 839e(b)(D) (emphasis added). In order for BPA to use resources in the 7(b)(2) Case, therefore, BPA is acquiring such resources only in an amount to meet the *general requirements* of public body, cooperative, and Federal agency customers. In other words, if a public body, cooperative, or Federal agency customer does not have a general requirement, BPA is not acquiring power in the 7(b)(2) Case to meet its load. More importantly for the instant issue, BPA can only use a resource to meet such remaining requirements loads in two circumstances. First, a resource may be used if purchased by BPA "from *such* customers," that is, from public body, cooperative, and Federal agency customers *with general requirements*. *Id*. Section 7(b)(4) defines general requirements as "the public body, cooperative or Federal agency customer's electric power purchased from the Administrator under section 5(b) of this Act …" 16 U.S.C. § 839e(b)(4). Section 5(b)(1) of the Act provides:

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1). Thus, if the public body, cooperative, or Federal agency customer does not have a general requirement determined under a section 5(b) contract, BPA cannot have purchased a resource from it for use in the 7(b)(2) Case.

Second, a resource may be used by BPA in the 7(b)(2) Case if the utility (whether a preference customer or IOU) has "not committed [the resource] to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D). In order to make a determination of whether to commit a resource to load under section 5(b), a utility must have a section 5(b) contract with BPA. The utility's general requirements are determined in part by excluding "such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region." 16 U.S.C. § 839c(b)(1). Absent a utility establishing in its contract the resources it will use to serve its regional firm load, BPA cannot know its general requirement. Resources not committed to load, in the context of section 7(b)(2), can only be determined by knowing the resources a utility has committed to load under its section 5(b) contract. Resources are therefore not available from a preference customer under section 7(b)(2)(D)(ii) in the absence of the utility having a section 5(b) contract. Further, resources purchased by the Administrator are available under section 7(b)(2)(D)(i) only from "such" customers; that is, those that have a general requirement pursuant to a section 5(b) contract. Basically, Congress prescribed the context for implementing the 7(b)(2) rate test. The rate test generally concerns, in the Program Case, the preference customers BPA serves under requirements contracts executed pursuant to section 5(b) of the Act, including their resources, and the same customers and their resources in the 7(b)(2) Case. BPA's decision is consistent with this statutory context.

WPAG argues the requirement of a section 5(b) contract creates essentially a null set of non-Federal resources. WPAG Br., WP-07-B-WA-01, at 18. WPAG claims by requiring either the owner or the purchaser to have a section 5(b) contract, Staff has created a situation where there will be virtually no non-Federal resources available to serve load in the 7(b)(2) Case. *Id*. WPAG states this is because utilities sign section 5(b) contracts in order to purchase power from BPA, and in order to make such purchases they must declare the non-Federal resources they will use to serve their load in order to establish a net requirement under section 5(b). *Id*. This results in the virtual elimination of non-Federal resources from the 7(b)(2) Case. *Id*. WPAG argues this result conflicts with both the purpose and the language of section 7(b)(2)(D). *Id*.

As explained previously, however, requiring an owner or purchaser of a resource to have a section 5(b) contract in order for the resource to be available in the 7(b)(2) Case is required by section 7(b)(2). WPAG's attempt to justify its argument relies on ignoring express provisions of section 7(b)(2) and is thus contrary to section 7(b)(2). Although WPAG claims Staff's interpretation of the Act would create a null set of non-Federal resources, WPAG has simply recited the requirements of section 5(b)(1) of the Northwest Power Act. Therefore, the possibility (indeed, likelihood) that utilities' declarations under section 5(b)(1) may reduce the non-Federal resources in the 7(b)(2) Case is simply a fact, and a logical result, of following the law. There can be no dispute that resources are not available in the 7(b)(2) Case if they are "committed to load pursuant to section 5(b)." Also, the evidence in this case shows that Staff has not created a null set. Staff proposes a portion of Priest Rapids and Wanapum dams, the Nine Canyon wind farm, and a portion of the Boardman Coal Plant be included in the resource stack pursuant to section 7(b)(2)(D)(ii). Doubleday, *et al.*, WP-07-E-BPA-85, at 63-65.

In addition, the number of resources in the stack may be limited due to the manner in which parties have chosen to participate in the opportunities provided by the Northwest Power Act. In establishing the Northwest Power Act, Congress anticipated that BPA's preference customers would build resources and sell them to BPA. "It is anticipated under this legislation that each BPA customer group will provide BPA, through the acquisition procedures of section 6, with sufficient power to meet each such customer group's load requirements." H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2d Sess. 34 (1980). "Under this bill the region's publicly-owned utilities will finance power plants, to meet their projected load growth through sales to BPA. Although BPA will be merely reselling this power back to these same utilities, the Committee recognized that the sale to Bonneville would be a sale to a non-exempt person…" H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2d Sess. 43 (1980). Indeed, in describing section 7(b)(2)(D), the legislative history refers to the resources in the resource stack including *preference customers' new resources*. The report of the House Committee on Interstate and Foreign Commerce states that "[t]he 'rate ceiling' is essentially that preference customers' cost of power from BPA will not exceed the costs they would have paid for power if: (1) preference customers were served from available Federal base system resources and, after these were exhausted, *from such customers' own new resources* …" H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2d Sess. 34 (1980) (emphasis added). The report of the Senate Committee on Energy and Natural Resources similarly states: "(2) The costs of resources to meet these requirements are (a) the costs of available Federal Base System resources; (b) c*osts of new resources*, either actual or hypothetical, *constructed or acquired by the public bodies and cooperatives* as necessary to meet their preference customer load requirements using the financing costs of such agencies that would have resulted if actions of the Administrator under Section 6 of the Bill were not achieved …" S. Rep. No. 96-272, 96th Cong., 1st Sess. 58 (1979). The fact that preference customers did not develop new resources in the manner Congress anticipated does not mean the Act should be ignored. Furthermore, WPAG's claim that BPA's interpretation creates a "null set" of non-Federal resources is simply incorrect. The non-Federal resources included in the resource stack in the 7(b)(2) Case are listed in the Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-50A, at 30-32.

PPC argues that even under Staff's proposed interpretation of section 7(b)(2)(D)(ii), BPA must deem the portion of Rocky Reach that is purchased by Alcoa available in the 7(b)(2) Case, because it is not dedicated to load by an IOU or public body or cooperative pursuant to section 5(b). PPC Br., WP-07-B-JP25-01, at 24. As explained above, however, this is only part of the test. Another part of the test is established by section 7(b)(2) and reflected in the Implementation Methodology. Section 7(b)(2) directs BPA to exclude all resources committed to load pursuant to section 5(b) from the 7(b)(2)(D) resource stack. Therefore, it must be determined that two conditions exist. Doubleday, *et al.*, WP-07-E-BPA-85, at 28. First, BPA must have access to the resource in the 7(b)(2) Case. *Id*. To establish this, the resource must be owned or purchased by a customer with a section 5(b) contract with BPA. *Id*. If the owner does not have a 5(b) contract and the resource output is for the owner's own use, then BPA cannot use the resource in the 7(b)(2) Case. *Id*.

The IOUs argue the Draft ROD erroneously suggests that section 7(b)(2)(D)(ii) requires that resources are to be considered committed to a utility's loads only if that utility has included that resource in its section 5(b) requirements contracts—i.e., in an exhibit to such contract. IOU Br. Ex., WP-07-R-JP6-02, at 20. The IOUs contend that would be an incorrect reading of sections 5(b)(1)(B) and 7(b)(2)(D) of the Northwest Power Act. *Id*. The IOUs argue that section 7(b)(2)(D)(ii) sets forth the statutory test relating to dedication of resources to load for purposes of section 7(b)(2): "not committed to load *pursuant to* section 5(b)." *Id*. The IOUs state the pertinent language in section 5(b) of the Northwest Power Act regarding commitment of resources to load reads as follows: "such other resources as such [utility] determines, pursuant to contracts under [the Northwest Power Act], will be *used* to serve its firm load in the region." *Id*. (emphasis added). The IOUs conclude this language does not require that the resources be specified *in* or *under* contracts under the Northwest Power Act; rather, section 7(b)(2)(D)(ii) merely requires that such resources are committed to load "*pursuant to"* section 5(b). *Id*.

The IOUs state the legislative history of the Northwest Power Act indicates that, for purposes of section 5(b)(1), resources that a utility determines, pursuant to contracts under the Northwest Power Act, will be used to serve its firm load in the region are resources that will in fact be *used* to serve the utility's firm load in the region.

> Section 5(b)(1) requires the Administrator to offer to sell to each preference agency and to each investor-owned utility the firm power it needs to meet its firm power load within the region to the extent that it cannot meet its load with its own resources. Those resources must be the resources used in the year prior to enactment of this bill and *such other resources that will be used to serve its firm load in the region*.

IOU Br. Ex., WP-07-R-JP6-02, at 21, *citing* H.R. Rep. No. 976, Part 1, 96th Cong., 2d Sess., 59 (1980) (emphasis added). The IOUs state this language indicates that *use* of the resource determines whether it is committed to load; nothing in this language suggests an intent that resources must be specified *in* or *under* a section 5(b) contract to be considered committed to load. *Id*. The IOUs state that in other words, for purposes of determining the amount of power that BPA is required and permitted to sell to a utility under a Northwest Power Act section 5(b) contract, that utility is not permitted to acquire and use actual resources to meet its firm load in the region without the recognition that such utility has determined, pursuant to such contract, to so use such actual resources. *Id*. The IOUs contend a utility's decision to purchase less power from BPA than that needed to satisfy its full load in the region inherently reflects such utility's determination pursuant to its section 5(b) contract to use other resources to serve its firm load in the region not served by purchases from BPA. *Id*.

The IOUs argue that if and to the extent BPA allows utilities to dedicate unspecified resources in their section 5(b) contracts, it is particularly important, for purposes of section 7(b)(2), that all resources—whether or not specified in such contracts—that each utility uses to serve its firm load in the region be recognized and treated as committed to load pursuant to section 5(b). IOU Br. Ex., WP-07-R-JP6-02, at 22. The IOUs state, in other words, the flexibility allowed a utility under its section 5(b) contract should not unduly result in limiting the resources that are treated, for purposes of section 7(b)(2), as having been determined by the utility, pursuant to a section 5(b) contract, to be used to serve its firm load in the region. *Id.*

The IOUs argue that in applying section 7(b)(2), BPA must in any event treat a utility's use of resources to serve its firm load in the region as committing those resources "to load pursuant to section [5(b)]"—whether or not the utility has identified such resources in its section 5(b) contract. IOU Br. Ex., WP-07-R-JP6-02, at 23. The IOUs contend BPA's preference customers should not be able to use resources that are "owned or purchased" within the meaning of section 7(b)(2)(D) of the Northwest Power Act to serve their firm loads in the region without such resources being considered for purposes of section 7(b)(2) as committed to their firm loads in the region under their section 5(b) net requirements contracts, and that such a result would be contrary to the provisions and intent of the Northwest Power Act. *Id.*

BPA understands the IOUs' concern. BPA does not believe utilities should be able to manipulate the section 7(b)(2) rate test through their section 5(b) contracts unless such is intended and permitted by the Northwest Power Act. However, at this time BPA does not find the IOUs' argument conclusive. For example, although the IOUs argue it is incorrect to conclude that resources are committed to load only by specifying such resources in a section 5(b) contract, the IOUs quote section 5(b), which refers to "such other resources as such [utility] determines, pursuant to contracts [under the Northwest Power Act], will be used to serve its firm load in the region." IOU Br. Ex., WP-07-R-JP6-01, at 21. The latter language suggests that resource commitments are made in the contracts. Because the IOUs have raised this issue in their Brief on Exceptions, no other party has had the opportunity to respond to the IOUs' argument. Although this does not preclude BPA from making a final decision on this issue, BPA believes it would benefit from other parties' legal analyses and BPA will therefore defer a definitive decision on this issue until a subsequent rate case. BPA will shortly begin its FY 2010-2011 rate proceeding.

The IOUs state the Draft ROD interprets section 7(b)(2)(D) to require that a resource sold by a preference agency is nevertheless includable in the section 7(b)(2) resource stack – regardless of whether the purchaser is BPA or any other entity – so long as the resource is not committed to load by the purchaser pursuant to section 5(b). IOU Br. Ex., WP-07-R-JP6-02, at 2-4. The IOUs argue the Draft ROD fails to give effect to both (i) and (ii) of section 7(b)(2)(D). *Id.* As noted above, section 7(b)(2)(D) (i) and (ii) apply to "all resources [that were] (i) purchased from such customers by the Administrator pursuant to section 6, or (ii) not committed to load pursuant to section 5(b)." The IOUs claim the Draft ROD's construction of section 7(b)(2)(D) improperly reads section 7(b)(2)(D)(i) out of the statute and renders it mere surplusage. *Id. citing Navajo Nation v. U.S. Forest Serv.*, 2008 WL 3167692, *10 n.16 (9th Cir. 2008) ("We 'must interpret statutes as a whole, giving effect to each word and making every effort not to interpret a provision in a manner that renders other provisions of the same statute inconsistent, meaningless or superfluous.'" (quoting *Boise Cascade Corp. v. EPA*, 942 F.2d 1427, 1432 (9th Cir. 1991))). The IOUs argue this is because, under the Draft ROD's interpretation of section 7(b)(2)(D), any resource sold to BPA would be includable in the 7(b)(2) resource stack under section 7(b)(2)(D)(ii) because any resource purchased by BPA cannot be committed to load pursuant to section 5(b), in light of the fact that BPA, by definition, cannot be a *purchaser* under a section 5(b) contract. *Id.* Thus, under the Draft ROD's interpretation of section 7(b)(2)(D), section 7(b)(2)(D)(i) will never have any effect. In other words, in each case in which a resource satisfies section 7(b)(2)(D)(i) (resource sold to BPA), it would, under the Draft ROD's interpretation, also necessarily satisfy section 7(b)(2)(D)(ii) (resource not committed to load).

BPA disagrees that its interpretation of section 7(b)(2)(D) renders section 7(b)(2)(D)(i) surplusage. When determining the resources used to meet section 5(b) loads in the 7(b)(2) Case, BPA includes in the resource stack (i) resources purchased from preference customers by the Administrator pursuant to section 6, and (ii) resources not committed to load pursuant to section 5(b). 16 U.S.C. § 839e(b)(2)(D). Under (ii), a preference customer may have numerous resources not committed to load pursuant to section 5(b), but only some of which were sold to the Administrator pursuant to section 6 of the Act. This leaves resources that preference customers have not dedicated to load and have not sold to the Administrator. Thus, subsection (ii) does not subsume subsection (i) under BPA's interpretation.

The IOUs argue the Draft ROD's interpretation relies on the following assumed "apparent logic": a preference agency that has sold power would, in the absence of the Northwest Power Act, have used such power to serve its own load or sold it only to "another regional load that otherwise would have purchased from BPA." IOU Br. Ex., WP-07-R-JP6-02, at 25. The IOUs claim BPA's "apparent logic" is unsupported speculation because, for example, it is speculative to assume without support that (i) preference agencies would, in the absence of the Northwest Power Act, only sell power to other preference agencies, and (ii) such sales would be at cost. *Id*. The IOUs argue BPA must assume that such sales are at the preference agency's cost in order to be consistent with BPA's position that preference agency resources included in the resource stack are included at the preference agency's cost; this is because, in the absence of the Northwest Power Act, sales of resources from one preference agency to another are the only apparent vehicle by which power from one preference agency's resources can be made available to another preference agency in meeting the general requirements in the section 7(b)(2) Case. *Id*. The IOUs state that, in effect, BPA's interpretation assumes that preference agencies in the 7(b)(2) Case should be treated as continuing to own power that they have sold to non-preference entities. *Id*. No such assumption is warranted, permitted, or required by the statutory language. *Id*. The IOUs' argument is not persuasive. The IOUs view the reasonableness of BPA's assumption outside the context of section 7(b)(2). Section 7(b)(2) prescribes the resources used to meet preference customers' requirements loads in the 7(b)(2) Case. The Act requires BPA to assume that, after using FBS resources to meet such loads, preference requirements would be served with resources that were owned or purchased by preference customers that were either purchased by the Administrator pursuant to section 6 of the Act (that is, resources originally developed by the preference customers), or resources not committed to load under section 5(b) (which means resources owned or purchased by preference customers that no regional utility has dedicated to its load pursuant to section 5(b)). These assumptions prescribe resources that are to be used to meet preference requirements and therefore one cannot assume that such resources would have been sold in the market or used otherwise.

The IOUs claim there is no basis for assuming that in the absence of the Northwest Power Act preference agencies would only sell power to other preference agencies. IOU Br. Ex., WP-07-R-JP6-02, at 26. The IOUs state that prior to the Northwest Power Act, Mid-Columbia Public Utility Districts (Grant PUD, Chelan PUD, and Douglas PUD) sold substantial amounts of power to investor-owned utilities. *Id*. Similarly, there is no basis for assuming that, in the absence of the Northwest Power Act, such sales would be at cost. *Id*. An assumption that any preference agency would sell power at cost, when it could have sold such power at a price greater than cost, is unsupported. *Id*. This is particularly true inasmuch as sales by preference agencies above cost help to reduce their retail rates. *Id*. Once again, however, section 7(b)(2) prescribes the preference customer resources that are assumed to be used to meet preference requirements in the 7(b)(2) Case. It does not matter whether such resources might have been sold in a non-7(b)(2) world in a different manner. Furthermore, assuming power sales made by preference customers were made at cost is a reasonable assumption in the context of section 7(b)(2). This places such resources in the resource stack on the same footing as the FBS resources in the 7(b)(2) Case and the Program Case, which are also included at cost.

The IOUs argue section 7(b)(2)(D) must be construed to give effect to both sections 7(b)(2)(D)(i) and (ii). IOU Br. Ex., WP-07-R-JP6-02, at 27. Accordingly, resources includable in the section 7(b)(2) resource stack under section 7(b)(2)(D)(i) and (ii) should be limited to the following: (a) resources owned by preference agencies and sold to BPA pursuant to section 6 of the Northwest Power Act, and (b) resources owned by preference agencies (and not sold) but not committed to load pursuant to section 5(b). *Id*. In response, the IOUs' latter construction makes little sense. Under the IOUs' interpretation in (b), the preference customers' resources would be limited to resources preference customers owned but did not sell and did not commit to load. In other words, the Act would only allow preference customers' essentially idle or mothballed resources to be used under section 7(b)(2)(D)(ii) to meet preference customers' requirements in the 7(b)(2) Case. This is not a reasonable interpretation.

The IOUs note the Draft ROD's statements that the IOUs' interpretation would exclude resources exported from the region under the reading that the extra-regional purchaser now "owns" the resource, and given the concern in section 9(c) about resources being sold outside of the region, it is unreasonable to believe that Congress would place hurdles in the way of the export of 5(b) resources and allow a loophole through section 7(b)(2)(D). IOU Br. Ex., WP-07-R-JP6-02, at 28, citing Draft ROD at 441-42. The IOUs argue, to the contrary, that their interpretation of section 7(b)(2)(D) creates no such loophole. The IOUs argue the effect of their interpretation with respect to preference agency sales of resources outside the region is to preclude the inclusion of such resources in the section 7(b)(2) resource stack, which does not encourage export of any resources outside the region. *Id*. In response, however, simply because an extra-regional party purchases power from a preference customer's resource does not mean the extra-regional purchaser gains property rights over the power such that it can never be returned to meet regional preference customer loads.

WPAG argues that BPA's reasons for recognizing the plain language of the Act and therefore amending its flawed 1984 Legal Interpretation are not persuasive. WPAG Br. Ex., WP-07-R-WA-01, at 22-24. WPAG states that in defending its treatment of conservation in the DROD, BPA argues that if rate case parties had an opportunity to contest an interpretation and failed to do so, the absence of such comment adds validity to such interpretation, and provides BPA with a basis for continuing to rely on such interpretation. *Id*. However, with regard to the inclusion of the Mid-Columbia resources in the 7(b)(2) Case, BPA argues just the opposite position – that the absence of comment on the portion of the 1984 Legal Interpretation dealing with Mid-Columbia resources is evidence that this long-standing legal interpretation lacks merit. *Id*. WPAG has mischaracterized BPA's position. The first principle cited by WPAG is certainly correct—where parties fail to challenge an agency decision, it adds validity to such decision. On its second point, however, BPA did not say that the absence of comment on this issue in the 1984 Legal Interpretation shows that such interpretation lacks merit, rather, that this particular issue was not fully analyzed by any party, including BPA. When one actually reviews the statutory language, one sees that BPA ignored the plain language of the Act, which requires BPA to preclude resources that have been dedicated to load pursuant to section 5(b) of the Act, which applies to both preference customers and IOUS.

WPAG also states BPA suggests that the fact that the 1984 Legal Interpretation has been in place since 1984, and has been relied upon by BPA in every subsequent rate case, is of little moment. WPAG Br. Ex., WP-07-R-WA-01, at 22. WPAG claims, in contrast, in defending its treatment of conservation in the context of the section 7(b)(2) rate test for both the WP-02 and WP-07 cases, BPA argues that the fact that its approach has been used in many rate cases over a long period of time lends it credence. *Id*. WPAG, however, has not accurately described the facts. BPA does not state that the fact that the 1984 Legal Interpretation has been in place since 1984, and has been relied upon by BPA in every subsequent rate case, is of little moment. Indeed, the opposite is true. With regard to the instant issue, however, BPA never had to implement its 1984 interpretation regarding dedicated resources in the actual development of rates at any time until BPA's WP-07 rate case. Therefore, BPA did not, regarding this issue, use the interpretation in every subsequent rate case. When a rate case party noted in the WP-02 rate case that BPA's interpretation was inconsistent with the plain language of the Act, BPA did not adjust rates because the FBS proved sufficient to meet preference loads in the 7(b)(2) Case for the final proposal, but BPA realized its 1984 interpretation was flawed.

WPAG states that in the Draft ROD, BPA argues that its prior reliance on the portion of the 1984 Legal Interpretation dealing with Mid-Columbia resources in final records of decision in prior rate cases should be disregarded, because the treatment of the Mid-Columbia resources did not affect the level of the final PF rate. WPAG Br. Ex., WP-07-R-WA-01, at 23. WPAG argues that because the 1984 Legal Interpretation did not move dollars in a particular case does not change the fact that the Administrator, in a final record of decision, addressed the issue in detail and with finality. *Id*. WPAG again has not accurately described the factual context of its argument. BPA, by definition, did not address the issue *with finality* in BPA's WP-96 rate case because

BPA did not have to make *any decision whatsoever* on the issue. BPA's unnecessary analysis simply followed the established 1984 Legal Interpretation unquestioningly. The fact that BPA did not have to address the issue to establish rates shows that the discussion was dicta. When the issue became moot for the development of final rates, BPA did not have to analyze the issue any further than following the 1984 Legal Interpretation. A more detailed review would have shown that BPA's interpretation was inconsistent with the plain language of the Act.

WPAG argues that BPA's plain language interpretation renders the statutory provisions regarding least cost non-Federal resources owned or purchased by preference customers being available to serve 7(b)(2) Case loads mere surplusage. WPAG Br. Ex., WP-07-R-WA-01, at 24. This is simply incorrect. BPA's plain language interpretation of section 7(b)(2)(D) is consistent with the language of the Act and is a reasonable interpretation. BPA concludes that "the Administrator [will] assume[ ] that all resources that would have been required … to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were—purchased from such customers by the Administrator pursuant to section 6, or not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D). To effectuate this assumption, BPA will determine the resources that were purchased from such customers by the Administrator under section 6, and the resources not committed to load by regional utilities pursuant to section 7(b), and will include such resources in a resource stack to serve 7(b)(2) Case loads using least-cost resources first. Under BPA's interpretation, it is critical to determine which utilities' resources have been committed to load pursuant to section 5(b) of the Act, and to reflect that determination in the 7(b)(2) rate test. BPA's interpretation also relies upon, and ensures, that the resources included in the resource stack and used to serve preference loads in the 7(b)(2) Case are used in least-cost order. This gives explicit effect to this provision and does not render it surplusage.

WPAG argues that BPA's stated desire to adhere to the plain language of section 7(b)(2) appears to be episodic. WPAG Br. Ex., WP-07-R-WA-01, at 24. WPAG argues BPA's assumption that the monetization of power sales to DSIs should be included in the 7(b)(2) Case is not consistent with the statutory language that refers to "…direct service industrial customer loads which are served by the Administrator …" *Id*. WPAG states BPA asserts that the payment of money to the DSIs is sufficient to include the costs in the 7(b)(2) Case power costs, even though BPA is providing no electrical service to such loads. *Id*. WPAG fails to point out, however, that the payment of money to the DSIs reflects the monetization of a power sale for legitimate business reasons. Furthermore, WPAG fails to note that BPA did *not include the DSI loads* that would have been served by BPA in the absence of the monetization in the 7(b)(2) Case, which would have increased the PF Preference rate. Instead, BPA is including the same costs in the Program Case as in the 7(b)(2) Case. This issue is discussed in greater detail in a separate section of this ROD. Furthermore, the law recognizes that where the plain language of the statute is consistent with the intent of the Act, the plain language controls. However, the law also provides that where the language of an Act is inconsistent with legislative intent, a strict interpretation may not stand. Given that BPA is spending money to monetize a DSI power sale, and that DSI power sales are recognized in the 7(b)(2) to reflect the Program Case, it is consistent with the intent of section 7(b)(2) to reflect the monetization costs in the 7(b)(2) Case.

APAC argues that BPA's adoption of a new legal interpretation would impose additional costs on preference customers. APAC Br., WP-07-B-AP-01, at 42. APAC notes that a reduction in the available Mid-Columbia resources means more expensive resources must be selected from the resource stack, which in turn results in a higher 7(b)(2) Case rate and higher preference customer rates. *Id*. APAC correctly describes the general effect of BPA's application of the language of section 7(b)(2). This effect, however, is simply the result of using the language of section 7(b)(2) to conduct the section 7(b)(2) rate test and develop BPA's rates. APAC can make the judgment that the interpretation imposes "additional" costs on preference customers by comparing to lower results produced by an interpretation inconsistent with the statute. BPA's preference customers have repeatedly noted BPA's statement that BPA must properly implement section 7(b)(2), even if it has an adverse effect on REP benefits for exchanging utilities. This metaphorical door swings both ways. BPA also must properly implement section 7(b)(2) even if it has an adverse effect; *i.e.*, a reduction in the section 7(b)(2) rate trigger on BPA's preference customers.

APAC argues that Staff "then seemingly admits that the reason it excluded the Mid-C resources now is to reach its desired – and intended – result of "*decreasing the rate test trigger and increasing new REP benefits*." *Id*. at 43 (emphasis in APAC Brief). APAC cites Doubleday, *et al.*, WP-07-E-BPA-60, at 22 to support its argument. Upon review of the cited testimony, however, there is absolutely nothing in such testimony to support APAC's defamatory claim. Staff's proposed treatment of the Mid-Columbia resources is to properly implement the language of section 7(b)(2).

APAC argues BPA cannot change its 1984 Legal Interpretation now and apply it to prior decisions, which APAC characterizes as retroactive ratemaking. APAC Br., WP-07-B-AP-01, at 46. APAC argues BPA has no authority to apply its plain-language interpretation of section 7(b)(2) when determining the PF Exchange rate used in calculating REP benefits for the 2002-06, and 2007-08 rate periods. *Id*. WPAG makes similar arguments. WPAG Br., WP-07-B-WA-01, at 14-15. Parties' arguments regarding retroactive ratemaking are addressed in greater detail elsewhere in this ROD. In addition, however, APAC and WPAG ignore the factual context of Staff's development of the Lookback Amount in this proceeding, which is also addressed in greater detail elsewhere in this ROD. In summary, the Ninth Circuit's opinions in *PGE* and *Golden NW* concluded that BPA had improperly allocated the costs of BPA's unlawful 2000 REP Settlement Agreements to BPA's preference customers. In order to respond to the Court's opinions, in simple terms, Staff proposes to first determine the amount of REP settlement costs that were charged to BPA's preference customers under BPA's WP-02 rates for FY 2002-06 and WP-07 rates for FY 2007-08. Staff then compares such costs with the REP benefits the IOUs would have received during those periods under the REP in the absence of the REP settlements. Staff then calculates the difference between the two cases and returns the overcharged amount to BPA's preference customers. In order to determine the REP benefits the IOUs would have received under the REP in the absence of the REP settlements, BPA must review three elements: the IOUs' respective ASCs, BPA's PF Exchange rate, and the IOUs' loads.

In order to determine the PF Exchange rate that would have been used to calculate REP benefits for FY 2002-06, Staff placed itself back in time when BPA was developing its WP-02 supplemental power rate proposal. Staff knew it could not use the PF Exchange rate BPA had established in the first portion of the WP-02 rate case because it was developed based on costs, loads, and market prices that increased dramatically immediately after its development and BPA's base rates, including the PF Exchange rate, required prompt revision to ensure cost recovery as required by law. 16 U.S.C. § 839e(a). The initial PF Exchange rate, and BPA's other initial power rates, were fundamentally flawed because of their inability to recover BPA's costs as required by law. These rates therefore could not have been approved by FERC and could not have been charged to BPA's customers. Because the REP settlements were in effect at that time, and BPA did not use the PF Exchange rate to calculate settlement benefits, BPA was able, with the agreement of the rate case parties, to simply adopt adjustment clauses to increase the power rates and ensure cost recovery. In the absence of the REP settlements, however, the dramatic changes in loads and market prices would have affected the significance and implementation of BPA's section 7(b)(2) rate test and the establishment of the PF Exchange rate, which in turn is used to establish REP benefits. In the absence of the REP settlements, the IOUs would not have agreed to adjustment clauses, but would have pursued their section 7(b)(2) issues. BPA therefore, instead of adopting adjustment clauses, would have revised its base rates, as is well documented in the rate case record. In order to revise base rates, BPA would have had to incorporate its dramatically changed loads and market prices into the section 7(b)(2) rate test. The results of the rate test would be used to establish the PF Exchange rate. This rate would then be compared with the utilities' ASCs to calculate REP benefits.

In conducting the rate test with new load and market price information, BPA would have determined that the FBS was insufficient to meet 7(b)(2) Customers' loads in the 7(b)(2) Case. Therefore, unlike BPA's initial WP-02 rate case, BPA would have had to decide whether Mid-Columbia resources dedicated to loads by preference customers and IOUs should be excluded from the rate test in a context where BPA's determination of that issue would actually affect the development of BPA's rates. Staff therefore proposed what it would have done in such circumstances. BPA's Legal Interpretation and Implementation Methodology are not set in stone. BPA can change its Legal Interpretation and Implementation Methodology in any general BPA power rate proceeding. The existence of the 1984 Legal Interpretation and 1984 Implementation Methodology therefore would not have controlled BPA's implementation of the rate test in the WP-02 rate case if BPA determined the Legal Interpretation and Implementation Methodology were flawed and should be corrected. Because this would be the first time BPA's Mid-Columbia resource determination would affect BPA's rates, BPA would have conducted an extremely thorough legal examination of the issue. BPA knew the DSIs argued in the WP-02 rate case that the plain language of section 7(b)(2) provides that resources "committed to load pursuant to section 5(b)," which expressly include resources committed by preference customers *and IOUs* (16 U.S.C. § 839c(b)(1)), could not be included in the resource stack. The DSIs' plain-language argument had no readily apparent rebuttal. Thus, in a proceeding where BPA must calculate the REP benefits IOUs would have received during FY 2006-08 in the absence of the REP settlements, BPA is reviewing how BPA would have conducted the section 7(b)(2) rate test. This has to done because the initial WP-02 rates were developed in circumstances that changed almost immediately, rendering the initial rates unable to recover BPA's costs, as required by law. In reviewing the DSIs' argument, BPA would have concluded that it would have to change its Legal Interpretation and Implementation Methodology in the WP-02 rate case in order to comply with the plain language of section 7(b)(2). Thus, BPA is not retroactively applying a new legal determination. Instead, BPA is noting that BPA's legal determination regarding the exclusion of the IOUs' dedicated Mid-Columbia resources from the resource stack, raised in the first instance by the DSIs in BPA's initial WP-02 rate case but rendered moot, would have become ripe based on the changed load and market price conditions known during the WP-02 supplemental proceeding and would have been decided in accordance with the plain language of section 7(b)(2).

APAC argues Staff has failed to provide adequate justification for the change in interpretation. APAC Br., WP-07-B-AP-01, at 47; APAC Br. Ex., WP-07-R-AP-01, at 31. This argument is refuted by the record. In addition to the foregoing discussion, BPA's initial 1984 Legal Interpretation reached a conclusion in conflict with the plain language of section 7(b)(2). BPA's 1984 Legal Interpretation was not developed in circumstances where BPA was developing rates in which resources from the resource stack were required to serve 7(b)(2) Customers' loads in the 7(b)(2) Case. When BPA actually had to do so, and examined the applicable law, BPA reached a conclusion consistent with the plain language of section 7(b)(2). APAC essentially argues BPA is required to implement a legal interpretation it knows is contrary to the plain language of the Act. The law does not so require. BPA is justified in changing its Legal Interpretation, especially one which was never previously used to establish BPA's rates, in order to ensure BPA implements the section 7(b)(2) rate test in accordance with the plain language of section 7(b)(2) of the Northwest Power Act.

APAC argues that administrative agencies may not depart from long-established constructions of ambiguous regulations absent significant changes in circumstances, citing a state court case. APAC Br., WP-07-B-AP-01, at 47; APAC Br. Ex., WP-07-R-AP-01, at 9. The Supreme Court states the principle differently. In *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837, 863-64 (1984), the Court recognized that "[a]n initial agency interpretation in not instantly carved in stone. On the contrary, the agency, to engage in informed rulemaking, must consider varying interpretations and the wisdom of its policy on a continuing basis." Furthermore, "[c]ourts will accord *Chevron* deference to an agency's revised interpretation of a statute if the agency justifies that revision with 'reasoned analysis.'" *Natural Resources Defense Council v. EPA*, 526 F.3d 591, 608 (9th Cir. 2008), *quoting Rust v. Sullivan*, 500 U.S. 173, 187 (1991); *Nat'l Cable & Telecomm. Ass'n*, 545 U.S. at 981. In fact, in *Chevron*, the Supreme Court "deferred to an agency interpretation that was a recent reversal of agency policy." *Id., citing Chevron*, 467 U.S. at 857-58. Furthermore, the Supreme Court has explicitly "rejected the argument that an agency's interpretation 'is not entitled to deference because it represents a sharp break with prior interpretations' of the statute in question." *Rust v. Sullivan*, 500 U.S. 173, 186 (1991), *quoting Chevron*, 467 U.S. at 862. "An agency is not required to "establish rules of conduct to last forever." *Id. citing Motor Vehicle Mfrs.*, 463 U.S. at 46-57, *quoting Am. Trucking Ass'n Inc. v. Atchison, T. & S.F.R. Co.*, 387 U.S. 397, 416 (1967); *NLRB v. Curtin Matheson Scientific, Inc.*, 494 U.S. 775 (1990). Rather, an agency "must be given ample latitude to adapt rules and policies to the demands of changing circumstances." *Id., citing Motor Vehicle Mfrs.*, 463 U.S. at 42, *quoting Permian Basin Area Rate Cases*, 390 U.S. 747, 784 (1968).

APAC states that Mid-Columbia resources must be dedicated to load under section 5(b) contracts in order to be excluded from the resource stack. APAC Br., WP-07-B-AP-01, at 47; APAC Br. Ex., WP-07-R-AP-01, at 9. APAC states it sent a data request for this information and received six contracts in response. *Id*. APAC states all of these contracts with IOUs were entered into as part of the REP settlement agreements and therefore are not valid and enforceable contracts under section 5(b), by which Mid-Columbia resources are committed to IOU load. *Id*. APAC fails to mention Staff's rebuttal testimony, which addressed this issue in detail. Staff's testimony established that numerous contracts exist under which BPA's utility customers, particularly the IOUs, have dedicated their Mid-Columbia purchases to load. Doubleday, *et al.*, WP-07-E-BPA-85, at 22. First, when BPA conducted the WP-02 supplemental rate case in 2000-2001, the IOUs had executed REP Settlement Agreements. *Id*. Attached to the REP Settlement Agreements were separate firm power requirements contracts offered under section 5(b) of the Northwest Power Act. *Id*. These contracts were intended to be "standalone" contracts. *Id*. Under these contracts, all IOUs that purchased Mid-Columbia resources from 7(b)(2) Customers dedicated such purchases to their own loads for purposes of calculating their net requirements. *Id*.[20]

Arguments regarding the continued validity of the RL contracts, however, are unnecessary. For purposes of FY 2002-2008, if one assumes that the REP Settlement Agreements had not been offered and implemented, IOUs expecting to receive positive benefits under the REP would have executed Residential Purchase and Sale Agreements to implement the REP, just as they did in 1981. *Id*. at 23. It would be illogical and unreasonable to think that IOUs eligible to receive benefits under the REP would fail to execute the RPSAs and receive such benefits for their residential consumers. *Id*. Similarly, in 1981 BPA offered requirements power sales contracts to its preference and IOU customers. *Id*. All of the IOUs executed the 20-year requirements contracts. *Id*. In each of the requirements contracts of IOUs that purchased Mid-Columbia resources from 7(b)(2) Customers, the IOUs dedicated such purchases to their own loads pursuant to section 5(b) of the Northwest Power Act. *Id*. In the absence of requirements contracts, the IOUs could not purchase requirements power from BPA. *Id*. at 23-24. The IOUs' 20-year requirements contracts expired in 2001. *Id*. at 24.

In developing the Subscription contracts that would follow the expiration of the IOUs' 1981 RPSAs and requirements contracts, BPA offered the IOUs two options. *Id*. One option was to execute an REP Settlement Agreement to resolve disputes arising under the REP. *Id*. As noted above, the REP Settlement Agreements attached separate requirements power contracts with the IOUs. *Id*. The Record of Decision for the REP Settlement Agreements provided that the IOUs could not purchase any requirements power other than the requirements power provided under the attached requirements contracts. *Id*. The second option offered to the IOUs was to execute RPSAs to participate in the REP for the next 10-year period. *Id*. Because the RPSA does not provide requirements power to the IOUs, the IOUs would have had to execute separate requirements contracts for their requirement power purchases from BPA, just as they did in 1981. *Id*. In 2000, the IOUs elected to execute the REP Settlement Agreements. *Id*.

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[20] These requirements contracts have never been terminated by the parties. *Id*. Even if one assumed that BPA could not make power sales at the RL rate under these agreements, the parties could simply change the applicable rate to the NR rate, and BPA could make requirements sales to the IOUs under the contracts, and such sales would be unrelated to the REP settlements.

As noted, in the absence of the REP settlements, the record demonstrates the IOUs would have executed RPSAs and participated in the REP. *Id*. In addition to the RPSAs, the IOUs would have executed requirements power sales contracts with BPA for the 10-year Subscription period. *Id*. Just as it would be unreasonable to think that IOUs eligible to receive benefits under the REP would fail to execute RPSAs in the absence of the REP settlements, it would be equally unreasonable to think that the IOUs would have failed to sign new requirements contracts for the 10-year Subscription period. *Id*. The IOUs would not have given up the opportunity to purchase requirements power from BPA regardless of how frequently the IOUs might purchase such power. *Id*. Thus, for purposes of FY 2002-2008, it is reasonable to assume the IOUs would have executed requirements contracts and dedicated their Mid-Columbia purchases to their own loads in such contracts, just as they did in their 1981 requirements power sales contracts and in their 2000 RL requirements contracts. *Id*.

Furthermore, even assuming for the sake of argument that the IOUs would not have wanted to dedicate their Mid-Columbia resources to their loads under their requirements contracts, they would have had no choice but to do so. *Id*. BPA's Section 5(b)/9(c) Policy states that as long as a utility acquired a resource prior to enactment of the Northwest Power Act and used it to meet its native load, the utility must continue to dedicate that resource to native load and cannot place a larger requirement on BPA. *Id*. Furthermore, even if a power sales contract expired after enactment of the Northwest Power Act, if there were a follow-on contract for the same resource, this would not be treated as a loss of contract right. *Id*. Instead, the follow-on purchase would also have to be dedicated to the utility's native load. *Id*. at 24-25.

Finally, BPA is currently negotiating requirements power sales contracts with the IOUs for both the period from October 1, 2008, through September 30, 2011 ("bridge contract") and for the period from October 1, 2011, through September 30, 2028 ("Regional Dialogue contract"). *Id*. at 25, Attachments 2 and 3. Such contracts are scheduled to be executed in August 2008. *Id*. Just as the IOUs dedicated their Mid-Columbia resources to native load in their 1981 requirements contracts and their 2000 requirements contracts, the IOUs will continue to do so as described in this testimony in the bridge and Regional Dialogue requirements contracts. *Id*. In summary, the record establishes that the IOUs would have executed section 5(b) requirements contracts in 2000 in the absence of the REP Settlement Agreements, and would have dedicated their Mid-Columbia resources to their loads. This precludes BPA from assuming such resources would have been available for the resource stack.

WPAG argues that BPA's 1984 interpretation is consonant with the other portions of this section of the statute. WPAG Br., WP-07-B-WA-01, at 13-14; WPAG Br. Ex., WP-07-WA-01, at 20-21. WPAG argues that when read in conjunction with section 7(b)(2)(D)(i), it results in all least-cost resources owned or purchased by preference customers being available to serve such customers' general requirements load in the 7(b)(2) Case, except for those preference customer resources that have been dedicated to preference customer load under section 5(b). *Id*. WPAG argues the effect and purpose of this subsection is to avoid double counting least-cost resources owned or purchased by preference customers that have been declared to load under section 5(b), since these resources are subsumed in the term general requirements used in section 7(b)(2)(D) and recognizes that in the absence of a growing power supply from BPA, all least-cost resources owned or purchased by preference customers would be used by them to serve their load. *Id*.

The problem with WPAG's speculation is that it does not reflect the plain statutory language of the Act or the facts. It would not make sense for preference customers to have access to all resources owned or purchased by such customers if some of those resources had been acquired by IOUs and dedicated to their loads under section 5(b) requirements contracts. Once resources have been dedicated to serve load in accordance with section 5(b), they have reduced the Administrator's obligation, and they are not available to be used by any other party for any other purpose. The fact that precluding use of preference customers' dedicated resources in the resource stack would avoid double counting costs of resources dedicated to load under section 5(b) is a point that only applies to preference customers' dedicated resources. It is perfectly consistent with the fact that IOUs' dedicated resources under section 5(b) would not be available to serve preference loads. Doing otherwise would increase the Administrator's obligations.

In its Brief on Exceptions, WPAG argues its interpretation of section 7(b)(2)(ii) also effectuates the underlying expectation of the "without the Act" world, in conjunction with section 7(b)(2)(D)(i), that in the absence of a growing power supply from BPA, all least cost resources owned or purchased by preference customers would be used by them to serve their load, regardless of any prior sales arrangements with IOUs. WPAG Br. Ex., WP-07-R-WA-01, at 21. WPAG claims this implements the common sense expectation that in a "without the Act world" in which BPA's power supply would be limited, preference customers would not have surplus output from non-Federal resources to share with the IOUs. *Id*. WPAG's arguments do not necessarily follow. To the contrary, for example, where public agencies have long-term contracts for the sale of resources to IOUs, such as exist for the Mid-Columbia power, even if the Northwest Power Act had not been enacted, the public agencies would not have had access to such resources because they had been purchased by the IOUs. Indeed, at the time the Act was passed, a large portion of the Mid-Columbia resources had been sold to the IOUs under decades-long contracts. It is unreasonable to expect that Congress intended BPA to assume that the public agencies would breach their then-existing contracts through directing that the publics could have withdrawn the resources bound by contract to IOUs.

WPAG argues that when considered in conjunction with the requirement that either the owner of the non-Federal resource, or the purchaser of its output, must have a section 5(b) contract with BPA, the result of these two provisions is to virtually eliminate any least-cost resources owned or purchased by preference customers from being considered available to serve 7(b)(2) Case loads. WPAG Br., WP-07-B-WA-01, at 16. WPAG argues that these interpretations fail to effectuate the alleged underlying purpose of sections 7(b)(2)(D)(i) and (ii), which is to ensure that all least-cost preference resources are assumed to be available to serve 7(b)(2) Case loads. *Id*. WPAG argues the Staff's proposed interpretations render the statutory provisions regarding least-cost non-Federal resources owned or purchased by preference customers being available to serve 7(b)(2) Case loads mere surplusage. *Id*.

Contrary to WPAG's contentions, the interpretations of section 7(b)(2) based on the plain language of that section do not eliminate resources owned or purchased by preference customers from being available to meet preference loads in the 7(b)(2) Case. First, a limited number of resources in the resource stack is explained by the failure of preference customers to develop new resources and sell those resources to BPA, as expected by Congress and explained above.

Second, WPAG's claim that the interpretations "virtually eliminate any *least cost resources* owned or purchased by preference customers from being considered available" misstates the statute. Under section 7(b)(2)(D), BPA first determines the resources owned or purchased by preference customers that were (i) purchased from such customers by the Administrator pursuant to section 6, and (ii) not committed to load pursuant to section 5(b). Only after establishing such resources, and in determining the order in which resources will be used to serve preference customers in the 7(b)(2) Case, does BPA determine which of those resources are least-cost. The Act does not assume the resources are least-cost; rather, that once determined, they be used least-cost first to serve preference load. This is precisely what BPA does in conducting the rate test.

In addition, as noted above, it makes perfect sense that resources committed to load under section 5(b) by either preference customers or IOUs are simply not available to serve preference loads in the 7(b)(2) Case. They are already serving regional requirements loads. This, however, leaves all of the remaining resources owned or purchased by 7(b)(2) Customers that are not committed to regional loads available to serve preference loads.

2. Section 7(b)(2) Procedural Issues

In its Brief on Exceptions, PPC states that in BPA's WP-02 Rate Case (in which BPA originally set rates for 2002-2006), BPA and the parties litigated the implementation of section 7(b)(2), and BPA ultimately determined that the rate test allowed only $48 million of Residential Exchange Benefits to be borne by preference customers. PPC Br. Ex., WP-07-R-PP-01, at 18. PPC, however, fails to note that the $48 million of forecasted benefits were based on BPA's development of its fatally flawed 7(b)(2) rate test and base rates in May 2000. BPA's May 2000 base rates were based on load and market price information that promptly became outdated and required BPA to reopen the WP-02 hearing and revise the rates through a supplemental proposal before they could be filed with FERC for approval. FERC could not have approved the May 2000 base rates given their inability to recover BPA's costs as required by law. Thus, PPC's reference to $48 million of forecasted REP benefits is essentially meaningless.

PPC notes that, in its Record of Decision in that case, BPA dedicated over 60 pages to defending its 7(b)(2) rate test determinations. PPC Br. Ex., WP-07-R-PP-01, at 18. PPC fails to note, however, that the 60-page discussion was only for those issues that were relevant to the 7(b)(2) test at the time the fatally flawed 7(b)(2) rate test and base rates were developed. PPC also fails to note that, in the absence of the REP Settlement Agreements, when it became apparent that the initial base rates were inadequate, BPA would have rerun the 7(b)(2) rate test and established revised base rates to insure the proper implementation of the 7(b)(2) rate test using the new load and market information available at that time. Thus, the 7(b)(2) rate test used to develop the initial WP-02 base rates was a flawed rate test performed with outdated data and produced flawed results.

PPC claims that no party followed through with any challenge to BPA's 7(b)(2) determinations at the Ninth Circuit. PPC Br. Ex., WP-07-R-PP-01, at 18. *See* APAC Br. Ex., WP-07-R-AP-01, at 7. PPC's claim is incorrect. BPA's IOU customers filed petitions for review and briefs challenging BPA's 7(b)(2) determinations in the WP-02 rate case. The IOUs withdrew their arguments when they determined the 7(b)(2) issues would not affect them given the fact they were operating under the REP Settlement Agreements, which were unaffected by the WP-02 7(b)(2) rate test. In the absence of the REP Settlement Agreements, the IOUs would have pursued their challenges to BPA's implementation of section 7(b)(2) in developing its WP-02 base rates because the PF Exchange rate would have applied to the IOUs through their participation in the REP in the absence of the REP Settlement Agreements.

PPC states that now that BPA has been directed by the Ninth Circuit to give effect to 7(b)(2) as a cap on the amount of REP costs that can be imposed on preference customers, BPA is proposing to redetermine the rate test for FY 2002-2008. PPC Br. Ex., WP-07-R-PP-01, at 19. PPC fails to note, however, that the Court's decision does not require BPA to determine 7(b)(2) rate protection based on a fundamentally and fatally flawed 7(b)(2) rate test conducted before BPA incurred massive changes in loads and market prices that occurred during the development of the WP-02 rates (as supplemented with CRACs). Doing so would be indefensible and would provide preference customers unjustified benefits. PPC notes that BPA now proposes to re-make its decisions in a way that would allow it to pay about five times the amount of REP benefits that it determined were lawful during 2002-2006. *Id*. PPC fails to note, however, that the $48 million used as a base case by PPC is fundamentally flawed as noted above. PPC also fails to note that when the rate test is conducted properly using data that was available when BPA developed its supplemental WP-02 rate proposal, REP benefits would properly be determined to be significantly greater than based upon the flawed rate test conducted in developing the inadequate initial WP-02 base rates. Indeed, this is no surprise. During the litigation of *PGE* and *Golden NW*, BPA noted that there were a number of ratemaking issues regarding section 7(b)(2) that, if decided against BPA's preference customers, could significantly increase forecasted REP benefits to nearly $300 million. In BPA's ratemaking, a single issue can have a tremendous effect on the 7(b)(2) rate test and thus the amount of REP benefits BPA provides to the IOUs and other exchanging utilities. The 2000 REP Settlement Agreements capped the REP benefits to the IOUs' residential and small farm customers at approximately $145 million per year, and also capped the amount of REP costs that could be recovered from BPA's preference customers in rates. This provided valuable insurance to BPA's preference customers from the IOUs' ASCs increasing in the future and from preference customers losing significant 7(b)(2) arguments in BPA's rate cases. Now that certain 7(b)(2) ratemaking issues have to be addressed, and certain issues have been decided contrary to the preference customers' arguments, PPC wants to avoid the legitimate costs that must be allocated to preference customers under law.

PPC states that neither the *PGE* nor *Golden NW* decisions commented on any perceived error in BPA's conduct of the rate test in its WP-02 case. PPC Br. Ex., WP-07-R-PP-01, at 19. *See* APAC Br. Ex., WP-07-R-AP-01, at 10. This argument collapses under knowledgeable review. The Court in *Golden NW* remanded BPA's rates to be set in accordance with the Court's opinion. The Court was not briefed on the correct manner of addressing on remand the Court's conclusion that BPA improperly allocated REP Settlement Agreement costs to preference customers. The Court was not briefed on the facts that BPA's WP-02 7(b)(2) rate test and base rates were fundamentally flawed; for example, that the base rates would have failed to recover BPA's costs, that the 7(b)(2) rate test did not use information that was available during the development of BPA's WP-02 supplemental proposal, and that the base rates developed on the flawed rate test could not have been approved by FERC because of their failure to recover costs. Simply because a Court does not identify such problems does not mean they can legitimately be ignored in responding to the Court's decisions.

PPC cites a number of general legal principles in support of an estoppel argument. PPC Br. Ex., WP-07-R-PP-01, at 19-20. PPC states that Federal appellate courts have held that findings that are "necessary to support the judgment in a prior proceeding will bar relitigation on that issue in a subsequent proceeding involving the same parties." *Id*. at 20. Similarly, PPC argues that "findings of agencies made in the course of proceedings which are judicial in nature should be given the same preclusive effect as findings made by a court." *Id*. PPC's estoppel arguments fail for several reasons. First, PPC incorrectly analogizes BPA's ratemaking rulemaking proceedings to employment dispute adjudications involving individual litigants, not ratemaking or similar rulemaking proceedings that develop the administrative record for adopting agency policies. Second, PPC disregards the fact that the Ninth Circuit invalidated several of BPA's 2002 decisions as erroneous and remanded so that BPA could generally set rates in accordance with its opinion and BPA's governing statutes.

In the three inapposite cases cited by PPC (apart from *General Dynamics Corp.*, which only raised the issue in a footnote because it did not apply to the facts considered), an agency tried to avoid implementing an ordered remedy after admitting liability for employment discrimination. An employment discrimination hearing is inapposite to BPA's ratemaking proceedings. Furthermore, the *Diamond v. Roskens* case relied upon by PPC is no longer good law because after it was issued by the D.C. District Court, it was reversed by the D.C. Court of Appeals in *Diamond v. Atwood*, 43 F.3d 1538 (D.C. Cir. 1995). In its reversal order, the Court of Appeals pointed out that:

> the relitigation of findings contained in a final agency or EEOC order "would require an employee who has successfully invoked an administrative scheme designed to remedy discrimination to prove his or her entire case again in deferral court when the agency refuses to take the ordered corrective action. The result would undercut the utility of administrative dispute resolution."

Id at 1541 (quoting *Moore v. Devine*, 780 F.2d 1559, 1563 (11th Cir. 1986)).

The principle from *Diamond v. Roskens* and the other estoppel principles relied upon by PPC apply in the narrow context of employment discrimination complaints that have been accepted as true in a final agency adjudicatory decision. *Id.* In line with the reasoning from the Eleventh Circuit quoted above, the D.C. Circuit has reasoned that the principle properly applies when an agency has made an administrative ruling that it is liable for employment discrimination in order to protect the employee from the burden of relitigating the issue. *Scott v. Johanns*, 409 F.3d 466, 470 (D.C. Cir. 2005). Indeed, the D.C. Circuit Court of Appeals has recently failed to extend this principle even to other Title VII employment discrimination complaints, namely, complaints where an agency makes a finding of no discrimination. *Id.* at 469. BPA's WP-02 rate case was an administrative ratemaking and rulemaking proceeding, not an administrative adjudication or dispute resolution. BPA did not admit liability for any improper conduct in its initial WP-02 rate case, so the principle applicable to employment discrimination adjudications that PPC relies upon does not apply to BPA's present proceeding.

PPC further claims that BPA's ratemaking proceedings, although they may be characterized as rulemaking proceedings, are sufficiently formal (*e.g.* cross-examination, testimony, briefing) to preclude a re-determination of the 7(b)(2) rate ceiling BPA determined in the WP-02 case. *Id*. First, BPA's ratemaking proceedings are not simply characterized as rulemaking proceedings, they *are* rulemaking proceedings. *See U.S. v. Tex-La Elec. Co-op., Inc*., 693 F.2d 392, 401 n.12 (5th Cir. 1982) ("ratemaking is rulemaking"). Second, PPC again relies on an inappropriate analogy to an adjudication of an employment dispute. In *Astoria Federal Savings and Loan v. Solimino*, the Supreme Court stated that application of *res judicata* to factual determinations made by an agency will depend upon the context of the proceedings: "Although administrative estoppel is favored as a matter of general policy, its suitability may vary according to the specific context of the rights at stake, the power of the agency, and the relative adequacy of agency procedures." *Astoria*, 501 U.S. 104, 109-110 (1991). The Court determined that the application of preclusion to administrative determinations depends upon "whether a common-law rule of preclusion would be consistent with Congress' intent in enacting the statute." *Id.* at 110. Significantly, BPA's WP-07 Supplemental Proceeding is being held in response to a remand from the Court. BPA is determining the best manner in which to reimburse its preference customers from previous overcharges in their rates. As noted above, in order to do so, BPA must place itself at the time it was developing its supplemental WP-02 rate proposal. In the absence of the REP Settlement Agreements the Court found unlawful in *PGE*, when critical factual conditions related to BPA's ratemaking changed dramatically and it became apparent that BPA's initial WP-02 base rates were inadequate to recover its costs, BPA would have rerun the 7(b)(2) rate test and established revised base rates to insure the proper implementation of the 7(b)(2) rate test using the new load and market information available at that time. Thus, it would make no sense to apply any preclusive effect to flawed premises, facts or conclusions used in the 7(b)(2) rate test to develop the initial, and fatally flawed, WP-02 base rates.

In addition, Congress intended for BPA to recoup the Federal investment when setting rates. 16 U.S.C. § 825s; 16 U.S.C. § 839e(a)(1). Congress explicitly provided that rate schedules must be designed to recoup the Federal investment, which implies that inadequate rate schedules must be redesigned to do so. Congress also prescribed directives for the establishment of BPA's rates. 16 U.S.C. § 839e. BPA's statutory mandates and supporting legislative history include no implications that common law rules of preclusion should apply to BPA's ratemaking. Quite the opposite, BPA's governing statutes reflect Congressional intent that BPA *should* modify its rates when necessary, which is evinced by the requirement that BPA periodically review and revise its rates if necessary to recover costs. Accordingly, PPC's suggestion that BPA's WP-02 fatally flawed determinations have preclusive effect is misplaced. BPA should not be precluded from reexamining the validity of WP-02 ratemaking decisions that are necessary to properly establish rates in the WP-07 Lookback proceeding in circumstances where the Court's finding, that the REP Settlement Agreements were unlawful, has a direct effect on the manner in which BPA would have developed its WP-02 rates.

Finally, PPC asserts that the fact that an agency is the party seeking to revisit its prior determination does not grant it broader latitude to revisit them. PPC Br. Ex., WP-07-R-PP-01, at 20. First, BPA is not the party seeking to revisit its WP-02 rates. Instead, BPA is doing so upon direction from the Court. Further, as noted above, the proposition from *Diamond v.*

Roskens relied upon by PPC is applicable to agency employment dispute resolution proceedings and is inapposite to BPA's present remanded ratemaking proceeding. Also, the *Diamond* case relied upon by PPC was reversed by the D.C. Court of Appeals. *Diamond v. Atwood*, 43 F.3d 1538 (D.C. Cir. 1995).

PPC notes BPA's recognition in the Draft ROD that it must re-open its WP-02 rate test determinations because "the WP-02 rate proceeding record lacks essential ASC information for BPA to determine the amount of REP benefits that would have been paid to the IOUs but for the REP settlements." PPC Br. Ex., WP-07-R-PP-01, at 20. PPC argues this is not persuasive because the rate test is unaffected by ASC filing information—a point demonstrated by the law as well as the fact that BPA indeed ran the fully litigated rate test in the WP-02 proceeding without the IOUs' ASC filings. *Id*. PPC's argument is not persuasive to any knowledgeable examiner. As established in the WP-07 Supplemental Proceeding, BPA forecasted exchanging utilities' ASCs in its initial WP-02 rate case, which was needed in part to implement the 7(b)(2) rate test. PPC's claim that the 7(b)(2) rate test is unaffected by ASC information is incorrect. This is demonstrated by section 7(b)(2) itself. Section 7(b)(2), as noted previously, compares a set of costs of serving preference customers called the Program Case (which is based on all Northwest Power Act provisions being used in the development of such costs) with the 7(b)(2) Case (which is developed using five assumptions regarding the Act). One of the assumptions required by section 7(b)(2) is that the REP is assumed to exist in the Program Case and is assumed *not* to exist in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2)(C). The costs of the REP in the Program Case, and the costs that are absent from the 7(b)(2) Case, can only be determined using ASC information. In the 1980s and 1990s, exchanging utilities submitted ASC filings to BPA and BPA applied the ASC Methodology to determine the utilities' ASCs. When the REP was being implemented, it was relatively easy to forecast utilities' ASCs for ratemaking purposes based on their recent ASC reports. Because BPA entered into REP settlements with exchanging preference customers and IOUs in the mid-1990s, BPA did not implement the REP and BPA could no longer use current ASC determinations for its rate case forecasts. BPA therefore had to forecast ASCs using the best manner it could determine. In some circumstances, BPA could escalate relatively recent ASC determinations. For other circumstances, BPA had to develop a forecasting model that would forecast utilities' ASCs using recent cost information for each respective utility. In any event, however, ASC information has *always* been critical to conducting the 7(b)(2) rate test. As noted previously, BPA's initial WP-02 base rates, and the 7(b)(2) rate test on which they were based, were fatally flawed because they were developed just before tremendous changes in BPA's load obligations and market prices for power. Because BPA simply adopted CRACs in its supplemental WP-02 rate case to ensure its rates would recover its costs, the flawed WP-02 7(b)(2) rate test did not contain a forecast of REP costs that reflected the radical changes in the market. Higher market prices have a direct effect on utilities' ASCs. In order for BPA to reasonably determine a revised PF-02 PF Exchange base rate, BPA had to rerun the section 7(b)(2) rate test using information available at the time BPA developed its supplemental WP-02 rate proposal. This allows BPA to determine the REP benefits the IOUs would have received in the absence of the REP Settlement Agreements.

PPC argues that BPA must limit its re-considerations on remand to those issues that the court addressed, *i.e.* the effect of the 7(b)(2) calculation on the preference customers' rates. PPC Br. Ex., WP-07-R-PP-01, at 20. *See* APAC Br. Ex., WP-07-R-AP-01, at 10. PPC claims that to do otherwise is an impermissible retraction of an agency's final determination, and would be unfair to the parties that litigated the WP-02 proceeding. *Id*. In response, BPA is addressing only the issues the Court addressed. The Court determined that BPA's REP Settlement Agreements were unlawful and that BPA improperly allocated REP Settlement Agreement costs to the PF Preference rate. In order to remedy these errors, BPA must determine the amount of the REP Settlement Agreement benefits the IOUs received, compare it with the amount of REP benefits the IOUs would have received during the same period if they had participated in the REP instead of the settlements, and return the difference to BPA's preference customers. It would be unreasonable for any party to argue that in the absence of the REP Settlement Agreements, the IOUs would have failed to participate in the REP and thereby forego hundreds of millions of dollars of rate relief for their residential and small farm consumers. PPC, however, wants BPA to use the flawed WP-02 7(b)(2) rate test that was conducted with inaccurate information when compared to the time of BPA's supplemental WP-02 rate proposal. PPC characterizes BPA as retracting a final determination, when in fact BPA is responding to the Court to correct the unlawful determinations BPA made in the REP Settlement Agreements and WP-02 rates.

PPC also states BPA's response to the Court's remand would also result in an "end-run" by the agency around both the safeguards provided in the Northwest Power Act, which require challenges to final agency actions to be filed within 90 days, and the Ninth Circuit's remand. PPC Br. Ex., WP-07-R-PP-01, at 21. Although characterizing BPA's actions as an "end run" may be dramatic and convey a sense of impropriety, knowledgeable reviewers will look at the facts and the law in evaluating PPC's argument. PPC essentially argues that the BPA should be required to use only the fatally flawed section 7(b)(2) rate test and WP-02 base rates in responding to the Court's remand. BPA has explained why this would be unreasonable, inequitable and likely unlawful. Further, BPA has explained how it has directly responded to the Court's remand, and done so in a manner that does not constitute an "end run" in any rational world. In addition, responding to a remand does nothing to violate the requirement that parties must challenge BPA's final actions under the Northwest Power Act within 90 days. Parties had the opportunity to challenge BPA's REP Settlement Agreements and WP-02 rate within 90 days and did so. This is what created the Court's remand. In the event any party believes BPA's response to the remand is unlawful, such party is free to file a petition for review within 90 days after FERC's final approval of BPA's WP-07 rates. There is, again, no "end run" of any statutory requirements.

PPC states that although BPA appears to acknowledge that it would be problematic to retroactively apply a new agency regulation, such as the Average System Cost Methodology, it does not put a similar limitation on its new 7(b)(2) Implementation Methodology. PPC Br. Ex., WP-07-R-PP-01, at 21. *See* APAC Br. Ex., WP-07-R-AP-01, at 26; WPAG Br. Ex., WP-07-R-WA-01, at 11. PPC claims that while not admitting that it is "retroactively applying" its new methodology to the 2002-2006 period, BPA is proposing to conduct the rate test for that period using the same rules that it proposes in its new methodology. *Id*. PPC has badly mischaracterized BPA's positions. BPA is not using its new Implementation Methodology retroactively or using the same rules that it proposes in the new Implementation Methodology to conduct the rate test to determine the WP-02 PF Exchange rate. BPA has previously explained this at length, yet PPC ignores the record and insists on continuing its mischaracterization. *See* Section 16.10. In summary terms, BPA's new Implementation Methodology only applies prospectively to BPA's development of its FY 2009 power rates. BPA has not applied it for purposes of conducting the rate test for the Lookback Analysis. Indeed, if BPA had applied the new Implementation Methodology to the development of the PF Exchange base rate, the rate would have turned out significantly different than using the 1984 Implementation Methodology, as BPA did, because BPA made a number of changes in the 2008 Methodology that are not contained in the 1984 Implementation Methodology BPA used for the Lookback. *Cf*. 1984 Implementation Methodology and 2008 Implementation Methodology.

As noted previously, the initial WP-02 7(b)(2) rate test was fatally flawed due to its failure to reflect dramatic changes in BPA's loads and market prices for power. In conducting the rate test with new load and market price information available at the time of BPA's supplemental WP-02 proceeding, BPA would have determined that the FBS was insufficient to meet 7(b)(2) Customers' loads in the 7(b)(2) Case. Therefore, unlike BPA's initial WP-02 rate case, BPA would have had to decide whether Mid-Columbia resources dedicated to loads by preference customers and IOUs should be excluded from the rate test in a context where BPA's determination of that issue would actually affect the development of BPA's rates. Staff therefore proposed what it would have done in such circumstances. BPA's Legal Interpretation and Implementation Methodology are not set in stone. BPA can change its Legal Interpretation and Implementation Methodology in any general BPA power rate proceeding. The existence of the 1984 Legal Interpretation and 1984 Implementation Methodology therefore would not have controlled BPA's implementation of the rate test in the WP-02 rate case if BPA determined the Legal Interpretation and Implementation Methodology were flawed and should be corrected. Because this would be the first time BPA's Mid-Columbia resource determination would affect BPA's rates, BPA would have conducted an extremely thorough legal examination of the issue. BPA knew the DSIs argued in the WP-02 rate case that the plain language of section 7(b)(2) provides that resources "committed to load pursuant to section 5(b)," which expressly include resources committed by preference customers *and IOUs* (16 U.S.C. § 839c(b)(1)), could not be included in the resource stack. The DSIs' plain-language argument had no readily apparent rebuttal.

Thus, in a proceeding where BPA must calculate the REP benefits IOUs would have received during FY 2002-08 in the absence of the REP Settlement Agreements, BPA is reviewing how BPA would have conducted the section 7(b)(2) rate test. This has to done because the initial WP-02 rates were developed in circumstances that changed almost immediately, rendering the initial rates unable to recover BPA's costs, as required by law. In reviewing the DSIs' argument, BPA would have concluded that it would have to change its Legal Interpretation and Implementation Methodology in the WP-02 rate case in order to comply with the plain language of section 7(b)(2). Thus, BPA is not retroactively applying its new Legal Interpretation or Implementation Methodology, which contain numerous changes from their 1984 counterparts. Instead, BPA is noting that BPA's legal determination regarding the exclusion of the IOUs' dedicated Mid-Columbia resources from the resource stack, raised in the first instance by the DSIs in BPA's initial WP-02 rate case but rendered moot, would have become ripe based on the changed load and market price conditions known during the WP-02 supplemental proceeding and would have been decided in accordance with the plain language of section 7(b)(2).

PPC's mischaracterizations extend also to the mischaracterization of Staff's testimony. PPC quotes BPA's witnesses during cross-examination:

> *Q. And ... during the lookback period, you proposed applying the new methodology ... in order to determine correct 7(b)(2) results during the lookback period?*
>
> A. I wouldn't phrase it quite like that. I wouldn't say that we are proposing to implement the new methodology in the lookback. I would say that the methodology that we are proposing for the lookback period comes to the same conclusion as the proposed methodology. But we are proposing a different resolution of issues under the 1984 methodology than is explicitly stated therein.

PPC Br. Ex., WP-07-R-PP-01, at 21. PPC states there is no distinction between applying an old methodology to past determinations with modifications that make it essentially identical to a new methodology, and applying a new methodology to past determinations. *Id*. As noted previously, however, *BPA simply did not amend the 1984 Implementation Methodology to be essentially identical to the 2008 Implementation Methodology*. Furthermore, as is apparent from the cited testimony, BPA's witnesses stated they were *not* applying the new Implementation Methodology to the Lookback period. Staff's testimony also points out that, as previously explained, BPA assumes it would have made *one* change to the 1984 Implementation Methodology when using it in the spring/winter of 2000/2001 to develop a revised WP-02 base PF Exchange rate for the Lookback period. That change concerns the need to comply with the express language of the Northwest Power Act with regard to an issue that was moot in BPA's initial WP-02 proceeding but was ripe in the Lookback when BPA reflected the factual changes in loads and market prices that occurred at the time BPA developed its supplemental WP-02 proposal. As Staff's testimony correctly notes, the one change assumed in the 1984 Implementation Methodology for the Lookback period is, not surprisingly, continued in BPA's 2008 Implementation Methodology, which logically continues what BPA would have revised in the immediately previous WP-02 rate proceeding to establish a proper WP-02 PF Exchange rate. BPA's testimony concludes by noting that because BPA was proposing a change to the 1984 Implementation Methodology, BPA's proposal was different than if the 1984 Implementation Methodology were applied without the correction.

WPAG notes the manner in which BPA established the 1984 Implementation Methodology, which was in a section 7(i) hearing preceding BPA's 1985 rate case. WPAG Br. Ex., WP-07-R-WA-01, at 11-12. BPA fails to mention that BPA did not establish its 1984 Legal Interpretation in a section 7(i) hearing, but rather in a simple notice and comment process. WPAG argues BPA's recognition that it can change its Implementation Methodology in a section 7(i) hearing is "an unprecedented departure" from BPA's "accepted practice" of revising the regulations. *Id*. WPAG's argument, although certainly dramatic, is extremely weak. First, section 7(b)(2) of the Northwest Power Act was first implemented in BPA's 1985 rate case. Because BPA needed to develop a formal legal interpretation of section 7(b)(2) and a methodology of how to implement the rate test before it ran the rate test for the first time and established its 1985 rates, and because this was an issue of first impression, BPA decided to establish these items before the 1985 section 7(i) rate hearing started. This was also done in recognition that, once established, future revisions would not require separate processes because subsequent revisions would not have to revisit the entire development of the Legal Interpretation and Implementation Methodology from scratch. BPA established the Legal Interpretation in a simple notice and comment process. Because the Implementation Methodology was considered closely related to ratemaking, BPA established the Implementation Methodology in an abbreviated section 7(i) hearing. BPA then used them in establishing BPA's 1985 rates. Until the current rate case, the Legal Interpretation and Implementation Methodology were not revised, due in large part that BPA executed REP settlements in the 1980s and 1990s with exchanging preference customers and IOUs. Thus, BPA does not have an often-used "accepted practice" for establishing the Legal Interpretation other than a simple notice and comment process. Indeed, BPA has exceeded the process provided for the establishment of the 1984 Legal Interpretation by including the proposed revised Legal Interpretation in BPA's initial WP-07 Supplemental Proposal, thereby allowing parties to review it during the entire section 7(i) hearing and to address it in legal memoranda filed with their direct and rebuttal cases, as well as in their initial briefs and briefs on exceptions. BPA has essentially equaled the process provided for the establishment of the 1984 Implementation Methodology by including the proposed revised Implementation Methodology in BPA's initial Supplemental Proposal, allowing it to be reviewed throughout the section 7(i) hearing. Indeed, instead of establishing the Implementation Methodology from scratch, BPA proposed only limited substantive changes to the Implementation Methodology, which remains largely the same. In summary, BPA can revise its Implementation Methodology in a section 7(i) hearing, and doing so can hardly be called an "unprecedented departure."

WPAG argues that BPA has elected to not reopen the WP-02 rates and not reopen the WP-02 docket or administrative record. WPAG, Br. Ex., WP-07-R-WA-01, at 12. WPAG argues, as a consequence, there is no section 7(i) rate proceeding applicable to the WP-02 rates in which to modify the 1984 Legal Interpretation and Implementation Methodology as it applies to those rates. *Id*. WPAG's argument is based on a misunderstanding of BPA's WP-07 Supplemental Proceeding. BPA is not reestablishing BPA's WP-02 rates. BPA is responding to a remand of BPA's WP-02 rates from the Ninth Circuit, which found such rates unlawful, and must respond to that remand by giving effect to the Court's decisions in *PGE* and *Golden NW*. BPA has previously explained at length how it is responding to the remand. In summary, BPA is determining the amount of the unlawful REP Settlement Agreement benefits that were provided to the IOUs. BPA is then determining the amount of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements, because the IOUs would have participated in the REP in the absence of those Agreements. The difference between the two is then refunded to preference customers. This comprises a fair, reasonable and complete satisfaction of the Court's remand. In order to determine the REP benefits the IOUs would have received under the REP, however, BPA must determine what BPA's PF Exchange rate would have been. In order to determine the PF Exchange rate, BPA would have to include the costs it had to recover from its WP-02 power rates, then conduct the section 7(b)(2) rate test. The base rates established in the initial WP-02 ROD, including the PF Exchange rate, were based on costs that became inaccurate shortly after the base rates were released. BPA filed a motion to stay FERC's review of BPA's initial WP-02 base rates in order that BPA could reopen the WP-02 proceeding and revise the rates to ensure they recovered BPA's total costs and could be approved by FERC. Due to circumstances at the time, BPA decided to adopt CRACs and not revise base rates. In the absence of the REP Settlement Agreements, however, and as explained elsewhere, BPA would have rerun the 7(b)(2) rate test with the updated information and developed a new PF Exchange rate. Because of the updated information, certain issues that were moot under the previous load and market price data became issues that had to be addressed by BPA. In the initial WP-02 rate case, BPA's DSI customers argued that BPA was not properly applying the law regarding resources used to meet preference loads in the 7(b)(2) Case, because section 7(b)(2)(D)(ii) of the Northwest Power Act only includes (ignoring section 7(b)(2)(D)(i) for the moment) those resources "not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D)(ii). Section 5(b)(1) expressly provides that both preference customers and IOUs dedicate resources to their loads under section 5(b):

> Whenever requested, the Administrator shall offer to sell *to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and <u>to each requesting investor-owned utility electric power</u> to meet the firm power load of such public body, cooperative or investor-owned utility in the Region* to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1) (emphasis added). Because section 5(b) applies to requirements determinations for both preference customers *and* investor-owned utilities, section 7(b)(2)(D)(ii) precludes BPA from including resources owned or purchased by 7(b)(2) Customers in the 7(b)(2) Case resource stack if such resources are committed to load by preference customers *or* investor-owned utilities. This is the plain meaning of the statutory language. When this issue became ripe in determining the PF Exchange rate that would have existed in the absence of the REP Settlement Agreements, BPA had to address it. BPA concluded it could not ignore the law and would have revised its Legal Interpretation and Implementation Methodology in a supplemental WP-02 hearing to revise base rates in order to allow BPA to correctly apply the law and properly conduct the 7(b)(2) rate test. Thus, in the context of a remand of BPA's WP-02 rates, the assumed revision to the 1984 Legal Interpretation and Implementation Methodology occurs in the current section 7(i) WP-07 Supplemental Proceeding.

PPC states BPA responds in the Draft ROD by stating that the IOUs did not have a "full and fair opportunity" to litigate rate test issues in the past proceedings. PPC Br. Ex., WP-07-R-PP-01, at 22. BPA readily acknowledges that the IOUs litigated the PF Exchange rate and section 7(b)(2) issues in the May 2000 proposal, but notes that "they did not have a similar opportunity to challenge the PF Exchange Rate and 7(b)(2) in the subsequent WP-02 Supplemental rate proceeding." *Id*. This is because, with signed REP Settlement Agreements with the IOUs and the knowledge that the 7(b)(2) rate test would not affect the IOUs' consumers' benefits under the settlements, BPA decided to adopt CRACs to correct the inability of the initial WP-02 base rates to recover BPA's costs. With the adoption of CRACs, it was unnecessary to run the 7(b)(2) rate test.

PPC notes that in response to testimony by PPC and WPAG concerning BPA's improper analysis of the Mid-Columbia resources even under its own methodology, BPA conducted further analyses of the availability of those resources in the 7(b)(2) Case and concluded that certain portions of those resources should have been deemed available to serve preference customer loads. PPC Br. Ex., WP-07-R-PP-01, at 22. PPC states BPA has proposed to implement these changes in its analysis of FY 2009 rates, but it is unclear whether BPA has affirmatively committed to correcting its error for past periods under its proposed re-creation of past 7(b)(2) rate tests. *Id*. In response, BPA affirms that it will reflect the identified portions of Mid-Columbia resources in its 7(b)(2) rate test for FY 2002-2008.

Decision

BPA will include preference customer-owned resources in the 7(b)(2) Case resource stack only if they are not committed to load by preference customers or IOUs pursuant to contracts under section 5(b) of the Northwest Power Act.

16.11 Slice Surplus Power in the Section 7(b)(2) Rate Test

Issue 1

Whether BPA properly reflects sales of surplus power associated with the Slice product in performing the section 7(b)(2) rate test.

Parties' Positions

The IOUs note BPA assumes, in performing the section 7(b)(2) rate test, that it sells, at market rates, surplus power associated with the Slice product when, in fact, BPA is selling the same power to Slice customers under the Slice rate. IOU Br., WP-07-B-JP6-01, at 4. The IOUs contend BPA then reverses this assumption after performing the section 7(b)(2) rate test and allocating any section 7(b)(2) trigger amount. *Id*. The IOUs argue the reasons for making and reversing this assumption are not adequately explained by BPA. *Id*. BPA should explain any necessity for, and the consequences of, any such proposed treatment. *Id*.

BPA Staff's Position

BPA Staff states that all surplus sales should be reflected in the section 7(b)(2) rate test. Doubleday, *et al.*, WP-07-E-BPA-85, at 155-158. There is no difference in the section 7(b)(2) rate test regardless of whether BPA assumes the sale of surplus power is to the market or to the Slice customers. *Id.* BPA receives the same amount of forecast revenue whether the surplus is sold in the market and credited to rates or sold to the Slice customers at the Slice rate. *Id.*

Evaluation of Positions

The IOUs argue that BPA assumes, in performing the section 7(b)(2) rate test, that it sells, at market rates, surplus power associated with the Slice product when, in fact, BPA is selling the same power to Slice customers under the Slice rate. IOU Br., WP-07-B-JP6-01, at 88, *citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 23, Table 2.5.3; Brodie, *et al.*, WP-07-E-BPA-70, at 12-13. The IOUs claim BPA then reverses this assumption after performing the section 7(b)(2) rate test and allocating any section 7(b)(2) trigger amount. *Id.*, *citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 31, Table 2.6. The IOUs argue the reasons for making and reversing this assumption are not adequately explained by BPA, and BPA should explain any necessity for, and the consequences of, any such proposed treatment. *Id.*

In the Final Proposal, Staff used only the non-Slice portion (77.37 percent) of the secondary energy produced by the Federal Columbia River Power System (FCRPS) in the calculation of rates. Doubleday, *et al.*, WP-07-E-BPA-85, at 155. The non-Slice portion is the amount of forecast revenue from the sale of 77.37 percent of the FCRPS secondary energy in the West Coast electric markets. *Id.* In addition to these sales, the other 22.63 percent of the secondary produced by the FCRPS is sold as a part of the Slice product at the PF Slice rate. *Id.* at 155-156. In the Supplemental Proposal, Staff proposed using revenues as if all of the secondary energy produced by the FCRPS was sold in the electric markets in the calculation of rates in the Rate Design Step ratemaking. *Id.* at 156.

In the Rate Design Step, the PF rate pool includes the firm portion of the Slice product sales; it does not include the surplus portion. *Id.* Therefore, it is more proper from a general ratemaking perspective to include the total secondary revenue credit produced by the FCRPS in the rate pool that is paying the costs of the FCRPS at this point in the ratemaking process, the total PF rate pool. *Id.* After the Rate Design Step, in the Slice Separation Step, the Slice product, costs, loads, and secondary revenue credit are removed from the PF Preference load pool to produce the non-Slice PF Preference rate. *Id.*

The IOUs may assume BPA is receiving a different amount of revenue for the surplus sold to Slice customers. *Id.* It is true that the surplus is sold to Slice customers at the Slice rate. *Id.* It is also true that the Slice rate appears to be lower than the forecast market rate that BPA assumes for the sales of the remaining surplus. *Id.* But focusing on rates diverts one from the pertinent question: what are the revenues to BPA from the two sales? *Id.* at 156-157. In the rate setting process, it does not matter whether BPA is assuming the surplus is sold in the market or to Slice customers. *Id.* at 157. In either case, BPA is realizing the same amount of revenue from the surplus. *Id.* Even though BPA is selling the surplus to the Slice customers at the Slice rate, BPA is realizing the same amount of revenue within the rate setting process because the Slice customers receive no secondary revenue credits. *Id.*

The apparent difference arises from the difference between the amount of surplus sales that produce the secondary revenue credit and the amount of sales at the Slice rate. In the Supplemental Proposal, the total revenue expected from secondary sales is $743,968,000, including surplus sales to Slice purchasers. Supplemental WPRDS Documentation, WP-07-E-BPA-49A, at 23. This revenue is the same as if all secondary generation is sold in the market. The Slice portion of this, 22.63 percent, is $168,344,000. *Id.* at 31. This amount is removed from the secondary revenue credit included in the PF Preference rate for non-Slice customers. The amount remaining as the secondary revenue credit for the non-Slice customers is

$575,624,000. The expected sales of secondary energy are 1,732 aMW. *Id*. at 63. The secondary sales are valued at an average of $37.9/MWh. However, the $168 million of the secondary revenue credit is not reflected in the Slice rate. As a result, the Slice rate will recover the $168 million on an expected basis. Slice sales are expected to be 2,164 aMW. *Id*. at 63. Dividing the $168 million by the 2,164 aMW yields a rate of $8.8/MWh, the amount that the Slice rate exceeds the non-Slice PF Preference rate. Thus, although the expected market rate and the Slice rate are markedly different, they both recover the expected market value of the surplus sales.

The development of the Slice rate is such that the Slice customers are paying the weighted average of the firm rate for the firm power sales and the forecast market rate for the surplus sales. Doubleday, *et al.*, WP-07-E-BPA-85, at 158. BPA notes that it receives the revenue from the Slice customers at the forecast market rate for the forecast surplus sale whether or not the surplus is generated in actual operations. *Id*. Therefore, there is no difference in the section 7(b)(2) rate test regardless of whether BPA assumes the sale of surplus power is at the market rate or at the Slice rate. *Id*.

Decision

BPA properly reflects sales of surplus power associated with the Slice product in the section 7(b)(2) rate test.

16.12 DSI Service Benefits and Load Reduction Agreement Costs

Issue 1

Whether BPA should include DSI service benefit costs, or an amount of load reflecting the DSI service monetary benefits, in the 7(b)(2) Case and include the 17 aMW BPA sale to the Port Townsend Paper Corporation in the general requirements of PF Preference rate customers in the 7(b)(2) Case.

Parties' Positions

The IOUs argue that DSI service benefits must be treated the same for purposes of determining 7(b)(2) Case costs, regardless of (i) whether the service benefits provided to DSIs are in the form of monetary payments by BPA to the DSIs, (ii) whether the service benefits provided to DSIs are in the form of power sales at the IP or FPS rate, and (iii) whether the service benefits provided to DSIs are in the form of power sold by BPA directly to DSIs or sold by BPA indirectly to DSIs through sales to PF Preference rate customers for resale to DSIs. IOU Br., WP-07-B-JP6-01, at 32.

PPC and WPAG argue that section 7(b)(2)(A) of the Northwest Power Act addresses the assumption that BPA is to make with regard to DSI service. PPC Br., WP-07-B-PP-01, at 46-49; WPAG Br., WP-07-B-WA-01, at 20-21. Section 7(b)(2)(A) states that the Administrator is to assume that "public body and cooperative customers' general requirements had included during such five-year period the [DSI] customer loads which are—(i) served by the Administrator, and (ii) located within or adjacent to [their service territories].” *Id*. at 20, *citing* 16 U.S.C. § 839e(b)(2)(A). Because BPA is not serving DSI loads but instead is providing service benefits, BPA should not allow DSI loads to be included in public agency loads in the 7(b)(2) Case. WPAG Br., WP-07-B-WA-01, at 21.

<u>BPA Staff's Position</u>

Because the DSIs have a monetized power sale, BPA Staff believes DSI monetary payments are an alternate form of delivery in lieu of sales of power by BPA to the aluminum DSIs. Doubleday, *et al.*, WP-07-E-BPA-85, at 151. Staff noted BPA would consider how the form of delivery of DSI benefits selected by BPA should be reflected in the 7(b)(2) rate test based on the complete record and recommend a resolution to the Administrator. *Id*.

<u>Evaluation of Positions</u>

A. Background of DSI Service

In order to provide context to the discussion of DSI service, the Administrator takes official notice of two previous BPA Records of Decision: “BPA's Service to DSI Customers for FY 2007-2011, Administrator's Record of Decision” (Final ROD), issued June 30, 2005, and “Supplement to Administrator's ROD on BPA Service to DSI Customers for FY 2007-2011” (Supplemental ROD), issued May 31, 2006.

Beginning in July 2004, BPA initiated the Regional Dialogue public process as part of its effort, in cooperation with its customers and constituents, to identify and decide issues regarding BPA's power supply role for FY 2007-2011. *See Bonneville Power Administration's Policy Proposal for Power Supply Role for Fiscal Years 2007-2011,* issued July 7, 2004. BPA service to the DSIs has been steadily declining since the pre-1995 period, when contracts totaled over 3,000 aMW, to 1995, when contracts were reduced to 2,000 aMW, to 2002, when contracts were reduced to 1,500 aMW. Over the same period, BPA service to public utilities has grown significantly. Among the issues presented by BPA was whether it should continue the steady ramp-down of service to its DSI customers when existing power supply contracts with those customers expired on September 30, 2006, or whether to eliminate further service. BPA proposed providing up to 500 aMW of service (cumulative) to creditworthy DSIs, at a known and capped cost, where such service would enable continued operation of DSI facilities, thereby maintaining Pacific Northwest jobs.

BPA indicated that, in order to eliminate the market and default risks to BPA associated with a traditional “take-or-pay” physical power sales contract, and to meet the known and capped cost prerequisite for DSI service, its preferred alternative was to provide service benefits to the DSIs financially, by cashing out, or monetizing, the value of a power sales contract in lieu of physically delivering power. BPA also indicated it believed it was unlikely that service to the DSIs under the Industrial Firm Power (IP) rate schedule would provide a rate low enough to support economic operation by DSI customers that use BPA power to smelt aluminum. The aluminum smelters would make up over 95 percent of BPA's DSI load under a 500 aMW scenario. The proposal to provide 500 aMW of service benefits to the DSIs represented a continuation in the ramping-down of BPA's role as a supplier of power service to the DSIs.

The culmination of the first phase of the Regional Dialogue process was the Policy for Power Supply Role for Fiscal Years 2007-2011, Administrator's Record of Decision (February 4, 2005). In the ROD, BPA decided that for the 2007-2011 period it would continue the ramp-down in DSI service by providing eligible DSI customers some level of service benefits, at a known quantity and capped cost, at rates no lower than rates paid by BPA's public preference customers, and under contractual terms no better than those offered to other customers. However, in order to provide an opportunity for additional dialogue with (and among) customers, in the hope of achieving a possible consensus for a balanced and durable solution for BPA service to the DSIs, the ROD reserved for later decision: (1) the actual level of service benefits it would provide; (2) the eligibility criteria it would apply in determining which DSIs would qualify for such service benefits; and (3) the mechanism or mechanisms it would use to deliver those service benefits. BPA's resolution of these issues was addressed in "BPA's Service to DSI Customers for FY 2007-2011, Administrator's Record of Decision" (Final ROD), issued June 30, 2005.

The Final ROD concluded that BPA would offer the DSI aluminum smelters 560 aMW of service benefits for the FY 2007-2011 period at a capped cost of $59 million per year. BPA would offer Port Townsend Paper Company 17 aMW of service benefits through its local utility at a rate approximately equivalent to, but in no case lower than, the PF rate. BPA was to review its decision to supply 560 aMW of benefits at a $59 million capped cost to the aluminum companies for FY 2007-2011 after the cost impact of a June 10, 2005, injunction on river operations became more clear and before final contracts with the DSIs were signed. A decision to reduce the amount of service benefits BPA would have provided to the aluminum companies, up to and including a decision not to serve any aluminum smelter load, was possible.

As indicated, the Final ROD concluded BPA would make 560 aMW of benefits available for the aluminum smelters and 17 aMW for Port Townsend. This was accomplished through a secondary surplus power sales contract priced in a manner that, when monetized relative to expected market value, resulted in an equivalent financial value of up to $12/MWh for the smelters. This would be the default mechanism for delivery of service benefits to the aluminum companies for FY 2007-2011. The contract contains a right for BPA to provide physically delivered surplus power in lieu of the financial transaction, if BPA determines it can completely remove all risk associated with market power purchases to serve the contract load at or below the $59 million annual cap. The sales are made under BPA's surplus rate schedule. BPA would attempt to structure any physically delivered surplus power sale, or its financial equivalent, through the local utility whose service territory includes a smelter to be served.

In a "Supplement to Administrator's ROD on BPA Service to DSI Customers for FY 2007-2011" (Supplemental ROD) issued May 31, 2006, BPA concluded that while the costs of changes to hydro operations had impacted BPA's revenues, BPA concluded in the PFR II process that these costs were not enough to require a change in the balance originally proposed on benefit levels, and that the maximum benefit level should remain at $59 million per year. Consistent with its decision in the DSI ROD, BPA would not provide benefits that bring the

DSIs' power costs below the Priority Firm Power rate, and BPA would administer the contracts and adjust the benefits provided so that the effective power price paid by the DSIs does not drop below the Priority Firm Power rate.

In addition, the Supplemental ROD concluded that BPA would exercise its option to physically deliver power under the contract (unless the company has exercised its option to lock in the contract market price) only where any credit (default) risks associated with providing a physical supply to a company have been addressed, and where BPA could supply a company's load, including locking down any necessary market supplied purchases, on a fully hedged basis at a cost at or below the cost cap. Prior to exercising its option (if available), BPA would conduct a public process. The purpose of the public process would be to explain why BPA wants to exercise the option, and how the transaction can be executed such that the cost to BPA would be within the capped cost levels established in the DSI ROD.

BPA executed power sales contracts with each of the following three aluminum DSIs and their Public Utility Partners: Block Power Sales Agreement between BPA, Columbia Falls Aluminum Company, and Flathead Electric Cooperative, Contract No. 06PB-11745, dated June 14, 2006 ("CFAC Contract"); Block Power Sales Agreement between BPA, Alcoa, and Public Utility District No. 1 of Whatcom County, Wash., Contract No. 06PB- 11744, dated June 19, 2006 ("Alcoa Contract"); Block Power Sales Agreement between BPA, Golden Northwest Aluminum, and Public Utility District No. 1 of Klickitat County, Wash., Contact No. 06PB-11746, dated June 27, 2006 ("Golden Northwest Contract"). IOU Br., WP-07-B-JP6-01, at 33.

Additionally, BPA executed a contract to sell power for the Port Townsend Paper Corporation plant, a non-aluminum DSI load:

> BPA, Port Townsend and Public Utility District No. 1 of Clallam County, Wash. ("Clallam PUD") executed two separate contracts for power service to Port Townsend rather than executing a single three party contract. On September 13, 2006, BPA and Clallam PUD executed a Surplus Firm Power Sales Agreement and, on the same day, Port Townsend executed a power sales contract with Clallam PUD for surplus firm power service to Port Townsend.

IOU Br., WP-07-B-JP6-01, at 34, *citing* BPA Brief in *Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration*, Nos. 05-75638, 05-75639, 06-73756, 06-74223, 06-74237, 06-74797, and 06-75361 (*PNGC*) at 19. The DSI ROD describes the Port Townsend Paper Corporation load as follows: "BPA's one remaining small non-smelter DSI, Port Townsend Paper's 17 aMW paper mill load." IOU Br., WP-07-B-JP6-01, at 34, *citing* DSI ROD, at 9.

B. DSI Service Benefits in the Supplemental Proposal

Section 7(b)(2) specifies that in determining public body and cooperative customers' power costs during any year after July 1, 1985, and the ensuing four years, the Administrator should assume:

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are --

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …"

16 U.S.C. § 839e(b)(2).

In BPA's initial Supplemental Proposal, the within or adjacent DSI loads were added to the PF sales forecast, but no IP load or rate class was assumed. Keep, *et al.*, WP-07-E-BPA-68, at 19. For the rate period, no direct service to the DSIs was forecast, and BPA Staff did not increase PF load due to DSI service in the 7(b)(2) Case. *Id*. Also, DSI financial benefits were excluded from the 7(b)(2) Case because BPA would not have DSI contracts in the 7(b)(2) Case. *Id*. Staff described BPA's DSI costs of service as follows:

> 9.4.6 DSI Costs of Service
> On June 30, 2005, BPA's Administrator signed the Record of Decision *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million, plus 17 aMW of power to Port Townsend Paper Corporation, for FY 2007-2011. *See* Gustafson, *et al.*, WP-07-E-BPA-17. These costs are included in the Slice Revenue Requirement and will be subject to the annual Slice True-Up. Slice customers will pay their proportionate share of these costs.

Supplemental WPRDS, WP-07-E-BPA-49, at 126.

In rebuttal testimony, Staff reconsidered whether it had properly reflected the DSI service obligations in the 7(b)(2) Case. Staff stated that "[w]e agree that the DSI financial benefits paid by BPA are part of the power costs for the general requirements of public agency customers." Doubleday, *et al.*, WP-07-E-BPA-85, at 152. Staff also noted that "[b]ecause the DSIs have a monetized power sale, we agree that the monetary payments are an alternate form of delivery in lieu of sales of power by BPA to the aluminum DSIs. We will consider whether the form of delivery of DSI benefits selected by BPA should increase the section 7(b)(2) trigger amount or reduce the level of REP benefits based on the complete record and recommend a resolution to the Administrator." *Id*. at 151.

C. Review of Arguments Regarding DSI Service Benefits

As described above, BPA is providing DSI service benefits to the three aluminum DSI loads in the form of financial payments by "cashing out," or monetizing, the value of a power sales contract. The DSI ROD recognizes that sales and delivery of physical power or payment of the monetized value of a power contract are alternative means of delivering service benefits to the DSIs:

> In simplest terms, in addressing this issue BPA must resolve how it can best structure the new contracts to deliver 560 aMW of service benefits to the aluminum smelter DSIs without breaching or creating the possibility of breaching the $59 million annual cost cap. The two primary elements to be considered as part of this structure or "delivery mechanism" are the rate schedule that will be employed, and whether benefits will be delivered as: (1) physical power, or (2) the value of a physical contract monetized, based on its relative market value, and paid to the DSIs. As part of its July 2004 proposal, BPA indicated it was examining offering eligible DSI loads a "defined and limited financial incentive to operate" in place of a traditional physical power sale under the Industrial Firm (IP) rate. BPA stated that in order to implement this mechanism for delivering benefits, in which BPA would pay the DSI the difference between the cost of the DSIs' market power purchases and the cost to BPA of serving the DSIs in the traditional manner, it would need to be assured that the cost impact on other customers was "roughly no greater than if BPA had exercised its discretion to serve the DSI customers" directly with physical power deliveries using the IP rate. BPA noted this approach eliminated the take-or-pay risk associated with a physical power sale for both BPA and the DSIs, while providing additional operating flexibility to the companies, and allowing them to make operating decisions in light of the availability of the financial credit from BPA. BPA's principal goals behind this proposal were to eliminate the inherent risk and cost uncertainty associated with augmenting the Federal system to serve DSI load and to minimize the risk of bad debt even in the case of bankruptcy.

IOU Br., WP-07-B-JP6-01, at 35, *quoting* DSI ROD, at 18-19. The DSI ROD acknowledges that BPA is providing service benefits to the DSIs financially, by cashing out, or monetizing, the value of a power sales contract in lieu of physically delivering power:

> BPA indicated that, in order to eliminate the market and default risks to BPA associated with a traditional "take-or-pay" physical power sales contract, and to meet the known and capped cost prerequisite for DSI service, *its preferred alternative was to provide service benefits to the DSIs financially, by cashing-out, or monetizing, the value of a power sales contract in lieu of physically delivering power.*

Id. at 17-18, *quoting* DSI ROD, at 2 (emphasis added by IOUs).

In the Supplemental Proposal, Staff did not include the costs of service benefits for the aluminum DSIs or the sale of 17 aMW of power for Port Townsend Paper Corporation in 7(b)(2) Case costs in the performance of the section 7(b)(2) rate step for the FY 2009 rate period:

> For the rate period, no direct service to the DSIs has been forecast, therefore there is no addition to PF load due to DSI service in the RAM2007 7(b)(2) Case. Also, DSI financial benefits are excluded from the 7(b)(2) Case because BPA does not have DSI contracts in the 7(b)(2) Case.

IOU Br., WP-07-B-JP6-01, at 36, *quoting* Keep, *et al.*, WP-07-E-BPA-68, at 19. In response to a data request, BPA Staff stated its argument for inclusion of DSI monetary service benefit costs in the Program Case and not in the 7(b)(2) Case as follows:

> In summary, the ratemaking logic supporting [BPA Staff's] decision to include DSI agreement monetary benefits in the Program Case and not in the 7(b)(2) Case is that in the 7(b)(2) Case there is no customer class with which to enter into such an agreement and there is no logical way to allocate "intra-utility" costs to other public body customers.

IOU Br., WP-07-B-JP6-01, at 32, *quoting* Response to Data Request JP6-BPA-27. The IOUs contend this argument rests on an unsupported premise that DSI benefit costs can be included in the 7(b)(2) Case costs if, and only if, such costs would have actually been incurred by a PF Preference rate customer and such customer was actually able to allocate those costs to other PF Preference rate customers. IOU Br., WP-07-B-JP6-01, at 36. The inclusion of the cost of DSI monetary service benefits paid by BPA in the 7(b)(2) Case costs is, under the Northwest Power Act, not conditioned on whether or not the PF Preference rate customer would in fact determine to serve the DSI load and is not conditioned on whether any expenses or costs incurred by the PF Preference rate customer would be shared by other PF Preference rate customers. *Id*. Similarly, the inclusion of the cost of serving a DSI load in the 7(b)(2) Case costs is, under the Act, not conditioned on whether the PF Preference rate customer would in fact determine to serve the DSI load and is not conditioned on whether or not any expenses or costs incurred by the PF Preference rate customer would be shared by other PF Preference rate customers. *Id*. at n. 19.

Nothing in the Act requires that costs in the 7(b)(2) Case be only those costs that may be incurred by a PF Preference rate customer (or incurred by a PF Preference rate customer and allocated to other PF Preference rate customers). *Id*. For example, costs of certain PF Preference rate customer resources are included in the 7(b)(2) Case resource stack and may be drawn from the resource stack and included in the 7(b)(2) Case costs even though, in fact, the costs of that resource are borne solely by the PF Preference rate customer. *Id*. The IOUs' foregoing logic is persuasive.

In the 7(b)(2) Case, BPA is to determine the general requirements (including the costs of serving within and adjacent DSI loads) of PF Preference rate customers. BPA retains the role of serving the general requirements (including the within and adjacent DSI loads) of PF Preference rate customers in the 7(b)(2) Case. *Id.* at 37. Staff's rebuttal testimony agrees that the DSI financial benefits paid by BPA are part of the power costs for the general requirements of public agency customers: "We agree that the DSI financial benefits paid by BPA are part of the power costs for the general requirements of public agency customers." *Id*., *quoting* Doubleday, *et al.*, WP-07-E-BPA-85, at 152. Section 7(b)(2) compares "the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers [as adjusted]," the Program Case rate, with the "power costs for general requirements of such customers [if the Administrator makes five assumptions]," the 7(b)(2) Case rate. 16 U.S.C. § 839e(b)(2). If the costs of DSI service are included in the power costs for the general requirements of public agency customers in the Program Case, the same costs should be reflected in the 7(b)(2) Case. It is true that one of the assumptions in the 7(b)(2) Case is that public agencies' general requirements include "the direct service industrial customer loads which are (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives." *Id*. However, the monetization of an obligation to sell power to the DSIs is properly viewed as a manner of serving DSI loads.

The DSI monetary payments are treated by Staff as an alternate form of delivery of DSI benefits in lieu of sales of power by BPA at IP rates. As noted above, questions of whether a public body customer would enter into a DSI benefit contract or could allocate the costs of such a contract are irrelevant because BPA actually entered into those contracts: monetized power sales contracts to provide DSI benefits. IOU Br., WP-07-B-JP6-01, at 38. For the 7(b)(2) Case, BPA develops a 7(b)(2) Case PF rate. *See* Supplemental Section 7(b)(2) Rate Test Study Documentation, WP-07-E-BPA-50A, at 49. This is the rate at which BPA is assumed in the 7(b)(2) Case to serve the PF Preference rate customer loads, including the within or adjacent DSI loads. *Id*. It is reasonable and appropriate to recognize the monetized power sales contacts for service to DSI loads in the 7(b)(2) Case and to assume that the 7(b)(2) Case PF rate should and would reflect BPA's costs that it incurs under those monetized power sales contacts for service to DSI loads. *See* IOU Br., WP-07-B-JP6-01, at 38. BPA treats the monetary payments as an alternate form of delivery of DSI benefits in lieu of sales of power by BPA at IP rates, and the form of delivery selected by BPA should not bias the 7(b)(2) rate test. *Id*.

Even if it were assumed that the financial benefits were being provided by the individual public agency customer, those costs are still part of power costs for the general requirements of the public agency customers and should be included in 7(b)(2) Case costs. *Id*. Section 7(b)(2) directs the projection of "costs" in the 7(b)(2) Case and does not require that all such costs be allocable among PF Preference rate customers in the form of a "rate" in the 7(b)(2) Case. *Id*. In short, BPA's costs of monetizing the value of DSI power sales contracts should not be excluded from the 7(b)(2) Case on the grounds that a PF Preference rate customer could not or would not have incurred similar costs and could not have allocated them to other PF Preference rate customers. *Id*. at 39.

The three aluminum DSI plants for which BPA provides service benefits pursuant to the three monetized power sales contracts are within or adjacent to BPA preference customers' geographic service territories. *Id*. Further, a preference agency customer is a party to each of the power sales contracts under which BPA is providing the monetized DSI service benefits. *Id*. The three DSI aluminum plants receiving BPA service benefits pursuant to the three monetized power sales contracts are Columbia Falls, Ferndale, and Goldendale. *Id*. These plants are listed as within or adjacent to BPA preference customers' geographic service territories in Appendix B to the Report of the Senate Committee on Energy and Natural Resources, S. Rep. No. 272, 96th Cong., 1st Sess. 66 (1979). *Id*. The Port Townsend Paper Corporation plant must also be considered as meeting the "within or adjacent" test because it is in fact being served by a preference customer (Clallam PUD). *Id*. Staff recognized that the Port Townsend Paper Corporation plant meets the "within or adjacent" test. *Id*.

Monetized DSI service benefits or the use of a BPA power contract to sell surplus power (at the FPS rate) to a preference customer for resale to a DSI should be treated the same as DSI loads in the 7(b)(2) Case. *Id*. at 39-40. Providing monetized DSI service benefits (*e.g.*, the three power sales contracts for aluminum DSIs) and BPA's entering into a power contract to sell surplus power (at the FPS rate) to a preference customer for resale to a DSI (Port Townsend Paper Corporation) – rather than BPA's providing power directly to DSI loads – should not affect the determination of 7(b)(2) Case costs. *Id*. Section 7(b)(2) Case costs should include BPA's costs of providing service benefits to its historic DSI customers. *Id*. at 40. If a DSI is served through a surplus sale to a preference customer, such sale should be treated the same as a direct BPA sale to a DSI load. *Id*. As noted above, in the 7(b)(2) Case the Administrator assumes that

> (A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are – (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …

16 U.S.C. § 839e(b)(2)(A). This language refers to the DSI loads that "are served by the Administrator." Thus, the Act does not distinguish between whether DSI loads are served by power sales at the IP or FPS rate. This is reflected in BPA's Proposed Legal Interpretation and Implementation Methodology, which provide:

> <u>DSI Loads</u>: Those loads of direct service industries (DSI) that are forecast to be served by BPA, during the Five-Year Period, pursuant to sections 5(d)(1) or 5(f) of the Northwest Power Act.

Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachments A and B, at LI-4 and IM-3, respectively.

Under Staff's initial approach to determining the 7(b)(2) Case costs, providing DSI service benefits in monetary form rather than providing an equivalent amount of service to DSIs through direct power sales by BPA has the effect of reducing REP benefits by an amount almost equal to the DSI monetary benefits. IOU Br., WP-07-B-JP6-01, at 40. In other words, Staff's initial approach to determining 7(b)(2) Case costs has the practical effect of imposing virtually the entire cost of the DSI service benefits on the PF Exchange rate. *Id*. The IOUs note Staff's rebuttal testimony suggests that failing to include the cost of the DSI financial benefits in the section 7(b)(2) Case costs does not reduce REP benefits: "because we are further reducing the REP benefits to account for Lookback amounts, there is no reduction in the proposed REP benefits to the IOUs. The IOUs' proposed treatment simply allows the IOUs to repay the Lookback Amount faster." *Id*. at 40-41, *quoting* Doubleday, *et al.*, WP-07-E-BPA-85, at 154. The IOUs note that Staff's argument ignores the fact that, under Staff's proposal, future REP benefits would be greater after the Lookback Amount has been amortized. IOU Br., WP-07-B-JP6-01, at 41. BPA acknowledges this argument has merit.

The IOUs contend the Staff argument also ignores the fact that BPA must correct the treatment of DSI financial benefits in the 7(b)(2) Case costs performed in the Lookback Study for FY 2007-2008. *Id*. In response, however, BPA notes that no party argued in BPA's initial WP-07 rate case that the DSI service benefits should be included in the 7(b)(2) Case for the 7(b)(2) rate test. Therefore, although including DSI service benefit costs in the 7(b)(2) Case is appropriate for FY 2009, it would not be appropriate for FY 2007-2008.

The IOUs cite a Staff analysis using the WP-07 Supplemental RAM model for FY 2009, including market prices, loads and other data and assumptions used in the Supplemental Proposal, indicating that (i) the DSI monetary service benefits are equivalent to about 350 aMW of IP load and (ii) if BPA were to provide benefits to the DSIs through sales of 350 aMW under the IP rate in lieu of DSI monetary benefits, the projected REP benefits would increase from $250 million to about $300 million in FY 2009:

> Unrelated to this proceeding, [BPA Staff] did provide a "DSI Heads Up" analysis at the February 13, 2008 WP-07 Supplemental Proposal and ASC Methodology workshop. The "Heads Up" was developed using the WP-07 Supplemental RAM model for FY 2009, including market prices, loads and other data and assumptions used in the WP-07 Supplemental Proposal. Staff removed the current DSI monetary payments to aluminum smelters and substituted sales at the IP rate. The additional IP load resulted in additional augmentation purchases at forecast market rates. Staff iterated the increased IP load to a solution of an additional net augmentation cost to BPA of $55 to $59 million (*i.e.*, gross augmentation costs minus IP revenue), which was the amount of DSI monetary payments that were removed. This analysis indicated that BPA could sell about 350 aMW to smelter DSIs at the IP rate with no net increase in costs to BPA, without consideration of any associated REP benefit cost increases. The FPS sale to Clallam PUD for Port Townsend Paper service benefits was not changed in this analysis. This analysis also indicated that including 350 aMW of IP load increases REP benefits from $250 million to about $300 million in FY 2009.

Id. at 41-42, *quoting* BPA Response to Data Request JP6-BPA-11. PPC notes the IOUs' citation of the BPA analysis is an argument that BPA should assume, in the alternative, that it is serving the DSIs 350 aMW at the IP rate for purposes of 7(b)(2). PPC Br., WP-07-B-JP25-01, at 48. PPC argues that even if BPA were able to serve the DSIs 350 aMW at the IP rate at a net cost of $55 million, there is no provision of the Act that allows BPA to assume service it is not providing, simply because it estimates it could do so at a cost that equals the expense of an initiative it has undertaken that is not otherwise relevant to its 7(b)(2) Case calculations. *Id.* PPC argues it is important to note that the IOUs rely on a Staff document produced just before the Supplemental Proposal to argue that 350 aMW of DSI service could be an appropriate assumption for the 7(b)(2) Case. *Id.* Staff provided the 350 aMW number in a document that was part of its "No Surprises" workshop, although Staff declined using the figure in its Initial Proposal. *Id.* PPC argues there is no justification for now changing course and including that number in the rate test based simply on the IOUs' recitation of the argument Staff raised before the Supplemental Proposal but rejected at that time. *Id.* at 48-49. In response, PPC has mischaracterized Staff's testimony. On cross-examination, Staff simply noted that it did not include the IOUs' calculation in Staff's proposal. Tr. 333. Staff did not say it declined to do so because it would be inappropriate for any reason. *Id.* In addition, PPC fails to note Staff's rebuttal testimony, where Staff noted "[w]e acknowledge that this is a potential way of reflecting DSI benefits in the 7(b)(2) Case …" Doubleday, *et al.*, WP-07-E-BPA-85, at 154-155. Thus, there would be no "changing course" and no problem in adopting the IOUs' argument if BPA believes the argument to be well-founded. Nevertheless, BPA does not support the IOUs' alternative proposal. As explained in greater detail below, if there is no electric power sold to the DSIs in the Program Case, then there are no megawatt-hours to add to the general requirements in the 7(b)(2) Case. Dollars cannot be added to megawatt-hours. Therefore, the monetized power sale cannot be reflected as load in the 7(b)(2) Case.

The IOUs argue BPA's decision to provide DSI benefits through monetary payments to DSIs (or through power sales through the local utility) should not reduce the level of REP benefits provided by BPA. IOU Br., WP-07-B-JP6-01, at 42. The IOUs note BPA stated in the DSI ROD that, in order to provide DSI benefits through monetary benefits to DSIs, BPA would need to "be assured that the cost impact on other customers was 'roughly no greater than if BPA had exercised its discretion to serve the DSI customers' directly with physical power deliveries using the IP rate." *Id. quoting* DSI ROD, at 18-19. The IOUs state BPA's decision to provide DSI service benefits as monetary payments has a substantial effect on the PF Exchange rate unless BPA includes the DSI service benefits in the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 42. Given BPA's decision to provide DSI benefits by a mechanism other than direct physical power deliveries by BPA under the IP rate, both fundamental fairness and BPA's stated criterion – cost impact on other customers roughly no greater than a DSI power sale under the IP rate – require that BPA avoid imposing, in effect, the entire cost of DSI benefits on the PF Exchange rate. *Id.* The IOUs state such a cost shift is unjustified, unfair, and unnecessary. *Id.* In response to this argument, Staff's calculations showed that approximately 55 percent of the DSI financial benefits are borne by the IOUs through reduced REP benefits, not "the entire cost." Doubleday, *et al.*, WP-07-E-BPA-85, at 154. In addition, although a particular decision might increase or decrease REP benefits, this is not determinative of any issue. BPA must decide each issue in the first instance based on the law and facts, regardless of the consequences for REP benefits. In the instant case, BPA agrees with the IOUs in part; that is, BPA believes it is appropriate to include the costs of the DSI service benefits in the 7(b)(2) Case. BPA does not believe, however, that the 350 aMW of DSI sales at the IP rate that Staff has concluded is equivalent to its DSI service benefit monetary payments must be included in the general requirements of the PF Preference rate customers in the 7(b)(2) Case. Certainly, because the DSIs are operating, it is not unreasonable to assume they would be served by their local public utility in the 7(b)(2) world. On the other hand, BPA is not physically serving the DSIs with power except in the case of Port Townsend. This is an issue where reasonable grounds exist for including and excluding the load. On balance it is reasonable to exclude the loads, other than the 17 aMW sale by BPA for the Port Townsend Paper Corporation load.

PPC argues whether the costs of financial payments to the DSIs can be included in the 7(b)(2) Case depends on the language of the Northwest Power Act. PPC Br., WP-07-B-PP-01, at 47. BPA agrees. There are only five assumptions BPA makes when determining the loads and costs of preference customers in the 7(b)(2) Case. *Id.* Section 7(b)(2)(A) addresses the assumption that BPA is to make with regard to DSI service. *Id.* It states that the Administrator is to assume that "public body and cooperative customers' general requirements had included during such five-year period the [DSI] customer loads which are – (i) served by the Administrator, and (ii) located within or adjacent to [their service territories]." *Id., citing* 16 U.S.C. § 839e(b)(2)(A). Under this section of the statute, BPA's relationship with the DSIs is to be factored into the power costs of preference customers only when the DSIs are being "served by the Administrator." PPC Br., WP-07-B-PP-01, at 47. PPC argues BPA is not providing power to the DSIs, and to the extent they are operating, it is through power from sources other than BPA. *Id*. PPC's argument, however, ignores the facts. First, BPA has the discretionary statutory authority to serve the DSIs after the expiration of their initial Northwest Power Act power sales contracts. 16 U.S.C. § 839c(d)(1). BPA has the statutory authority to serve the DSIs firm power at the IP rate or the FPS rate. 16 U.S.C. §§ 839c(d)(1); 839c(f); 839e(c); 839e(f). BPA intends to continue DSI service during the rate period. As noted previously, however, in order to eliminate the market and default risks to BPA associated with a traditional "take-or-pay" physical power sales contract, and to meet the known and capped cost prerequisite for DSI service (which benefits BPA's preference customers), BPA's preferred alternative was to provide service benefits to the DSIs financially, by cashing out, or monetizing, the value of a power sales contract in lieu of physically delivering power. Thus, the monetization of a power sale is simply an alternative manner of making a power sale. There is no basis for the monetization other than the initial existence of a power sale. Thus, a monetization of a power sale is properly viewed as a manner of serving DSI load.

Furthermore, Congress intended that the section 7(b)(2) rate test would compare the Program Case with a 7(b)(2) Case, where DSI loads served by BPA were assumed to be included in preference customers' loads served by BPA. 16 U.S.C. § 839e(b)(2)(A); "The loads for establishing the resource requirements are (a) Public body, cooperative and Federal agency customer total requirements on the Administrator exclusive of new large industrial loads; and (b) DSI total loads within or adjacent to the service territory of the public bodies and cooperatives." S. Rep. No. 96-272, 96th Cong., 1st Sess. 20 (1979). Where BPA makes DSI sales in the Program Case, such service should properly be reflected in the 7(b)(2) Case. If the Program Case sales to the DSIs have been monetized for legitimate business reasons, then the monetization should be reflected in the 7(b)(2) Case costs. Because the monetization does not result in loads which are served by BPA in the Program Case, *see* 16 U.S.C. § 839e(b)(1)(A)(i), there is no load to reflect in the general requirements of 7(b)(2) Customers in the 7(b)(2) Case. To not reflect the Program Case costs of monetization of power sales in the 7(b)(2) Case would defeat the language and intent of section 7(b)(2). Section 7(b)(2) is not implemented in a void and must be viewed in its factual context. Failure to reflect BPA's monetized DSI sales in the 7(b)(2) Case would bias the 7(b)(2) Case by improperly reducing the cost of the 7(b)(2) Case. It is therefore proper to include the monetized DSI power sale costs in the 7(b)(2) Case. When determining the meaning of a statute, the courts look not only to the particular statutory language but also to the design of the statute as a whole and to its object and policy. *U.S. v. Crandon,* 494 U.S. 152, 158 (1990); *K Mart Corp. v. Cartier, Inc.,* 486 U.S. 281, 291 (1988); *Pilot Life Ins. Co. v. Dedeaux,* 481 U.S. 41, 51 (1987). The court may not adopt a plain-language interpretation of a statutory provision that would undermine Congress's clear purpose of the statute. *Albertsons, Inc., v. C.I.R.,* 42 F.3d 537, 545-546 (1994); *United States v. American Trucking Ass'ns., Inc.,* 310 U.S. 534 (1940); *Brooks v. Donovan,* 699 F.2d 1010, 1011 (9th Cir.1983), *citing International Tel. & Tel. Corp. v. General Tel. & Elec. Corp.,* 518 F.2d 913, 917-918 (9th Cir.1975). In this case, Congressional intent is clear that the 7(b)(2) Case should reflect the Administrator's costs of serving DSI loads. Failing to reflect such service when monetized for legitimate business reasons would be contrary to such intent.

PPC argues Staff's Proposed Implementation Methodology defines DSI loads that can be considered in the rate test as "[t]hose loads of direct service industries (DSI) that are forecast to *be served by* BPA, during the Five-Year Period, pursuant to sections 5(d)(1) or 5(f) of the Northwest Power Act." PPC Br., WP-07-B-PP-01, at 47-48, *quoting* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B at IM-3 (emphasis added). PPC states financial payments to the DSIs are not a power cost of serving the general requirements load of preference customers under the assumptions outlined in section 7(b)(2), and thus cannot be included in the 7(b)(2) Case. PPC Br., WP-07-B-PP-01, at 47-48. In response to this argument, in addition to the foregoing discussion, the record establishes that "the DSI financial benefits paid by BPA are part of the power costs for the general requirements of public agency customers." Doubleday, *et al.*, WP-07-E-BPA-85, at 152. Furthermore, "[b]ecause the DSIs have a monetized power sale, … the monetary payments are an alternate form of delivery in lieu of sales of power by BPA to the aluminum DSIs." *Id*. at 151. Staff acknowledged the proposed Implementation Methodology refers to DSI loads "that are forecast to be served by BPA," but this language refers to the amounts by which the general requirements would change pursuant to section 7(b)(2)(A). Staff did not propose to include any DSI load in the Program Case because the power sales were monetized; therefore, the general requirements in the 7(b)(2) Case were not so adjusted in the Supplemental Proposal.

PPC argues the structure of BPA's arrangements for service to the DSIs is fundamentally at odds with the approach advocated by the IOUs. The IOUs argue there is no meaningful difference between physical power deliveries to the DSIs and a monetization or "cashing out" of a contract for physical power deliveries to them. PPC Br., WP-07-B-JP25-01, at 49. PPC suggests this argument fails to recognize that the underlying power sale contracts are not with the DSIs – they provide for a sale of surplus power from BPA to certain preference customers, with those preference customers passing on an equivalent amount of power to the DSIs. *Id*. PPC argues although BPA has chosen to buy out these power sale obligations, BPA's financial settlement does not alter the nature of the prior arrangements. *Id*. PPC contends the underlying contracts do not provide for service to the DSIs by the Administrator – they provide for service by certain preference customers. *Id*. Thus, for purposes of the 7(b)(2) rate test, PPC claims these cannot be treated as DSI service provided by the Administrator. *Id*. Again, PPC does not acknowledge the complete facts. The contracts that provide service to preference customers *exist only to provide service to the DSIs*. If the DSIs did not exist, these power sales to preference customers for the DSIs would not exist. If BPA was not providing service benefits to the DSIs, these power sales to preference customers for the DSIs would not exist. There can be no reasonable dispute that the power sales to the preference customers reflected in the associated contracts *must* result in service benefits provided to the DSIs. They can be used for no other purpose. Section 7(b)(2) refers to DSI loads "served by the Administrator," regardless of whether such service is through IP sales or FPS sales. Providing power sales to BPA's preference customers to be used solely for providing service benefits to the DSIs is a proper manner of serving the DSIs.

WPAG and PPC dispute the IOUs' argument that BPA's planned payment of money to certain DSIs, in lieu of actual power deliveries, can be treated as "within or adjacent to" loads as that term is used in section 7(b)(2). WPAG Br., WP-07-B-WA-01, at 20; WPAG Br. Ex., WP-07-R-WA-01, at 30-31; PPC Br. Ex., WP-07-R-PP-01, at 35-37. WPAG and PPC argue this interpretation is contrary to section 7(b)(2)(A), which requires the Administrator to assume, when implementing the section 7(b)(2) rate test, that "[t]he public body and cooperative customers' *general requirements* had included during such five-year period the direct service industrial customer loads which are – located within or adjacent to the geographic service boundaries of such public bodies and cooperatives…" *Id. citing* 16 U.S.C. § 839e(b)(2)(A) (emphasis added by WPAG). WPAG and PPC note the term "general requirements" is defined in the statute to mean "electric power purchased from the Administrator …" *Id. citing* 16 U.S.C. § 839e(b)(4). WPAG and PPC argue the meaning of this statutory language is that the actual electrical load of a "within or adjacent to" DSI must be assumed to be included in the power purchased from BPA by a public body or cooperative for purposes of implementing the section 7(b)(2) rate test. *Id*. WPAG and PPC argue this statutory language neither contemplates nor permits a DSI that is placing no electric load on BPA to be included in the general requirements of the adjacent public body or cooperative. *Id*. WPAG and PPC state money is not electric load and cannot be treated as such for purposes of implementing the section 7(b)(2) rate test. *Id*.

WPAG's argument addresses the IOUs' alternative of reflecting load rather than the financial benefits in the 7(b)(2) Case. As discussed below, BPA agrees that the DSI service benefits should not be reflected in the public agencies' general requirements in the 7(b)(2) Case. WPAG's interpretation of the facts, however, is too restrictive. As explained above, the provision of service benefits to the DSIs began with BPA's intent to sell power to the DSIs. Regardless of whether such service would be at the IP or FPS rate, such service would be meeting DSI loads. BPA is selling power to preference customers that can serve the DSIs, but is choosing to monetize the transaction for legitimate business reasons. In section 7(b)(2)(A), "the Administrator assumes that public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are – served by the Administrator and located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …" 16 U.S.C. § 839e(b)(2)(A). As recounted earlier, the contracts involved in providing service benefits to the DSIs all involve "within or adjacent" preference customers. A preference customer is a party to each of the power sales contracts under which BPA is providing the monetized DSI service benefits. IOU Br., WP-07-B-JP6-01, at 39. The three aluminum DSI plants for which BPA provides service benefits pursuant to the three monetized power sales contracts are Columbia Falls, Ferndale, and Goldendale. *Id*. These plants are listed as within or adjacent to BPA preference customers' geographic service territories in Appendix B to the Report of the Senate Committee on Energy and Natural Resources, S. Rep. No. 272, 96th Cong., 1st Sess. (1979), Appendix B, at 66. *Id*. The Port Townsend Paper Corporation plant also meets the "within or adjacent" test because it is in fact being served by a preference customer (Clallam PUD). *Id*. Staff's rebuttal testimony acknowledges that the Port Townsend Paper Corporation plant meets the "within or adjacent" test. Doubleday, *et al.*, WP-07-E-BPA-85, at 153.

The first question is whether the monetized power sale to the DSIs should be reflected as an increase to the preference customers' general requirements in the 7(b)(2) Case. It is clear that the general requirements in the 7(b)(2) Case are to "the direct service industrial customer loads which are – (i) served by the Administrator, and (ii) located within or adjacent …" 16 U.S.C. § 839e(b)(2)(A). The question then is whether a monetized power sale constitutes "load … served by the Administrator …." "General requirements" is defined as "… electric power purchased from the Administrator …." 16 U.S.C. § 839e(b)(4). Electric power is denominated in megawatt-hours. Monetized power sales are denominated in dollars. If there is no electric power sold to the DSIs in the Program Case, then there are no megawatt-hours to add to the general requirements in the 7(b)(2) Case. Dollars cannot be added to megawatt-hours. Therefore, the monetized power sale cannot be reflected as load in the 7(b)(2) Case.

The second question is the treatment of the financial costs of the monetized power sale in the 7(b)(2) Case. The rate test is to compare "the projected amounts to be charged for firm power for the combined general requirements … exclusive of [specified] amounts … may not exceed in total … an amount equal to the power costs for general requirements … if, the Administrator assumes that …" 16 U.S.C. § 839e(b)(2). The question, then, is whether the financial costs are part of the "power costs for general requirements" in the 7(b)(2) Case. Here, as noted above, the IOUs' argument is persuasive. The value of a power sales contract cannot be excluded from the 7(b)(2) Case on the grounds that a PF Preference rate customer could not or would not have incurred similar costs and could not have allocated them to other PF Preference rate customers. The inclusion of the cost of serving a DSI load in the 7(b)(2) Case costs is, under the statute, not conditioned on whether or not the PF Preference rate customer would in fact determine to serve the DSI load and is not conditioned on whether or not any expenses or costs incurred by the PF Preference rate customer would be shared by other PF Preference rate customers. Therefore, the same financial cost of the monetized power sale should be included in the 7(b)(2) Case revenue requirement as was included in the Program Case revenue requirement.

In their Briefs on Exceptions, WPAG and PPC note BPA is proposing to include in the power costs under the 7(b)(2) Case the cash payments it is expecting to make to the DSIs to monetize their power purchases from BPA, even though BPA will provide no actual load service to the DSIs. WPAG Br. Ex., WP-07-R-WA-01, at 31; PPC Br. Ex., WP-07-R-PP-01, at 33. WPAG and PPC speculate, with no factual foundation, that BPA's proposal is motivated by a desire to avoid shifting the costs of the DSI power monetization payments to the IOUs. *Id*. WPAG and PPC's speculation is simply wrong. BPA has no such goal, regardless of whether it would be understandable or not. BPA notes that preference customers have attributed negative motivations to BPA throughout the instant Supplemental Proceeding. Because BPA knows the manner in which it developed its rate proposal, BPA knows these aspersions are false and unsupported by facts. Therefore, BPA must assume the preference customers are making such statements in the hope that a reviewing court will simply assume that the preference customers' statements are true and adopt a predisposition against BPA's actions. BPA, however, assumes the Federal courts would not fall for such tactics and would not render decisions based on cursory review or unsupported allegations, but rather on the merits.

In their Briefs on Exceptions, WPAG and PPC argue that BPA's cash payments to monetize DSI power sales cannot be included in the 7(b)(2) Case. WPAG Br. Ex., WP-07-R-WA-01, at 31; PPC Br. Ex., WP-07-R-PP-01, at 34-42. However, a primary reason the DSI monetary benefits are included in the 7(b)(2) Case is because they are not a cost that BPA is directed to exclude from one Case or another. *See* 16 U.S.C. § 839e(b)(2). The monetization payments are a section 7(g) cost, but are not an Applicable 7(g) Cost. *See id*.; 16 U.S.C. § 839e(g). The only section 7(g) costs that are treated differently between the two Cases are Applicable 7(g) Costs. Non-Applicable 7(g) Costs are a part of the power costs of 7(b)(2) Customers (e.g., BPA programs, secondary revenue credit). The incorrect argument that the DSI monetization payments are not a part of the power costs of preference customers would improperly exclude non-Applicable 7(g) Costs.

Decision

BPA will include DSI service benefit costs in the 7(b)(2) Case and include the 17 aMW BPA sale to the Port Townsend Paper Corporation in the general requirements of PF Preference rate customers in the 7(b)(2) Case.

Issue 2

Whether DSI Load Reduction Agreement costs should be included in the 7(b)(2) Case.

Parties' Positions

The IOUs argue that to the extent the DSI LRA costs are included in the Program Case, they should also be included in the 7(b)(2) Case costs. IOU Br. Ex., WP-07-R-JP6-01, at 10.

BPA Staff's Position

BPA Staff took no position on this issue.

Evaluation of Positions

The IOUs note BPA's decision in the Draft ROD to reflect the DSI LRAs for Alcoa, Atofina, Columbia Falls, Longview, and Oremet in BPA's DSI load forecast for FY 2002-2006. IOU Br. Ex., WP-07-R-JP6-01, at 10, *citing* Draft ROD, WP-07-A-03, at 74. The IOUs argue that to the extent the DSI LRA costs are included in the Program Case, they should also be included in the 7(b)(2) Case costs, inasmuch as the exclusion of such costs is not specified by any one of the five assumptions to be made in the 7(b)(2) Case. IOU Br. Ex., WP-07-R-JP6-01, at 10, citing 16 U.S.C. § 839e(b)(2).

As the IOUs correctly note, BPA reduced DSI loads in FY 2002-2006 to reflect the fact that BPA executed LRAs with the DSIs that reduced or eliminated BPA's obligations to serve DSI load at certain times during FY 2002-2006 (as specified in the individual LRAs) and under which BPA paid the DSIs for such load reductions. BPA therefore incurred costs under the LRAs. Just as the reduced loads from the DSI LRAs are properly reflected in the Program Case and 7(b)(2) Case, the costs associated with such LRAs should also be included in the Program Case and 7(b)(2) Case.

Decision

BPA will include the costs of the DSI LRAs in the 7(b)(2) Case.

16.13 Serving Pre-Subscription Contracts in the 7(b)(2) Case

Issue 1

Whether and, if so, how Pre-Subscription contracts should be served in the 7(b)(2) Case.

Parties' Positions

Cowlitz, WPAG, and APAC argue that Pre-Subscription contracts cannot be served with FBS resources before serving the general requirements of public bodies and cooperatives in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 38; WPAG Br., WP-07-B-WA-01, at 19; APAC Br., WP-07-B-AP-01, at 49-52. They argue only contracts that were in existence as of December 5, 1980 can be served by the FBS, and these contracts were not in existence as of that date. *Id*. Also, WPAG argues that the Pre-Subscription loads cannot be included in the load of public bodies and cooperatives, which are limited to the general requirements of public bodies and cooperatives. WPAG Br., WP-07-B-WA-01, at 19.

The IOUs argue that section 7(b)(2)(B) of the Northwest Power Act does not limit the loads of public body, cooperative, and Federal agency customers assumed therein to be served with FBS resources to the general requirements of those customers served by BPA sales under section 5(b) of the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 105. It follows that the sales of FBS resources under section 7(b)(2)(B) include any sales of FBS resources at a rate other than the PF Preference rate. *Id*.

BPA Staff's Position

BPA Staff notes this is largely a legal issue regarding the interpretation of section 7(b)(2)(B) of the Northwest Power Act. Doubleday, *et al.,* WP-07-E-BPA-85, at 11-12. As a factual matter, Pre-Subscription sales were made as surplus sales under section 5(f) of the Northwest Power Act, and not as requirements sales under section 5(b), as an accommodation to the Pre-Subscription customers. *Id*. This allowed BPA to use the negotiated FPS rate established under section 7(f) of the Act to provide such customers with rate certainty through special rate design features. *Id*. The Pre-Subscription customers were historically (and continue to be) public body customers whose power requirements were (and are) generally met with section 5(b) sales. *Id.* at 12. In order to make a proper comparison of the costs of power to public body customers in the Program and 7(b)(2) Cases, the total loads of the public body customers should be reflected in both Cases. *Id.* at 13.

Evaluation of Positions

BPA's "Pre-Subscription" sales were sales of firm power BPA made to a subset of BPA's public body customers. Doubleday, *et al.*, WP-07-E-BPA-85, at 11. The Pre-Subscription sales were not made under section 5(b) of the Northwest Power Act like most firm sales to BPA's public body customers, but rather under section 5(f) to give these public body customers price certainty (based on the PF-96 Preference rate price level) for the first five years of the Subscription contract period. *Id*. at 11-12. The Pre-Subscription sales were made under section 5(f) of the

Northwest Power Act due to the particular circumstances existing at the time the sales were made. *Id*. at 14. At that time, BPA faced uncertainty in retaining public agency loads when market prices were low. *Id*. BPA had experienced both public agency and direct service industrial load loss in the years just prior to the execution of these contracts. *Id*. BPA sought to obtain early load commitments and wanted to sell these customers section 5(b) requirements power at the PF Preference rate. *Id*. The customers, however, wanted rate certainty that was not available through the PF Preference rate. *Id*. Although these sales would otherwise have been section 5(b) sales at the PF Preference rate, BPA agreed to accommodate the desires of these section 5(b) requirements customers by using a price structure (including, for example, price collars) available under BPA's FPS rate, which was developed under section 7(f) of the Northwest Power Act, and was approved by FERC for 10 years which allowed BPA to apply the rate over a contract period that did not have an effective PF Preference rate and which was based on the level of the PF Preference rate for section 5(b) requirements sales. *Id*. Because of this pricing structure, loads under these contracts were served at a rate that allowed a minimal number of price adjustments and could not be allocated additional costs under section 7(b)(3) of the Northwest Power Act, thereby receiving substantial cost protection. *Id*. at 14-15.

A. Serving Public Body, Cooperative, and Federal Agency Loads with FBS Resources in the 7(b)(2) Case

Section 7(b)(2) of the Northwest Power Act provides, in pertinent part:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers … may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that –
>
> the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are – served by the Administrator, and 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 five-year period, with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of the paragraph …

16 U.S.C. §§ 839e(b)(2), 839e(b)(2)(B).

WPAG argues that Pre-Subscription loads cannot be included in the load of public bodies and cooperatives under the section 7(b)(2) rate test because the loads protected by, and the loads included in, the section 7(b)(2) rate test are limited to the general requirements of public bodies and cooperatives. WPAG Br., WP-07-B-WA-01, at 19-20; WPAG Br. Ex., WP-07-R-WA-01, at 28-30. WPAG also cites the introductory portion of section 7(b)(2) and the definition of general requirements in section 7(b)(4). *Id.* WPAG's argument is inaccurate. BPA Staff did not propose to include Pre-Subscription sales to preference customers in 7(b)(2) Customers' general requirements in the 7(b)(2) Case. Doubleday, *et al.*, WP-07-E-BPA-85, at 12. Rather, BPA Staff served the Pre-Subscription sales prior to preference customers' general requirements. *Id.* This was not a matter of granting the Pre-Subscription sales a priority over preference customers' general requirements, but a way of providing equal priority to the FBS without adding Pre-Subscription sales to general requirements. *Id.* Therefore, WPAG's argument is more accurately defined as whether it is appropriate to use the FBS to serve Pre-Subscription sales in the 7(b)(2) Case.

Cowlitz and APAC argue that Congress specified which FBS resources were to be deemed available to meet the general requirements of preference customers in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 38; APAC Br., WP-07-B-AP-01, at 51; APAC Br. Ex., WP-07-R-AP-01, at 21. Cowlitz, WPAG and APAC argue that section 7(b)(2)(B) requires BPA to assume for purposes of section 7(b)(2) that the preference customers' general requirements were served during the rate period "with Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act [December 5, 1980] (during the remaining term of such contracts), excluding obligations to direct service industrial loads included in subparagraph (A) …" Cowlitz Br., WP-07-B-CO-01, at 38; WPAG Br., WP-07-B-WA-01, at 19-20; WPAG Br. Ex., WP-07-R-WA-01, at 28-30; APAC Br., WP-07-B-AP-01, at 51. Cowlitz, WPAG, and APAC argue BPA Staff has reduced the amount of the FBS available for general requirements by a series of "Pre-Subscription contract" section 5(f) sales entered into long after December 5, 1980. *Id.* Cowlitz, WPAG and APAC claim that BPA is not permitted to give those obligations a claim on the FBS superior to the general requirements of 7(b)(2) Customers. *Id.*

The IOUs argue that section 7(b)(2)(B) expressly describes the loads to be served with FBS resources in the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 105. It provides that *"public body, cooperative, and Federal agency customers* were served, during such five-year period, with Federal base system resources …" *Id.* (emphasis added by IOUs) The IOUs state that section 7(b)(2), subsection 7(b)(2)(A), and subsection 7(b)(2)(D) all refer to "general requirements," but subsection 7(b)(2)(B) does not state that preference customers' "general requirements" were served by the FBS. *Id.* Thus, additional firm power sales to preference customers, such as the Pre-Subscription sales, are properly served by the FBS in the 7(b)(2) Case. *Id.*

As noted previously, the Pre-Subscription sales were sales of firm power BPA made to a subset of BPA's public body customers. Doubleday, *et al.*, WP-07-E-BPA-85, at 11. (The Pre-Subscription sales must be distinguished from BPA's Hungry Horse power sales, which are statutorily required, as described in greater detail below.) The Pre-Subscription sales were not made under section 5(b) of the Northwest Power Act like most firm sales to BPA's public body customers, but rather under section 5(f) to give these public body customers price certainty (based on the PF-96 Preference rate price level) for the first five years of the Subscription contract period. *Id.* at 11-12. However, the Pre-Subscription customers were historically (and continue to be) public body customers whose power requirements were (and are) generally met through power sold under contracts executed pursuant to section 5(b). *Id*. at 12. These customers received PF Preference-priced power under section 5(b) contracts prior to the FY 2002-2008 time period; some of these customers received additional sales of power for this time period under section 5(b); and the majority of the Pre-Subscription contracts were converted into general requirements contracts, that is, section 5(b) sales, for the FY 2007-2011 time period. *Id*.

Also as noted above, the Pre-Subscription sales were made under section 5(f) of the Northwest Power Act due to the particular circumstances existing at the time the sales were made. *Id*. at 14. At that time, BPA faced uncertainty in retaining public agency loads when market prices were low. *Id*. BPA had experienced both public agency and direct service industrial load loss in the years just prior to the execution of these contracts. *Id*. BPA sought to obtain early load commitments and wanted to sell these customers section 5(b) requirements power at the PF Preference rate. *Id*. The customers, however, wanted rate certainty that was not available through the PF Preference rate. *Id*. Although these sales would otherwise have been section 5(b) sales at the PF Preference rate, BPA agreed to accommodate the desires of these section 5(b) requirements customers by using a price structure (including, for example, price collars) available under BPA's FPS rate, which was developed under section 7(f) of the Northwest Power Act. *Id*. The FPS rate was effective for a 10 year period and was therefore applicable over the desired contract period. Because of this pricing structure, loads under these contracts were served at a rate that allowed a minimal number of price adjustments and could not be allocated additional costs under section 7(b)(3) of the Northwest Power Act, thereby receiving substantial cost protection. *Id*. at 14-15.

Regardless of the foregoing facts, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with surplus FBS. *E.g., id*. at 15. This is the case for the Pre-Subscription sales at the time they were entered for the years FY 2002-2006. *Id. citing* FY 2002-2008 Lookback Study Documentation, WP-07-E-BPA-44A, at 196, Column G. The non-section 5(b) sales for FY 2007-2010 are associated with BPA's Hungry Horse Reservation obligation and are correctly included in the 7(b)(2) Case. *Id*. Cowlitz argues that although it is true that some of the sales were made in conjunction with a Hungry Horse obligation, that fact is legally irrelevant. Cowlitz Br., WP-07-B-CO-01, at 39. Cowlitz notes that, under the Northwest Power Act, the only basis for excluding FBS resources for purposes of section 7(b)(2) is if they were "obligated to other entities under contracts existing as of December 5, 1980." *Id*. *citing* 16 U.S.C. § 839e(b)(2)(B). In response, however, the Hungry Horse contracts are properly served with FBS resources in the 7(b)(2) Case. The Hungry Horse Dam is an FBS resource. BPA has a statutory obligation to provide power from Hungry Horse Dam to Montana customers. 43 U.S.C. § 593a; 16 U.S.C. § 837h; 16 U.S.C. § 839g(f); *see Central Mont. Elec. Coop. v. Bonneville Power Admin*., 840 F.2d 1472, 1477 (9th Cir. 1988). Therefore, BPA sells Hungry Horse power first to preference customers in Montana in compliance with Federal reclamation laws. 43 U.S.C. § 593a. This statutory obligation can only be implemented through contracts for the sale of such power. Such contracts have always been executed to implement the statute. In other words, as long as the statute exists, BPA will have to execute power sales contracts with Montana customers for the sale of Hungry Horse power. BPA's contract sales are limited to 20 years. 16 U.S.C. § 832d(a). Therefore, the implementing contracts must change over time even though the statutory obligation persists.

Section 7(b)(2)(B) refers to "Federal base system resources not obligated to other entities under contracts existing as of the effective date of this Act." 16 U.S.C. § 832e(b)(2)(B). This language must be interpreted in a manner that gives effect to the intent of the Act. Because Hungry Horse power will always be sold to Montana preference customers under contract as long as the statute exists, it is FBS power that will be available to serve only such customers and will not be available to serve other public body, cooperative, and Federal agency customers. In any event, all Hungry Horse power sales to preference customers are used to serve public body, cooperative, and Federal agency customers, which is consistent with section 7(b)(2)(B). BPA therefore properly serves the Hungry Horse statutory obligations as continuing contractual obligations that were effective prior to the Northwest Power Act.

In its Brief on Exceptions, Cowlitz claims BPA appears to reason that any and all FBS resource amount it assumes is used to serve the Pre-Subscription sales cannot therefore be available to meet general requirements in the 7(b)(2) Case. Cowlitz Br. Ex., WP-07-R-CO-01, at 24. Cowlitz has mischaracterized BPA's position. As stated in the Draft ROD, BPA has concluded that it will first serve section 5(b) preference loads with FBS resources, as well as BPA's statutorily required sales from the Hungry Horse Dam (which are made to preference customers and which are implemented through contracts that must continue to exist based on statutory requirements to establish such contracts both before and after the effective date of the Act, December 5, 1980). The preference parties did not expressly contest BPA's treatment of Hungry Horse loads in their Briefs on Exceptions. After serving section 5(b) and Hungry Horse loads with FBS resources, BPA serves additional preference loads with FBS remaining after serving the section 5(b) and Hungry Horse loads. Thus, contrary to Cowlitz's characterization, BPA has made FBS resources first available to serve public body, cooperative, and Federal agency customers in the 7(b)(2) Case.

Referring to the Draft ROD, Cowlitz reiterates that the Northwest Power Act requires section 5(b) sales to have priority to FBS resources over section 5(f) sales in the 7(b)(2) Case. Cowlitz Br. Ex., WP-07-R-CO-01, at 24. WPAG makes a similar argument. WPAG Br. Ex., WP-07-R-WA-01, at 28-30. In response, however, these arguments need not be addressed. As noted in BPA's Draft ROD, BPA has already concluded that it will first serve (1) section 5(b) requirements with FBS resources, and (2) Hungry Horse loads (which prior to December 5, 1980, BPA was statutorily required to meet BPA prospectively and indefinitely through continuing contracts for such sales), which are permitted under section 7(b)(2)(B) ("obligated to other entities under contracts existing as of the effective date of this Act (during the remaining term of such contracts))." 16 U.S.C. § 839e(b)(2)(B). Only then would BPA serve the Pre-Subscription contracts and then only if sufficient FBS resources remained. As a practical matter, the FBS was sufficient to serve section 5(b) requirements, Hungry Horse obligations, and Pre-Subscription contracts during the FY 2002-2006 Lookback period. The Pre-Subscription contracts expired during this period. Therefore, BPA has used the FBS in the manner advocated by preference customers. Even if the Hungry Horse contracts that were statutorily required prior to December 5, 1980, to establish contracts that continue indefinitely were not viewed as contracts entered into prior to December 5, 1980 (which would be an erroneous assumption), BPA still properly served such loads with FBS resources. This is because BPA used the FBS first to serve section 5(b) loads, then Hungry Horse loads, then other contractual obligations until the FBS resources were exhausted. Again, FBS resources were sufficient during FY 2002-2006 to meet all of these loads. The fact that BPA uses remaining FBS resources to meet other contractual obligations is not new. In BPA's WP-02 Administrator's Record of Decision, BPA stated that after serving 7(b)(2) Customers' loads, "BPA proposed to serve surplus sales and do so in a particular order, as provided in a BPA data response that describes an approach for determining which surplus power sales served in the Program Case would be served in the 7(b)(2) Case." WP-02 ROD, May 2000, WP-02-A-02, at 13-47. Pre-Subscription contracts were identified as contracts BPA would serve with remaining FBS resources. *Id*.

In its Brief on Exceptions, APAC states that BPA prioritized its FBS obligation to Pre-Subscription contracts over the section 7(b)(2) load, thereby raising the rate test ceiling by causing the section 7(b)(2) load to require resources from a more expensive resource stack sooner. APAC Br. Ex., WP-07-R-AP-01, at 21. APAC argues that if this priority is reversed "REP benefits would be reduced to zero." *Id*. First, APAC fails to note that BPA's Draft ROD proposed to serve section 5(b) loads first, along with Hungry Horse loads, and then serve Pre-Subscription contracts only because there were sufficient FBS resources to meet such obligations. BPA does not propose to prioritize Pre-Subscription contracts over section 5(b) loads. Second, APAC's claim that adjusting the priority of service would reduce REP benefits to zero makes no sense. Because the FBS is sufficient in FY 2002-2006 to meet section 5(b) loads, Hungry Horse loads, and Pre-Subscription contract loads, as a practical matter, it does not matter which order the loads are served. This was part of the basis for Staff's initial proposal. Thus, there should be no effect on REP benefits in this proceeding as a result of BPA's change.

APAC argues BPA cannot use FBS resources to serve Pre-Subscription contracts before serving preference customer loads in the 7(b)(2) Case because BPA did not give Pre-Subscription contracts such a priority in BPA's 2002 rate case, and there has been no change in circumstance between May 2000 and May 2008 to justify the change in treatment. APAC Br., WP-07-B-AP-01, at 49-51; APAC Br. Ex., WP-07-R-AP-01, at 21-23. With regard to the section 5(f) Pre-Subscription sales to preference customers at the FPS rate (based on the PF Preference rate), as noted above, BPA has reordered the load service in the 7(b)(2) Case to serve such loads with FBS resources only after section 5(b) sales to public body, cooperative, and Federal agency customer loads. This is consistent with BPA's previous treatment in the WP-02 rate case. This is also consistent with Staff's testimony, which noted "there may be circumstances where serving pubic body customer load with FBS resources in the 7(b)(2) Case is proper even if those sales were not actually made under the PF Preference rate" because "if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS." Doubleday, *et al.*, WP-07-E-BPA-85, at 11.

<u>Decision</u>

BPA will use FBS resources to serve preference customers' section 5(b) loads, then Hungry Horse sales, then Pre-Subscription contracts. Pre-Subscription sales to non-preference customers will be served with FBS only if the FBS is surplus to preference customers' loads.

16.14 Secondary Energy as Reserves

Issue 1

Whether BPA's secondary energy provides reserves for purposes of section 7(b)(2)(E) of the Northwest Power Act.

Parties' Positions

The IOUs argue that secondary energy available from BPA's resources, BPA's rights to withdraw power sales from the surplus power market, and BPA's rights to interrupt, curtail, or otherwise withdraw power deliveries outside the region provide reserves for purposes of the section 7(b)(2) rate test. IOU Br., WP-07-B-JP6-01, at 74-75. The IOUs claim BPA is no worse off today in terms of reserves because of the diminution of DSI load. *Id*. at 85. The amount (or value) of reserve benefits provided by (i) BPA's secondary energy and (ii) BPA's rights to withdraw power sales is conservatively valued by use of BPA's operating reserve rate for its transmission customers. *Id*. at 87.

CUB raises similar arguments. CUB Br., WP-07-B-CU-01, at 6-9.

WPAG, Cowlitz, and PPC argue that surplus firm power and secondary energy do not constitute reserves in the sense in which that term is normally used, or as it is used in the section 7(b)(2) rate test. WPAG Br., WP-07-B-WA-01, at 44; Cowlitz Br., WP-07-B-CO-01, at 41; PPC Br., WP-07-B-JP25-01, at 44. Because the timing and amount of secondary energy is insufficiently reliable to be used to serve firm load, it is similarly insufficiently reliable to provide reserves to ensure service to firm loads. WPAG Br., WP-07-B-WA-01, at 45. The Administrator is directed to assume that "reserve benefits as a result of the Administrator's actions under this chapter … were not achieved." *Id*. at 46. Because BPA was making secondary and surplus firm power sales long before the Northwest Power Act was passed, such surplus firm power and secondary sales do not provide reserves as a result of the Administrator's actions under the Act. *Id*. Selling secondary energy at a lower price in order to achieve operational reserves would not achieve any "quantifiable monetary saving" arising through the Act; it would merely reflect a decision by BPA to pay market value for such reserves. Cowlitz Br., WP-07-B-CO-01, at 41.

BPA Staff's Position

BPA Staff notes it is possible to construe surplus power as providing reserves. Doubleday, *et al.*, WP-07-E-BPA-85, at 127. However, the important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used in section 7(b)(2)(E). *Id*. The proposed Implementation Methodology instructed Staff they do not. *Id*. However, because the proposed Implementation Methodology is conformed to the Legal Interpretation, Staff will rely on the final Legal Interpretation regarding whether these reserves meet the intent of section 7(b)(2)(E). *Id*.

Evaluation of Positions

A. Statutory and Regulatory Background

In developing the 7(b)(2) Case, section 7(b)(2)(E) of the Northwest Power Act requires the Administrator to assume:

> (E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from –
>
> * * *
>
> (ii) 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)(E).

Section 3(17) of the Northwest Power Act defines reserves:

> "Reserves" means the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers.

16 U.S.C. § 839a(17).

BPA's proposed Legal Interpretation provides:

> **13. Interpretation: Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.**
>
> **Discussion:**
>
> Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from … reserve benefits as a result of the Administrator's actions under this chapter were not achieved." 16 U.S.C. § 839e(b)(2)(E). Reserve Benefits result from BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these restriction rights are unavailable to BPA. Without the restriction rights, BPA would have to incur the costs of providing an equivalent amount of reserves from another source. This subsection provides that the 7(b)(2) Case is to assume that cost reductions attributable to Reserve Benefits are not achieved in the 7(b)(2) Case. Therefore, the 7(b)(2) Case revenue requirement is to assume the extra cost of procuring the reserves provided to the Program Case.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 7(b)(2) Legal Interpretation at LI-17.

BPA's proposed Legal Interpretation and Implementation Methodology provide the following definitions:

> 13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.
>
> 14. Reserve Benefits: The annual financial value of interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 7(b)(2) Legal Interpretation at LI-4; Section 7(b)(2) Rate Test Study,, WP-07-E-BPA-50, Attachment B, Proposed 7(b)(2) Implementation Methodology, at IM-3. BPA's proposed Implementation Methodology also provides:

> **7. Reserve Benefits**
> Section 7(b)(2)(E)(ii) requires BPA to assume that the Quantifiable Monetary Savings resulting from Reserve Benefits were not achieved. Reserve Benefits result from BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these restriction rights are unavailable to BPA. Without the restriction rights, BPA would incur the costs of providing an equivalent amount of reserves from another source. Therefore, it will be assumed that BPA will incur a level of costs for the benefit of public utilities based on the value of the reserves provided by the restriction rights to the Program Case as determined in BPA's rate proposal. The value of reserves determination is currently based, in large part, on the cost of an alternative reserve resource. Also, if the level of reserves provided by the restriction rights is insufficient in the 7(b)(2) Case, based on BPA planning criteria, then additional reserve resource costs will be added in the 7(b)(2) Case.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, Proposed 7(b)(2) Implementation Methodology, at IM-9.

In the Supplemental Proposal, the Section 7(b)(2) Rate Test Study noted:

> The Proposed *Implementation Methodology* allows for reserves from sources other than DSIs subject to the criteria listed ther[e]in. However, within this Supplemental Proposal, reserve benefits provided under the Northwest Power Act are forecast to be zero. These circumstances eliminate the need for a financing benefits analysis to quantify the value of reserves for this rate case.

Supplemental Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, at 4.

B. Secondary Energy, Surplus Power Sales, and Reserves

The Northwest Power Act defines "reserves" as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." 16 U.S.C. § 839a(17); IOU Br., WP-07-B-JP6-01, at 70; CUB Br., WP-07-B-CU-01, at 7. The IOUs argue reserve benefits must include the benefits provided by any reserves that meet the statutory definition. IOU Br., WP-07-B-JP6-01, at 72. The IOUs cite the Senate Committee on Energy and Natural Resources Report, which states the purpose and role of reserves under the Northwest Power Act is "to protect firm loads for any reason, including low or critical streamflow conditions, and … to protect firm loads against the delayed completion [sic in original] or unexpectedly poor performance of regional generating resources or conservation measures, and against the unanticipated growth of regional firm loads …" *Id., citing* S. Rep. No. 96-272, 96th Cong., 1st Sess. 28 (1979).

The IOUs argue BPA's major sources of reserves are BPA's secondary energy and BPA's surplus market sales. IOU Br., WP-07-B-JP6-01, at 73. The IOUs state BPA's firm power loads in the region receive substantial benefits from the reserves provided by (i) secondary energy available from BPA's resources and (ii) power available from BPA's rights to withdraw energy sales from the surplus power market. *Id*. The IOUs and CUB argue that BPA's surplus sales satisfy the statutory definition of reserves. IOU Br., WP-07-B-JP6-01, at 72-73; CUB Br., WP-07-B-CU-01, at 7. CUB notes that Northwest Power Act section 5(d)(1)(A) states that "[t]he Administrator is authorized to sell in accordance with this subsection electric power to existing direct service industrial customers. Such sales shall provide a portion of the Administrator's reserves for firm power loads within the region." CUB Br., WP-07-B-CU-01, at 6, *citing* 16 U.S.C. § 839c(d)(1)(A). Thus, CUB argues the Northwest Power Act contemplates that the Administrator will use sources other than DSI contracts as reserves. CUB Br., WP-07-B-CU-01, at 6.

The IOUs also argue that for purposes of the section 7(b)(2) rate test, reserves are not limited to those provided by the DSIs. IOU Br., WP-07-B-JP6-01, at 103. In that regard, witnesses for Cowlitz and Clark state as follows:

> In addition, §§ 7(b)(2) and (E)(ii) require BPA to assume that the quantifiable monetary savings resulting from its rights to interrupt DSI load were not achieved. This means, in effect, that all of the reserve benefits otherwise obtained from the DSIs must be replaced with other arrangements in the 7(b)(2) Case. In the Appendix B Numerical Analysis, the replacement reserves were assumed to cost twice what the DSIs related reserves were assumed to cost customers in the Program Case.

Id. at 103-104, *citing* Schoenbeck and Beck, WP-07-E-JP17-01, at 12. Although historically BPA's sales to DSI load were a major source of BPA reserves, reserves for purposes of the section 7(b)(2) rate test are not limited to any particular source, DSI or otherwise. IOU Br., WP-07-B-JP6-01, at 104. In the 7(b)(2) Case, BPA is required to assume that all reserve benefits that result from the Administrator's actions under the Northwest Power Act were not achieved. *Id*. Thus, contrary to the implication in the Cowlitz and Clark statement, rights to interrupt DSI load are not the only source of reserve benefits that must be recognized and assumed to not be achieved in the 7(b)(2) Case. *Id*. The IOUs argue that by erroneously implying that BPA reserves for purposes of the section 7(b)(2) rate test are limited to those provided by service to DSI load, Cowlitz and Clark ignore reserves provided by secondary energy available from BPA resources, contractual recall provisions in BPA contracts, and BPA's other rights to withdraw power from the secondary power market. IOU Br., WP-07-B-JP6-01, at 104-105.

Staff agreed that reserves for purposes of section 7(b)(2) are not limited to the reserves BPA receives from its DSI customers. Doubleday, *et al.*, WP-07-E-BPA-85, at 128. BPA, however, must review any form of alleged reserves to ensure it performs the functions reserves were intended to perform under the Northwest Power Act. Staff notes the term "reserves" is used in a number of different ways and for different purposes in a variety of contexts. *Id*. The term "reserves" used in section 7(b)(2)(E) of the Northwest Power Act has a specific meaning and usage that may or may not conform to the use of the same word in other contexts. *Id*. The important question is not whether a particular citation or quotation might portray something a party calls "reserves." *Id*. at 128-129. The important question is how the rate test is to be performed giving full weight to the term "reserves" as Congress intended it to be used in conducting the section 7(b)(2) rate test. *Id*. at 129.

The IOUs argue for three alternative sources of reserves. The first is from secondary energy available from BPA resources. IOU Br., WP-07-B-JP6-01, at 74-75. As noted above, the Northwest Power Act states that "'[r]eserves' means the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, *as provided by specific contract provisions*, portions of the electric power supplied to customers." 16 U.S.C. § 839a(17) (emphasis added). This is clarified in the Senate Report. "The term 'reserves' is defined as electric power needed to avert particular planning or operating shortages, for the benefit of firm power customers, and available to the Administrator *from specifically identified resources or rights*." S. Rep. No. 96-272, 96th Cong., 1st Sess. 23 (1979). Secondary energy does not meet these qualifications. In and of itself, secondary energy is not "from specifically identified resources or rights." Instead, secondary energy is provided generally by the Federal system. In and of itself, secondary energy also does not have contract provisions that provide reserves. Secondary energy exists only as it is generated; it does not provide reserves unless it is tied to a contract or right. This leaves two sources argued by the IOUs: contractual recall provisions in BPA contracts and BPA's other rights to withdraw power from the secondary power market. IOU Br., WP-07-B-JP6-01, at 76-78.

CUB argues the statutory definition of reserves contemplates different ways power can constitute reserves and surplus sales meet the criteria. CUB Br., WP-07-B-CU-01, at 7. First, surplus sales are "available to the Administrator" insofar as section 5(d)(1)(A) of the Northwest Power Act specifically authorizes the Administrator to conduct surplus sales. *Id*., *citing* 16 U.S.C. § 839c(d)(1)(A). (BPA assumes CUB meant to cite section 5(f) of the Act, 16 U.S.C. § 839c(f), which authorizes surplus sales.)

In response, however, "surplus sales" are conducted under contracts and thus are not available absent specific contract provisions. Second, surplus power sales derive "from resources" insofar as the Northwest Power Act defines "resource" as electric power. *Id.*, *citing* 16 U.S.C. § 839a(19). Once again, however, resources are not sold absent contracts.

Third, CUB states surplus power sales produce reserves and are available to the Administrator by virtue of the Administrator's right to sell surplus power via contract in the hour ahead, day ahead, balance of the week, balance of month, monthly, and seasonal markets. CUB Br., WP-07-B-CU-01, at 7. These short-term contract options give the Administrator the right to withdraw power from customers in the wholesale market when power is needed for BPA's firm power customers. *Id*. CUB argues that treating surplus sales as reserves is consistent with BPA's legal interpretation of 7(b)(2) reserve benefits. *Id*. Staff defines Reserve Benefits as: "[t]he annual financial value of interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions." *Id., citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-4. CUB argues that where the Administrator can choose the amount, timing, and duration of power sales by virtue of being able to sell on the hour ahead, day ahead, balance of the week, balance of month, monthly, or seasonal markets, surplus sales provide the Administrator with financial value by virtue of their flexibility. *Id*. at 8. CUB states that given their flexibility, the Administrator can use surplus sales to forestall resource acquisitions and to avoid starting up off-line generation. *Id*.

The IOUs similarly argue secondary energy available from BPA's resources provides reserves. IOU Br., WP-07-B-JP6-01, at 74. (BPA notes that sales of secondary energy are a subset of surplus sales. As such, CUB and the IOUs are making the same essential argument.) The IOUs contend BPA's secondary energy can be used to avert particular planning or operating shortages for the benefit of BPA's firm power customers and is available to BPA from its substantial resources. *Id*. The IOUs state BPA only sells its secondary energy in the surplus market when, and for so long as, BPA determines that it does not need the secondary energy to avert planning or operating shortages. *Id., citing* Russell, *et al.*, WP-07-E-BPA-67, at 33 (stating that "[s]econdary market sales are made when generation exceeds BPA's firm load obligations"). The IOUs argue, accordingly, secondary energy is available and can be used to avert particular planning or operating shortages for the benefit of BPA's firm power customers and is available to BPA from its substantial resources. *Id*.

Staff agreed with the IOUs' assertion that secondary energy provides some value in averting operating shortages. Doubleday, *et al.*, WP-07-E-BPA-85, at 124. Staff, however, did not agree that secondary energy provides value in averting planning shortages. *Id*. As the IOUs have noted, BPA makes secondary market sales when generation exceeds BPA's firm load obligations. *Id*. However, the reason the generation is termed "'secondary" is that it cannot be counted on as being available on a firm basis. *Id*. at 124-125. Therefore, BPA cannot plan on secondary energy being present when required; it is only when it actually occurs within an operating year that BPA gains the knowledge that the secondary energy is available. *Id*. at 125.

As a result, Staff recognizes the ability of secondary energy to provide some operating benefits, but not planning benefits. *Id*.

The IOUs state BPA makes substantial sales of secondary energy. IOU Br., WP-07-B-JP6-01, at 74. For FY 2009, BPA projects secondary energy sales of 1,732 aMW and secondary energy sales revenues of $575.6 million. *Id., citing* Supplemental WPRDS Documentation, Vol. 1 of 2, WP-07-E-BPA-49A, at 48; Brodie, *et al.*, WP-07-E-BPA-70, at 12-13.

The existence of large amounts of secondary energy does not dictate that such energy constitutes reserves. Furthermore, even if one assumes for the sake of argument that secondary energy provides reserves, secondary sales revenues do not contribute at all to the provision of reserves. Doubleday, *et al.*, WP-07-E-BPA-85, at 125. This is because section 3(17) defines reserves as "electric power." 16 U.S.C. § 839a(17).

CUB argues that BPA, in practice, treats surplus sales as reserves. CUB Br., WP-07-B-CU-01, at 8. CUB cites BPA's testimony in the WP-07 rate proceeding as demonstrating that BPA has been treating surplus sales as reserves:

> Factors such as weather, time of year, and fish and wildlife constraints cause generation levels available from BPA's hydro-based system to vary widely from year-to-year, month-to-month and even day-to-day. In addition to this wide variation in BPA's surplus energy amounts, BPA must manage variations in load. As a consequence of these competing factors, BPA must routinely participate in the West Coast wholesale market – both selling power when a surplus exists, and buying to make up any shortfalls.

Id., *citing* Mainzer, *et al.*, WP-07-E-BPA-26, at 5, 11.

However, the foregoing testimony does not state that BPA's secondary energy sales constitute reserves. Rather, it simply notes that BPA must buy and sell in the market to accommodate variations in hydro system generation and BPA's loads. The testimony also reinforces the point that BPA cannot plan on secondary energy being present when required.

CUB argues that recognizing surplus sales as reserve benefits is consistent with the purpose of the Northwest Power Act and the purpose of the REP. CUB Br., WP-07-B-CU-01, at 8. CUB states the value of surplus sales will continue to increase insofar as any future carbon regulation will render BPA's electric generation with zero carbon emissions more valuable. *Id*. CUB claims if BPA continues its practice of using surplus sales primarily to lower preference rates, preference rates will fall, while IOUs' residential and small farm rates will increase. *Id*. CUB believes growing rate disparity between preference and non-preference customers, and the need to keep peace in the region, led Congress to enact the Northwest Power Act more than 25 years ago. *Id*. at 8-9. CUB is concerned failing to recognize surplus sales as reserve benefits under the 7(b)(2) Case will aggravate existing tension once again between preference and non-preference customers. *Id*. at 9. CUB contends, in contrast, treating surplus sales as reserve benefits would not just mitigate the rate disparity between preference and non-preference customers, but would also be consistent with one purpose of the Northwest Power Act: to share the low cost of the Federal system's power among all the region's customers. *Id*.

CUB misunderstands how BPA's rates are determined in this regard. Revenues from surplus sales are not used primarily to "to lower preference rates." Revenues from surplus sales are allocated to all rate pools served with FBS and new resources, that is, Federal system resources (excluding 5(c) exchange resources). It is the Priority Firm rate that is the primary beneficiary of revenues from surplus sales. Participants in the REP purchase energy at the Priority Firm rate pursuant to section 7(b)(1) of the Northwest Power Act. As such, if events unfold as CUB predicts and BPA's hydro-based generation becomes more valuable, REP participants will share in that value through their access to purchases at the Priority Firm rate. Furthermore, as discussed above, revenues do not provide reserves, and reserves are electric power. Therefore, even if BPA's generation becomes more valuable due to carbon constraints, those constraints will not produce any more electric power. More dollars do not equate to more reserves. Even if it were allowed, treating surplus power as reserves is a poor way to transfer increased value to REP beneficiaries. Any increased value, should it occur, is directly transferred to REP participants' residential consumers through section 7(b)(1) of the Act, not through section 7(b)(2)(E).

In summary, BPA agrees that reserves for purposes of section 7(b)(2) are not limited to the reserves BPA receives from its DSI customers. BPA also agrees that secondary energy provides some value in averting operating shortages. BPA, however, does not agree that secondary energy provides value in averting planning shortages. The mere existence of secondary energy does not provide the type of reserves contemplated by section 7(b)(2)(E).

C. BPA's Rights to Withdraw Power Sales from the Surplus Power Market

The IOUs state that BPA's surplus sales in the wholesale market are made under the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 75. The IOUs also believe BPA's rights to withdraw power sales from the surplus power market provide reserves. *Id*. BPA's surplus market sales are a major source of its reserves because BPA only sells its secondary energy in the surplus market when, and for so long as, BPA determines that it does not need the secondary energy to avert planning or operating shortages. *Id*. As a result, BPA's surplus market sales provide electric power needed to avert particular planning or operating shortages for the benefit of BPA's firm power customers and available to BPA from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers. *Id*.

Staff noted that, at most, surplus market sales provide operating reserves. Doubleday, *et al.*, WP-07-E-BPA-85, at 126. Almost all of BPA's surplus sales are sales of secondary energy. *Id*. Staff does not agree that surplus market sales provide planning reserves. *Id*. BPA has sold some firm surplus, but the terms of the sales are such that they provide little planning reserve benefits. *Id*.

Further, the IOUs' statement that "BPA *only* sells its secondary energy in the surplus market when, and for so long as, BPA determines that it does not need the secondary energy to avert planning or operating shortages" is not true. The first condition to selling secondary energy is that it exists: "BPA only sells secondary when it is determined to be available." Second, there must be a market: "BPA only sells secondary when there is a purchaser." Therefore, the IOUs' argument regarding BPA's determination of when to sell secondary energy is an overstatement.

The IOUs state reserve benefits are achieved through BPA's rights to interrupt, curtail or otherwise withdraw power that is supplied to customers. IOU Br., WP-07-B-JP6-01, at 75. The IOUs contend BPA is able to achieve such reserve benefits in at least two ways. *Id*. First, BPA achieves such reserve benefits by controlling the duration of its sales of surplus energy in the real-time, day-ahead, balance-of-month, and forward electricity markets. *Id*. By controlling the duration of such surplus sales, BPA can withdraw power from the wholesale market when such power is needed for its regional firm power customers. *Id*. at 75-76. Second, BPA may establish these rights through contractual recall provisions. *Id*. at 76.

Staff granted that at most these sales provide operational benefits, not planning benefits. Doubleday, *et al.*, WP-07-E-BPA-85, at 125. The ability to withdraw sales from the market is limited to the term of the availability of the power supply supporting the surplus sales. *Id*. at 126. Because almost all of BPA's surplus sales are from secondary energy, there is no long-term benefit from the withdrawal of the sales, and there is no planning benefit from the ability to withdraw the sales from the market. *Id*. Secondary energy is by its nature a power supply that cannot be known to be available until BPA is within the operating year and can observe precipitation. *Id*. There are no planning benefits from such a power supply. *Id*.

Further, the IOUs state that reserves come through "controlling the duration" of surplus power sales, and BPA "may establish these rights through contract." IOU Br., WP-07-B-JP6-01, at 76. However, section 3(17) of the Northwest Power Act states that "[r]eserves" means the electric power … provided by *specific* contract provisions…" 16 U.S.C. § 839a(17) (emphasis added). The IOUs argue that general contract terms, such as duration, constitute reserves.

The Northwest Power Act, as amplified by the Senate Report ("from specifically identified resources or rights," S. Rep. No. 96-272, 96th Cong., 1st Sess. 23 (1979)), focuses on specific contract rights included for the purpose of ensuring a contract provides reserves, not general contract rights inherent in all contracts, such as duration.

The IOUs state BPA has established its right to interrupt, curtail or otherwise withdraw power supplied to customers through contractual recall provisions. For example, BPA has included such contractual recall provisions in at least two general categories of sales: (i) sales made prior to May 8, 2007, under the Western Systems Power Pool ("WSPP") Agreement Schedule C, and (ii) certain sales of power delivered outside the region. IOU Br., WP-07-B-JP6-01, at 76. Reserves include BPA's rights to interrupt, curtail, or otherwise withdraw sales of surplus power when necessary. *Id*. BPA sells surplus energy in the real-time, day-ahead, balance-of-month, and forward electricity markets, controlling the duration of those sales so that BPA can withdraw power from the wholesale market when needed for its regional firm power customers. *Id*. BPA's wholesale market surplus sales thus benefit, and avoid service and cost risks to, BPA's utility firm power loads in the region. *Id*. BPA may establish these rights through contractual recall provisions or through power sales for limited terms (*e.g.*, hour-ahead, hourly, day-ahead, balance-of-week, balance-of-month, monthly, and seasonal). *Id*. This ensures that such BPA surplus power sales benefit and do not pose service and cost risks to BPA's firm power load in the region under sections 5(b), 5(c) and 5(d) of the Northwest Power Act. *Id*.

As noted above, the fact that BPA's surplus sales are made for different terms does not constitute reserves within the meaning of section 7(b)(2)(E). BPA has sold surplus power for decades but has never considered such sales to be anything similar to the type of reserves previously provided by the DSIs. In order to do so, surplus power contracts would have to include provisions similar to those previously included in DSI power sales contracts. Reserves are not any resource that might generally be construed to provide power to BPA, but rather resources that are specifically designated to be called upon for reserves in particular circumstances. Reserves means "electric power needed to avert *particular* planning or operating shortages for the benefit of firm power customers …" 16 U.S.C. § 839a(17) (emphasis added). In addition, just as reserves must be intended to meet particular operating and planning shortages, power sales must provide "rights to interrupt, curtail, or otherwise withdraw, *as provided by specific contract provisions*." *Id*. (emphasis added). Thus, specific reserve rights must be included in power sales contracts in order for BPA to receive reserves from such sales.

WPAG notes that reserves are generally defined as either generation that can be called upon or firm load that can be interrupted within a specified time period to support an electrical system such as BPA's Federal power system, and are required for the reliable operation of such power system. WPAG Br., WP-07-B-WA-01, at 45. Operating reserves consist of spinning and non-spinning reserves (contingency reserves) and regulating reserves. *Id*. at n. 8. "Regulating reserves" are capable of immediately responding to the moment-to-moment changes of automatic generation control, and "spinning reserves" need to be on line, responsive to frequency deviations and fully available within ten minutes. *Id*. Non-spinning reserves are generating resources capable of serving demand within ten minutes, or interruptible load that can be removed from the system within ten minutes. *Id*. In short, reserves are composed of either firm generation or firm load that is reliably available to be called on in short order when needed. *Id*., *citing generally* WECC, NERC/WECC Planning Standards and Minimum Operating Reliability Criteria, Definitions (August 2002).

On the Federal system, firm energy capability is defined as the amount of energy that can be generated under critical water conditions, which are usually the worst streamflows of record during a specific period. WPAG Br., WP-07-B-WA-01, at 45. Secondary energy is energy generated by water conditions in excess of critical water conditions, and which is deemed for planning purposes to be too uncertain to occur to be relied upon to serve firm load. *Id*. Although some amount of secondary energy is likely to occur during a year, the amount and timing are unpredictable, and it is certainly not uniformly available across the months of a year. *Id*. Because the timing and amount of secondary energy are insufficiently reliable to be used to serve firm load, they are similarly insufficiently reliable to provide reserves to ensure service to firm loads. *Id*. Energy that may or may not be there when it is needed does not qualify as a reserve. *Id*.

Surplus firm power is power that is forecast to be generated under critical water conditions for which BPA has no forecast or existing load service obligation. WPAG Br., WP-07-B-WA-01, at 46. Although available on the system prior to being committed for sale, surplus firm power could hypothetically qualify for use as reserves. *Id*. However, its continued availability is suspect on a planning basis because BPA seeks to sell any surplus to cover its costs, and once sold it is unavailable to be called upon to support the Federal system. *Id*. PPC reiterates WPAG's argument, noting that neither BPA's sales of secondary energy nor firm surplus energy provides the kind of reserves that are necessary to support the reliable operation of the Federal power system, and they are not comparable in either reliability or availability to the types of reserves obtained in the past from BPA's rights to interrupt DSI load, served under section 5(d) of the Northwest Power Act, on very short notice. PPC Br., WP-07-B-JP25-01, at 45.

WPAG and PPC present compelling arguments. The ability to use surplus sales as reserves is highly suspect. First, surplus sales are firm within the hour. Once scheduled, and delivery for the hour has begun, the power cannot be interrupted except for *force majeure*. As WPAG has demonstrated, a firm sale within the hour cannot constitute operating reserves, whether spinning or regulating, which must be available immediately, or non-spinning, which must be available within 10 minutes. Second, as described by WPAG, most surplus sales cannot be counted as planning reserves because their certainty cannot be ascertained until after the planning window has closed.

As noted previously, Staff acknowledges it is possible to construe surplus power as providing some type of reserves. Doubleday, *et al.*, WP-07-E-BPA-85, at 127. However, the important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used for purposes of the section 7(b)(2) rate test. *Id*. The proposed Implementation Methodology instructs they do not. *Id*., *citing* Proposed Implementation Methodology, WP-07-E-BPA-50, Attachment B, at IM-9. The proposed Implementation Methodology instructs that Reserve Benefits stem from an action that "forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions." Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, Proposed Implementation Methodology, at IM-4. Surplus sales do not meet this test due to the inability to interrupt them during an hour and the period of commitment of the sale.

D. Reserves Resulting from the Administrator's Actions under the Act

Section 7(b)(2)(E) of the Northwest Power Act directs BPA to assume the quantifiable monetary savings to preference customers resulting from "reserve benefits *as a result of the Administrator's actions under this Act*" were not achieved. 16 U.S.C. § 839e(b)(2)(E) (emphasis added). The IOUs argue that BPA surplus sales in the wholesale market, such as those under the FPS-07 rate schedule, are made under the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 76-77. The IOUs note BPA adopted the FPS-07 rate in the WP-07 proceeding for its surplus power sales in the wholesale power market:

> BPA has sold, and will continue to sell, secondary energy in the real-time, day-ahead, balance-of-month and forward electricity markets. BPA engages in sales (and purchase) transactions with most of the major participants in the West Coast wholesale energy market. Like other market participants, BPA, in all of the

> aforementioned transactions, adheres to Western Systems Power Pool (WSPP) contract terms and conditions, which reflect industry standards. The proposed FPS-07 rate will be used in all of the transactions just described.

Id., *citing* Mainzer, *et al.*, WP-07-E-BPA-26, at 5. BPA described the purpose of the FPS-07 rate schedule as follows:

> BPA developed the FPS-07 rate schedule to replace the FPS-96R rate schedule which expires on September 30, 2006. As with the FPS-96R rate schedule, BPA's overall objective of the FPS-07 rate schedule is to provide BPA with a degree of flexibility so that it can effectively market surplus firm energy from the Federal Columbia River Power System (FCRPS) in the West Coast wholesale energy market.
>
> Factors such as weather, time of year, and fish and wildlife constraints cause generation levels available from BPA's hydro-based system to vary widely from year-to-year, month-to-month and even day-to-day. In addition to this wide variation in BPA's surplus energy amounts, BPA must manage variations in load. As a consequence of these competing factors, BPA must routinely participate in the West Coast wholesale market—both selling power when a surplus exists, and buying to make up any shortfalls.
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> * * * *
>
> At least as early as the 1987 Wholesale Power and Transmission Rate Proceeding (WP-87), the Administrator concluded that he had the authority to establish a type of market-based rate. *See*, WP-87-A-02 at 242-251 (discussing the Market Transmission rate, MT-87). Later, in the WP-96 rate case, BPA pointed out that section 7(e) of the Northwest Power Act grants the Administrator considerable rate design discretion, including the ability to employ rate designs that use a market-based approach. *See*, WP-96 Administrator's Final Record of Decision, WP-96-A-02 at 457. The Agency further found that section 7(e) and its legislative history make clear that BPA's cost allocation directives concern the amount of revenues to be recovered from customer classes, and not the design of the rates to recover those revenues. *Id.* at 458. Therefore, in the aggregate, BPA's rates must be, and are, designed to recover BPA's total costs.
>
> The proposed FPS-07 rate schedule, like its predecessors the FPS-96 and FPS-96R rate schedules, provides BPA with improved assurance of cost recovery and an enhanced ability to keep rates low. Revenues under the FPS-07 rate schedule are credited against BPA's revenue requirement and, as such, FPS-07 will serve as one component of BPA's overall rate structure to ensure that, in the aggregate, BPA recovers its overall costs.

Id. at 77-78, *citing* Mainzer, *et al.*, WP-07-E-BPA-26, at 3-4. The IOUs claim the foregoing quoted language demonstrates that BPA has concluded that the Northwest Power Act authorizes

BPA to adopt market-based rates "so that it can effectively market surplus firm energy from the Federal Columbia River Power System ('FCRPS') in the West Coast wholesale energy market." *Id*. The IOUs argue, in short, that BPA's sale of surplus power at market-based rates is a "result of the Administrator's actions under this chapter [(the Northwest Power Act)]." *Id*. at 78. Some preference customer groups contend otherwise.

WPAG argues that because BPA was making secondary and surplus firm power sales long before the Northwest Power Act was passed, such surplus firm power and secondary sales do not provide reserves as a result of the Administrator's actions under the Northwest Power Act and therefore cannot be categorized as reserves for purposes of implementing the section 7(b)(2) rate test. WPAG Br., WP-07-B-WA-01, at 46. PPC similarly argues that neither the Federal power system's production of surplus and secondary energy nor the Administrator's sale of that energy can reasonably be characterized as the result of the Administrator's actions "under" the Northwest Power Act. PPC Br., WP-07-B-JP25-01, at 45. PPC claims it necessarily follows that any purported "reserves" available as a result of these sales cannot yield any "quantifiable monetary benefits" of the kind contemplated by section 7(b)(2)(E). *Id*.

Under WPAG's and PPC's logic, reserves BPA obtained from the DSIs also could not be considered as reserves for purposes of section 7(b)(2). This is because BPA previously included interruptibility provisions in the DSIs' pre-Northwest Power Act contracts, which provided BPA with reserves. All parties acknowledge that DSI reserves qualify as reserves for purposes of the section 7(b)(2) rate test. The fact that reserves were available prior to the Northwest Power Act does not preclude them from being "a result of the Administrator's actions under this [Northwest Power] Act" if the Administrator's actions under the Act enable such reserves. In the instant case, the Administrator has entered into surplus power contracts under section 5(f) of the Northwest Power Act and, as the IOUs have noted, has established rates under the Act in order to accommodate such sales. 16 U.S.C. §§ 839c(f), 839e(f). Nevertheless, and more importantly, this does not mean that surplus power sales provide the type of reserves that are intended to be reflected in section 7(b)(2).

E. BPA's Sales Under WSPP Agreement Schedule C and Reserves

The IOUs state that prior to May 8, 2007, sales under the WSPP Agreement Schedule C expressly permitted interruptions for reasons other than reliability, including "to meet [the] Seller's public utility or statutory obligations to its customers." IOU Br., WP-07-B-JP6-01, at 79. The WSPP filed a revision to the WSPP Agreement Schedule C on March 9, 2007, to allow interruptions only for reasons of reliability of service to native load. *Id*. FERC approved WSPP's proposed revision effective May 8, 2007. *Id*. During the period FY 2002 through May 7, 2007, BPA sold power under the WSPP Agreement Schedule C, which contained recall provisions. *Id*. *citing* Response to Data Request No. JP6-BPA-43. In the Supplemental Response to Data Request No. JP6-BPA-44, Staff confirmed that its sales under the WSPP Agreement Schedule C during that period included recall provisions that permitted interruptions "to meet Seller's public utility or statutory obligations to its customers." *Id*.; *see* Response to Data Request No. PP-JP6-13; Supplemental Response to Data Request No. JP6-BPA-44, set forth in Exhibit WP-07-E-JP6-13. The IOUs state that prior to May 8, 2007, the WSPP Agreement Schedule C specifically provided BPA the ability to interrupt power deliveries to meet BPA's public utility or statutory obligations to its customers. *Id*. Such WSPP Agreement Schedule C sales were available to BPA "from rights to interrupt, curtail, or otherwise withdraw" and, therefore, constitute "reserves" under the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 80. Therefore, BPA's sales under WSPP Agreement Schedule C clearly provided reserves to BPA prior to May 8, 2007. *Id*.

This is consistent with Staff's statement that surplus sales provide operating reserves, but does not establish that such reserves are those to be reflected in the 7(b)(2) rate test. Doubleday, *et al.*, WP-07-E-BPA-85, at 128-129. As noted previously, the reserves provided by contracts must be needed to avert *particular* planning or operating shortages for the benefit of firm power customers, and must include *specific contract provisions* to enable the exercise of such reserves. 16 U.S.C. § 839a(17). The cited contracts do not satisfy these criteria. Also, the ability to "interrupt" such sales is based on the seller's "public utility and statutory obligations," which are statutory constraints that apply generally to BPA's surplus power sales. For example, BPA's surplus power sales must respect public preference and the requirements of the Regional Preference Act. 16 U.S.C. § 839c(a); 16 U.S.C. § 837; 16 U.S.C. § 839f(c). As discussed below, however, these are general requirements that apply to all BPA surplus sales and are not specific provisions to provide particular reserves. Even assuming *arguendo* that WSPP sales prior to May 8, 2007, provided reserves consistent with section 7(b)(2)(E), the section 7(b)(2) rate test is not backward-looking. Past sales cannot be considered as reserves during the Five-Year Period.

The IOUs argue the Draft ROD erroneously argues that the WSPP Schedule C sales contracts prior to May 8, 2007, do not provide reserves consistent with the statutory definition of the term and consistent with section 7(b)(2)(E). IOU Br. Ex., WP-07-R-JP6-01, at 29. The IOUs claim the Draft ROD's argument ignores the fact that the WSPP Schedule C sales contracts included a specific contract provision that allowed for Interruptions, which is quoted in the Draft ROD at page 492. *Id*. The IOUs contend nothing in the definition of "reserves" in the Northwest Power Act requires that the specific contract provision providing the reserves list or otherwise denominate any particular planning or operating shortages for which deliveries under the contract may be interrupted. *Id*. The IOUs argue the specific contract provision satisfies the statutory definition of "reserves" so long as the contract provision allows BPA, when faced with "particular planning or operating shortages," to interrupt, curtail, or otherwise not make deliveries. *Id*. In response, the determination of rates and the conduct of the 7(b)(2) rate test is a forward-looking exercise of the projected costs, revenue credits, and the projected sales (load amounts) over which the projected costs would be allocated. In both the WP-02 and WP-07 rate cases, BPA did not forecast any sales under WSCC Schedule C. As noted below, the conduct of the Lookback analysis has been performed from a perspective of what was known at the time revised base rates would have been developed in June 2001 for setting FY 2002-2006 rates, and in the fall of FY 2006 for FY 2007-2009 rates. The fact that actual sales under the WSCC Schedule C occurred is not relevant to this forward-looking exercise.

In addition, the point of section 7(b)(2)(E)(ii) is to quantify the difference in cost of acquiring reserves between the Program Case and the 7(b)(2) Case. In this instance, if any reserves were attributable to these sales (BPA's fundamental position is that the ability to recall or interrupt these sales does not constitute reserves) there would not be a difference in the cost of acquiring these reserves between the two Cases. The amount of these sales and their costs would be the same in the two Cases. Thus, there would not be an additional cost element of acquiring these "reserves" in the 7(b)(2) Case. The nature of WSCC Schedule C sales is different than the reserves addressed in the Fifth Assumption of section 7(b)(2). This assumption concerns the replacement of reserves associated with, for example, DSI sales in the Program Case when they are served with interruptible firm power or non-firm power, whereas in the 7(b)(2) Case the DSI loads are served with non-interruptible firm power. There is a difference in cost to replacing reserves created by DSI interruptible firm sales and non-firm in the Program Case. Because the character and composition of WSCC Schedule C sales are the same in both Cases, there is no inherent difference in the cost of any reserves associated with these sales if they existed.

The IOUs argue the Draft ROD's assertion that BPA's "public utility and statutory obligations" are "statutory constraints that apply generally to BPA's surplus power sales" misses the point. IOU Br. Ex., WP-07-R-JP6-01, at 30. The IOUs state WSPP Schedule C provision prior to May 8, 2007, allowed BPA to interrupt surplus power sales under WSPP Schedule C when needed to meet BPA's "public utility and statutory obligations," e.g., obligations to deliver power under BPA's Northwest Power Act section 5(b) requirements. *Id*. The IOUs state there is no requirement that the contract provision providing the right to interrupt be tied to a particular planning or operating shortage identified in such contract provision. *Id*. As noted above, however, if there were reserves associated with the WSPP Schedule C sales, the amount of the reserves and their costs would be the same in both Cases. The point of section 7(b)(2)(E)(ii) is to quantify the difference in cost of acquiring reserves between the two Cases and, because there is no difference, there is no substance to the IOUs' arguments on this issue.

The IOUs note the Draft ROD states that inclusion of WSPP Schedule C sales prior to May 8, 2007, in reserves under section 7(b)(2)(E) would be inappropriate because it would be "backward-looking." IOU Br. Ex., WP-07-R-JP6-01, at 30. The IOUs state BPA should recognize in any Lookback analysis that WSPP Schedule C sales contracts prior to May 8, 2007, provide reserves for purposes of section 7(b)(2)(E). *Id*. In response, however, BPA's approach to similar arguments in determining the Lookback is addressed in greater detail elsewhere in this ROD. Basically, BPA is placing itself in the winter/spring of 2000/2001 when BPA was developing a supplemental rate proposal, and determining how BPA would have developed a revised base PF Exchange rate in the absence of the REP Settlement Agreements. Because BPA's base rates were established prior to significant increases in public agency loads and market prices for power, the base rates initially established in May 2000 were inadequate to recover BPA's costs and could not be approved by FERC. BPA then developed CRACs to address BPA's cost recovery problems. In the absence of the REP Settlement Agreements, however, BPA would have conducted the 7(b)(2) rate test in order to establish revised base rates, including the PF Exchange rate. In developing the PF Exchange rate that would have been established absent the REP Settlement Agreements, BPA uses the information available at the time BPA developed its supplemental WP-02 proposal. Despite the fact that BPA did not expect the IOUs to sign new RPSAs to participate in the REP, parties to BPA's initial WP-02 rate case were still responsible for raising issues regarding the rate test. BPA responded to these issues in the May 2000 ROD. If a party did not raise an issue, however, BPA logically assumes that BPA would not have addressed such issue in the supplemental WP-02 rate case. No party argued in the WP-02 rate case that WSPP Schedule C sales provide BPA with reserves. BPA therefore assumes it would not have addressed the issue in developing a revised WP-02 PF Exchange rate.

F. BPA Rights to Interrupt, Curtail, or Otherwise Withdraw Power Deliveries Outside the Region and Reserves

The IOUs argue that any BPA rights to interrupt, curtail, or otherwise withdraw power deliveries to outside the region provide reserves. IOU Br., WP-07-B-JP6-01, at 81. The IOUs claim BPA is required by statute to include, in at least some of its contracts for the sale or exchange of surplus energy for use outside the Pacific Northwest, contract provisions pursuant to which BPA may terminate deliveries of electric energy under such contracts whenever "it can reasonably be foreseen that such delivery would impair [BPA's] ability to meet … the energy requirement of any Pacific Northwest customer." *Id.*, *citing* 16 U.S.C. § 837b(a). The IOUs state BPA's contracts for the disposition of surplus peaking capacity must also include provisions providing for termination of the contracts. *Id.*, *citing* 16 U.S.C. § 837b(c).

The IOUs note that in Response to Data Request No. JP6-BPA-44, Staff indicated it has a number of contracts for power sales outside the region. IOU Br., WP-07-B-JP6-01 at 81. The IOUs argue BPA should recognize that any rights to interrupt, curtail, or otherwise withdraw power deliveries outside the region provide reserves. *Id.* The IOUs claim that BPA fails to adequately address any contractual rights to interrupt, curtail, or otherwise withdraw power deliveries outside the region and fails to recognize that any such contractual rights provide reserves. *Id.* The IOUs state BPA has recognized that it has exercised recall rights under contracts (and has not renewed contracts for surplus sales) in the wholesale power market when the power was needed to serve BPA's firm loads. *Id.* For example:

> With the Northwest facing power shortages as early as this winter, BPA is giving notice to its California customers that long-term contracts for surplus and excess federal power sales will not be renewed. Where contracts have recall or conversion rights, BPA is exercising those rights. BPA sold several hundred megawatts of power to California when the Northwest had surplus and excess power.
>
> *By law, BPA is directed to sell outside the Northwest only power that is surplus to the region's needs.* Buyers have different rights under each contract. Where contract terms allow, BPA can convert energy sales into capacity exchanges or give notice of termination. In contracts that contain no recall or conversion provisions, BPA is notifying California buyers that contracts will not be renewed.

Id. at 81-82, *citing* "BPA Recalls California Contracts," *BPA Journal* (Oct. 2000), at 3 (emphasis added). The IOUs state that when the cold snap hit, BPA reduced its surplus sales to meet required loads in the Northwest. IOU Br., WP-07-B-JP6-01, at 82. BPA structures surplus sales to gain revenue while retaining the ability to recall the power when it is needed. *Id.* Revenue gained from selling surplus power is used to offset power purchases when Northwest loads exceed BPA capacity. *Id. citing* "Power Demand Soars as Temperatures Plummet," BPA Press Release (Feb. 2, 1996), at 1.

The IOUs cite section 3(a) of the Regional Preference Act, which states that:

> [a]ny contract for the sale or exchange of surplus energy for use outside the Pacific Northwest … shall provide that the Secretary, after giving the purchaser notice not in excess of sixty days, will not deliver electric energy under such contract whenever it can reasonably be foreseen that such delivery would impair his ability to meet, either at or after the time of such delivery, the energy requirement of any Pacific Northwest customer.

16 U.S.C. § 837b(a).

Rights to terminate deliveries outside the region on specified notice, such as those included in contracts pursuant to the Regional Preference Act, do not provide the type of reserves referenced in section 7(b)(2)(E). 16 U.S.C. § 837. The notice of termination of delivery requirements under the Regional Preference Act are *sixty months* for capacity (*five years*) and *sixty days* for energy. *Id*. The reserves BPA previously obtained from the DSIs are of a different character. The report of the House Committee on Interior and Insular Affairs describes the reserves obtained from the DSIs:

> Sales to the DSIs are required under this subsection to continue to provide a portion of BPA's power system reserves. The Committee understands and intends that the new DSI contracts under the legislation will provide capacity reserves similar to those provided in the present contracts. Fifty percent of the then operating DSI load may be restricted to for a period of up to two hours to provide a forced outage or peaking power reserve. One hundred [sic] per cent of the DSI load may be restricted by BPA for up to five minutes whenever frequency problems arise on the regional grid.
>
> The DSIs will also provide two types of energy reserves. Approximately 25 percent of the DSI load is to be treated as firm load for purposes of resource operation and will provide an operating reserve that may be restricted at any time in order to protect the Administrator's firm loads within the region and for any reason, including low or critical streamflow conditions and unanticipated growth of regional firm loads. An additional 25 percent of the DSI load will be treated as a firm load for both planning and operating purposes and will provide a planning reserve to protect the Administrator's firm loads against the delayed completion or unexpectedly poor performance of regional generating resources or conservation measures implemented or acquired by BPA.

H.R. Rep. No. 96-976, Part II, 96th Cong., 2d Sess. 48 (1980). The reserves previously provided by the DSIs cannot be achieved through the generic implementation of regional preference provisions in surplus sales. For example, similar to the points WPAG established previously, surplus sales (much less one hundred percent of such sales) cannot be interrupted at any time for five minutes to address regional frequency problems. The DSI contracts show the specific types of contract provisions that are intended to meet particular planning or operating shortages.

Further, BPA has been making extraregional sales for decades under the Regional Preference Act (since 1964). BPA's past extraregional surplus power sales necessarily included certain statutory termination of delivery rights, but such sales have never been considered as reserves in the same sense as those provided by the DSIs. In any event, there are only two extraregional contracts remaining during the Five-Year Period. Of these, only one contract is subject to the 60-day notice of restriction. Even assuming *arguendo* the Regional Preference Act's 60-day notice requirement provided reserves as contemplated in section 7(b)(2)(E), BPA has only one such sale.

BPA has one power sale that is subject to the five-year notice of restriction. The Regional Preference Act provides that:

> [a]ny contract for the disposition of surplus peaking capacity shall provide that (1) the Secretary may terminate the contract upon notice not in excess of sixty months, and (2) the purchaser shall advance or return the energy necessary to supply the peaking capacity, except that the Secretary shall not require such advance or return during the purchaser's daily peak periods.

16 U.S.C. § 837b(c). This provision requires sixty months (5 years) notice for termination of deliveries. The section 7(b)(2) rate test compares rates for the year plus the ensuing four years, the Five-Year Period. Although the identical time frames in these two sections may be coincidental, the fact that both are five years militates against any likelihood that sales under section 3(c) of the Regional Preference Act would produce any reserves during the Five-Year Period. Also, because the Supplemental Proposal covers a one-year test period, the Five-Year Period in this proceeding is a true five years, meaning that any notice given to recall out-of-region contracts would not be effective during the Five-Year Period.

In summary, although BPA's extraregional sales must comply with the notice provisions in the Regional Preference Act for energy and capacity sales, respectively, the compliance with such provisions does not provide BPA with reserves as intended in section 7(b)(2)(E). In any event, the number of existing BPA contracts subject to the 60-day or 60-month termination of delivery provisions is very limited.

G. Reserve Benefits and the Diminution of DSI Load

The IOUs state that Exhibit WP-07-E-JP6-10 represents what BPA considers to be its DSI and surplus sales by year for the period FY 1981-2007 and shows the linear trend of those sales during the same period. IOU Br., WP-07-B-JP6-01, at 84. The IOUs claim this linear trend indicates the amount of BPA surplus sales has trended up during the period, while the amount of BPA DSI sales has trended down. *Id*. at 84-85. The IOUs assert these trends are consistent with BPA's surplus sales tending to replace DSI sales during the period. *Id*. at 85.

The IOUs and CUB argue BPA is no worse off today in terms of reserves because of the diminution of DSI load. IOU Br., WP-07-B-JP6-01, at 85; CUB Br., WP-07-B-CU-01, at 8. They state the value of surplus sales has increased dramatically over recent years such that BPA has not lost reserve benefits because of DSI load diminishing. *Id.* They claim, in fact, the reserve benefits available to BPA from its surplus power sales in the wholesale power market are superior in several respects to those it previously received from its sales to DSIs. IOU Br., WP-07-B-JP6-01, at 85. For example, the DSI reserves provided recall or interruption rights only for specified portions of the power sales to the DSIs and only for specified purposes and durations. *Id*. By contrast, BPA has much more flexibility in its wholesale market surplus sales to establish withdrawal or recall rights through limitation of the term of the sale and otherwise. *Id*.

Staff did not agree that BPA's surplus sales are "tending to replace DSI sales during the period." Doubleday, *et al.*, WP-07-E-BPA-85, at 130. Simply because two things occur at the same time does not mean one is a causal factor of the other. *Id*. DSI sales are firm power sales. *Id*. Surplus sales are almost entirely secondary sales. *Id*. Firm power is not the same as secondary power. *Id*. If the IOUs had also included sales to preference customers, they would have discovered an upward trend as well. *Id*. Sales to preference customers are firm power sales. *Id*. It is much more likely that sales to preference customers have replaced the sales to DSIs, as they are both sales of firm power. *Id*. Also, the diminution of sales to the DSIs has other causal factors, including BPA's marketing decisions and DSI business operating decisions, not whether secondary power was being sold by BPA. *Id*. Further, it is Staff's understanding that the increase in surplus sales is driven more by the supply of secondary power than the diminution of sales to the DSIs. *Id*. The increase in the supply of secondary power is a result of the increased requirements of fish operations on the river, resulting in less firm power generation and more secondary power generation. *Id*. Therefore, the IOUs' claim that surplus sales are replacing DSI sales is more a matter of coincidence of timing than causality. *Id*. at 130-131. Surplus sales are not a replacement for DSI sales. *Id*. at 131. Staff agrees that in theory the recall rights provided by surplus sales could be superior to the recall rights provided by sales to the DSIs if it were BPA's practice to write surplus sales contracts with total recall provisions. *Id*.

Thus, the IOUs' and CUB's argument is not persuasive. Surplus sales have not replaced sales to DSIs. The two do not equate. Even if surplus sales did replace DSI sales, the reserves provided under the two classes of contracts are not the same. Finally, the argument that the value of surplus sales has increased over recent years and therefore BPA has not lost reserve benefits is a *non sequitur*. The value of surplus sales does not provide reserves or Reserve Benefits. Reserves are provided by electric power, not money.

H. Reserves in the Program Case and 7(b)(2) Case

The IOUs state that Staff appeared to argue during cross-examination that even if BPA's surplus sales provided reserves within the meaning of the Northwest Power Act section 7(b)(2)(E)(ii), such reserves would provide no quantifiable monetary savings because under BPA's analysis such reserves and their savings would occur in both the Program Case and the 7(b)(2) Case:

> [surplus sales] occur in both cases as surplus sales. So the rationale that's being offered here is that we – because those surplus sales occur in the 7(b)(2) case, we could turn to them, and since they are under this hypothesis a recognized source of reserves, we could turn to those surplus sales as a source of reserves. … So,

> therefore, presuming those sales provide the reserves, they would be provided at the same cost and the quantifiable savings would be zero.

IOU Br., WP-07-B-JP6-01, at 85-86, *citing* Tr. 340. BPA's fundamental premise is thus that the reserves from surplus sales would be "provided at the same cost" in both the Program Case and section 7(b)(2) Case. *Id*. at 86. The IOUs argue this premise is incorrect because BPA must assume that these reserves (and their quantifiable monetary savings) are not achieved in the 7(b)(2) Case. *Id*. If necessarily assumed to not occur in one Case, reserves and their savings by definition cannot occur in both Cases. *Id*.

The IOUs argue, in other words, that BPA projects surplus sales to occur in both the Program Case and the 7(b)(2) Case. *Id*. Surplus sales provide reserve benefits (as a result of BPA's action under the Northwest Power Act) that provide quantifiable monetary savings. *Id*. Thus, these surplus sales reserve benefits and their quantifiable monetary savings must be assumed *not* to be achieved in the 7(b)(2) Case. *Id*. However, BPA ignores this requirement (*i.e.*, to assume surplus sales reserve benefits and their quantifiable monetary savings were not achieved in the 7(b)(2) Case) and instead erroneously assumes that surplus sales are a permitted source of reserves in the 7(b)(2) Case because surplus sales are projected to occur in the 7(b)(2) Case. *Id*. The IOUs claim BPA's argument – contrary to the express requirement of section 7(b)(2)(E) – effectively fails to assume that reserve benefits as a result of BPA's surplus sales under the Northwest Power Act were not achieved. *Id*. at 86-87. BPA's approach fails to give any effect to the language of the Northwest Power Act that requires BPA to assume that reserve benefits were not achieved. *Id*. at 87.

BPA disagrees that this approach fails to give any effect to the statutory language. The question here is whether section 7(b)(2)(E) instructs that BPA, in determining the Quantifiable Monetary Savings, can or cannot consider the same source of reserves if such source is available in the 7(b)(2) Case. Section 7(b)(2) states that the Administrator is to assume that –

> the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from –
>
> * * *
>
> (ii) 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), 839e(b)(2)(E). The statutory language is not instructive. Therefore, a review of the legislative history is appropriate.

The Senate Report introduces the concept of reserves by stating that "[a]mong the changes the Committee substitute makes are the following: Definitions of … 'direct service industrial customer', … and 'reserves' are provided in section 3." S. Rep. No. 96-272, 96th Cong., 1st Sess. 19 (1979). This shows that the definition of reserves was developed at the same time as the definition of a DSI.

The Report explains the intent of the definition of reserves:

> Section 3(n). – The term "reserves" is defined as electric power needed to avert particular planning or operating shortages, for the benefit of firm power customers, and available to the Administrator from specifically identified resources or rights. In this section, the term "firm power customers of the Administrator" is intended to mean the firm power loads of such customers. It is not intended that the Administrator's reserves will be used to protect other than firm loads.

Id. at 23. The next mention of reserves is specific to the reserves provided by the DSIs:

> The power quality provided the direct-service industries is determined by *the reserve obligations set forth in their contracts in order to protect service to firm loads* of the Administrator. It is intended that these contracts at least *provide peaking power reserves* similar to those provided in the present contracts, and that the *energy reserves* shall include a reserve approximately equal to 25 percent of the direct service industrial load *to protect firm loads for any reason*, including low or critical streamflow conditions, and an *additional energy reserve* of approximately the same amount *to protect firm loads* against the delayed completition [sic] or unexpectedly poor performance of regional generating resources or conservation measures, and against the unanticipated growth of regional firm loads.

Id. at 28 (emphasis added). The foregoing quotation helps explain the intent of reserves. Reserves are meant to protect firm loads. The foregoing paragraph details the contractual provisions expected in DSI contracts. These provisions were to provide peaking reserves and energy reserves. The energy reserves were to protect firm loads for any reason, including low or critical streamflow conditions. Additional energy reserves were to protect firm loads against resource contingencies.

The next mention of reserves is again specific to DSIs:

> Section 7(d)(2). – The Administrator is authorized to establish a special rate applicable to an existing direct service industrial customer whose continued operation would otherwise be threatened if: (1) it primarily uses raw materials which are indigenous to the region such as nickel ore, and (2) it accepts a contract similar to its existing modified firm power sales contract with the Administrator which provides that all the customer's power *provides reserves to meet firm loads* in the region.

Id. at 32 (emphasis added). In this case, the legislative history discusses a special rate applicable to a certain DSI under specific conditions, including if that customer agrees that all of its power purchase provides reserves. Another mention is specific to section 7(b)(2):

> (2) The cost of resources to meet these requirements are (a) the costs of available Federal Base System resources; (b) Costs of new resources, either actual or hypothetical, constructed or acquired by the public bodies and cooperatives as necessary to meet these preference customer load requirements using the financing costs of such agencies that would have resulted if actions of the Administrator under Section 6 of the Bill were not achieved; plus (c) *Any other general system operating costs including reserves*, related to service to such customers.

Id. at 58 (emphasis added). This is one of very few discussions of reserves specific to section 7(b)(2)(E), where the costs of reserves are included in other general system operating costs. The legislative history also notes:

> a. Rate Availability. This rate applies to all "Industrial Firm" sales to BPA's direct-service industries *which provide planning and operating reserves*. … The operation of the System to carry out this purpose results from treating as a firm load the maximum amount of the DSI load (not all of which can be covered under critical streamflow planning), to the extent that this maximum load can be met in the initial period of the PNW Coordination Agreement Critical Period while protecting firm loads against the worst historical streamflow and maintaining an ability to restrict an equivalent amount of the DSI Loads in the later periods (without provisional or advance energy being made available for this amount of the DSI load). Further, in actual operation DIS [sic] power withdrawn or curtailed in excess of interruptions for critical streamflows would be replaced by power purchased by BPA on a short-term basis, if available.

Id. at 59 (emphasis added). The foregoing mention of reserves deals directly and specifically with the rate paid by DSIs. The legislative history also states:

> (1) 1980-81 through 1984-85. The industrial rates will be set to the levels estimated to be necessary to offset the increased costs to BPA which result from the purchase of IOU exchange power to the extent those costs are not covered through rates applicable for the other classes of power sold by BPA. Generally the costs will be shared during this period with any sales of excess firm, IOU load growth, new large industrial loads of preference customers, and contract demand sales for other special purposes. The rates will be applied to the entire projected availability. *This rate is adjusted for the reserve benefits the contracts provide.*

Id. (emphasis added). This mention of reserves deals specifically with the rate paid by DSIs during the 1980-85 time period. A specific adjustment is given for the reserves provided. The legislative history also states:

> (2) 1985-86 and all future. The rate will be set at a level no less than that set for the year 1984-85 and that is equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial customers. This level is determined by applying a typical margin of cost ("markup" between the

> preference customers' retail industrial rates and their respective wholesale power costs) to the BPA wholesale rates to the preference customers for all power used to serve their industries. *The rate is then adjusted for reserves…*

Id. (emphasis added). This mention of reserves parallels the prior reference to reserves by noting the DSI rate adjustment for reserves beginning in 1985. The legislative history also states:

> (3) The rates set under paragraphs (1) and (2) above are adjusted to reflect the credits for the value of power system reserves made available to the region's power system through the ability of BPA to interrupt service to the DSI loads. These credits to the DSI rate are then shared as a cost of reserves to all firm power sales, including that portion of the DSI load considered as not providing these reserves (currently 50 percent of the DSI load).

Id. This paragraph provides specific information on the rate adjustments in the DSI rate for the reserves provided. The legislative history also states:

> b. The cost of reserves associated with firm sales. (Not charged to that portion of the DSI load providing *such reserves*.)

Id. at 60 (emphasis added). The costs of reserves are allocated to all power rates under section 7(g). Here the report language is specific that the costs of reserves are not charged to the portion of the DSI loads that provide such reserves. This language is instructive in that it ties the costs of reserves expected to be in BPA's rates to those being provided specifically by the DSIs. The legislative history also states:

> The specific rate limit factors are objective in nature. The first, the size and cost of the Federal Base System Resources, will be determinable in much the same way that BPA applies in its current power marketing operations and ratemaking. The size and location of DSI loads with respect to preference customer service areas are also easily identified. The amount of new resources needed to meet preference customer load growth, including the applicable DSI load, and its cost may require some minor estimating. This is principally because preference customer resource construction probably will never exactly match preference customer load growth (high or low). The monetary benefits which would not be available to preference customers without the program will be the hardest to determine. This analysis limits its consideration to two specific areas, lower financing costs and *lower system planning and operating reserve costs*. Consideration of other savings may be appropriate if they can be stated and quantified in an objective manner and they are not recognized in A.5. All these items will be fully reviewed in the normal rate setting process.

Id. at 61. The foregoing paragraph is quite specific regarding reserves, particularly because it is speaking expressly to the section 7(b)(2) rate test. This speaks directly to the Quantifiable Monetary Benefits in section 7(b)(2)(E), limiting them to lower financing costs and lower reserve costs. This language limits the consideration of Quantifiable Monetary Benefits from other sources to those that can be stated and quantified in an objective manner and not recognized in paragraph A.5, which speaks to section 7(g). The legislative history also states:

> 5. Reserves.
> a. The value of reserves provided by the right to interrupt the DSI load was calculated for each year in the following manner (no attempt was made to treat energy and capacity reserves separately)
>
> 1. The average megawatts of regional reserves being provided are normally considered to be one-half the DSI load. A more precise estimate is determined by taking one quartile of the DSI load plus whatever portion of the top quartile is assumed to be available in the given year.
> 2. The average cost of each megawatt of reserves is estimated by determining the capital costs (no O&M) associated with all of the "new resources" that are in place in the given year and the total Federal Base System costs in that year.
> 3. Applying the resultant average cost to the amount of reserves provided yields the total number of dollars associated with these reserves. The method described here does not establish the only way to evaluate the value of the reserves, but instead is an attempt to arrive at a reasonable estimate for purposes of this numerical analysis.
>
> b. The amount of reserves applied to the preference customer rate limit computation is determined by
>
> 1. reducing the average cost of each megawatt of reserves by the ratio of the total rate limit load to the total program resources;
> 2. reducing the megawatts of reserves provided by the DSIs by the percent DSIs within or adjacent to preference customers (85 percent assumed);
> 3. applying the average cost to the number of reserve megawatts.
>
> c. The amount of Reserve Adjustment credited to the DSIs under this study of the program is equal to one-half of the total value of the reserves. Thus approximately one-half of the savings to the region, in not building standby generation reserves, was credited to the DSIs for providing these reserves, and the remaining one-half was shared among the region's firm loads including 50 percent of the DSI load. The crediting of 50 percent of the value of the reserves to the DSIs does not set a precedent for future BPA rate cases. The form of availability credit or other reserve credit mechanism to be applied is not meant to be specified or prejudiced by the assumptions that are here.

Id. at 63-64. This final mention in the text provides further direction about the valuation of reserves provided by the DSIs. The further references in the Report are in the numerical analyses where reserves are quantified. Notably, the numerical analyses always affix the value of reserves to those provided by the DSIs.

The Senate Report thus establishes an expectation that the provision of reserves would always be in relation to the DSIs. In its discussion of reserves, the Report cites the specific contract provisions that would provide the reserves to BPA. Despite the presence of surplus sales during the formulation of the Northwest Power Act, the Senate Report does not have any mention or expectation that surplus power sales would provide reserves under the Act. The silence on this matter is instructive. Congress did not expect generic surplus sales to provide reserves under the Act, despite such sales being a regular occurrence during the drafting of the bill. As noted previously, however, surplus sales may provide reserves in the event such sales contracts contain *specific* provisions needed to avert *particular* planning or operating shortages for the benefit of firm power customers. 16 U.S.C. § 839a(17).

I. Quantification of Reserve Benefits

The IOUs state that section 7(b)(2)(E) of the Northwest Power Act includes a requirement to assume that quantifiable monetary savings from reserve benefits as a result of BPA's actions under the Northwest Power Act were not achieved. IOU Br., WP-07-B-JP6-01, at 87. The IOUs state these quantifiable monetary savings reflect the amount or value of the reserve benefits. *Id*. The IOUs contend that the amount (or value) of reserve benefits provided by (i) BPA's secondary energy and (ii) BPA's rights to withdraw power sales is conservatively valued by use of BPA's operating reserve rate for its transmission customers. *Id*. The current rate applied by BPA for operating reserves is 7.93 mills/kWh ($7.93/MWh). *Id*. The IOUs claim this rate provides a reasonable but conservative benchmark for determining the amount of reserve benefits provided by (i) BPA's secondary energy and (ii) BPA's rights to withdraw power sales. *Id*. This conservative valuation of reserve benefits equals the product of (i) the BPA rate for operating reserves of $7.93/MWh and (ii) the projected secondary energy sales expressed in MWh. *Id*. Using this rate and BPA's secondary energy sales of 1,732 aMW for FY 2009, the IOUs claim a conservative valuation of reserve benefits provided by (i) BPA secondary energy and (ii) rights to withdraw surplus power sales is the following:

$$\$7.93/\text{MWh} \times (1{,}732 \text{ aMW} \times 8760 \text{ MWh/aMW}) = \$120.3 \text{ million.}$$

Id. at 87-88.

Staff noted that assuming, *arguendo*, surplus sales provide the type of reserves that meet the statutory direction provided in section 7(b)(2)(E), Staff would need to determine the value of the reserves being provided in the Program Case in order to compute the difference in costs from the 7(b)(2) Case. Doubleday, *et al.*, WP-07-E-BPA-85, at 131. In doing so, Staff would seek the least costly source of reserves in the 7(b)(2) Case. *Id*. Given the assumption that surplus power supplied reserves, Staff would note that the same amount of surplus sales is available in the 7(b)(2) Case as in the Program Case. *Id*. at 131-132. Therefore, the least costly source of reserves in the 7(b)(2) Case likely would be the same surplus sales used in the Program Case. *Id*. at 132. These reserves would have the same cost in both Cases, leading to no cost adjustment between the Cases. *Id*. This difference is not true of reserves supplied by DSIs. *Id*. If displaceable DSI loads supplied reserves in the Program Case, the same would not be true in the 7(b)(2) Case because there are no displaceable DSI loads in the 7(b)(2) Case. *Id*. Any within or adjacent DSI load served by the Administrator in the Program Case would become firm COU load in the 7(b)(2) Case. *Id*. Therefore, a cost differential between the two Cases can arise due to reserves being supplied by DSI power sales. *Id*.

Cowlitz argues that secondary sales do not provide "quantifiable monetary savings" relating to any reserve benefits as a matter of fact or law. Cowlitz Br., WP-07-B-CO-01, at 41. Because BPA's secondary energy sales now take place in a competitive marketplace, there are no "monetary savings" to be achieved from such sales even if they were to provide reserve benefits within the meaning of section 7(b)(2)(E). *Id*. Operating reserves must be available within a very short period of time to cover unplanned outages or other contingencies. *Id*., *citing* Schoenbeck and Beck, WP-07-E-JP17-01-CC1, at 10 (IOUs acknowledge "no longer than ten minutes"); *see also APAC*, 126 F.3d at 1164 (operating reserves "are called upon to replace generation failures"). None of BPA's short-term sales are interruptible in this fashion, and owing to the pressures of a competitive marketplace, all are classified as firm power. *Id.* To the extent that BPA sold power that was instantaneously interruptible in order to provide operating reserves, it would obtain a lower price for such power. *Id*. Selling secondary energy at a lower price in order to achieve operational reserves would not achieve any "quantifiable monetary saving" arising through section 7(b)(2)(E); it would merely reflect a decision by BPA to pay market value for such reserves. *Id*.

Cowlitz argues that for these reasons, BPA should clarify the Legal Interpretation to state that "*Quantifiable Monetary Saving from* Reserve Benefits *within the scope of § 7(b)(2)(E)(ii)* arise *only* from BPA's restriction rights on loads provided for in power sales contracts *at a cost to BPA less than the market value of such reserve benefits*" – *i.e.*, certain DSI contracts. Cowlitz Br., WP-07-B-CO-01, at 41-42, *citing cf.* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed 7(b)(2) Legal Interpretation, at LI-17. To the extent that BPA determined to secure reserves through restriction rights in market-based power sales, "reserves would be the same in both Cases, leading to no cost adjustment between the Cases." *Id*., *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 132.)

PPC also argues there is no purpose served by treating reserves that supposedly result from surplus and secondary sales as unavailable under the 7(b)(2) Case. PPC Br., WP-07-B-JP25-01, at 46. In addition to the unsound statutory foundation for treating surplus and secondary energy sales as a source of "reserve benefits" to be assumed away for purposes of the section 7(b)(2) rate test, there is a fatal logic problem as well. *Id*. If, as urged by CUB and the IOUs, we assume that (1) surplus and secondary energy sales can be deemed to provide "reserve benefits" within the meaning of section 7(b)(2)(E)(ii), 16 U.S.C. § 839e(b)(2)(E)(ii), (2) the actions of the Administrator under the Northwest Power Act produce these benefits, and (3) these benefits provide "quantifiable monetary benefits" within the meaning of 7(b)(2)(E), 16 U.S.C. § 839e(b)(2)(E), this still does not alter the results of the section 7(b)(2) rate test. *Id*. If these "reserve benefits" are assumed to exist for purposes of the Program Case, but not for the 7(b)(2) Case, then under the 7(b)(2) Case there is a reserve "hole" that needs to be filled. *Id*. The Administrator would need to fill this "hole" with the least costly reserves that would be available at that point. *Id*. If it is valid, from an operational and planning perspective, to treat surplus and secondary energy sales as sources of reserves, then assuming under 7(b)(2)(E) that these reserves did not occur would leave this source of reserves untapped. *Id*. These untapped reserves would become the appropriate resources for the Administrator to use to meet the now-unfilled need for reserves under the 7(b)(2) Case. *Id*. The entire process becomes circular and serves no purpose. *Id*. PPC concludes the Administrator should reject this approach. *Id*.

Based on the foregoing analysis and discussion, BPA finds that surplus power sales, especially the sale of secondary energy, do not provide Reserve Benefits that result in Quantifiable Monetary Savings. The legislative history of the Northwest Power Act links the expected Reserve Benefits in section 7(b)(2)(E) closely to the DSIs. Although the DSIs may not be the sole source of such reserves, the provision of such reserves must be explicitly featured in the power sales contract, offering express monetary benefits to the provider of the reserves. BPA's surplus power sales have no such contractual provisions. The presence of termination dates or withdrawal clauses are not the type of explicit contractual provisions encompassed in section 3(17) of the Act. 16 U.S.C. § 839a(17). BPA will include language similar to that proposed by Cowlitz to clarify the 7(b)(2) Legal Interpretation.

Decision

BPA's secondary energy sales do not provide appropriate reserves for purposes of section 7(b)(2)(E) of the Northwest Power Act. Even if secondary energy provided such reserves, there would be no quantifiable monetary benefits from such reserves.

16.15 Uncontrollable Events

Issue 1

Whether terminated nuclear plant costs, costs of financial reserves for risk, and planned net revenues for risk are costs of Uncontrollable Events.

Parties' Positions

The IOUs argue that in performing the section 7(b)(2) rate step, BPA must subtract, from the projected amounts to be charged PF Preference rate customers in the Program Case, the amounts charged such customers for BPA's costs of Uncontrollable Events. IOU Br., WP-07-B-JP6-01, at 54. In particular, they claim BPA must subtract at least three categories of costs that are costs of Uncontrollable Events: (1) BPA's costs associated with two terminated nuclear plants, (2) BPA's costs of Financial Reserves for Risk, and (3) BPA's costs of Planned Net Revenues for Risk ("PNRR"). *Id*.

Cowlitz and WPAG argue that certain costs associated with terminated plants should not be considered "Uncontrollable Events" within the meaning of 7(b)(2) and 7(g) because they are based on a reasoned process of deliberation leading to the discretionary termination of a generating facility. Cowlitz Br., WP-07-B-CO-01, at 43; WPAG Br., WP-07-B-WA-01, at 43. Also, Starting Financial Reserves Available for Risk do not arise on account of Uncontrollable Events because they are matters are related to ongoing business activities. *Id*.

BPA Staff's Position

BPA Staff did not exclude costs from the Program Case that are due to conditions that simply vary over time and are typically reflected in rates. Doubleday, *et al.*, WP-07-E-BPA-85, at 143.

Also, as noted in the Implementation Methodology, Uncontrollable Events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business and government and are routinely reflected in rate development. *Id*. Terminated plant costs of WNP-1 and WNP-3, BPA's Financial Reserves for Risk, and BPA's costs of Planned Net Revenues for Risk are not costs of Uncontrollable Events. *Id*. at 144.

<u>Evaluation of Positions</u>

A. The Nature of Uncontrollable Events

Section 7(b)(2) of the Northwest Power Act states:

> [a]fter July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive of amounts charged such customers under subsection (g) of this section for the costs of ... uncontrollable events*, may not exceed in total, as determined by the Administrator, during [the test period], an amount equal to the power costs for general requirements of such customers if, the Administrator [makes the Five Assumptions specified in section 7(b)(2).]

16 U.S.C. § 839e(b)(2) (emphasis added). The only other use of this term in the Northwest Power Act is in section 7(g):

> 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) (emphasis added). Obviously, the two uses of the term are linked by the usage in section 7(b)(2).

In order to implement the 7(b)(2) rate test, BPA must determine what constitutes Uncontrollable Events. The legislative history of the Act provides no help in this regard. Further, there is no help from the original proceedings that established the 1984 Legal Interpretation, 49 Fed. Reg. 23,998 (June 8, 1984) and 1984 Implementation Methodology, b2-84-F-02. Although previously addressed by BPA in prior rate cases, the term "Uncontrollable Event" is defined for the first time in the proposed Implementation Methodology:

> <u>Uncontrollable Event</u>: A discrete event which differs from the continuum of changing events that occur in nature, business and government (such as changes

in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment B, Proposed Implementation Methodology, at IM-2. This definition is based on the Administrator's previous decisions in section 7(i) rate proceedings regarding the treatment of Uncontrollable Events. *See* 1996 Administrator's Record of Decision, WP-96-A-02, at 256-263; 2002 Administrator's Record of Decision, WP-02-A-02, at 13·25-13·46. Because BPA did not identify any Uncontrollable Events or the costs of such events, no Uncontrollable Events were reflected in the Supplemental Proposal.

The IOUs argue that BPA has never subtracted any costs of Uncontrollable Events from the Program Case costs although BPA has been performing the section 7(b)(2) rate test for the entire period since January 1, 1985, when the rate test first became applicable. IOU Br., WP-07-B-JP6-01, at 54. The IOUs argue that given the magnitude of BPA's activities and BPA's exposure to Uncontrollable Events, the absence of any costs of an Uncontrollable Event during this period demonstrates that Staff is applying unduly restrictive criteria when determining the costs of Uncontrollable Events for the purposes of conducting the section 7(b)(2) rate test. *Id*. at 54-55.

The fact that BPA has never subtracted any costs of Uncontrollable Events from Program Case costs does not necessarily mean that Staff's proposed definition is unduly restrictive when determining the costs of Uncontrollable Events. BPA also has never subtracted any costs of experimental resources from Program Case costs. The lack of experimental resource costs is not the result of unduly restrictive criteria, but of such costs never having been incurred. The term "Uncontrollable Events," if taken as expansively as proposed by the IOUs, would encompass millions of events and would make little sense in the context of the section 7(b)(2) rate test. Doubleday, *et al.*, WP-07-E-BPA-85, at 143; WPAG Br., WP-07-B-WA-01, at 44 ("Under the proposed definition, virtually every action taken by BPA in the normal course of business would arguably qualify as an uncontrollable force. Routine actions like buying insurance, setting aside contingencies and even hedging activities would suddenly become costs of uncontrollable forces."). There are millions of "events" that occur daily and which are beyond BPA's control. *Id*. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. *Id*. The section 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). *Id*. For this reason, Uncontrollable Events should not exclude costs from the Program Case that are due to conditions that simply vary over time and are typically reflected in rates. *Id*. Also for this reason, as noted in the Implementation Methodology, Uncontrollable Events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business and government and are routinely reflected in rate development. *Id*. Thus, it is not surprising that BPA has not previously identified an Uncontrollable Event. *Id*. This, however, does not mean that Staff's definition is too restrictive. *Id*. In contrast, the IOUs' proposed definition would be too broad. *Id*. If nearly all events are Uncontrollable Events, excluding such costs from the Program Case would prevent the 7(b)(2) rate test from ever finding that the Program Case rates exceed the 7(b)(2) Case rates. *Id*.

The context of the formulation of the Northwest Power Act is also instructive. Early drafts of what was to become the Northwest Power Act were circulating during the mid- to late-1970s. What was to become the section 7(b)(2) rate test first appeared in Amendment No. 134 to S. 885 in 1979. The Uncontrollable Events provision may have arisen in light of an event that exposed vulnerabilities in the Federal hydrosystem, the June 5, 1976 collapse of Teton Dam. Teton Dam was a Bureau of Reclamation facility in southeastern Idaho that failed approximately one year after construction was completed. Although there were no hydroelectric facilities installed, the failure of the dam gives context to the phrase "Uncontrollable Events." If such an event were to occur at an FCRPS facility, the replacement costs of lost generation could be treated as a 7(g) cost to be equitably allocated to power rates. As such, the replacement generation would not be included in the 7(b)(2) Case because the replacement generation would not be a Federal base system resource, nor would it be a resource includable in the resource stack under section 7(b)(2)(D). As such, the costs of the replacement generation would not be included in the "power costs for general requirements of such customers" being determined in the 7(b)(2) Case. Therefore, to remove this bias from the section 7(b)(2) rate test, where such costs would be included in "the projected amounts to be charged for firm power" in the Program Case, it is a reasonable conclusion that Congress would direct that such costs be excluded when comparing the rates in the two Cases. Otherwise, the section 7(b)(2) rate protection would remove the costs of the replacement power due to the Uncontrollable Event from the PF Preference rate.

The IOUs argue that the fact that Staff claims it is unable to identify each event that occurs daily and that is beyond BPA's control does not justify Staff's arbitrarily assuming that the costs of such myriad events are zero. IOU Br., WP-07-B-JP6-01, at 55. The IOUs argue that Staff's rebuttal testimony reveals that Staff quantifies the cumulative effect of the cost of these Uncontrollable Events when Staff notes that "PNRR, along with other measures, mitigates the risk of a wide range of uncertainties routinely experienced in ratemaking." *Id.* at 55-56, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 149. The IOUs cite Staff's rebuttal testimony, which states that "[t]he cost of mitigating a wide range of uncertainties is not the same as the cost of Uncontrollable Events, which are discrete events not routinely reflected in ratemaking." *Id.* at 56. The IOUs argue Staff's statement is unsupported because Staff has admitted that it faces Uncontrollable Events routinely when it points out that there are millions of such events that occur daily and which are outside of BPA's control. *Id.* The IOUs argue the fact that such events may be extremely numerous, and therefore administratively burdensome to forecast on a discrete basis, does not alter the nature of such events. *Id.* Staff's decision to deal with the forecast cost of these events on an aggregate basis and therefore not discretely – which makes practical sense – does not and cannot preclude those costs from being the costs of Uncontrollable Events. *Id.*

The IOUs' foregoing argument does not recognize an important distinction drawn by Staff. The millions of "events" that occur daily and which are beyond BPA's control are *not* what the Act refers to as "Uncontrollable Events." That is, the section 7(b)(2) rate test was not designed to remove the costs of those kinds of events from the Program Case. Such types of events would naturally occur in both the Program Case and the 7(b)(2) Case, and there is no logical reason to attempt to distinguish such costs, assuming they could be identified. The more logical interpretation of section 7(b)(2) is that "Uncontrollable Events" refers to significant events that do not occur frequently and that would have the effect of temporarily affecting the rate test instead of allowing the rate test to be conducted in a more stable environment. Unfortunately, there is no legislative history to help with this analysis, but the logic from the context of section 7(b)(2) is quite strong. "Uncontrollable Events" refers to costs that might occur in the Program Case but would not necessarily be charged to 7(b)(2) Customers in the 7(b)(2) Case due to the Five Assumptions.

The IOUs cite Staff's rebuttal testimony, which states:

> As noted previously, the section 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This suggests that the comparison is between rates that share the same basic costs but for the specific exceptions. For this reason, uncontrollable events should not exclude costs from the Program Case that are due to conditions that simply vary over time and are typically reflected in rates.

IOU Br., WP-07-B-JP6-01, at 56-57, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 143. The IOUs claim Staff's argument erroneously focuses on the assumptions required to be made for the 7(b)(2) Case and erroneously ignores the Applicable 7(g) Costs required to be subtracted from the Program Case costs in the section 7(b)(2) rate test. *Id*. at 57.

Staff recognizes that Applicable 7(g) Costs *are* removed from the Program Case. However, even if one assumed such costs, including costs of Uncontrollable Events, are removed from the Program Case but included in the 7(b)(2) Case, the nature of the costs included in both cases is a helpful guide to determining the nature of the costs of Uncontrollable Events. In other words, both cases (excepting statutory adjustments) reflect basic BPA ratemaking. BPA routinely forecasts costs and recovers such costs through proposed rates. Where there is an exclusion of costs from the Program Case, for example, the treatment of the exclusion should reflect the manner in which BPA recovers costs through ratemaking. If BPA accounts for normal variations in market prices through a forecast and risk coverage, then normal variations in market prices should not constitute an Uncontrollable Event.

Cowlitz notes the IOUs argue that Applicable 7(g) Costs should be added to power costs in the 7(b)(2) Case, while subtracting them from the Program Case. Cowlitz Br., WP-07-B-CO-01, at 42, *citing* LaBolle, *et al.*, WP-07-E-JP6-08, at 26. Cowlitz argues that Congress did not direct BPA to subtract Applicable 7(g) Costs from the Program Case and add them to the 7(b)(2) Case; it specifically directed BPA to make the comparison between the power costs in the two Cases exclusive of such costs. *Id*. at 42-43.

Although Cowlitz claims that Congress "specifically directed" BPA to compare both Cases exclusive of such costs, the statutory language provides no such direction. As noted previously, section 7(b)(2) of the Northwest Power Act states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive of amounts charged such customers under subsection (g) of*

> *this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events*, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator [makes the Five Assumptions specified in section 7(b)(2).]

16 U.S.C. § 839e(b)(2). As BPA recognized in the original 1984 Legal Interpretation, the plain meaning of the foregoing language is that the Administrator first projects the Program Case amounts to be charged (rates) for preference customers' general requirements for each year after July 1, 1985, plus the ensuing four years. The Administrator then ensures that such amounts are *exclusive of* (that is, minus or without) the costs of conservation, resource and conservation credits, experimental resources, and Uncontrollable Events. The Administrator then compares these Program Case amounts (rates) with the power costs (rates) for preference customers' general requirements determined using the Five Assumptions in section 7(b)(2). Thus, contrary to Cowlitz's claim, the plain reading of this language is that the costs of conservation, resource and conservation credits, experimental resources, and Uncontrollable Events are not removed from the 7(b)(2) Case that reflects the Five Assumptions. There is certainly no "specific direction" to remove these costs from both Cases; in fact, based upon the plain language of the Act, just the opposite is true.

Nevertheless, BPA does not find the IOUs' argument persuasive. Normal operating risks are not Uncontrollable Events. Congress established a much higher bar than the multitude of everyday events that might occur in the normal course of business. Logically, the costs of Uncontrollable Events are those costs that would not be reflected in the 7(b)(2) Case due to their special nature and require the removal from the Program Case rates to remove the potential bias in the section 7(b)(2) rate test.

B. Costs of the Terminated WNP-1 and WNP-3 Plants Are Not Costs of Uncontrollable Events

The IOUs continue their arguments by pointing to a series of costs they believe fall within the rubric of Uncontrollable Events. First, the IOUs argue BPA's costs of the terminated WNP-1 and WNP-3 plants are costs of Uncontrollable Events. IOU Br., WP-07-B-JP6-01, at 57. The IOUs state these nuclear plants were terminated after the Washington Public Power Supply System ("Supply System") was unable to issue bonds to finance their completion. *Id*. The IOUs argue the Supply System's inability to issue bonds was an Uncontrollable Event, and BPA's costs with respect to these terminated nuclear plants are costs of an Uncontrollable Event. *Id*.

As noted in Staff's testimony, the termination of WNP-1 and WNP-3 was based on a reasoned process of deliberation leading to the discretionary termination of a generating facility. Doubleday, *et al.*, WP-07-E-BPA-85, at 144. This is not an Uncontrollable Event. *Id*. BPA previously issued a ROD regarding the termination of WNP-1 and WNP-3 ("WNP-1 and WNP-3 ROD"). *Id*. In that ROD, BPA conducted a thorough analysis of numerous factors relating to the discretionary decision of whether the plants should be terminated. *Id*. BPA listed a number of decision factors. *Id*. These factors included how completing WNP-1 and WNP-3 would affect BPA's competitiveness; BPA's need for additional resources; how WNP-1 and WNP-3 compare to BPA's other resource alternatives; and the advantages and risks of WNP-1 and WNP–3 and their alternatives. *Id*. BPA also reviewed the alternate uses of WNP-1 and WNP–3. *Id*. In summary, the Administrator stated:

> On balance, it is my determination that based on the totality of factors, on the assumptions regarding the future of the plants, and on other circumstances, neither the long term continued preservation of WNP-1 and -3 or the ultimate completion of the projects under the terms of the existing agreements is in the best interest of BPA and the region's ratepayers. Consistent with this determination, I find that the plants are not capable of producing energy consistent with prudent utility practice.

Id. at 144-145. The decision to terminate WNP-1 and WNP-3 was a carefully reasoned discretionary decision in which the Administrator explained the reasons for that decision. *Id*. at 145. A decision of this nature is not an Uncontrollable Event. *Id*.; Cowlitz Br., WP-07-B-CO-01, at 43 ("These matters are related to ongoing business activities and are not uncontrollable events."); WPAG Br., WP-07-B-WA-01, at 43 ("The termination costs of WNP-1 and 3 are part of the normal business risk associated with the development of generating resources needed to serve load, and are not an event of nature.") Indeed, this decision would be best characterized as a controllable event: a discretionary decision made by the Administrator. Doubleday, *et al.*, WP-07-E-BPA-85, at 145.

The IOUs claim the fact that BPA made a measured, rational response to these Uncontrollable Events does not render the events controllable. IOU Br., WP-07-B-JP6-01, at 57. However, the Supply System's inability to sell bonds at a particular time was not viewed by the Administrator as something that unilaterally terminated the plants. Doubleday, *et al.*, WP-07-E-BPA-85, at 145. Instead, one of the options still available to the Administrator was "the ultimate completion of the projects." *Id*. Thus, the termination was a "determination … based on the totality of factors," which was not an Uncontrollable Event. *Id*.

Further, the termination of WNP-1 and WNP-3 did not result in costs allocable under section 7(g). WNP-1 and WNP-3 plant costs, including the termination costs, are costs of the Federal base system. WNP-1 and WNP-3 were resources acquired by the Administrator under long-term contracts in force on December 5, 1980; as such, they meet the definition of Federal base system resources, 16 U.S.C. § 839a(10), and the costs are allocated pursuant to section 7(b)(1), 16 U.S.C. § 839e(b)(1). Section 7(b)(1) costs are not section 7(g) costs; therefore, they cannot be Applicable 7(g) Costs.

The IOUs argue that BPA's costs of the terminated WNP-1 and WNP-3 plants must be subtracted as section 7(g) costs in the section 7(b)(2) rate test from the projected amounts to be charged PF Preference rate customers in the Program Case. IOU Br., WP-07-B-JP6-01, at 58. The IOUs claim projected amounts to be charged PF Preference rate customers in the Program Case include, for example, average annual costs of $348 million for terminated WNP-1 and WNP-3, which are costs of an Uncontrollable Event that must be subtracted from the Program Case costs but included in the 7(b)(2) Case costs. *Id*.

Even if BPA were to accept that the termination of WNP-1 and WNP-3 were Uncontrollable Events, BPA would have to determine which costs were due to Uncontrollable Events and which were not. Doubleday, *et al.*, WP-07-E-BPA-85, at 145. Not all of the costs of WNP-1 and WNP-3 are due to Uncontrollable Events. *Id*. The debt service costs were incurred as a result of the decision to build the projects; such decision cannot be considered an Uncontrollable Event, even under the IOUs' definition. *Id*. Therefore, the only costs that would possibly qualify as Uncontrollable Event costs under the IOUs' definition would be the costs of termination. *Id*. In the WP-07 Supplemental Proposal, the WNP-1 and WNP-3 decommissioning costs are projected to be $200,000 in FY 2009. *Id*.

The IOUs argue that BPA has previously recognized that the costs of terminated generating facilities, such as WNP-1 and WNP-3, are the costs of Uncontrollable Events for purposes of section 7(g) of the Northwest Power Act. IOU Br., WP-07-JP6-01, at 59. The IOUs claim initial long-term power sales contracts under the Northwest Power Act entered into by BPA with utilities in the region recognized that BPA's costs of Uncontrollable Events allocated under section 7(g) of the Northwest Power Act include costs of a "terminated generating facility":

> <u>Allocation of Certain Section 7(g) Costs</u>. *Costs of uncontrollable events, including but not limited to costs of a terminated generating facility*, and costs of experimental resources, in excess of the cost of cost-effective resources, shall be allocated pursuant to section 7(g) of P.L. 96-501 [the Northwest Power Act] and shall be allocated among Customers on a uniform per kilowatt or kilowatthour basis.

Id. at 59-60, *citing* Exhibit WP-07-E-JP6-09 (emphasis added).

The IOUs note Staff's rebuttal testimony, which states:

> The IOUs refer to section 8(j) of the 1981 General Contract Provisions (GCPs) entitled "Allocation of certain section 7(g) Costs," which falls under section 8 of the GCPs, entitled "Equitable Adjustment of Rates." Most of BPA's power sales contracts executed in 1981 included the GCPs as an exhibit. The 1981 power sales contracts terminated on July 1, 2001. This date precedes the effective date of BPA's 2007 wholesale power rates, which went go into effect on October 1, 2006. Section 8 of the GCPs, including section 8(j), governed only the development of rates that were to be in effect during the term of the 1981 power sales contracts, that is, the rates that would apply to the sales made under those contracts. Those sales terminated on July 1, 2001. The rates being developed in this proceeding will not be in effect during the term of the 1981 contracts, and section 8 of the GCPs does not apply.

Id. at 60, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 145. The IOUs note that they do not argue that BPA is currently bound by section 8 of the GCPs of 1981 contracts; rather, that the language of section 8 of the GCPs of the 1981 contracts recognized that costs of Uncontrollable Events "includ[e] … costs of a terminated generating facility." *Id*. BPA understands the IOUs' position. There is no dispute that the cited contract provision does not apply to BPA's current power sales contracts.

In addition, however, Staff's rebuttal testimony states that section 8(j) did not establish that all terminated generating facility costs are costs of Uncontrollable Events. Doubleday, *et al.*, WP-07-E-BPA-85, at 146. The quoted language refers to "[c]osts of uncontrollable events, including but not limited to costs of a terminated generating facility…" *Id*. The first requirement of this provision is that the event be an "uncontrollable event." *Id*. BPA does not dispute that, during the time when this provision was actually in effect, it was possible for the costs of a terminated generating facility to be included in the costs of an Uncontrollable Event. *Id*. This would occur where the termination of the facility was a result of an Uncontrollable Event. *Id*. This requires review of the particular terminated generating facility to determine if its termination was a reasoned discretionary decision or if it was the result of an Uncontrollable Event, such as an earthquake, a flood, a terrorist act, and so on. *Id*. at 146-147.

The termination of a generating facility that is the result of a reasoned decision-making process that has taken place over a period of time, and where the decision could have been decided either way, cannot be considered an Uncontrollable Event. *Id*. at 147. In deciding whether to terminate a generating facility, the owner must receive and analyze information about many factors relating to termination. *Id*. How much would it cost? Is there a market for the power above cost? *Id*. What would be the decommissioning costs? These many questions must be weighed by the decision-maker. *Id*. The decision that is informed by such analyses where there is not a required termination, but rather a discretionary decision to do so, is not uncontrollable. *Id*. Uncontrollable Events can cause the termination of a generating facility. *Id*. The cost of termination of a generating facility, however, is not a cost of an Uncontrollable Event unless the termination is caused by an Uncontrollable Event. *Id*.

Furthermore, section 8(j) of the 1981 GCPs could not have required BPA to allocate the costs of WNP-1 and WNP-3 pursuant to section 7(g) of the Northwest Power Act. Section 7(g) applies "[e]xcept to the extent that the allocation of costs and benefits is governed by provisions of law in effect on the effective date of this Act, or by other provisions of this section." 16 U.S.C. § 839e(g). Section 3(10) of the Northwest Power Act defines Federal base system resources as "the Federal Columbia River Power System hydroelectric projects; *resources acquired by the Administrator under long-term contracts in force on the effective date of this Act* [and resources to replace reductions in capability.]" 16 U.S.C. § 839a(13) (emphasis added). BPA has always treated WNP-1 and WNP-3 as FBS resources. Section 7(b)(1) provides rate directives governing the allocation of FBS resources, including WNP-1 and WNP-3. Section 7(b)(1), an "other provision[ ] of this section [7]," provides that the rate for preference customers' requirements and the Residential Exchange Program "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." 16 U.S.C. § 839e(b)(1). Therefore, the costs of WNP-1 and WNP-3 are FBS costs and cannot be allocated under section 7(g). Assuming *arguendo* that the termination of WNP-1 and WNP-3 was an Uncontrollable Event, the only costs of WNP-1 and WNP-3 that could be allocated under GCP section 8(j) would have been the costs of the termination, not the costs of the resources themselves. In fact, since the termination ROD was issued on September 16, 1993, BPA has had three general rate cases (not including the rate extension for FY 1996). BPA did not allocate any costs associated with WNP-1 and WNP-3 under section 7(g) in any of those cases.

Thus, BPA does not find the IOUs' argument persuasive, and WNP-1 and WNP-3 termination costs will not be treated as Applicable 7(g) Costs of an Uncontrollable Event for purposes of the section 7(b)(2) rate test.

C. Costs of Starting Financial Reserves Available for Risk Are Not Costs of Uncontrollable Events

The IOUs note the Supplemental Proposal provides "[s]tarting financial reserves available for risk comprise cash in the Bonneville Fund and cash equivalents in the form of a deferred borrowing balance at the start of the first fiscal year of the rate period, *i.e.*, FY 2009" as reduced by reserves "virtually certain to be distributed to customers in the near future." IOU Br., WP-07-B-JP6-01, at 61-62, *citing* Normandeau, *et al.*, WP-07-E-BPA-73, at 5. The IOUs state Starting Financial Reserves Available for Risk are BPA's central risk mitigation tool. *Id*. at 62. During years of low secondary revenue or other financial exigencies, reserves can be drawn upon to provide funds for paying operating expenses and paying the Treasury, and during years of high net revenue reserves they can be replenished. *Id*. BPA projects Starting Financial Reserves Available for Risk as of the beginning of the rate period. *Id*. As of the beginning of FY 2009, BPA projects that it will have "an expected value of Power starting reserves available for risk for FY 2009 of $1,031 million." *Id*. The IOUs claim that in the absence of the risk of Uncontrollable Events that give rise to the need for Starting Financial Reserves Available for Risk, BPA's revenue requirement during the rate period would be lower by an expected value amount equal to the Starting Financial Reserves Available for Risk of $1,031 million. *Id*. The IOUs argue that BPA must subtract Starting Financial Reserves Available for Risk from the Program Case as Applicable 7(g) Costs of Uncontrollable Events. *Id*.

First, the IOUs are equating an asset with a cost. Doubleday, *et al.*, WP-07-E-BPA-85, at 147. BPA's financial reserves primarily consist of cash in the BPA Fund at the U.S. Treasury. *Id*. Cash on hand is an asset. *Id*. at 147-148. Staff did not understand how an asset can become a cost. *Id*. at 148. Furthermore, if the risks were not present, as the IOUs posit, BPA's revenue requirement would not be lower by $1,031 million. *Id*. BPA's rates are set to recover costs. *Id*. Revenues from rates must be adequate to demonstrate cost recovery, not just in the rate period, but for the entire cost recovery period that extends for another 50 years. *Id*. If BPA were to lower rates to recover $1 billion less revenue, it could not demonstrate cost recovery to FERC over the entire cost recovery period. *Id*. Because the cost recovery period extends for 50 years, lowering rates by $1 billion would result in a $50 billion underrecovery over the cost recovery period. *Id*. This would be noticed by FERC, resulting in the rejection of the rate proposal. *Id*.

The IOUs state that they do not propose a $1 billion reduction to revenue requirement, but that an amount equal to 20 percent of BPA's Starting Financial Reserves Available for Risk should be subtracted as Applicable 7(g) Costs for each year of the Five-Year Period of the section 7(b)(2) rate test for FY 2009. IOU Br., WP-07-B-JP6-01, at 63. Even assuming a 20 percent adjustment, however, this would amount to $10 billion over the 50-year cost recovery period.

Second, the IOUs argue that normal utility business risk constitutes an "Uncontrollable Event" for purposes of the 7(b)(2) rate test. IOU Br., WP-07-B-JP6-01, at 63. In the same way that Planned Net Revenues for Risk (PNRR) have been used to mitigate normal utility uncertainty by increasing the availability of financial reserves, a sufficient amount of starting financial reserves can mitigate the need to include PNRR costs in the rate base. *Id*. In either case, cash over and above the normal or average condition forecast need for cash will exist in the event something other than normal or average conditions actually occur. *Id*.

Staff noted it is simply a normal utility risk when actual conditions that are part of a continuum of possible conditions depart from the normal or average conditions forecasted in a rate proceeding. *Id*.; Cowlitz Br., WP-07-B-CO-01, at 43 ("These matters are related to ongoing business activities and are not uncontrollable events."); WPAG Br., WP-07-B-WA-01, at 43-44 ("The items that the IOUs have suggested for inclusion in the category of uncontrollable forces are financial steps taken by BPA to address normal business risks. The fact that BPA has taken prudent actions to address these matters indicates that they are normally occurring business events which can be addressed by reasonable actions.") Such departures from the forecasted average themselves or the business decisions brought on by these departures do not rise to the level of "Uncontrollable Events." *Id*.

The IOUs argue Staff's rebuttal testimony erroneously asserts (i) that the IOUs are confusing "an asset with a cost", and (ii) that BPA cannot lower rates based the level of financial reserves, because:

> BPA's rates are set to recover costs. Revenues from rates must be adequate to demonstrate cost recovery, not just in the rate period but for the entire cost recovery period that extends for another 50 years. … We believe this might be noticed by FERC, resulting in rejection of the rate proposal.

IOU Br., WP-07-B-JP6-01, at 63, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 148. The IOUs argue that Staff overlooks the fact that BPA itself characterizes PNRR as a cost (Doubleday, *et al.*, WP-07-E-BPA-85, at 150) and treats PNRR and Starting Financial Reserves Available for Risk as interchangeable tools.

The IOUs are correct that PNRR is a non-cash expense and is added to BPA's revenue requirement when needed to mitigate risk. However, PNRR is not interchangeable with Starting Financial Reserves Available for Risk. PNRR is intended to add to BPA's financial reserves, allowing Starting Financial Reserves Available for Risk to increase for the next rate period. The IOUs separately argue about treating PNRR as a cost of an Uncontrollable Event. However, Starting Financial Reserves Available for Risk are not the same as PNRR, and the two issues are dealt with separately in this ROD.

The IOUs argue, in making this argument, Staff overlooks the fact that BPA already has a mechanism, the Dividend Distribution Clause (DDC), to lower rates based on the level of financial reserves. IOU Br., WP-07-B-JP6-01, at 63. The IOUs note BPA explains how the DDC works: "If the forecast AMNR is greater than the defined DDC Threshold for the fiscal year, the DDC will trigger and a rate reduction will go into effect beginning in October of the FY 2009." *Id*. at 63-64, *citing* 2007 Supplemental Wholesale Power Rate Schedules (FY 2009) and 2007 Supplemental General Rate Schedule Provisions (GRSPs) (FY 2009), WP-07-E-BPA-51, at 83. For FY 2009, the DDC Threshold is set at $1.05 billion. *Id*. at 64. Thus, subtracting Starting Financial Reserves Available for Risk from the Program Case as an Applicable 7(g) Cost associated with Uncontrollable Events would be equivalent to lowering the DDC Threshold by the amount of the Starting Financial Reserves for Available for Risk and spreading out the rate reduction over the Five-Year Period. *Id*. Further, Staff's concern about demonstrating cost recovery is misplaced. *Id*. Subtracting Starting Financial Reserves Available for Risk from the Program Case as an Applicable 7(g) Cost associated with Uncontrollable Events would impact the section 7(b)(2) trigger amount but would not change BPA's overall costs and revenues. *Id*. Therefore, it would not impact BPA's cost recovery demonstration to FERC. *Id*.

The 7(b)(2) Case is to mirror the Program Case except as changed by the Five Assumptions. The IOUs argue that the 7(b)(2) Case power costs can reflect a subtraction of $1.031 billion dollars to distribute Starting Financial Reserves Available for Risk as a cost of an Uncontrollable Event. There are two problems with this argument. First, reflecting a different power cost in the 7(b)(2) Case due to Starting Financial Reserves Available for Risk is not one of the Five Assumptions and therefore is not allowed. Second, assuming *arguendo* that Starting Financial Reserves Available for Risk is a cost of an Uncontrollable Event, the proper treatment is not to subtract such cost from the power costs in the 7(b)(2) Case, but to subtract such cost from the Program Case rate. However, here the IOUs' argument fails. Starting Financial Reserves Available for Risk are not costs allocated pursuant to section 7(g). Therefore, they cannot be Applicable 7(g) Costs.

The IOUs argue that the proper recognition and treatment of Applicable 7(g) Costs can significantly affect the section 7(b)(2) trigger amount. IOU Br., WP-07-B-JP6-01, at 64. For example, Starting Financial Reserves Available for Risk must be subtracted from the Program Case as an Applicable 7(g) Cost associated with Uncontrollable Events. *Id*. Absent the risk of Uncontrollable Events, BPA could use these reserves available for risk to reduce its rates. *Id*. Properly treating Starting Financial Reserves Available for Risk as an Applicable 7(g) Cost associated with Uncontrollable Events would, for FY 2009, reduce the section 7(b)(2) trigger amount by 1.85 mills per kWh. *Id*. at 65. Properly treating Starting Financial Reserves Available for Risk as an Applicable 7(g) Cost increases the Applicable 7(g) Cost subtracted from the Program Case from 1.26 mills/kWh (or $1.26/MWh) to 3.11 mills/kWh (or $3.11/MWh) for FY 2009. *Id*. This analysis assumes that BPA corrects the error in its Proposed Legal Interpretation and Proposed Implementation Methodology, so that Applicable 7(g) Costs are *not* excluded from the 7(b)(2) Case. *Id*.

Thus, the IOUs' argument is not persuasive. As stated above, normal operating risks are not Uncontrollable Events. The IOUs' argument regarding the treatment of Starting Financial Reserves Available for Risk is built on the premise that normal operating risks are Uncontrollable Events. Because they are not, the IOUs' argument fails. Furthermore, because Starting Financial Reserves Available for Risk are not a cost allocated pursuant to section 7(g), they cannot be considered Applicable 7(g) Costs. The fact that something could significantly impact exchange benefits is not a basis to call it something (an Uncontrollable Event cost) it is not.

D. Costs of Planned Net Revenues for Risk Are Not Costs of Uncontrollable Events

The IOUs state PNRR is a component of the revenue requirement often used by BPA "to bolster reserves to mitigate the impacts of operating and non-operating risks." IOU Br., WP-07-B-JP6-01, at 66, *citing* Normandeau, *et al.*, WP-07-E-BPA-73, at 7-20. More specifically, PNRR is the amount necessary, together with Cost Recovery Adjustment Clause and other measures, to mitigate the wide uncertainties BPA faces to achieve its Treasury Payment Probability standard. Doubleday, *et al.*, WP-07-E-BPA-85, at 148-149. PNRR, however, is only one component of the total cash flow for risk. *Id*. at 149. BPA has previously defined the range of uncertainties to include operating risk: hydro and thermal generation performance, California market prices, Southwest gas prices, and generating and non-generating public utility load uncertainty. *Id*. As a counterpart to RiskMod, the Non-Operating Risk Model produces cost distributions that reflect the impact of non-generating risks that Power Services is facing in the FY 2009 rate period. *Id*. These non-operating risks include, but are not limited to, fish and wildlife operations and maintenance and capital recovery expenses and other expenses. *Id*., *citing* Risk Analysis Study, WP-07-E-BPA-48.

The Supplemental Proposal states that Staff does not include PNRR because "[t]he rate period comprises only a single year, which reduces the total amount of risk to be mitigated, and the projections of starting reserves available for risk are unusually robust. These reserves, combined with a modest CRAC (*see* next section) are sufficient to meet BPA's TPP standard without reliance on PNRR." IOU Br., WP-07-B-JP6-01, at 66, *citing* Normandeau, *et al.*, WP-07-E-BPA-73, at 7-20. The IOUs argue BPA must subtract PNRR, if any, from the Program Case as Applicable 7(g) Costs of Uncontrollable Events. *Id*. The IOUs argue the fact that BPA often includes PNRR in its revenue requirements to cover the costs of Uncontrollable Events does not and cannot force the conclusion that such events are not "Uncontrollable Events" and that such costs are not the costs of "Uncontrollable Events." *Id*.

PNRR, along with other measures, mitigates the risk of a wide range of uncertainties routinely experienced in ratemaking. Doubleday, *et al.*, WP-07-E-BPA-85, at 149. The cost of mitigating a wide range of uncertainties is not the same as the cost of Uncontrollable Events, which are discrete events not routinely reflected in ratemaking. *Id*. at 149-150; WPAG Br., WP-07-B-WA-01, at 43-44 ("The items that the IOUs have suggested for inclusion in the category of uncontrollable forces are financial steps taken by BPA to address normal business risks. The fact that BPA has taken prudent actions to address these matters indicates that they are normally occurring business events which can be addressed by reasonable actions."). Therefore, PNRR costs are not the costs of Uncontrollable Events and should not be included in the section 7(g) adjustment in the section 7(b)(2) rate test. *Id*. at 150.

Thus, the IOUs' argument is not persuasive. PNRR is a risk mitigation tool that protects BPA from normal operating and non-operating risks. These risks are part of BPA's everyday business risk. Such risk does not constitute Uncontrollable Events, as explained above. Therefore, in the event BPA includes PNRR in its revenue requirement as a risk mitigation tool, the amount of

PNRR will not be treated as a cost of Uncontrollable Events. PNRR is a non-cash expense that is included in the revenue requirement for both the Program Case and the 7(b)(2) Case. As such, it not a cost that would be excluded from the 7(b)(2) Case due to the Five Assumptions. Therefore, it should not be subtracted from Program Case rates to remove bias from the rate comparison.

Decision

The section 7(b)(2) rate test will not exclude the costs of WNP-1 and WNP-3, starting financial reserves available for risk, or PNRR as costs of Uncontrollable Events. The definition of Uncontrollable Events in the proposed Legal Interpretation will be adopted.

16.16 Applicable 7(g) Costs

Issue 1

Whether BPA should remove Applicable 7(g) Costs from the Program Case and include such costs in the 7(b)(2) Case.

Parties' Positions

The IOUs and OPUC argue BPA should remove Applicable 7(g) Costs from the Program Case and include such costs in the 7(b)(2) Case as BPA previously decided in its 1984 Legal Interpretation and Implementation Methodology. IOU Br., WP-07-B-JP6-01, at 43; OPUC Br., WP-07-B-PU-02, at 20-24. The IOUs argue that the Lookback analysis failed to comply with the 1984 Legal Interpretation treatment of Applicable 7(g) Costs. IOU Br., WP-07-B-JP6-01, at 45.

PPC argues that because section 7(b)(2), in describing a rate ceiling for preference customers, explicitly excludes the Applicable 7(g) Costs, it contemplates that preference customers are responsible for paying those costs, and that the rate test does not protect preference customers from those costs. PPC Br., WP-07-B-JP25-01, at 50.

Cowlitz argues BPA should reject the IOUs' suggestion, which is an improper attempt to nullify section 7(b)(2) rate protection by adding to the Five Assumptions in a fashion that would assign additional costs in the 7(b)(2) Case. Cowlitz Br., WP-07-B-CO-01, at 42-43. Congress did not direct BPA to subtract Applicable 7(g) Costs from the Program Case and add them to the 7(b)(2) Case; it directed BPA to make the comparison between the power costs in the two Cases exclusive of such costs. *Id.* at 43.

BPA Staff's Position

Section 7(b)(2) states:

> After July 1, 1985, *the projected amounts to be charged* for firm power for the combined general requirements of public body, cooperative and Federal agency customers, *exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events*, *may not exceed in total*, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, *an amount equal to the power costs* for general requirements of such customers if, the Administrator assumes [the Five Assumptions.]

16 U.S.C. § 839e(b)(2) (emphasis added). The question of the treatment of Applicable 7(g) Costs goes to the proper construction of "the projected amounts to be charged for firm power for the combined general requirements…, exclusive of [Applicable 7(g) Costs] …" and the proper construction of "the power costs for general requirements … if, the Administrator assumes [the Five Assumptions.]"

BPA Staff relied upon the proposed Legal Interpretation to construct the proposed Implementation Methodology. Staff noted that BPA would address parties' properly raised legal issues in the Draft and Final Records of Decision. Applicable 7(g) Costs are defined as

> 4. Applicable 7(g) Costs: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz.*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources and Uncontrollable Events.

Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act (Proposed Legal Interpretation), at LI-2 . This definition is unchanged from the 1984 Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (1984 Legal Interpretation), b2-84-FR-03, at 5.

Staff maintains the Lookback analysis treated Applicable 7(g) Costs in the same manner as in the WP-02 Final Proposal, which is the same manner used since the onset of the rate test in the 1985 rate case. Doubleday, *et al.*, WP-07-E-BPA-85, at 138. This treatment is consistent with the 1984 Section 7(b)(2) Implementation Methodology, Section 7(b)(2) Implementation Methodology Administrator's Record of Decision, b2-84-F-02, Appendix C (1984 Implementation Methodology). *Id.* at 138-139.

Evaluation of Positions

The IOUs argue that in the 1984 Legal Interpretation, BPA specifically concluded that Applicable 7(g) Costs – costs of conservation, resource and conservation credits, experimental resources and uncontrollable events – are to be included in the 7(b)(2) Case for the purpose of comparison with the Program Case. IOU Br., WP-07-B-JP6-01, at 43. In the 1984 Legal Interpretation, BPA reasoned that it would be inappropriate to exclude Applicable 7(g) Costs from the 7(b)(2) Case for the purpose of comparison with the Program Case because Applicable 7(g) Costs are specifically subtracted from the Program Case, but not excluded from the 7(b)(2) Case:

> C. Specific Statutory Interpretations
>
> 1. *Applicable 7(g) costs should be excluded from the program case, but not from the 7(b)(2) case.*
>
>   (a) *Proposed Interpretation*. In the Notice of Proposed Interpretation, BPA proposed that applicable 7(g) costs should be excluded from the program case, but not from the 7(b)(2) case.
>
>   (b) *Summary of the Comments*: The DSIs and the ICP support BPA's interpretation that applicable 7(g) costs should be excluded from the program case before comparison with the 7(b)(2) case.
>
>   The PNGC, PPC, PGP and Northern Lights argue that applicable 7(g) costs should be excluded from both the 7(b)(2) case and the program case. PNGC Comments at 2; PGP Comments at 3; PPC Comments at 5; Northern Lights Comments at 3. APAC apparently argues that 7(g) costs would be double-counted if they were included only in the 7(b)(2) rate before comparison with the program case, and then added back into the 7(b)(2) rate in the event the 7(b)(2) rate was triggered. APAC Comments at 48-49. APAC also argues that "[b]ecause the section 7(g) exclusion occurs before the enumeration of the differences between the program and section 7(b)(2) cases, both cases must exclude that section 7(g) costs." APAC Comments at 49. APAC further argues that inclusion of 7(g) costs in the 7(b)(2) cases would violate the intent and meaning of section 7(b)(2). APAC Comments at 49-50.
>
>   (c) *Discussion*: Section 7(b)(2) is clear: "* * * the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, * * * an amount equal to the power costs for general requirements of such customers if the Administrator assumes * * *."
>
>   Section 7(b)(2) is explicit in excluding the applicable 7(g) costs from the program case before comparison is made with the 7(b)(2) case.
>
>   Since section 7(g) costs are specifically excluded from the program case, but not excluded from the 7(b)(2) case, it would be inappropriate to subtract section 7(g) costs from the 7(b)(2) case for the purpose of comparison with the program case. If Congress intended the power costs in the 7(b)(2) case to be exclusive of conservation costs and other section 7(g) costs, language to that effect would have been included in the provisions.

(d) *Decision*: The projected amounts to be charged 7(b)(2) customers for their firm power general requirements will include the applicable 7(g) costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, regardless of the implementation of section 7(b)(2).
Section 7(b)(2), however, is explicit in excluding the applicable 7(g) costs from the program case before comparison is made with the 7(b)(2) case.

Id., quoting 1984 Legal Interpretation, 49 Fed. Reg. 23,998, 24,002 (June 8, 1984) (italics in original; underlining emphasis added by IOUs). The IOUs note that, as recognized by BPA's rationale and conclusion in the 1984 Legal Interpretation, the plain language of the statute requires the inclusion of the Applicable 7(g) Costs in the 7(b)(2) Case, and BPA cannot interpret the statute otherwise. IOU Br., WP-07-B-JP6-01, at 43-45.

The OPUC argues that Staff's proposal is a change in policy. OPUC Br., WP-07-B-PU-2, at 20. The OPUC claims review of the 1984 Implementation Methodology and the 1984 Legal Interpretation reflect that BPA previously concluded that Applicable 7(g) Costs should be subtracted only from the Program Case. *Id.* Referring to material presented by Staff in August 2007, which describes the mechanics of the 7(b)(2) rate test, the OPUC argues that BPA's understanding of the appropriate treatment of Applicable 7(g) Costs, at least in August 2007, mirrored the stated policy in the 1984 Implementation Methodology ROD. *Id.* at 21. The OPUC argues that a significant flaw is Staff's failure to acknowledge the 1984 Legal Interpretation, in which the Administrator determined that Applicable 7(g) Costs should be excluded from the Program Case but not the 7(b)(2) Case. *Id.* at 21-22.

Staff demonstrated that the IOUs and the OPUC have mischaracterized BPA's 1984 Legal Interpretation. The 1984 Legal Interpretation focuses on the comparison of power costs as they have been determined for each Case. In the solution of power costs for the Program Case, Applicable 7(g) Costs are included. In the solution of power costs for the 7(b)(2) Case, Applicable 7(g) Costs are included only if the resources associated with the Applicable 7(g) Costs have been selected from the 7(b)(2)(D) resource stack.

The 1984 Implementation Methodology ROD, which was contemporaneous with the 1984 Legal Interpretation, showed how the Legal Interpretation was to be implemented. The ROD first set forth a hypothetical rate test by positing a Program Case rate of 20 mills/kWh, from which 3 mills/kWh of Applicable 7(g) Costs are removed:

> "The projected amounts to be charged" means the program case. "Exclusive of amounts charged … under section 7(g)" means that the enumerated section 7(g) costs are to be subtracted from the program case. There is no parallel command in the statute to subtract from the 7(b)(2) case the costs corresponding to those allocated under section 7(g) in the program case. The result, in a numerical display, would be as follows:

20 mills	("the projected amount to be charged"; also called the program case amount)
- 3 mills	(certain 7(g) charges)
17 mills	(the amount to be compared with the 7(b)(2) case amount; also called the net program case amount)

Section 7(b)(2) Implementation Methodology ROD, August 1984, b-2-84-F-02, at 4. At this point, the 1984 ROD implements the language of the 1984 Legal Interpretation cited by the IOUs. The 20 mill/kWh Program Case rate, exclusive of the 3 mills/kWh of Applicable 7(g) Costs, equals the 17 mill/kWh Program Case rate for purposes of the rate test. The 1984 ROD continues by hypothesizing a 7(b)(2) Case rate of 15 mills/kWh:

> This amount, 17 mills, is to be compared to the 7(b)(2) case amount. For illustrative purposes, assume that the 7(b)(2) case amount is 15 mills, which *may include costs that correspond to those allocated under section 7(g) in the program case*. The program case amount is therefore 2 mills greater than the 7(b)(2) case amount (17 mills - 15 mills = 2 mills). The test has thus triggered.

Id. at 5 (emphasis added). Note that the 1984 Implementation Methodology uses the words "may include," not "includes" or "must include." Therefore, the 1984 ROD recognized that the 1984 Legal Interpretation did not require Applicable 7(g) Costs to be included in the 7(b)(2) Case. This is further highlighted in the next paragraph of the 1984 ROD:

> Double counting of all or some of the section 7(g) costs (conservation; resource and conservation credits ("billing credits"); experimental resources; and uncontrollable events) may be theoretically possible, as explained above. However, it does not occur in all instances. The costs of both experimental resources and uncontrollable events are included in total in both the program case amount (20 mills, in the example given above) and in the 15 mill 7(b)(2) case amount. *But the costs of billing credits and conservation, although appearing in the 20 mill figure, are not necessarily included in the 15 mills. This is because billing credits and programmatic conservation are added to the resources used to serve the 7(b)(2) customers only to the extent that they are needed after the FBS is exhausted and only in the event that they are the least-cost resources to be added.* If the FBS is sufficient to serve the 7(b)(2) load, or other available additional resources have lower costs, then billing credits and programmatic conservation will not be added to the 7(b)(2) case.

Id. (emphasis added). The foregoing text is clear that the 7(b)(2) Case includes Applicable 7(g) Costs only if the resources associated with those costs are chosen from the 7(b)(2)(D) resource stack. Therefore, based on the contemporaneous 1984 ROD implementation of the 1984 Legal Interpretation, the Legal Interpretation should be read in such a way as to allow for Applicable 7(g) Costs to be excluded from the 7(b)(2) Case. The 1984 Legal Interpretation was addressing whether there is a comparable subtraction of Applicable 7(g) Costs in the 7(b)(2) Case; it was not addressing which costs comprised the power costs in the 7(b)(2) Case.

The IOUs argue BPA's Lookback analysis failed to comply with the conclusion in the 1984 Legal Interpretation that the Northwest Power Act requires the inclusion of Applicable 7(g) Costs in the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 45. The IOUs argue that if BPA performs a Lookback analysis, BPA must include the section 7(g) costs identified in section 7(b)(2) in the section 7(b)(2) Case costs. *Id*.

Staff responded that the Lookback analysis conforms to the 1984 Implementation Methodology. Doubleday, *et al.*, WP-07-E-BPA-85, at 141. As shown above, the contemporaneous implementation implemented the 1984 Legal Interpretation to allow the treatment Staff used in the Lookback analysis.

The IOUs argue that the proposed Legal Interpretation, in effect, seeks to rewrite the statutory language of section 7(b)(2) and erroneously concludes that Applicable 7(g) Costs are to be excluded from the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 45-46, *quoting* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-7-10. The IOUs argue the Proposed Legal Interpretation is contrary to the plain language of the statute, noting that the 1984 Legal Interpretation recognized that the statutory language requires the inclusion of conservation costs and other Applicable 7(g) Costs in the 7(b)(2) Case and recognizes that "[i]f Congress intended the power costs in the 7(b)(2) Case to be exclusive of conservation costs and other section 7(g) costs, language to that effect would have been included in the provisions." *Id., quoting* 1984 Legal Interpretation, at 24,002.

With respect to the treatment of the costs of conservation and billing credits, the Proposed Legal Interpretation is consistent with the 1984 Implementation Methodology. Staff proposed changes to the language in the proposed Implementation Methodology only to clarify BPA's treatment of the Applicable 7(g) Costs of conservation and billing credits. As shown above, BPA's contemporaneous implementation understood the 1984 Legal Interpretation to allow the treatment as clarified in the Proposed Legal Interpretation. The 1984 Legal Interpretation states "Applicable 7(g) costs should be excluded from the program case, but not from the 7(b)(2) case." 1984 Legal Interpretation, b2-84-FR-03, at 10. The 1984 Legal Interpretation focuses on the subtraction of Applicable 7(g) Costs from the amounts to be charged in the Program Case, but specifies that no subtraction is to be made in the 7(b)(2) Case after the power costs have been determined, which include the costs of any resources needed from the resource stack. The 1984 Legal Interpretation makes this clear by stating "[s]ince section 7(g) costs are specifically excluded from the program case, but not excluded from the 7(b)(2) case, it would be inappropriate to subtract section 7(g) costs from the 7(b)(2) case *for the purpose of comparison with the program case*." 1984 Legal Interpretation, b2-84-FR-03, at 10-11 (emphasis added). Conversely, the Proposed Legal Interpretation states "Applicable 7(g) Costs are to be excluded from the Program Case rates and the 7(b)(2) Case rates prior to comparison with the 7(b)(2) Case rates." Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-7. Although this may initially appear as a change of interpretation, such is not the case. The proposed Legal Interpretation focuses on the treatment of Applicable 7(g) Costs at the beginning of the determination of power costs in the 7(b)(2) Case before the costs of any resources needed from the resource stack have been added. Here, because the Applicable 7(g) Costs are resource costs, the power costs in the 7(b)(2) Case should exclude these resource costs unless and until the resources associated with such costs are selected from the 7(b)(2)(D) resource stack. Once such a resource is selected, the costs of that resource will be included in the power costs in the 7(b)(2) Case. If the costs associated with a resource in the stack were included in the power costs in the 7(b)(2) Case before it was determined whether the resource was needed to meet remaining general requirements, and then the 7(b)(2) Case added that resource and its costs, this would create a double counting of the cost of the resource within the 7(b)(2) Case, thereby improperly inflating the power costs in the 7(b)(2) Case.

BPA understands that Staff's proposed language in the Legal Interpretation may have created some confusion. Therefore, the language in the Legal Interpretation will be changed to:

* * * *

> The second half of the above-noted language then describes how BPA is to initially construct the revenue requirement in the 7(b)(2) Case. Specifically, the 7(b)(2) Case revenue requirement is equal to "the power costs for general requirements of such customers …" as modified by the Five Assumptions. The phrase "power costs for general requirements of such customers" is a direct reference back to the same power costs, general requirements, and customers discussed in the earlier clause when calculating the costs of the Program Case. The only substantive textual difference between this clause and the previously discussed language is the reference to "power cost." That difference, however, is immaterial because the phrase "power costs" is simply a short-hand reference to the longer description of "the amounts to be charged for firm power" used in the preceding section. Because the two clauses are identical in all material respects, the two provisions should be interpreted consistently. Consequently, the same power costs that were used to serve the "general requirements" in the Program Case should be used to construct the revenue requirement for the 7(b)(2) Case; that is, "the projected amounts to be charged for firm power … ~~exclusive of" Applicable 7(g) costs~~.

* * * *

> In summary, BPA will interpret the aforementioned statutory language as meaning that the Program Case and 7(b)(2) Case must begin with the same power costs, exclusive of costs related to the Five Assumptions. That is, the costs of resources associated with the Applicable 7(g) Costs will be excluded from ~~both the Program Case and~~ the 7(b)(2) Case power costs through ~~prior to~~ application of the Five Assumptions. The Applicable 7(g) Costs will be subtracted from the Program Case rates prior to comparison with the 7(b)(2) Case rates. This interpretation is consistent with the statutory language and the purpose of the section 7(b)(2) rate test. It also avoids unnecessary conflicts with, and gives full effect to, the other provisions of section 7(b)(2).

* * * *

The proposed Implementation Methodology will be revised to conform with these changes.

The IOUs note that Staff's Proposed Legal Interpretation relies on three arguments: (i) a "consistency" argument, (ii) a "symmetry" argument, and (iii) a "conservation as a resource" argument. IOU Br., WP-07-B-JP6-01, at 46.

(a) Consistency Argument

The IOUs state that in the "consistency" argument, the proposed Legal Interpretation erroneously concludes that, because the reference to 7(b)(2) Case "power costs" corresponds to "the amounts to be charged for firm power" in the Program Case, the express statutory direction to subtract Applicable 7(g) Costs from the Program Case somehow implies a statutory intent to exclude Applicable 7(g) Costs from the 7(b)(2) Case. *Id., citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-8. In its "consistency" argument, Staff states that the reference to Program Case "power costs" corresponds to "the amounts to be charged for firm power" in the 7(b)(2) Case. IOU Br., WP-07-B-JP6-01, at 45. The IOUs argue Staff then ignores the fact that the statute expressly mandates the subtraction of the Applicable 7(g) Costs from the Program Case "amounts to be charged for firm power" but is silent about any subtraction of the Applicable 7(g) Costs from the corresponding "power costs" in the 7(b)(2) Case. *Id*. at 46-47. The IOUs argue the express statutory direction to subtract Applicable 7(g) Costs from the Program Case does not and cannot support the conclusion that Applicable 7(g) Costs are to be excluded from the 7(b)(2) Case. *Id*. at 47. If Congress had intended that the Applicable 7(g) Costs be excluded from the 7(b)(2) Case, it would have so stated. *Id. quoting* 1984 Legal Interpretation, at 24,002. Under the statutory construction principle of *expressio unius est exclusio alterius*, explicit enumeration of one item in a class excludes other items of that class that are not listed. *Id*. at fn. 23. The OPUC similarly argues that Staff's reliance on textual support for the proposed treatment ignores that the exclusionary language of section 7(b)(2) applies only to the Program Case. OPUC Br., WP-07-B-PU-02, at 22.

Here, however, the IOUs and OPUC miss the point of the statute and Staff's proposed interpretation. BPA agrees that the "exclusive of" language refers solely to Program Case rates; that is, to "the projected amounts to be charged." However, the language "*an amount equal to the power costs* for general requirements of such customers if, the Administrator assumes [the Five Assumptions.]" indicates that BPA is to look out in time – any year after July 1, 1985, plus the ensuing four years – to determine what the power costs would be and what the general requirements (or loads) would be, given the specific assumptions of section 7(b)(2). The specific assumptions are part of the equation of solving for power costs. The proper treatment of Applicable 7(g) Costs is that, to the extent such costs are reflected in the 7(b)(2) Case rates, they properly belong and should not be removed unless the logic of the Five Assumptions so dictates. This is addressed later in this analysis.

(b) Symmetry Argument

In the "symmetry" argument, the IOUs argue the proposed Legal Interpretation inexplicably concludes the following:

> (i) the Congressionally mandated Five Assumptions somehow negate the Congressionally-mandated subtraction of Applicable 7(g) Costs from the Program Case,
> (ii) the results of the section 7(b)(2) rate [test] were to be somehow "skewed" if Applicable 7(g) Costs are subtracted from the Program Case but included in the 7(b)(2) Case, and
> (iii) the Congressionally-mandated subtraction of Applicable 7(g) Costs from the Program Case without an implied exclusion of Applicable 7(g) Costs from the 7(b)(2) Case somehow "could create a cost incongruity.

IOU Br., WP-07-B-JP6-01, at 47-48, *citing* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-8-9. The "symmetry" argument rests upon the unsupported assertion that the Five Assumptions are the only Congressionally identified and intended drivers of the section 7(b)(2) rate test. IOU Br., WP-07-B-JP6-01, at 48. This assertion ignores the express Congressional mandate to subtract Applicable 7(g) Costs from the Program Case and instead assumes that such subtraction was not an intended "driver" of the rate test. *Id.*

BPA does not find anything in the proposed Legal Interpretation that draws the conclusion that the Five Assumptions are the only Congressionally identified and intended drivers of the section 7(b)(2) rate test. The proposed Legal Interpretation clearly states that the "statutory language further directs BPA to modify this revenue requirement by excluding [the Applicable 7(g) Costs.]" Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation at LI-8. The exclusion of Applicable 7(g) Costs is not enumerated with the Five Assumptions; therefore, BPA recognizes that this factor of the rate comparison is in addition to the Five Assumptions. The IOUs may be addressing the sentence that states "Congress specifically identified the Five Assumptions as the factors the Administrator was to 'assume' *in conducting the rate test*." *Id.* (emphasis added). In order to reduce confusion, this sentence should be reworded to reflect the temporal nature of the construction of the section 7(b)(2) rate test. The Five Assumptions are applied before the comparison of the rates; namely, in the construction of "the power costs … if, the Administrator assumes [the Five Assumptions.]" Therefore, the cited sentence should read "Congress specifically identified the Five Assumptions as the factors the Administrator was to "assume" *in determining power costs in the 7(b)(2) Case*." This removes the temporal nature of the treatment of the Applicable 7(g) Costs when rates are being compared as opposed to the power costs used to determine the rates before comparison. However, the sentence will remain that states "[f]or example, if Applicable 7(g) costs were excluded from the Program Case (making it less expensive), but included in the 7(b)(2) Case (making it more expensive), it could create a cost incongruity that could become a determinative factor in whether the rate test will trigger." This sentence captures the temporal nature of constructing both the "the projected amounts to be charged" in the Program Case and the "the power costs … if, the Administrator assumes [the Five Assumptions]" in the 7(b)(2) Case. It is after the construction of these two amounts that the exclusionary language relating to the Applicable 7(g) Costs is then applied solely to the Program Case.

The IOUs state the "symmetry" argument asserts that failure to imply the exclusion of Applicable 7(g) Costs from the 7(b)(2) Case, while giving effect to the expressly required subtraction of Applicable 7(g) Costs from the Program Case, "could create a cost incongruity" and cause the results of the section 7(b)(2) rate test to be "skewed." IOU Br., WP-07-B-JP6-01, at 48, *quoting* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation at LI-8 through LI-10. The IOUs claim this assertion is unsubstantiated, and the "symmetry" argument's unexplained reference to giving the "full and proper effect to the rate test construct envisioned by Congress" neither explains the effect envisioned by Congress nor supports the "symmetry" argument. IOU Br., WP-07-B-JP6-01, at 48. Again, if Congress had intended that the Applicable 7(g) Costs be excluded from the 7(b)(2) Case, it would have so stated. *Id.* at 48-49*, quoting* 1984 Legal Interpretation, at 24,002.

There may be some confusion prompting the IOUs' argument. The symmetry spoken of here is one of construction of the power costs for each of the two Cases. There should be symmetry between the power costs included in the Cases, but for costs related to the Five Assumptions. As such, the proposed Legal Interpretation should be modified to make clear that symmetry does not extend to costs related to the Five Assumptions. Therefore, the sentence that reads "[s]pecifically, if the 'power costs' used in the 7(b)(2) Case were not interpreted to mean the same power costs in the Program Case, a conflict would occur between the above-mentioned paragraph and section 7(b)(2)(D)(i), the fourth of the Five Assumptions[]" will be modified to read "[s]pecifically, if the 'power costs' used in the 7(b)(2) Case were not interpreted to mean the same power costs in the Program Case, *exclusive of costs related to the Five Assumptions*, a conflict would occur between the above-mentioned paragraph and section 7(b)(2)(D)(i), the fourth of the Five Assumptions."

The OPUC further argues that Staff's interpretation of section 7(b)(2) with respect to Applicable 7(g) Costs is belied by the fact that Congress made a specific provision for Applicable 7(g) Costs in section 7(b)(2). OPUC Br., WP-07-B-PU-02, at 23. The OPUC argues that Congress could have obtained the same result obtained under Staff's new legal interpretation by simply omitting any mention of Applicable 7(g) Costs from section 7(b)(2). *Id.*

BPA disagrees with the OPUC's argument. BPA recognizes the specific provision excluding Applicable 7(g) Costs from the Program Case rates. If, as the OPUC suggests, Congress had omitted the mention of Applicable 7(g) Costs from section 7(b)(2), then the rate comparison would have been made with a higher Program Case rate and the rate test trigger would be higher. In the example cited in the 1984 ROD above, with no mention of Applicable 7(g) Costs, the Program Case rate would be 20 mills/kWh rather than 17 mills/kWh. Thus, the difference in the trigger would be 3 mills/kWh higher using the OPUC's hypothesis than the trigger with the exclusionary language included. This is *not* the result obtained by Staff's proposed Legal Interpretation. The Staff proposal would result in the 17 mills/kWh Program Case rate, not the 20 mills/kWh Program Case rate.

Further, the Staff proposal would also result in the 15 mills/kWh 7(b)(2) Case rate. The IOUs and the OPUC are arguing that Applicable 7(g) Costs be added to the 7(b)(2) Case rate, resulting in an 18 mills/kWh 7(b)(2) Case rate in the 1984 ROD example. (This math does not take into account the load differences between the two Cases, which would most likely make the 3 mills/kWh of Applicable 7(g) Costs in the Program Case closer to 5 mills/kWh in the 7(b)(2) Case. Such distinction in the load differentials is not important to this argument.) Clearly, the 18 mills/kWh 7(b)(2) Case rate is not the proper result, especially if, as the 1984 ROD contemplates, some of the 15 mills/kWh rate included costs attributable to resource costs associated with Applicable 7(g) Costs. This would result in inappropriate double counting of costs in the 7(b)(2) Case rate.

(c) Conservation as a Resource Argument

The IOUs argue that in the "conservation as a resource" argument, the Proposed Legal Interpretation erroneously concludes that

> (i) the power costs to be projected in the 7(b)(2) Case are the power costs for the 7(b)(2) Case general requirements for PF Preference rate customers as increased by an amount of load equal to their conservation,
> (ii) conservation by preference agencies is required to meet their "remaining general requirements" when in fact their remaining general requirements inherently reflect such conservation, and
> (iii) conservation and conservation costs may be included in the 7(b)(2) Case resource stack (and must otherwise be excluded from the 7(b)(2) Case costs unless drawn from the 7(b)(2) Case resource stack) because failure to do so would "completely frustrate the purpose of referring to section 6 resources."

IOU Br., WP-07-B-JP6-01, at 48, *quoting* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-50, Attachment A, Proposed Legal Interpretation, at LI-10.

The IOUs' remaining argument refers to the treatment of conservation in the 7(b)(2) Case, not the treatment of Applicable 7(g) Costs in the 7(b)(2) Case. The arguments concerning the treatment of conservation in the section 7(b)(2) rate test are dealt with as a separate issue. *See* Section 16.2, Issue 1. Therefore, BPA will respond here to just point (iii) above concerning the treatment of Applicable 7(g) Costs.

The IOUs argue that because BPA erroneously treats conservation as a resource in the 7(b)(2) Case, it has not properly included the costs of conservation in the power costs used in determining the 7(b)(2) Case rates. BPA offers qualified agreement. If conservation was not a resource included in the 7(b)(2)(D) resource stack, and if conservation was not included in solving for general requirements in the 7(b)(2) Case, then BPA would agree with the IOUs' conclusion. In that circumstance, the costs of conservation (and billing credits) must be included in the 7(b)(2) Case power costs. To do otherwise would provide the benefits of conservation, lower general requirements, to 7(b)(2) Customers without any of the costs included in the rates for those customers. Congress did not intend that conservation be a free good in the 7(b)(2) Case.

However, BPA does not agree with the IOUs' argument that the Staff proposal erroneously treats conservation in the 7(b)(2) Case. As explained elsewhere in this ROD, conservation is a resource and must be applied to remaining general requirements after loads are first served by Federal base system resources. As such, these conservation resources must be included in the 7(b)(2)(D) resource stack and used in the determination of general requirements in the 7(b)(2) Case if they are the least-cost resources available. Because this is the proper treatment of the conservation and billing credit resources, the costs of those resources should not be included in the power costs of the 7(b)(2) Case rates unless chosen from the stack and applied in the determination of general requirements. To do otherwise would constitute improper double counting of conservation and billing credit costs in the power costs in the 7(b)(2) Case.

If any of these costs of conservation and billing credits are included in the power costs in the 7(b)(2) Case, then there is no subtraction of these costs thereafter before the comparison of the rates between the two Cases. It is this later subtraction that the 1984 Legal Interpretation was speaking to when it came to the conclusion that Applicable 7(g) Costs should be excluded from the Program Case, but not from the 7(b)(2) Case. 1984 Legal Interpretation, b2-84-FR-03, at 10. This conclusion is still valid today and is validated by the treatment specified in the proposed Legal Interpretation. The difference in the language between the two Legal Interpretations arises from temporal distinctions. The 1984 Legal Interpretation was focused at the end of the rate test process, when the exclusion of Applicable 7(g) Costs is made from the Program Case rates but not from the 7(b)(2) Case rates, immediately prior to the comparison of the rates. The proposed Legal Interpretation is focused at the beginning of the rate test process, when the power costs are being determined for the 7(b)(2) Case.

At this point, it would be useful to discuss the question of why Applicable 7(g) Costs are identified in section 7(b)(2). In section 7(g), there are eight items specifically mentioned. Although this is not an inclusive list ("including, but not limited to," 16 U.S.C. § 839e(g)), the comparison of the list in section 7(g) with the subset named in section 7(b)(2) can help determine the appropriate treatment of the costs identified in section 7(b)(2).

The eight cost and benefit categories in section 7(g), and those specified in section 7(b)(2) for exclusion from the Program Case projected costs, are:

	Section 7(g)	**Section 7(b)(2)**
1)	conservation	conservation
2)	fish and wildlife measures	-----
3)	uncontrollable events	uncontrollable events
4)	reserves	-----
5)	excess costs of experimental resources	experimental resources
6)	credits granted under section 6[(h)]	resource and conservation credits
7)	operating services	-----
8a)	the sale of … excess electric power	-----
8b)	the … inability to sell excess electric power	-----

The Senate Report describes the cost categories of section 7(g) in this manner:

> (1) The cost of conservation commensurate with the benefits to those acquiring power under the respective rates.
> (2) (not included in the Senate bill.)
> (3) The costs of uncontrollable events.
> (4) The cost of reserves associated with firm sales. (Not charged to that portion of the DSI load providing such reserves.)

(5) The costs of research and development including pilot project costs to the extent these projects are not cost effective.

(6) The costs of billing credits pursuant to subsection 6(h) of the proposed legislation.

(7) Rate adjustments for general overhead and from all other costs and benefits as appropriate.

(8a) The revenue benefits from the sale of excess firm and nonfirm – generally allocated in accordance with the resources contributing to such revenues.

(8b) Rate adjustment associated with the difference between the revenues from all sales and the cost of resources required for such sales.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 60-61 (1979) (listing reordered to match section 7(g)).

No argument has been presented in this proceeding regarding the treatment of the other four section 7(g) costs (#2, #4, #7, and #8) in the 7(b)(2) Case. (BPA recognizes that issues pertaining to the quantification of reserve benefits (#4) and the 7(b)(3) treatment of secondary sales (#8a) have been raised. These issues are distinguishable from the one addressed here in that they are specified for exclusion from the projected costs of the Program Case.) To the extent costs of such items are included in "the projected amounts to be charged" in the Program Case, those same costs are included in "the power costs … if, the Administrator assumes" the Five Assumptions. For example, the same fish and wildlife measure costs are included in both Cases. The issue arises regarding the treatment of the items common to both sections 7(g) and 7(b)(2). Section 7(b)(2) does not instruct that the costs of the other four 7(g) costs be excluded from the power costs of the Program Case prior to the rate comparison. Section 7(b)(2) does so instruct for the four Applicable 7(g) Costs. Therefore, there should be a discernable distinction between the four other costs and the Applicable 7(g) Costs.

As has been demonstrated elsewhere in this ROD, the costs of conservation are resource costs not included in the power costs of the 7(b)(2) Case unless selected from the resource stack. Billing credits (#6 on the list) are treated in the same manner as conservation. The same treatment is also in order for experimental resources. However, under section 7(b)(2), it appears that the total cost of the resource would be excluded from Program Case rates.

Also as decided elsewhere in this ROD, the costs of Uncontrollable Events are not the costs of normal operating risks, as the IOUs have argued. Rather, here one can validate the conclusion reached in the discussion on Uncontrollable Costs; they are resource costs, as are the other three. The commonality of the Applicable 7(g) Costs, unlike the other four named section 7(g) costs, is that they are all resource costs. Therefore, the reason these four factors are specified in section 7(b)(2) becomes clearer. The resources related to these costs are resources that would be placed in the section 7(b)(2)(D) resource stack and their costs included in the power costs of the 7(b)(2) Case if they are needed and they are the least-cost resources available.

As a result, the costs associated with all Applicable 7(g) Costs should be treated in a similar manner. Therefore, the costs of experimental resources and the replacement power costs arising out of Uncontrollable Events are to be treated as resource costs, excluded from the Program Case rates, and included in 7(b)(2) Case rates only if selected from the section 7(b)(2)(D) resource stack.

Decision

Because conservation, billing credits, experimental resources, and replacement power arising from Uncontrollable Events are resources properly included in the 7(b)(2)(D) resource stack and used in the solution of general requirements in the 7(b)(2) Case, the costs of such resources are properly excluded from the power costs in the 7(b)(2) Case unless and until such resources are chosen from the 7(b)(2)(D) resource stack as least cost resources. Once included in the power costs of the 7(b)(2) Case, such costs will not be excluded pursuant to section 7(b)(2) prior to the comparison of rates between the two Cases. The costs of such resources are properly excluded, as Applicable 7(g) Costs pursuant to section 7(b)(2), from the Program Case rates.

17.0 SLICE RATE AND REVENUE REQUIREMENT FOR FY 2009

17.1 Introduction

The Slice product is a sale of a fixed percentage of the generation output of the Federal Columbia River Power System (FCRPS). It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. BPA's Subscription sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

17.2 Annual Slice True-Up Adjustment Charge Calculation

Issue 1

Whether the average Slice Revenue Requirement for FY 2007-2009 that is determined in the WP-07 Final Supplemental Proposal should be the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2009.

Parties' Positions

The Slice Customers Group supports the approach of using the average Slice Revenue Requirement for FY 2007-2009 that is determined in the WP-07 Final Supplemental Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2009. Slice Customers Group Br., WP-07-B-JP22-01, at 3.

BPA Staff's Position

BPA Staff proposed that the calculation of the Slice True-Up Adjustment Charge for FY 2009 would be the difference between the Actual Slice Revenue Requirement for FY 2009 and the average Slice Revenue Requirement for FY 2007-2009 that was determined in the WP-07 Final Supplemental Proposal. Lee, *et al.*, WP-07-E-BPA-74, at 5; Lee, *et al.*, WP-07-E-BPA-84, at 2.

Evaluation of Positions

BPA Staff stated that the calculation of the Slice True-Up Adjustment Charge for FY 2009 would be the difference between the Actual Slice Revenue Requirement for FY 2009 and the average Slice Revenue Requirement for FY 2007-2009 that is determined in the Final Supplemental Proposal. Lee, *et al.*, WP-07-E-BPA-74, at 5. The Slice Customers Group argued that the calculation of the Slice True-Up Adjustment Charge for FY 2009 should be the difference between the Actual Slice Revenue Requirement for FY 2009 and the Slice Revenue Requirement for FY 2009 (one-year average) determined in the Final Supplemental Proposal. Brawley and Gregg, WP-07-E-JP22-01, at 8. The Slice Customers Group believed that Slice customers also would be paying a Slice rate that was based only on the FY 2009 Slice Revenue Requirement that is determined in the final Supplemental Proposal. *Id*. Staff disagreed with the

Slice Customer Group's proposal, and restated its initial proposal that the Slice True-Up Adjustment Charge be based on the three-year average Slice Revenue Requirement established in the final Supplemental Proposal. Lee, *et al.*, WP-07-E-BPA-84, at 2. Using the Slice Revenue Requirement for FY 2009 would be inappropriate because the applicable rate period is FY 2007-2009, and not FY 2009 alone. *Id*. The Slice Customers Group agrees with Staff's initial proposal and states that it supports the approach of using the average Slice Revenue Requirement for FY 2007-2009 determined in the final Supplemental Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2009. Slice Customers Group Br., WP-07-B-JP22-01, at 3.

Decision

BPA will use the average Slice Revenue Requirement for FY 2007-2009 that is determined in the WP-07 Final Supplemental Proposal as the basis for the calculation of the annual Slice True-Up Adjustment Charge for FY 2009.

18.0 MISCELLANEOUS ISSUES

18.1 Generation Inputs

Forecasts of generation input revenues were set in the WP-07 Final Proposal. WP-07 Administrator's Final ROD, WP-07-A-02, at 7·1-7·2, 7·17-7·18. In the WP-07 Supplemental Proposal, BPA Staff proposed to update the generation input revenue forecast for FY 2009. The revised forecast includes changes to anticipated revenues from the sale of Operating Reserves and Generation Supplied Reactive as well as inclusion of Within-Hour Balancing Service for Wind Integration. These forecast updates are based on changes to quantities of Generation Inputs needed by Transmission Services, the outcome of a recent FERC proceeding, and the Wind Integration rate case settlement. The underlying methodologies that were used in the WP-07 Final Proposal to price the Generation Inputs have not been changed.

In the WP-07 Final Proposal, FY 2009 revenue from Operating Reserves – Spinning and Supplemental was based on a need of 380 MW at a per-unit price of $5.63 per kilowatt per month. WPRDS, WP-07-FS-BPA-05, at 95. The revised forecast is $31.551 million, based on a forecast need of 467 MW. The revised amount is based on the FY 2008 amount of operating reserves requested by Transmission Services. Klippstein, *et al.*, WP-07-E-BPA-75, at 3.

In the WP-07 Final Proposal, FY 2009 revenue for Generation Supplied Reactive and Voltage Control was estimated to be $12.5 million, based on the uncertainty of the outcome of a Federal Power Act Section 206 proceeding at FERC challenging Generation Supplied Reactive and Voltage Control rates of non-Federal power producers. WP-07 Final ROD, WP-07-A-02, at 7·2-7·3. That proceeding resulted in the elimination of Transmission Services payments for inside-the-band Generation Supplied Reactive and Voltage Control for all generators in the BPA balancing area. As a result, Transmission Services is no longer compensating Power Services, and the revised forecast is $4.091 million, which is based solely on the cost of synchronous condensers. Klippstein, *et al.*, WP-07-E-BPA-75, at 2-3.

Pursuant to the Wind Integration rate case settlement, Power Services will supply generation inputs for the new Transmission Services control area service called "within-hour balancing service for wind generation" in FY 2009. Mainzer, *et al.*, WI-09-E-BPA-01, at 2. Staff's Supplemental Proposal forecast of $14.031 million, Klippstein, *et al.*, WP-07-E-BPA-75, at 3-4, will be revised to $19.124 million for the WP-07 Final Supplemental Proposal, based on the outcome of the Wind Integration rate case. Mainzer, *et al.*, WI-09-E-BPA-01, at 2.

No party raised issues with the generation inputs testimony or study in the WP-07 Supplemental Proposal. The Staff proposal for these uncontested generation input revenue forecasts will be adopted.

18.2 Low Density Discount

To avoid adverse impacts on retail rates of eligible utilities with low system densities, BPA applies a discount, to the extent appropriate, to BPA's rates for such purposes. This discount is called the Low Density Discount (LDD).

The methodology for calculating the LDD is explained in detail in BPA's Wholesale Power Rate Schedules and General Rate Schedule Provisions (GRSPs), WP-07-E-BPA-51, at 99-102. In summary, a utility must satisfy five eligibility criteria. Two of these criteria regard having a K/I (sales to investment) ratio less than 100 and a C/M (consumers per mile) ratio less than 12. If a utility does not meet the five eligibility requirements, its LDD is zero. If the utility satisfies the five requirements, it is eligible for the LDD.

BPA has established, in the GRSPs, a list of discounts that apply to the numerical results of the calculation of the two respective ratios. The purchaser receives the sum of the two potential discounts, but not in excess of seven percent. Once the percentage discount is determined, the discount is applied each month to the charges (excluding Unauthorized Increase Charges, Excess Factoring Charges, and charges for transmission services) for all power the utility purchases from BPA under the PF Preference rate, the PF Exchange rate, and the NR-02 rate. The LDD applies to the following components of the foregoing rate schedules: (1) Demand; (2) HLH energy purchases; (3) LLH energy purchases; and (4) Load Variance. The LDD reduces the recipient's monthly power bill by the applicable discount.

No parties raised any LDD issues in their Initial Briefs or Briefs on Exceptions. Therefore, BPA will adopt Staff's proposal to continue the current LDD methodology, including the provisions adopted in the Partial Resolution of Issues. *See* Evans, *et al.*, WP-07-E-BPA-31, at 1-2.

19.0 THE NATIONAL ENVIRONMENTAL POLICY ACT

19.1 Introduction

BPA has assessed the potential environmental effects that could result from implementation of the 2007 Supplemental 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, WP-07 falls within the scope of the Market-Driven alternative and is not expected to result in 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.[21]

19.2 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 related to 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.)

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

[21] 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.

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 relationships to the market (Business Plan EIS, section 2.1). Previous environmental studies for key BPA actions had shown that actual environmental impacts are determined by the market responses to BPA's marketing actions, rather than by the actions themselves. (*Id*., sections 2.1.5 and 4.1.2.) These market responses discussed in detail in section 4.2 of the Business Plan EIS, are: resource (including conservation) development; resource operation; transmission development and operation; and consumer behavior. These market responses determine the environmental impacts, which include air, land, and water impacts, as well as socioeconomic impacts. (*Id*., Figure 2.1-1 and Figure S-2.)

With this knowledge, BPA used market responses as the foundation for the environmental analyses of alternatives and modules in sections 4.4 and 4.5 of the Business Plan EIS. Section 4.4.3 also included an illustrative numerical example. As can be seen from the environmental analyses summarized in Tables 4.4-19 and 4.4-20, differences in total environmental impacts among the alternatives are relatively small.

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 each of the 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 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.)

In 2007, BPA completed a review of the Business Plan EIS and ROD through a Supplement Analysis. The Supplement Analysis was prepared to assess whether the Business Plan EIS still provides an adequate evaluation, at a policy level, of environmental impacts that may result from BPA's current business practices, and whether these practices are still consistent with the Market-Driven alternative adopted in the Business Plan ROD. As part of the preparation of the Supplement Analysis, changes that have occurred in the electric utility market and the existing environment were evaluated, and developments that have occurred in BPA's business practices and policies were considered. The Supplement Analysis found that the Business Plan EIS's relationship-based and policy-level analysis of potential environmental impacts from BPA's business practices remains valid, and that BPA's current business practices are still consistent with BPA's Market-Driven approach. The Business Plan EIS and ROD thus continue to provide a sound basis for making determination under NEPA concerning BPA's policy-level decisions.

19.3 Relevant RODs Tiered to the Business Plan ROD

Since 1995, over 40 strategic business decisions have been implemented through the Business Plan EIS and ROD. Several of these decisions and their RODs are directly applicable to WP-07.

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.

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 the 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.

<u>Policy for Power Supply Role for FY 2007-2011</u>

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. 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 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.

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 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.

WP-07 Wholesale Power Rate Adjustment Proceeding

In July, 2006, BPA issued a ROD for the 2007 Wholesale Power Rate Adjustment Proceeding. The proceeding adopted power rates for the three-year rate period commencing October 1, 2006, through September 30, 2009; established replacement rate schedules and General Rate Schedule Provisions for those that expired on September 30, 2006; and established the General Transfer Agreement Delivery Charge for the period of October 1, 2007, through September 30, 2009.

BPA reviewed the Business Plan EIS and ROD to determine whether the WP-07 Wholesale Power Rate Adjustment Proceeding was adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. Based on this review, BPA determined the WP-07 Wholesale Power Rate Adjustment Proceeding to be a direct application of the Market-Driven alternative. The issues related to this proceeding remained consistent with the analysis of key policy issues related to power products and services identified for the Market-Driven alternative. (Business Plan EIS, sections 2.2.3 and 2.6.) Even with revisions, this rate proposal did 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.) In addition, the rate proposal continued BPA's approach to power service and rates developed in the Power

Subscription Strategy and provided for in subsequent power rate cases. The WP-07 Proceeding was found to be within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD. Implementation of this rate proceeding did not result in environmental impacts significantly different from those examined for the Market-Driven alternative in the Business Plan EIS. Thus, BPA tiered its NEPA decision for the WP-07 Wholesale Power Rate Adjustment Proceeding to the Business Plan ROD.

Long-Term Regional Dialogue Policy

BPA signed the Long-Term Regional Dialogue Policy Administrator's ROD in July 2007. This ROD adopted a policy on BPA's long term power supply role after FY 2011. This policy was intended to provide BPA's customers with greater clarity about their Federal power supply so they could effectively plan for the future and make capital investments in long-term electricity infrastructure. The Long-Term Regional Dialogue Policy is expected to be implemented through new power sales contracts and a future rate case conducted before such contracts go into effect in FY 2012. The Long-Term Regional Dialogue Policy does not affect this WP-07 Supplemental Proceeding.

In accordance with NEPA, the Administrator considered the potential environmental consequences for each of the policy issues that comprise the Long-Term Regional Dialogue Policy. Some policy issues did not have the potential to result in environmental effects; thus NEPA was not implicated for these issues. Other policy issues represented a continuation of the status quo; therefore additional NEPA analysis of these issues was not necessary. For the remaining policy issues, potential environmental effects were analyzed in BPA's Business Plan EIS. All together, the policy issues addressed in the Long-Term Regional Dialogue resulted in a final Policy that was consistent with the Market-Driven alternative analyzed in the Business Plan EIS and adopted in the Business Plan ROD. BPA therefore tiered the Long-Term Regional Dialogue Policy NEPA ROD to the Business Plan ROD.

2008 Average System Cost Methodology

In June, 2008, BPA issued an Administrator's ROD for the 2008 Average System Cost Methodology (ASC) which (1) redefined the types of capital and expense items included in the ASC; (2) established new data sources from which ASCs were derived; and (3) changed the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP.

BPA evaluated the revision actions to the ASC under NEPA. These proposed actions were primarily administrative in nature and accordingly did not result in environmental effects. In addition, implementation of the methodology resulted in no resource or transmission development; therefore, no substantial change in consumer or utility behavior occurred. The 2008 Average System Cost Methodology business activities were anticipated in BPA's Business Plan EIS and are consistent with BPA's Market-Driven approach adopted in its Business Plan ROD. (See Business Plan EIS, Table 2.4.1, on *Determination of Firm Loads* and the Market-Driven Alternative, page 2-36; see also *Delivery of Power Under Residential Exchange*

Agreements, Business Plan EIS, page 4-10.). Therefore, BPA tiered the 2008 Average System Cost Methodology to the Business Plan ROD.

19.4 Environmental Analysis for the 2007 Supplemental Wholesale Power Rate Adjustment Proceeding

As discussed in detail throughout this ROD, BPA is conducting WP-07 to: (1) calculate REP benefits consistent with the Northwest Power Act; (2) apply the calculation to determine the lookback amount; and (3) use the calculation to determine REP benefits for FY 2009 and beyond.

As part of its consideration of WP-07, BPA conducted a NEPA evaluation of the three calculation components. BPA reviewed the Business Plan EIS and ROD to determine whether WP-07 is adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. This alternative was selected as BPA's business direction because it allows BPA to: (1) recover costs through rates; (2) develop rates that meet customer needs for clarity and simplicity; (3) continue to meet BPA's legal mandates; and (4) avoid adverse environmental impacts. The business activities that will occur as a result of WP-07 remain consistent with the analysis of key policy issues related to power products and services in the Business Plan EIS and the Market-Driven approach (section 4.2.1.4, Table 2.4-1). BPA's decision to revise the REP benefits calculation is primarily administrative in nature and thus would not be expected to result in environmental effects significantly different from those examined for the Market-Driven alternative. WP-07 is not expected to result in a substantial change in consumer or utility behavior with the potential for environmental effects. Based on this review, BPA determines that WP-07 is within the scope of the Market-Driven Alternative and will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD.

19.5 Public Comments

The public comment period closed May 5, 2008. There were no National Environmental Policy Act issues raised during the comment period or in parties' briefs.

19.6 NEPA Decision

Based on a review of the Business Plan EIS and ROD, BPA determines that WP-07 falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. WP-07 is not expected to result in 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 the 2007 Supplemental Wholesale Power Rate Adjustment Proceeding is tiered to the Business Plan ROD.

20.0 PROCEDURAL ISSUES

20.1 Introduction

This chapter of the ROD presents BPA's responses to the procedural issues raised by parties in their Initial Briefs and Briefs on Exceptions.

20.2 Tribal Issues

Issue 1

Whether the Administrator should reverse the Hearing Officer's decision to strike from the initial WP-07 rate case record portions of the joint testimony of CRITFC, the Nez Perce Tribe, and Yakama Nation (collectively referred to as the Tribes) regarding BPA's risk mitigation strategies and fish and wildlife spending.

Parties' Positions

The Tribes ask the Administrator to reinstate the rebuttal testimony of Sheets, *et al.,* WP-07-E-JP-13-03, at 18, lines 8-12, which was previously stricken from the WP-07 rate proceeding record, and consider and respond to the stricken testimony in this Supplemental Proceeding. CRITFC and Yakama Br., WP-07-B-JP13-01, at 18. The Tribes contend this tribal testimony "rebuts Bonneville's rebuttal testimony at WP-07-E-BPA-34, page A-4." *Id*. at 19. The Tribes also ask the Administrator to reinstate the testimony of Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, at 59, line 9, through 62, line 16, and related attachments, which were stricken from the WP-07 rate proceeding record, and consider it in this proceeding. CRITFC and Yakama Br., WP-07-B-JP13-01, at 20-21; CRITFC and Yakama Br. Ex., WP-07-R-JP13-01, at 7. The Tribes contend this tribal testimony stated that BPA has, in practice, operated to a 100 percent TPP, and when BPA has been forced to choose between making its Treasury payment and reducing its costs, BPA has decided to reduce fish and wildlife programs. *Id.*

BPA Staff's Position

BPA Staff has not addressed this procedural issue.

Evaluation of Positions

As noted above, the Tribes ask the Administrator to reinstate the rebuttal testimony of Sheets, *et al.,* WP-07-E-JP-13-03, at 18, lines 8-12, which was previously stricken from the WP-07 rate proceeding record, and consider and respond to the stricken testimony in this Supplemental Proceeding. CRITFC and Yakama Br., WP-07-B-JP13-01, at 18. The Tribes contend their testimony "rebuts Bonneville's rebuttal testimony at WP-07-E-BPA-34, page A-4." *Id*. at 19. The Tribes also ask the Administrator to reinstate the testimony of Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, at 59, line 9, through 62, line 16, and related attachments, which were stricken from the WP-07 rate proceeding record, and consider them in this proceeding. CRITFC and Yakama Br., WP-07-B-JP13-01, at 20-21; CRITFC and Yakama Br. Ex., WP-07-R-JP13-01, at 7. The Tribes contend their testimony stated that BPA has, in practice, operated to a 100 percent TPP, and when BPA has been forced to choose between making its Treasury payment and reducing its costs, BPA has decided to reduce fish and wildlife programs. *Id.*

The Tribes could have moved at any time prior to their Initial Brief for reinstatement of the previously stricken testimony, or they could have sought to refile the previously stricken testimony as their testimony in this Supplemental Proceeding. Because the Tribes have waited until their Initial Brief to make this request, they have deprived BPA and other parties of an opportunity to review the previous testimony, to consider its relevance and appropriateness for this case, to conduct oral and written discovery of such testimony, to cross-examine the sponsoring witnesses, and to address the issues raised in the testimony in oral argument and Initial Briefs. On these grounds alone, the request should be denied because of its prejudicial nature.

Nonetheless, BPA has reviewed the request on its merits. The first request is for reinstatement of three sentences of testimony, which read in total as follows:

> It is likely that other factors would also affect the TPP, including increases in costs, decreases in revenues, etc. Therefore, limiting the [Emergency NFB] surcharge to only the amount of the ESA costs may not collect enough to assure Treasury payment. BPA should modify its proposal so it can collect sufficient funds to repay the Treasury.

Sheets, *et al.*, WP-07-E-JP13-03, at 12, lines 8-12.

This is nearly identical to testimony (and arguments) the Tribes have made in this Supplemental Proceeding. *See, e.g.*, Sheets, *et al.*, WP-07-E-JP13-07-E1-CC1, at 8-10. BPA did not move to strike this testimony and has, in fact, addressed the issues raised by the Tribes in this chapter. As a result, to reinstate this prior tribal testimony for this Supplemental Proceeding would be unnecessary and redundant.

In their second request, the Tribes seek reinstatement of Sheets, *et al.*, WP-07-E-CR/NZ/YA-01, at 59, line 9, through 62, line 16, which is approximately four pages of testimony, and "related attachments" that contain many dozens more pages. The Tribes suggest that this testimony is limited to risk mitigation issues, but in fact the testimony (and the related attachments) addresses a wide range of issues, including fish and wildlife spending by BPA, which the Tribes do not otherwise raise in their brief.

The Tribes sought reinstatement of this same testimony during the initial WP-07 proceeding. The Administrator denied this request on several grounds, including that the Tribes were seeking to address issues already resolved in BPA's favor in prior litigation, and that the testimony the Tribes were seeking to reinstate had more to do with fish and wildlife spending issues than risk mitigation strategies. WP-07 Final ROD, WP-07-A-02, at 17·12-17·14 (Issue 6). The analysis and rationale in the WP-07 ROD for declining to reinstate the stricken testimony remains relevant and appropriate for this proceeding, and is hereby incorporated by reference.

Decision

BPA will not reverse the Hearing Officer's decision to strike the Tribes' testimony in the initial WP-07 proceeding regarding BPA's risk mitigation strategies.

20.3 RAM Procedural Issue

Issue 1

Whether BPA erred by failing to provide the parties with a version of the Rate Analysis Model (RAM) for FY 2002-2006 that could be easily manipulated for scenario analysis.

Parties' Positions

APAC claims that BPA failed to provide a workable 2002 RAM model that could be manipulated for various assumptions and sensitivities and that could be used to examine various rate test assumptions for the Administrator's review. APAC Br., WP-07-B-AP-01, at 54; APAC Br. Ex., WP-07-R-AP-01, at 24-26. APAC further argues that the 2002 RAM is inadequate for calculating a PF Exchange rate that properly determines a section 7(b)(3) allocation and assignment to exchanging utilities based on the settlement. APAC Br., WP-07-B-AP-01, at 33. APAC states the 2002 RAM treatment is improper because the settlement amounts in aggregate and to each exchanging IOU have been determined on a far different basis than a potential exchange amount based on IOU ASC filings and the associated REP loads. *Id*. APAC claims the two methods are like apples and oranges, and using a tool designed for oranges cannot correct for the overpayments of apples under the settlement. *Id*.

Cowlitz claims that when it tested BPA's calculation of the section 7(b)(2) rate test by eliminating the effects of all Five Assumptions except the cost of the REP from the RAM model, the RAM still produced significant REP benefits to be paid for entirely by preference customers. Cowlitz Br., WP-07-B-CO-01, at 9.

BPA Staff's Position

The Supplemental Proposal included the three RAM models that Staff used for its Lookback analysis and rate calculations. Forman, *et al.,* WP-07-E-BPA-76, at 60. BPA made these three models available to all parties. *Id.* Although the model used in the WP-07 proceeding is easier to use than the WP-02 model, the WP-02 model is functional. *Id.* The WP-02 model used by BPA and made available to parties is the model actually used to develop rates for the WP-02 Final Proposal. *Id*.

Evaluation of Positions

APAC claims that BPA failed to provide a workable 2002 RAM model that could be manipulated for analysis using various assumptions and sensitivities and that could be used to examine various rate test assumptions for the Administrator's review. APAC Br., WP-07-B-AP-01, at 54. BPA understands APAC's claim that it was unable to work with the 2002 RAM to analyze the alternatives it wished to analyze. However, because the 2002 RAM was the model actually used to develop BPA's WP-02 power rates, Staff logically used the model to prepare BPA's Supplemental Proposal. Staff, however, was able to perform all of the analyses it considered the most appropriate in order to present its case, as evidenced by the many pages of the Lookback Study, WP-07-E-BPA-44, and Documentation, WP-07-E-BPA-44A. Although BPA understands that parties would like to be given models that not only perform the function required of them but also lend themselves to alternative scenario analysis, it is not BPA's duty or responsibility to predict every sort of sensitivity or alternative solution that parties might wish to analyze when building its analytical models. BPA makes copies of its analytical models available to all parties, and the parties are responsible for constructing their own analyses. Furthermore, the 2002 RAM was developed approximately 10 years ago, when BPA's modeling was not as sophisticated as it is for the Supplemental Proposal. Staff is confident that the 2002 RAM is capable of properly performing necessary analyses, but Staff is also aware that it is difficult to construct alternative analyses using the 2002 RAM. These difficulties were a prime motivation for the revision of the 2002 RAM into the 2007 RAM.

APAC further argues that the 2002 RAM is inadequate for calculating a PF Exchange rate that properly determines a section 7(b)(3) allocation and assignment to exchanging utilities based on the REP settlements. APAC Br., WP-07-B-AP-01, at 33. APAC states the 2002 RAM treatment is improper because the settlement amounts in aggregate and to each exchanging IOU have been determined on a far different basis than a potential exchange amount based on IOU ASC filings and the associated REP loads. *Id*. APAC claims the two methods are like apples and oranges, and using a tool designed for oranges cannot correct for the overpayments of apples under the settlement. *Id*.

BPA is unsure why APAC would want to model a 7(b)(3) allocation based on REP settlements. APAC has offered no reason why it would be necessary to allocate costs related to agreements that have been declared illegal by the Court. No RAM model of any vintage was designed to perform a 7(b)(3) allocation of REP settlement costs. In the WP-02 rate case, BPA did not attempt such an allocation. BPA allocated REP settlement costs in the Subscription Step, which occurred after the 7(b)(3) allocation. As a result, BPA does not understand APAC's apples and oranges comparison. BPA used the 2002 RAM to perform the section 7(b)(2) rate test and the subsequent 7(b)(3) reallocation using REP costs (the oranges). REP settlement costs (the apples) were not introduced into the 2002 RAM until after the 7(b)(3) reallocation. Therefore, BPA did not, in the WP-02 rate case, use the 2002 RAM to allocate REP settlement costs pursuant to section 7(b)(3). In the instant proceeding, Staff has excluded all REP settlement costs from the 2002 RAM. Therefore, there is no need to allocate REP settlement cost pursuant to section 7(b)(3). Instead, BPA is assuming the Ninth Circuit rendered the REP settlement amounts unlawful, and therefore BPA is using REP costs (not REP settlement costs) based on

ASCs, REP loads, and a reconstructed PF Exchange rate. Therefore, it is not necessary to incorporate REP settlement costs in the 2002 RAM.

BPA is unsure how Cowlitz configured the 2002 RAM to model its analysis. However, as Staff was preparing its analyses of parties' cases, revisions to the 2009 RAM to reflect Cowlitz's positions yielded no REP benefits. As explained elsewhere in this ROD, this does not mean that exchanging utilities are entitled to no REP benefits; rather, BPA explains that Cowlitz's analysis was flawed for numerous reasons. Therefore, BPA is confident that the 2009 RAM is functioning properly in the areas that Cowlitz was analyzing. As noted above, the 2002 RAM is difficult to configure. However, the results of the 2002 RAM are similar to those of the 2009 RAM when using similar assumptions. Thus, BPA is confident that the 2002 RAM is performing properly for its intended purposes.

In its Brief on Exceptions, APAC argues that the RAM Model used to run the section 7(b)(2) rate test was never accessible to the parties during the WP-07 Supplemental Proceeding, meaning no party other than BPA could modify input assumptions or gauge the effect on rates caused by changed assumptions, in the time available for this proceeding. APAC Br. Ex., WP-07-R-AP-01, at 24. First, there can be no dispute that the 2007 RAM used to develop BPA's WP-07 rates and WP-07 Supplemental Proposal FY 2009 rates was made available to all parties at the beginning of BPA's initial WP-07 rate case and as part of the working papers that accompanied the publication of BPA's Supplemental Proposal. This single Excel spreadsheet model has built-in capabilities to easily change costs, loads, and a limited number of ratemaking assumptions that allowed scenario analysis by all parties. APAC's comments are thus addressed to BPA's 2002 RAM, a model consisting of five different linked spreadsheet models first developed in the mid-1990s.

APAC fails to point out that the 2002 RAM was initially made available to all parties for BPA's WP-02 rate case, which was conducted in 1999 and early 2000. The 2002 RAM was therefore subject to review by all parties, including opportunities for the parties to ask informal oral discovery questions in clarification sessions, to submit data requests to BPA regarding any aspect of the model, to file testimony regarding the model, and to cross-examine BPA's witnesses sponsoring the model. (These same opportunities have been provided in the WP-07 Supplemental Proceeding.) Using the 2002 RAM, BPA developed its WP-02 base rates in 2000, then held a supplemental rate case to adopt CRACs to ensure BPA's rates could recover its costs. After establishment of the CRACs, BPA filed its proposed rates with FERC for confirmation and approval. FERC subsequently granted final confirmation and approval to BPA's rates. Within 90 days of such approval, numerous parties filed petitions for review with the Ninth Circuit Court of Appeals challenging BPA's WP-02 rates. The parties were free to challenge any aspect of BPA's WP-02 rates, including BPA's 2002 RAM. No party chose to challenge BPA's 2002 RAM on the grounds that the model did not allow parties to conduct their own scenario analyses, or any similar reasons. The Court issued an opinion in the case, *Golden NW*, on May 3, 2007. This was the same model BPA made available again to all parties in BPA's WP-07 Supplemental Proceeding.

In any event, APAC's arguments are not persuasive. APAC states BPA asserts that its rates are properly calculated based on the data inputs, but no other party can test or demonstrate the veracity of this assertion. APAC Br. Ex., WP-07-R-AP-01, at 25. In response, as noted above, all parties had equal access to the RAM and could operate the RAM. In other words, the parties knew BPA's assumptions or input data and knew the results produced by the data. The parties could check to see that the results produced from the input data were consistent with BPA's inputs. The 2002 RAM has a built-in "Revenue Check" worksheet that is used to confirm that the forecast revenues from BPA's forecast rates, along with the forecast of other revenue credits, will be sufficient to recover BPA's power costs for the rate test period.

All parties have equal access to the 2002 RAM and need only mouse-click on the "Revenue Check" tab to confirm that BPA's forecast of FY 2002-06 posted rates covered the forecast cost for that time period. Although APAC argues that certain parties' staffs were unable to run the BPA RAM with changed input assumptions, BPA does not believe this was beyond their abilities, or, if it was, that BPA should be held responsible for their shortcomings. During the pendency of the WP-02 rate proceeding, BPA Staff member Raymond Bliven was employed by one of the cited parties' technical staff and served as a technical witness on behalf of one of BPA's customer classes. In his representation of the customer class, he was able to manipulate the RAM2002 model to run every scenario he desired at that time. The model used by BPA for the FY 2002-2006 Lookback analysis is the same model that Mr. Bliven used at the time of his representation of the customer class with a few minor modifications for the distinctions between the rate setting process (with the REP settlements) and the Lookback process (without the REP settlements). None of these modifications would have affected the ability of any party to run RAM2002. Thus, parties' staffs were able to figure out how the model worked in 1999. They should be able to do so in 2008.

APAC claims parties were denied the ability to test varying input assumptions. APAC Br. Ex., WP-07-R-AP-01, at 24. APAC argues that if parties cannot test varying inputs to the model, they cannot verify that the model functions properly and that it accurately "models" the real-world operations and costs that BPA's decision must reflect. *Id*. at 25. APAC argues that parties must be able to audit the logic of the model. *Id*. APAC claims parties must also be able to change the input data and the assumptions of the model, and see how those changes affect the output. *Id*. As noted previously, the 2002 RAM was provided to parties in 1999 and was used in BPA's WP-02 rate case. The response in the foregoing paragraph is equally applicable here. In addition, BPA's modeling at that time was not as sophisticated as it is today.

Parties did not claim on appeal of BPA's WP-02 rates that the 2002 RAM was inadequate or incapable of performing its functions. Notably, however, the parties have had BPA's 2002 RAM since 1999. In other words, parties have had the 2002 RAM for nearly 10 years. The parties' technical staffs, as demonstrated by their qualification statements, are some of the most technically capable in the region. They have had nearly 10 years to use BPA's RAM, revise the RAM, or develop their own model in order to present whatever assumptions or facts they wished to use in their analyses. They could then present the Administrator with their perspective on how a proper model should be developed and the assumptions that should be used in running the model. The parties have voluntarily chosen not to do so. Instead, after having had the RAM for so long and using the 2002 RAM in the WP-02 rate case without appeal of any shortcomings they could have alleged, they now complain that the RAM that was actually used to develop BPA's WP-02 rates should not be used by BPA to estimate the very rates it was used to develop, and should, in addition, be capable of allowing the parties to perform their own scenario analyses. Given the factual context described above, this is an unreasonable and impracticable request.

It is worthy of note that BPA, in this WP-07 Supplemental Proceeding, is attempting to replicate the development of BPA's WP-02 PF Exchange rate. BPA is using the reconstructed PF Exchange rate to calculate the difference between that rate and the IOUs' ASCs in order to calculate the REP benefits the IOUs would have received from FY 2002-2008 in the absence of the REP Settlement Agreements. This amount is compared with the benefits the IOUs received under the REP Settlement Agreements in order to determine a Lookback Amount that will be returned to BPA's preference customers. BPA is determining the reconstructed PF Exchange rate using information available at the time BPA developed its supplemental WP-02 proposal and in the absence of the REP Settlement Agreements. BPA therefore is keeping its reconstruction of the WP-02 PF Exchange rate the same as the development of the original WP-02 PF Exchange rate, except for changes that would have been reflected from developing rates at a later time than the original May 2000 WP-02 base rates. In order to reconstruct the PF Exchange rate that would most accurately resemble the rate that would have been developed in the absence of the REP Settlement Agreements, BPA must use the same model BPA used to develop the original WP-02 PF Exchange rate. This is why, although the 2002 RAM did not lend itself to scenario analysis, it is unquestionably the proper model to use in reconstructing the WP-02 PF Exchange rate.

APAC argues that parties in a rate case should be able to advocate and test varying assumptions and modifications to data, and if they cannot present the rate consequences of using those different inputs, they are denied full participation in the case. APAC Br. Ex., WP-07-R-AP-01, at 25. APAC argues this is a denial of due process to the intervenor as well as a significant disadvantage for the decision-maker. *Id*. at 26. To the contrary, however, parties can address every issue in the rate case they choose. Parties can file testimony, studies, data, and any other relevant information regarding such issues. The substantive issues will be decided on their merits, based on evidence in the record. One does not have to know the precise mathematical effect on rates of a particular position in order to fully argue or decide that position. Issues will be decided on their merits.

<u>Decision</u>

BPA did not err by providing the parties the actual version of the RAM used to develop BPA's FY 2002-2006 rates and by not providing newly created versions of the RAM that would more readily allow parties to conduct alternative scenario analyses. The models that parties claim to be unworkable or erroneous previously produced, and continue to produce, reliable results for their intended purpose.

20.4 Update of Data and Forecasts

Issue 1

Whether an update to BPA's financial study to correct for changes in the credit market at the time the final rate proposal is prepared will deprive parties of the right to examine and rebut evidence under section 7(i).

Parties' Positions

WPAG argues that BPA Staff's proposal to update, after the close of evidence, expert testimony and opinion evidence contested in this proceeding deprives parties of their rights to examine and rebut such evidence as guaranteed by section 7(i) of the Northwest Power Act. WPAG Br., WP-07-B-WA-01, at 22, *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 95.

BPA Staff's Position

This is a legal issue raised for the first time on brief. Staff proposed to "leave open the possibility of updating the financing study for the final Supplemental Proposal based on how changes that are occurring in credit markets appear at the time the final rate proposal is prepared." Doubleday, *et al.*, WP-07-E-BPA-85, at 95. A decision to update the study would be based on the occurrence of fundamental changes in credit markets that have impacted credit spreads since the time the Supplemental Proposal's financing cost study was prepared, with the result that the initial financing study no longer represents a reasonable projection of the spreads that will occur over the rate test period. *Id*.

Evaluation of Positions

It has been BPA's practice to update certain uncontested, objective numbers after the close of evidence to ensure that its final rate proposals are based on current data. WPAG Br., WP-07-B-WA-01, at 22. WPAG argues that in this proceeding Staff is proposing to update, after the close of evidence, expert testimony and opinion evidence that it previously contested in this proceeding. *Id*., *citing* Doubleday, *et al.*, WP-07-E-BPA-85, at 95. WPAG asserts doing so will deprive parties of their rights to examine and rebut such evidence guaranteed under section 7(i) of the Northwest Power Act. WPAG Br., WP-07-B-WA-01, at 22.

WPAG notes that BPA's rate cases guarantee parties certain procedural rights under section 7(i) of the Northwest Power Act, which provides in part:

> One or more hearings shall be conducted as expeditiously as practicable by a hearing officer to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data questions, and argument related to such proposed rates. In any such hearing –

> (A) any person shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person or the Administrator

Id., *citing* 16 U.S.C. § 839e(i)(2).

WPAG argues that through the introduction of evidence on contested matters after the parties' opportunity for examination, refutation, and rebuttal has passed, BPA would be subverting the fundamental purpose of the section 7(i) process: to subject BPA's rate proposal to public scrutiny and rebuttal so that the Administrator has a complete record upon which to base his decision. WPAG Br., WP-07-B-WA-01, at 22-23. Staff, however, did not propose to introduce new testimony and opinion evidence after the close of the hearing, and thus there is no deprivation of parties' rights to examine and rebut material under section 7(i).

As WPAG acknowledges, it has been BPA's practice to update data and forecasts for its final rate proposals. BPA has used this practice in many previous BPA rate cases. Because a rate proceeding can normally take up to nine months, it is important to update objective data. Such updates include the replacement of near-term forecast data with actual data. For example, in the instant proceeding, BPA filed the initial proposal in February 2008. Actual revenue data for FY 2008 was available only through December of 2007 at the time of the initial proposal. BPA expects to file the final proposal in September 2008. By the time BPA files the Final Record of Decision in this case, actual revenue data will be available through July of 2008. The updating of the forecast of revenue data for January of 2008 through July of 2008 will play a large role in the determination of expected starting FY 2009 financial reserves, which will affect BPA's use of risk mitigation tools for FY 2009. BPA does not read WPAG's argument as addressing this traditional type of update.

A second BPA practice is to update forecasts for the final rate proposal. Because of the passage of time and the availability of more recent information, BPA will modify its forecasts using this better information. In such instances, BPA uses the same models and forecasting techniques as presented in its initial case and substitutes more recent information to produce the updated forecast. Generally, such updates are in uncontested areas of the proceeding. For example, Staff has proposed to update the hydroregulation study presented in the initial case to incorporate a new FCRPS biological opinion. A biological opinion contains very specific conditions and constraints regarding the operation of the regulated hydroelectric projects on the Columbia River and Snake River systems. The new biological opinion is a result of litigation and is produced under the direction of the U.S. District Court of Oregon. Incorporating the new biological opinion into the hydroregulation study is not a contested issue in this proceeding. BPA does not read WPAG's argument as addressing this type of traditional update either.

A third BPA practice is to update data and forecasts in response to issues raised by parties in the proceeding. For example, in the instant case, Cowlitz argues for BPA to update the forecast of revenues from the sales of secondary energy. Cowlitz is the only party to raise this issue, with the WUTC concurring. Cowlitz argues that Staff's forecast in the initial case is dated, relying on old natural gas and market price forecasts. Cowlitz argues that BPA should update natural gas and market price forecasts. Such updates should result in an increase in revenue credits included in BPA's rates. As explained more fully in Chapter 12, BPA agrees with Cowlitz and will update the natural gas and market price forecasts. *See* Chapter 12, FY 2009 Market Price Forecast.

In the case at hand, BPA Staff responded to comments made by the OPUC raising concerns over BPA's estimate of financing benefits. *See* Hellman and McGovern, WP-07-E-PU-01, at 28. Staff testified "[i]t is evident that credit markets have been in disarray since the fall of 2007. In the latter part of 2007, these developments began to affect the credit spread relationships that are central to the financing cost study." Doubleday, *et al.*, WP-07-E-BPA-85, at 94. Staff continued to describe the current uncertainty that exists in credit markets today and how such changes could "change the expectation of credit spreads between the current time period and the time when the final Supplemental Proposal is published." *Id*.

Certainly, BPA understands and respects WPAG's concern in this matter; however, BPA believes it is reasonable to monitor the credit market and make changes to its study, only if necessary, in order to correct information that would otherwise render the analysis fundamentally flawed at the time BPA finalizes the Supplemental Proposal. Such action is both reasonable and prudent. Further, BPA does not agree with WPAG's assertion that to avoid depriving parties' rights under section 7(i) BPA must provide yet another round of examination and rebuttal. The courts make clear that every change to a proposed rule need not be subject to a new review and comment period. An agency does not have to "publish in advance every precise proposal which it may ultimately adopt as a rule." *California Citizens Band Ass'n v. United States*, 375 F.2d 43, 48 (9th Cir. 1967), *cert. denied*, 389 U.S. 844 (1967). To prohibit an agency from modifying a proposed rule based on comments would make no sense. If an agency were required to provide an additional comment period every time the agency responded to public comment, "either the comment period would continue in a never-ending circle, or, if the [agency] chose not to respond to the last set of public comments, any final rule could be struck down for lack of support in the record." *Rybacheck v. U.S. Environmental Protection Agency,* 904 F.2d 276, 1286 (9th Cir. 1990).

Consistent with case law, BPA does not apply section 7(i) in such a restrictive fashion that it would result in Staff's initial case being the only outcome that could be used in the final case if any party contests Staff's data or forecasts. Such a holding would then conflict with section 7(i)(5), which states:

> The Administrator *shall make a final decision* establishing a rate or rates *based on the record* which shall include the hearing transcript, together with exhibits, and such other materials and information as may have been submitted to, or developed by, the Administrator. The decision shall include a full and complete justification of the final rates pursuant to this section.

16 U.S.C. § 839e(i)(5) (emphasis added). Section 7(i)(5) clearly states that the Administrator is to make his decision "based on the record" of the proceeding. Such record includes the positions of all parties contesting a particular issue. The Administrator is to consider the positions of all

parties in reaching his decision. This ROD considers the parties' positions and gives the "full and complete justification" of the Administrator in reaching his decisions.

The House Interior Committee Report describes the procedural protections of section 7(i):

> Section 7(i) establishes rather detailed procedures for ratemaking. The Committee amendment clarifies the procedures adopted by the Senate to ensure adequate and effective review of BPA rates and revisions thereof. It is the clear intent of the Committee that no one may use these procedures to frustrate the Act or to delay rate revisions. The BPA must act fairly to ensure full public and customer input, but dilatory tactics must be avoided. Few relish rate changes that result in higher rates, but often they cannot be avoided. The burden is on BPA to justify increases. These procedures should ferret out unjustified or inadequately supported changes.

H.R. Rep. No. 96-976, Pt. I, 96th Cong., 2nd Sess. 69-70 (1980). Here, Congress describes the balancing BPA must undertake. BPA must ensure an adequate and effective review while not allowing such review to delay rate revisions. If BPA were required to subject every data or forecast update on a contested issue to another round of party review, BPA's rate proceedings could not conclude in a reasonable time frame.

The fact that the Administrator's final case is different from Staff's initial case does not constitute a new rate proposal for which BPA must provide an opportunity for rebuttal. This principle has been recognized in the context of BPA's rate proceedings. In *Central Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1118 (9th Cir. 1984), the Court addressed an argument similar to the position raised by WPAG in this proceeding:

> PGP argues that section 7(i)(2)(A), which provides parties a right to rebut materials "submitted" to or by BPA, compelled BPA to allow parties the opportunity to rebut the revised repayment study. Section 7(i)(2)(A) ensures that BPA creates a complete administrative record, allowing interested parties to participate in a meaningful way. *This does not mean, however, that each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin. Our holding is further supported by the language of section 7(i)(5), which provides no right of rebuttal for materials "developed" by the Administrator, presumably in response to received commentary.* The parties have not indicated the kind of rebuttal they would have made, nor suggested that the revisions were in fact based on any material not already contained in the record. No purpose would be served by requiring yet another round of notice and comment.

(Emphasis added.) In response to issues raised by the OPUC, Staff's testimony left open the possibility of updating the financing study for the final Supplemental Proposal based on how changes that are occurring in credit markets appear at the time the final rate proposal is prepared. Doubleday, *et al.*, WP-07-E-BPA-85, at 95. Therefore, BPA does not view the updates at issue here as an introduction of new material, but rather a revision of the case drawn from the record. Parties have had their procedural rights to review BPA's and other parties' arguments on the record, and there is no violation of parties' due process rights. BPA can adopt a position different from Staff's proposal based on record evidence, which can be provided by any party. As the Ninth Circuit has stated:

> [T]he APA 'does not require an agency to publish in advance every precise proposal which it may ultimately adopt as a rule.' *California Citizens Band Association v. United States*, 375 F.2d 43, 48 (9th Cir.), *cert denied*, 389 U.S. 844 … (1967). The main concern is to ensure that the final rule is sufficiently related to the proposed rule that the challenging party had notice of the agency's contemplated action.

Central Lincoln, 735 F.2d at 1118 (citations omitted).

In summary, BPA will only adopt decisions drawn from the administrative record. Doing so will necessarily produce a result different from BPA's initial proposal and one that has not been reviewed by the parties. Nevertheless, as the Ninth Circuit has recognized, "[t]his does not mean, however, that each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin." *Central Lincoln*, 735 F.2d, at 1118.

Decision

An update to BPA's financial study to correct for changes in the credit market at the time the final rate proposal is prepared, if done, will not deprive parties of the right to examine and rebut evidence under section 7(i).

Issue 2

Whether incorporating into the rate record the assumptions about new large single loads (NLSLs) determined in the ASC Expedited Review Process violates the parties' procedural rights or due process.

Parties' Positions

APAC claims that there will be no opportunity for parties during the litigation and presentation of evidence in this case to review BPA's calculation of the NLSL exclusion under section 5(c)(7)(A), such as the amount of such resources and how they are applied. APAC Br. Ex., WP-07-R-AP-01, at 29. APAC argues there is no opportunity to present evidence disputing BPA's treatment of such resources, and that this denies the parties fundamental procedural rights and the due process of law. *Id.*

BPA Staff's Position

This is a legal issue that Staff did not address. APAC raised this issue for the first time in its Brief on Exceptions.

Evaluation of Positions

In accordance with section 5(c)(7)(A) of the Northwest Power Act, BPA must exclude from the calculation of a utility's ASC the cost of additional resources in an amount sufficient to serve any NLSL of the utility. 16 U.S.C. § 839c(c)(7)(A). Section 3(13) of the Act defines an NLSL as follows:

> any load associated with a new facility, an existing facility, or an expansion of an existing facility –
>
> > (A). which is not contracted for, or committed to, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and
> >
> > (B). which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve-month period.

16 U.S.C. § 839a(13)(A)-(B).

In order for BPA to exclude the cost of serving an NLSL from an ASC, BPA must have specific factual information about an exchanging utility's resources. Under the traditional implementation of the REP, exchanging utilities would provide this information pursuant to the terms and conditions of an RPSA. These agreements were the contractual mechanisms that implemented the REP and defined BPA's and the exchanging utility's rights and obligations. However, BPA and exchanging utilities have not executed or implemented RPSAs since the mid-1990's. Boling, *et al.*, WP-07-E-BPA-57, at 4-5. Instead, the REP benefits were provided through REP settlement agreements, which did not require exchanging utilities to submit NLSL data to BPA.

As noted in Chapters 7 and 14 of this ROD, in response to the Ninth Circuit's decisions in *PGE* and *Golden NW*, BPA proposed to calculate new ASCs for the IOUs for two time periods. First, using the 1984 ASC Methodology, BPA proposed to calculate estimated ASCs that the IOUs would have filed with BPA had the REP Settlement Agreements not been executed. *See* Chapter 7. To do this, BPA calculated ASCs for the exchanging IOUs for each year beginning in FY 2002 and ending in FY 2008. *Id.* These estimated ASCs are referred to as "backcast ASCs." Second, BPA proposed to calculate forecast ASCs for FY 2009, using BPA's new 2008 ASC Methodology. Because the ASCs for FY 2009 were subject to a new and untested ASC Methodology, BPA proposed to calculate these ASCs in a separate administrative proceeding, referred to as an expedited ASC Review Process (Expedited Review Process). *See* 2007 Supplemental Wholesale Power Rate Adjustment Proceeding, 73 Fed. Reg. 7539, 7547 (Feb. 8, 2008). At the close of the Expedited Review Process, the resulting ASCs would be incorporated into the rate case record and used for rate-setting purposes in the WP-07 Supplemental Wholesale Power Rate Proceeding. McHugh, *et al.*, WP-07-E-BPA-71, at 23. To ensure that the resulting ASCs complied with the statutory directives of section 5(c) and the proposed 2008 ASC Methodology, BPA requested in the Expedited Review Process that utilities provide BPA with load data from 1993-2007 for the purpose of identifying NLSLs. BPA requested 14 years of load data because, as noted above, BPA generally did not have active RPSAs with the IOUs during these years, and therefore did not have the necessary information to determine whether to exclude the cost of a resource that might be serving an NLSL.

As BPA was receiving and reviewing this NLSL information, APAC noted in its direct testimony that BPA's proposed backcast ASCs for the FY 2002-2008 period did not take into account the NLSL exclusion required by section 5(c)(7)(A). Wolverton, WP-07-E-AP-01, at 36. In its first opportunity to respond, BPA Staff acknowledged in its rebuttal testimony that the backcast ASCs did not exclude the cost of resources used to serve NLSLs, explaining that at the time of the Supplemental Proposal BPA did not have any NLSL data from which to estimate an adjustment. Boling, *et al.*, WP-07-E-BPA-83, at 39. BPA Staff also stated they wanted to reflect NLSL adjustments for the backcast ASCs for BPA's final rate proposal. *Id.* Staff further explained that BPA was in the process of collecting additional load data from the IOUs in the Expedited Review Process to determine whether any NLSL adjustments would need to be made for the FY 2009 ASC forecasts. *Id.*

The Expedited Review Process, unlike the general rate case, focused solely on ASC issues, including NLSLs. The Process allowed any interested party to intervene, review materials related to issues addressed in the process, and provide comments to BPA regarding how BPA should address issues raised in the process. Because the load data made available during the Expedited Review Process could also be used to calculate an estimate of NLSL adjustments for the FY 2002-2008 period, BPA decided to calculate the NLSL adjustments for the FY 2002-2008 backcast ASCs under the terms of the 1984 ASCM in the Expedited Review Process and incorporate the results into the final WP-07 Supplemental rate record. This was the only feasible manner in which BPA could ensure that APAC's concern about the absence of NLSL adjustments could be addressed and, in addition, the most accurate data available could be used to forecast ASCs for BPA's rate proposal.

APAC claims that there will be no opportunity for parties during the litigation and presentation of evidence in this case to review BPA's calculation of the NLSL exclusion under section 5(c)(7)(A), such as the amount of such resources and how they are applied. APAC Br. Ex., WP-07-R-AP-01, at 29. APAC argues that there is no opportunity to present evidence disputing BPA's treatment of such resources, and this denies the parties fundamental procedural rights and the due process of law. *Id.* APAC's concerns are misplaced.

Contrary to APAC's claims, it has had a significant opportunity to present evidence disputing BPA's treatment of NLSLs. BPA Staff made it very clear in its rebuttal testimony that it proposed to calculate the NLSL resource costs within the Expedited Review Process. Boling, *et al.,* WP-07-E-BPA-83, at 39. In the Expedited Review Process, BPA posted its NLSL determinations on June 18, 2008, and requested comments from all interested parties. *See* Letter from Michelle Manary, BPA, to Interested Parties, Dated June 18, 2008, at 1-2. In this letter, BPA explained that because NLSL data is based on confidential load data provided by the IOUs, BPA would provide access to the underlying load data under the terms and conditions of a confidentiality agreement. *Id.* APAC requested this agreement, and after a miscommunication was clarified, was granted access to the data. *See* Letter from Michelle Manary, BPA, to Interested Parties, Dated September 15, 2008, at 3-4. APAC reviewed the data, and submitted comments on July 28, 2008. *Id.* BPA reviewed APAC's comments and made several revisions to the NLSL assumptions as a result of APAC's comments. *Id.* As these events establish, APAC has been afforded an opportunity to review and comment on the NLSL assumptions used in this case, and has not been denied any procedural protections. APAC's argument therefore lacks merit.

Second, APAC argues that there is no opportunity to present evidence disputing BPA's treatment of such resources, claiming that it must have the opportunity to review the resource cost information that forms the basis of the NLSL exclusions. As just noted, BPA provided APAC with this opportunity in the Expedited Review Process. Furthermore, there would have been no purpose served by allowing APAC another opportunity in this proceeding to review BPA's NLSL assumptions. To make an NLSL assumption, in the context of an ASC determination, two questions must be answered: (1) is there an NLSL, and if so, (2) what is the cost of the resources that serve that NLSL? Once these questions are answered, adjusting the resulting ASC (if necessary) becomes a matter of arithmetic. APAC was afforded an opportunity through the Expedited Review Process to comment on the two substantive issues relevant to the NLSL adjustment. APAC provided comments, which resulted in changes to BPA's NLSL assumptions. There is no need, then, for APAC to comment again in this proceeding on how the NLSL assumptions mathematically affect the resulting backcast ASCs.

Third, as noted in the preceding discussion on WPAG's similar concern, the courts have recognized that an agency may add supporting documentation to a final rule in response to public comments without triggering a new comment period. *See Rybacheck v. U.S. Environmental Protection Agency*, 904 F.2d 1276, 1286 (9th Cir. 1990). An agency may use "'supplementary' data, unavailable during the notice and comment period, that 'expand[s] on and confirm[s]' information contained in the proposed rulemaking and addresses 'alleged deficiencies' in the pre-existing data, so long as no prejudice is shown." *Solite Corp. v. EPA,* 952 F.2d 473, 484 (D.C. Cir.1991) (quoting *Community Nutrition Inst. v. Block,* 749 F.2d 50, 57-58 (D.C. Cir.1984)). This allowance is crucially important to avoid locking the agency into a "never-ending cycle" of responding to public comments. *Rybacheck*, 904 F.3d at 1286. This principle has a particular application in BPA rate proceedings. The Ninth Circuit has recognized that in the context of BPA's final rate case studies, section 7(i) of the Northwest Power Act does not requires that "each time BPA adjusts the conclusions to be drawn from the record, new notice and comment must begin." *Central Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1118 (9th Cir. 1984).

In the instant case, APAC made an argument, and BPA responded favorably to APAC's argument, that an adjustment to the backcast ASCs for NLSLs must be made. BPA used the

Expedited Review Process as the forum for parties to raise their questions or comments on how BPA calculated the NLSLs. Using the Expedited Review Process for this purpose made perfect sense because BPA had been in the process of obtaining the necessary load information from the IOUs. Also, no party has been prejudiced by BPA's decision to use the Expedited Review Process to address NLSL issues. Several parties, including APAC, noted their concerns in the Expedited Review Process about BPA's proposed NLSL adjustments. BPA made several corrections in response to these comments and will incorporate the results into the backcast ASC in the final rate case studies. The fact that APAC will not have the right to comment *again* on how these NLSL assumptions affect BPA's final studies does not create any due process problems. BPA is reflecting the results of the Expedited Review Process in the final studies, and as such, is not required to provide parties an opportunity to comment "each time BPA adjusts the conclusions to be drawn from the record." *Id.* There is, therefore, no procedural problem with incorporating the NLSL assumptions into the final studies of the WP-07 Supplemental Proceeding

Decision

Parties were afforded an adequate opportunity to review and comment on BPA's NLSL assumptions in the Expedited Review Process. Incorporating the results from the Expedited Review Process will not deprive any party of its procedural rights or due process.

20.5 BPA Did Not Improperly Expand the Scope of the Rate Proceeding

Issue 1

Whether BPA improperly expanded the scope of the rate proceeding to include issues regarding the lawfulness of the LRAs and violated section 7(i) of the Northwest Power Act by supplementing the record with the administrative records of the LRAs and 2004 Amendments.

Parties' Positions

The IOUs argue that BPA, by letter dated May 30, 2008, improperly expanded the scope of the rate proceeding to include issues of the lawfulness of the LRAs with PacifiCorp and Puget. IOU Br., WP-07-B-JP6-01, at 7-9. In addition, the IOUs contend that BPA improperly supplemented the administrative record following the close of cross-examination with the administrative records of the 2001 LRAs and 2004 Amendments to the 2000 REP Settlement Agreements. *Id*. at 9. According to the IOUs, BPA's attempt to expand the scope of the rate proceeding and supplement the record in this manner is contrary to section 7(i) of the Northwest Power Act.

BPA Staff's Position

BPA Staff took no position on this issue because it is purely a legal issue.

Evaluation of Positions

On May 30, 2008, counsel for BPA sent a letter to all parties to the rate case stating:

> After the completion of cross-examination in the WP-07 Supplemental Proceeding on May 29, 2008, there was a discussion among the parties regarding the possible need to supplement the administrative record. The discussion focused on whether the parties would need to supplement the record with materials related to the lawfulness of the 2001 Load Reduction Agreements (LRA) between BPA and two investor-owned utilities; the 2004 Amendments to the Residential Exchange Program Settlement Agreements; and the Reduction of Risk Discount provisions contained in the LRAs.
>
> During the discussion, Kurt R. Casad, counsel for BPA, indicated that he would confer with BPA's General Counsel regarding this matter. After such consultation, BPA wishes to reaffirm that the scope of this proceeding includes the issues of the lawfulness of the LRAs, the 2004 Amendments, and the Reduction of Risk Discount. *See 2007 Supplemental Wholesale Power Rate Adjustment Proceeding, Public Hearings, and Opportunities for Public Review and Comment,* 73 Fed. Reg. 7539, 7554 (Feb. 8, 2008). Consequently, these issues should be covered in the parties' briefs. In order to provide all parties a factual context in which to make the cited legal arguments, BPA is supplementing the WP-07 Supplemental Proceeding administrative record with the respective administrative records of the 2001 LRAs and 2004 Amendments. Parties to the litigation on the LRAs and 2004 Amendments previously received discs containing the noted administrative records at the time of the litigation. Parties that do not have discs of the cited administrative records will promptly receive a set from BPA upon request. Please contact Leslie Dimitman by email at lmdimitman@bpa.gov or at 503-230-5515 to request copies of the discs.

The IOUs contend that this letter is not a "reaffirmation" of the scope of the proceeding "but rather an impermissible attempt to expand the scope and record of this proceeding" in violation of section 7 of the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 9. BPA believes the IOUs have improperly characterized BPA's letter as well as BPA's Federal Register notice of February 8, 2008 describing the scope of the rate proceeding. 73 Fed. Reg. 7,539 (Feb. 8, 2008).

Section 7(i)(1) of the Northwest Power Act provides that, in establishing rates, notice of the proposed rates shall be published in the Federal Register "with a statement of the justification and reasons supporting such rates." 16 U.S.C. § 839e(i)(1). Section 1010.3 of the Procedures Governing Bonneville Power Administration Rate Hearings describes the nature of the information that BPA will provide in the Federal Register notice, stating that "[t]he notice shall … specify the proposed rates and *summarize* any studies, analyses, or other available information that BPA intends to use in the hearing to justify the proposed rates" (emphasis added). The Federal Register notice clearly summarized all information BPA intended to use in the instant hearing.

On February 8, 2008, BPA published a Federal Register notice initiating the WP-07 Supplemental Wholesale Power Rate Proceeding. 73 Fed. Reg. 7,539 (Feb. 8, 2008). At the very beginning of the notice, BPA stated that it was reopening its WP-07 Wholesale Power Rate Proceeding "to respond to recent decisions from the United States Court of Appeals for the Ninth Circuit." *Id*. Later in the notice, BPA explained that these decisions include *Golden NW, PGE,* and *Snohomish. Id.* at 7540. In *Snohomish*, 506 F.3d 1145 (9th Cir. 2007), the Court provided extensive discussion of the LRAs, the reduction of risk (or "litigation penalty") provision of the LRAs, and options available to BPA on remand involving the LRAs. In particular, the Court noted that BPA "could determine that our prior opinions undermined the entire 2001 LRAs" or alternatively, "BPA could determine that our decisions invalidated the 'litigation penalty' provisions of the LRAs, but that those provisions are tangential to the main agreement and severable … Because we cannot determine from the record what BPA intends to do – and BPA may have other options – we remand for further proceedings." *Id.* at 1155.

Similarly, later in the Federal Notice, BPA again addressed the need to consider *Snohomish*, as well as three unpublished memorandum decisions, when determining Lookback Amounts:

> The determination of utility-specific Lookback Amounts is complex. In addition to the REP Settlement Agreements, BPA must also account for the Court's decision in *Snohomish*, which remanded to BPA the 2004 amendments to the REP Settlement Agreements and the Reduction of Risk discount [provision of the LRAs] that the Court found was based on those Agreements. BPA also must consider three memorandum opinions that dismissed challenges to the LRAs.

Id. at 7552.

Thus, the Federal Register notice repeatedly states that BPA was reopening the WP-07 rate proceeding to respond to numerous decisions from the Ninth Circuit; that the decisions clearly implicate the LRAs; and that in *Snohomish*, the Court expressly stated that, on remand, BPA might determine that the Court's opinions "undermined the entire 2001 LRAs." Therefore, the IOUs' argument that the scope of the proceeding did not include the lawfulness or validity of the LRAs is not convincing.

Moreover, BPA believes the issue of the lawfulness or validity of the LRAs is a necessary component of the reopened WP-07 rate proceeding for purposes of addressing and developing its Lookback proposal. In light of the Court's opinions, BPA believes it has a responsibility to clearly state whether BPA believes the LRAs continue to be valid agreements, and why BPA believes they are valid, in order to decide the appropriate rate treatment of the LRAs. Otherwise, BPA's Lookback proposal is vulnerable to challenge on the ground that it is based on nothing more than an unsupported assumption that the LRAs are valid.

The IOUs argue that BPA improperly supplemented the administrative record of this proceeding with the administrative records of the 2001 LRAs and the 2004 Amendments to the Settlement Agreements. In particular, they contend BPA, by taking this action after the close of cross-examination, denied them "an adequate opportunity … to offer refutation or rebuttal" of such material, especially in light of the voluminous nature of the material, as required by section 7(i)(2)(A) of the Northwest Power Act. IOU Br., WP-07-B-JP6-01, at 9. However, BPA did not supplement the record with this material for purposes of debating the veracity of these administrative records, and neither BPA nor any other party sponsored these record materials through testimony. Rather, BPA supplemented the record with this material for purposes of providing background and context due to the unique nature of the remand. These records are identified clearly and can be readily distinguished from the evidentiary record developed in this proceeding.

Finally, to be clear, BPA does not believe that addressing the continued validity of the LRAs or supplementing the record with the administrative record of the LRAs restarts the 90-day statute of limitations under section 9(e)(5) of the Northwest Power Act to challenge the LRAs. On the contrary, as explained previously, BPA believes the 90-day window to challenge the LRAs expired years ago, that is, 90 days after the LRAs were executed. BPA's sole purpose in addressing the validity or lawfulness of the LRAs is to respond comprehensively to the Court's remand and to fully explain the basis for BPA's decisions.

Decision

BPA has not improperly expanded the scope of the rate proceeding by including consideration of the issue of the lawfulness of the LRAs, and has not violated section 7(i) of the Northwest Power Act by supplementing the record with the administrative records of the LRAs and 2004 Amendments.

20.6 Impartial and Lawful Decision Making

Issue 1

Whether the decisions in this ROD were made in an impartial manner based on the law.

Parties' Positions

Canby asserts in its Brief on Exceptions that Administrator Wright lacks impartiality and thus is unsuitable for deciding the REP-related issues in this proceeding. Canby Br. Ex., WP-07-R-CA-01, at 2, 13, 22. To support its assertion, Canby states that the Administrator has fabricated a new standard by which to make decisions – the "will of the region" standard – which in Canby's view is an "arbitrary and amorphous" standard. *Id*. at 13-14. Canby states that the Administrator intends to use this new standard rather than follow the requirements of the Northwest Power Act, the Administrative Procedures Act, and case law. *Id.*

Canby asserts that the Court's direction to the Administrator is absolutely clear in its *PGE* and *Golden NW* decisions, and only in the *Snohomish* decision does the Court give the Administrator the slightest bit of flexibility as to how to implement its ruling. *Id.* at 16. Canby argues that these rulings provide clear direction and criticizes the Administrator for referring to the Court's instructions as "guidance." *Id.* at 16. Canby contends that the Ninth Circuit did not suggest that the complexity of issues gave BPA the right to sample the "will of the region" or to inquire whether others (particularly the losing parties) thought that BPA's remedies were fair. *Id.* at 20. Therefore, Canby disagrees with the Administrator's statements that suggest he has discretion or even more discretion to "reconcile seemingly different sections of the Northwest Power Act" since the Court had spoken on the subject. *Id.* at 21.

WPAG suggests BPA has made inconsistent legal interpretations and analytical assumptions in order to establish REP benefits at a level equal to previous REP settlements. WPAG Br. Ex., WP-07-R-WA-01, at 6.

BPA Staff's Position

Because Canby raised its issue for the first time in its Brief on Exceptions, BPA Staff did not address it during the hearing. BPA Staff addressed all issues based on their merits.

Evaluation of Positions

Canby states the Administrator lacks impartiality to make the REP-related decisions in this proceeding because, in Canby's view, the Administrator has an overblown vision of what his discretion allows him to do. Canby Br. Ex., WP-07-R-CA-01, at 20. Canby contends that in rate cases the Administrator is not a "deal-maker," but rather acts in a quasi-judicial capacity to "judge" the results of a contested rate proceeding under section 7 of the Northwest Power Act. *Id*. at 1-2. Canby states that the Administrator has created a "will of the region" standard that is not supported by law, and that the Administrator is imposing this new standard in place of law. *Id.* at 18-20. Canby states that the Administrator "create[s] a new standard, not found in either the Northwest Power Act or Administrative Procedures Act, by which he will make decisions in this proceeding." *Id.* at 13.

In response, Canby never presented any evidence of the Administrator's alleged partiality during the WP-07 Supplemental Proceeding. Instead, Canby relies solely on the Administrator's statement in the Draft ROD. In the statement, the Administrator notes that "[t]hroughout these discussions, I and other BPA representatives stated that the agency's decisions must be based on the law. At the same time, I have stated that where the law offers me choices, my choices will be strongly influenced by the will of the region." *Id.* Canby states that the Administrator's statement regarding the "will of the region" indicates that the Administrator intends to "replace the statutory REP with a design of [his] own." As is apparent from the statement, this is simply untrue. The statement does not propose to settle anything in a manner that is contrary to law or to replace the statutory REP. Furthermore, BPA's WP-07 Supplemental Proposal is not based on a settlement. It is based on the administrative record and the law.

Canby criticizes the Administrator for stating "[w]hen I consider the issues raised in this proceeding, I will, when the discretion afforded me allows it, give greater weight to proposals that reflect agreement in the region when it exists." Canby Br. Ex., WP-07-R-CA-01, at 15, *quoting* Draft ROD at vii-ix. Canby fails to acknowledge the Administrator's statement a few sentences earlier that "… the statute can be vague on matters of substantial consequence, and there are many issues the Court has not addressed. As a result, there are a number of areas where I have discretion how to resolve issues." *Id.* It is within that context the Administrator states he will, "when the discretion afforded [him] allows it, give greater weight to proposals that reflect agreement in the region when it exists." Draft ROD at vii. The Administrator is not replacing the law with a new standard. Instead, he is exercising his lawful discretion consistent with sound business principles, one of which is to take into account the suggestions of customers and other regional interests. In summary, by referring to the "will of the region," the Administrator has not established a new standard that replaces the law; he has simply shared with the region some of his thoughts and considerations on how he intends to apply his discretion as permitted by law, where discretion is required to make decisions within the statutory framework. Moreover, the Administrator has concluded that where there is discretion, BPA as a public sector agency should be responsive to the constituency that it is statutorily charged to serve.

There is no question that the law provides BPA directions regarding how it must establish rates and implement programs under the Northwest Power Act. Clearly, the Administrator does not have boundless discretion to implement the Act. However, the exercise of some discretion is necessary for the Agency to function. Canby appears to believe that the law and Court rulings leave virtually no room for discretion by the Administrator. As explained previously in this ROD, however, case law as applied to the instant facts does not support this conclusion. The Court remanded BPA's WP-02 rates and, by definition, a remand requires the Administrator and the Agency to reconsider the issues being remanded. In concluding its decision in *Golden NW*, the Court states "[w]e therefore remand to BPA to set rates in accordance with this opinion." *Golden NW,* 501 F.3d at 1053. By remanding the rates, the Court understood that the Administrator would have to exercise at least some discretion in effectuating the remand. Hence, BPA's administrative function to set rates on remand, consistent with Court's decision, must be performed. Neither the Northwest Power Act nor the Court's opinions in themselves provide precise guidance regarding the manner in which to implement the Court's rulings. Moreover, the extensive record in this case displays the parties' general recognition that there were significant issues left to BPA to resolve in the remand.

Although not expressly directed at the Administrator, WPAG attributes negative motivations to the development of BPA's WP-07 Supplemental Proposal. WPAG Br. Ex., WP-07-R-WA-01, at 6. WPAG states that inconsistent legal interpretations and analytical assumptions employed by BPA in the Supplemental Proceeding are an effort to provide benefit levels previously provided by the REP settlements. *Id*. In response, as a factual matter, the 2000 REP Settlement Agreements provided approximately $145 million in settlement benefits to the IOUs' residential and small farm customers. BPA subsequently entered into Load Reduction Agreements with certain preference customers, DSIs, and two IOUs. These LRAs reduced a 250 percent rate increase to BPA's preference customers to a 46 percent increase, thereby saving preference customers hundreds of millions of dollars. WPAG combines the original REP Settlement Agreements with the IOU LRAs to establish an REP benefit amount of over $300 million per year. WPAG then relies on BPA's forecasted REP benefits for FY 2009 of approximately $250 million to conclude the latter must be based upon trying to equal the former. Instead, however, these facts are no surprise.

During the litigation of *PGE* and *Golden NW*, BPA noted that there were a number of ratemaking issues regarding BPA's WP-02 rates that, if decided against BPA's preference customers, could significantly increase forecasted REP benefits to nearly $300 million. For example, the treatment of Mid-Columbia resources in the 7(b)(2) Case resource stack is an issue that was moot in the initial WP-02 rate proceeding, but was not moot when loads and market prices changed during the West Coast energy crisis, which resulted in BPA's development of its supplemental WP-02 rate proposal. BPA's decision on that issue is based on the plain language of section 7(b)(2)(D) of the Northwest Power Act. Now that certain 7(b)(2) ratemaking issues have to be addressed, and certain issues have been decided contrary to the preference customers' arguments, it is understandable that WPAG would not be pleased with BPA's decisions. These decisions, however, are not made to try to replicate the REP settlements. They reflect the proper implementation of the Northwest Power Act, which has resulted in providing REP benefits to regional utilities like the IOUs while also providing substantial rate protection to BPA's preference customers.

BPA's REP forecast is developed in a formal evidentiary proceeding under section 7(i) of the Northwest Power Act. There are many technical and legal issues that must be addressed in order to develop this forecast. Contrary to WPAG's assertions, BPA's legal interpretations and analytical assumptions are not inconsistent, although BPA understands why parties will attempt to characterize them so for tactical appellate reasons. Each technical and legal determination must be reviewed on its merits. Review of the record shows that each of BPA's determinations is reasonable, although nearly every significant determination made by BPA will be challenged by one customer class or another. This is because for every decision BPA makes in a ratemaking proceeding, some customers will benefit while others will be harmed. This is the unfortunate reality of BPA ratemaking. However, if BPA had intended to use the level of prior REP settlements as a standard for prospective REP benefits, BPA would not have made many of the decisions documented in this ROD. Instead, BPA rejected the IOUs' positions on many issues, just as BPA rejected preference customers' arguments on many issues. Each BPA decision is explained and documented in the ROD based on its merits.

Decision

The extensive analysis in this ROD displays that BPA has properly addressed all issues in this proceeding in a fair and impartial manner based on the administrative record and the law.

21.0 PARTICIPANT COMMENT

21.1 Introduction

This section summarizes and evaluates the comments of participants in BPA's WP-07 Supplemental 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.

The comment period for this Supplemental proceeding commenced after publication of the FRN on February 8, 2008. 73 Fed. Reg. 7,539 (2008). The FRN announced the beginning of the section 7(i) proceeding and summarized BPA's Initial Supplemental Proposal. The FRN can be viewed at the BPA Web site: www.bpa.gov/power/pfr/rates/ratecases/wp07.

The written comment period ended on May 5, 2008. The participants' portion of the official record also consists of transcripts of two field hearings held in March 2008 in Portland, Oregon, and Spokane, Washington, where participants orally presented comments. A total of one letter and two comments were received, including one letter signed by the Montana Public Service Commission. Comments can be viewed at: www.bpa.gov/applications/publiccomments/closedcommentlisting.aspx.

BPA reviewed the participants' portion of the record and identified the concerns expressed by the participants to be addressed in this section of the draft ROD. A tally and summary of the testimony provided at the two field hearings and in the one letter BPA received, along with discussions of those concerns, is provided below. Although some issues have multiple signatories, each issue is tallied only once.

21.2 Evaluation of Participant Comments

The following summary indicates the total responses for each issue. BPA received one letter, and two persons made multiple comments at the two field hearings.

21.2.1 Table 1: General Rates Issues

General Rates Issues	Field Hearings Comments	Letters Comments
a. Supports BPA's proposal for implementing the Residential Exchange Program as outlined in its initial proposal, and continued support for this proposal depends on this result.		1

General Rates Issues	Field Hearings Comments	Letters Comments
b. Provide rate relief. BPA should increase the Residential Exchange payments for the IOUs, or at a minimum, return to previous levels.	2	
c. There is not enough funding to help all the households that request energy assistance.	1	
d. People should not be forced to choose between buying food and medicine and paying their utility bills.	1	
e. Ever-increasing utility rates make the lives of low-income persons, seniors, and the disabled ever more difficult.	1	

Discussion of Comments on General Rate Issues

One participant supported BPA's proposal as stated in the WP-07 Initial Supplemental Proposal, stating that their continued support of the proposal depends on its adoption without major changes in a final Record of Decision. The participant particularly specified the ASC Methodology consultation and the expedited FY 2009 ASC process as reasons for its support. The ASC Methodology consultation was a separate administrative proceeding to determine a methodology for calculating exchanging utilities' ASCs to determine the monetary benefits paid by BPA to utilities participating in the REP. Further information on this consultation, including the Federal Register Notice outlining this process, is available at: www.bpa.gov/corporate/finance/ascm/filings.cfm.

The expedited FY09 ASC process, where the ASCs used in the WP-07 Supplemental Proceeding are developed, can be found at: www.bpa.gov/corporate/finance/ascm/filings.cfm.

The two participants at the field hearings were primarily concerned with rate relief, in particular for low income persons, seniors, and the disabled. They discussed the agencies they worked for, and how they provided energy assistance through money and programs such as weatherization, energy-efficient light bulbs, and installation assistance for the elderly and disabled. BPA recognizes the impact that its power rates and REP benefit payments can have on the citizens of the Pacific Northwest. BPA has demonstrated a continued commitment to keeping its costs low through the recent set of public workshops called the Integrated Program Review. These workshops reviewed BPA's program spending levels for FY 2009-2012 and requested public comment.

22.0 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 2007 Wholesale Power Rate Schedules (FY 2009) and 2007 General Rate Schedule Provisions (FY 2009) attached hereto as Appendix A (WP-07-A-05A) 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 22nd day of September, 2008.

/s/ Stephen J. Wright
Administrator and Chief Executive Officer

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