2002 Supplemental Power Rate Proposal Study

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POWER ADMINISTRATION

SUPPLEMENTAL 2002 POWER RATE PROPOSAL
STUDY
TABLE OF CONTENTS

				Page
Table of Contents				i
List of Tables				iv
Commonly Used Acronyms				v
1.	OVERVIEW			1-1
	1.1	Background		1-1
		1.1.1	Development of 2002 Wholesale Power Rates	1-2
		1.1.2	The Nature of the Problem	1-2
	1.2	Developing a Solution		1-3
		1.2.1	Implementing Subscription Goals	1-4
		1.2.2	Meeting Treasury Payment Probability Goal	1-6
		1.2.3	Maintaining Regional Benefits	1-6
	1.3	Summary of Proposal		1-7
		1.3.1	Three-Component Cost Recovery Adjustment Clause	1-7
		1.3.2	Slice	1-9
		1.3.3	Investor-Owned Utilities Residential Exchange Program Settlement	1-10
		1.3.4	Early Signers	1-11
		1.3.5	Changes to the Dividend Distribution Clause	1-11
	1.4	Market Price Forecast		1-11
	1.5	Organization of Study		1-12
2.	RISK ANALYSIS			2-1
	2.1	Introduction		2-1
		2.1.1	Background	2-1
		2.1.2	Overview	2-1
	2.2	Changes in the Risk Analysis Study		2-3
		2.2.1	Overview of Changes in the Risk Analysis Study	2-3
		2.2.2	Modeling Changes in Risk Analysis Model	2-3
		2.2.3	Revisions in Loads and Resources	2-5
		2.2.4	Changes in the Risk Simulation Models	2-6
		2.2.5	Changes in the Non-Operating Risk Model	2-9
		2.2.6	Changes in the Natural Gas Price Forecast	2-9
		2.2.7	Changes in AURORA	2-9
		2.2.8	Results from Risk Analysis Model	2-18
3.	NO-SLICE RISK ANALYSIS			3-1
	3.1	Introduction		3-1
	3.2	Differences From the Risk Analysis Study		3-1
		3.2.1	Overview	3-1
		3.2.2	Revisions in Loads	3-2
		3.2.3	Results from Risk Analysis Model	3-2

4. SLICE AUGMENTATION COST ANALYSIS 4-1
4.1 Introduction and Overview of Chapter 4-1
4.2 Purpose of the Proposed Modifications 4-1
4.3 Approach to the Slice Rate Calculation in the May Proposal 4-1
4.4 Slice Portion of Increased Residential Exchange Program Settlement 4-2

5. RISK MITIGATION 5-1
5.1 Introduction 5-1
5.2 Treasury Payment Probability 5-2
5.3 Risk Mitigation Tools 5-3
5.3.1 Fiscal Year 2002 Start of Year Financial Reserves 5-5
5.3.2 Credits under the Fish Cost Contingency Fund 5-4
5.3.3 Planned Net Revenues for Risk 5-4
5.3.4 Cost Recovery Adjustment Clauses 5-4
5.3.4.1 Load-Based Cost Recovery Adjustment Clause 5-5
5.3.4.2 Financial-Based Cost Recovery Adjustment Clause 5-6
5.3.4.3 Safety-Net Cost Recovery Adjustment Clause 5-7
5.4 Dividend Distribution Threshold 5-8
5.5 ToolKit and Generation Risk Mitigation Modeling 5-10
5.6 Risk Mitigation ToolKit Results 5-13
5.7 Load-Based Cost Recovery Adjustment Clause Methodology 5-15
5.7.1 Introduction and Overview 5-15
5.7.2 Purpose of the Proposed Modifications 5-16
5.7.3 Approach to Augmentation Cost Recovery in the May Proposal and the Amended Proposal 5-16
5.7.4 Establishing the Monthly Augmentation Amount 5-17
5.7.5 Proposed Methodology 5-17
5.7.5.1 Application 5-18
5.7.5.2 Process 5-18
5.7.5.3 Calculations that are performed both before the beginning of a six-month period and after the end of the same six-month period 5-19
5.7.5.3.1 Determining the Monthly Augmentation Cost 5-19
5.7.5.3.1.1 Determining the Total Cost of Acquisition Pre-Purchases 5-19
5.7.5.3.1.2 Determining the Diurnal Augmentation Costs 5-21
5.7.5.3.1.3 Calculating the Total Augmentation Cost 5-23
5.7.5.3.2 Calculating the Monthly Augmentation Resale Revenues 5-24
5.7.5.3.3 Calculating Total Augmentation Resale Revenue 5-24
5.7.5.3.4 Calculating Net Augmentation Cost 5-24
5.7.5.3.5 Calculating Slice Revenues from Loads Subject to Cost Recovery Adjustment Clause and Non-Slice Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause 5-25

5.7.5.3.6 Calculating Total Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause 5-25
5.7.5.4 Calculating the Load-Based Cost Recovery Adjustment Clause Percent 5-26
5.7.5.4.1 Calculating the Load-Based Cost Recovery Adjustment Clause Percent 5-26
5.7.5.4.2 Calculating the Adjustment for Slice and Non-Slice Adjusted Rates.. .5-26
5.7.5.4.3 Adjusting a Purchaser's Bill... .5-27
5.7.6 Calculating the Amount of Over- or Under-Recovery of Augmentation Costs through the Load-Based Cost Recovery Adjustment Clause 5-28
5.7.6.1 Calculate the Load-Based Cost Recovery Adjustment Clause revenues that were actually collected during the six-month period separately for Slice and Non-Slice 5-28
5.7.6.2 Calculate the Load-Based Cost Recovery Adjustment Clause revenues that are needed to cover actual augmentation costs, divided between Slice and Non-Slice based on actual Load-Based Cost Recovery Adjustment Clause Revenues 5-28
5.7.6.3 Calculate the difference between the actual Load-Based Cost Recovery Adjustment Clause revenue received and the actual Load-Based Cost Recovery Adjustment Clause revenue required to cover actual augmentation costs. 5-30
5.7.6.4 Adjusting a Purchaser's Bill 5-30
5.8 Slice Cost-Shift Analysis 5-31
5.8.1 Summary of the Analysis..5-32
5.8.2 Results of the Six Pairs of Slice/No-Slice Cases 5-34

6. INVESTOR-OWNED UTILITY RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT 6-1
6.1 Introduction 6-1
6.2 Bonneville Power Administration's 2002 Final Power Rate Proposal for the Monetary Portion of Investor-Owned Utility Residential Exchange Program Settlements 6-1
6.3 Supplemental Proposal for Market Price Forecast for Investor-Owned Utility Residential Exchange Program Settlements 6-3

LIST OF TABLES

Table 2-1	System Augmentation Purchases as of January 1, 2001	2-7
Table 2-2	System Augmentation Expenses as of January 1, 2001	2-8
Table 2-3	Inputs to the Forward Market Price Simulator For FY 2002	2-10
Table 2-4	Inputs to the Forward Market Price Simulator For FY 2003	2-10
Table 2-5	Statistics for Simulated Monthly Forward Market Prices, FY 2002 ($MWh)	2-11
Table 2-6	Statistics for Simulated Monthly Forward Market Prices, FY 2003 ($MWh)	2-12
Table 2-7	Statistics for Calibrated Monthly Forward Market Prices, FY 2002 ($MWh)	2-15
Table 2-8	Statistics for Calibrated Monthly Forward Market Prices, FY 2003 ($MWh)	2-16
Table 2-9	Example of the Price Calibration Process	2-17
Table 2-10	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $140, Load Reduction = 0 MW)	2-19
Table 2-11	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $140, Load Reduction = 1500 MW)	2-19
Table 2-12	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $210, Load Reduction = 0 MW)	2-20
Table 2-13	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $210, Load Reduction = 1500 MW)	2-20
Table 2-14	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $315, Load Reduction = 0 MW)	2-21
Table 2-15	Net Revenue Summary, Slice = 2000 MW ($ Thousand) FY ’02 Avg. Price = $315, Load Reduction = 1500 MW)	2-21
Table 3-1	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $140, Load Reduction = 0 MW)	3-3
Table 3-2	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $140, Load Reduction = 1500 MW)	3-3
Table 3-3	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $210, Load Reduction = 0 MW)	3-4
Table 3-4	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $210, Load Reduction = 1500 MW)	3-4
Table 3-5	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $315, Load Reduction = 0 MW)	3-5
Table 3-6	Net Revenue Summary, Slice = 0 MW ($ Thousand) FY ’02 Avg. Price = $315, Load Reduction = 1500 MW)	3-5
Table 5-1	Treasury Payment Probability Analyses	5-14
Table 5-2	Preliminary Monthly Acquisition Amounts	5-17
Table 5-3	Cost Shift Analysis Summary	5-35

COMMONLY USED ACRONYMS

AAC	Adjusted Augmentation Costs
AAP	Acquisition Pre-Purchases
AAMT	Augmentation Amount
AANR	Audited Accumulated Net Revenues
ACA	Augmentation Cost Adjustment
ACTUALLBCREVREQ(NS)	Actual Load-Based Cost Recovery Adjustment Clause (non-Slice)
ACTUALLBCREVREQ(S)	Actual Load-Based Cost Recovery Adjustment Clause (Slice)
ADJUST	Adjustment to a Purchaser’s Monthly Bill
AE	Account Executive
AER	Actual Energy Regulation
aMW	Average Megawatt
Amended Proposal	Amended Proposal to the 2002 Power Rate Case
ANR	Accumulated Net Revenues
ANRT	Accumulated Net Revenue Threshold
APP	Augmentation Pre-Purchase
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BAC	Baseline Augmentation Cost
BPA	Bonneville Power Administration
Buydown	Cost of Load Buydown
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
CalPX	California Power Exchange
Cfs	cubic feet per second
COB	California-Oregon Border
CRAC	Cost Recovery Adjustment Clause
CUSTREV(S))	Customer contribution to total revenue without LB CRAC
DDC	Dividend Distribution Clause
DIURNALAC	Diurnal Augmentation cost
DJ	Dow Jones
DSIs	Direct Service Industrial Customers
EPBA	Eastern Power Business Area
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GRSPs	General Rate Schedule Provisions
HLH	Heavy Load Hour
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge

IOUs	Investor-Owned Utilities
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1,000 volts)
kW	Kilowatt (1,000 watts)
kWh	Kilowatthour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LB CRAC%	Percent applied to sales revenue for loads subject to the LB CRAC
LBCREVREC	Revenues Actually Received by BPA from the LB CRAC
LDD	Low Density Discount
LLH	Light Load Hour
LOAD	Load subject to LB CRAC
m/kWh	Mills per kilowatthour
May Proposal	May 2000 Final Power Rate Proposal
MARR	Monthly Augmentation Resale Revenues
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MW	Megawatt (1 million watts)
MWh	Megawatthour
NAC	Net Augmentation Cost
NACDIFF	Difference in Net Augmentation Cost
NAAC	Net Adjusted Augmentation Costs
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
OC	Option Cost
PBL	Power Business Line
PF	Priority Firm Power (rate)
PWF	Power Factor
PMDAM	Power Marketing Decision Analysis Model
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
PRICE	Price for Augmentation not Pre-purchased
Principles	Fish and Wildlife Funding Principles
Proposed Methodology	Augmentation Cost Recovery Methodology
RATE	Rate without LB CRAC applied
REP	Residential Exchange Program
REP Settlement	Investor-Owned Utilities Residential Exchange Program Settlement
REVDIFF	Revenue Difference
REVRATE	Adjusted Rate
REVw/LBC (S)	Actual Revenues (Slice) to BPA on loads subject to LB CRAC

REVw/LBC(NS)	Actual Revenues (non-Slice) to BPA on loads subject to LB CRAC
REVw/oLBC(S)	Baseline Revenues (Slice) revenue to BPA on loads subject to LB CRAC before application of LB CRAC
REVw/oLBC(NS)	Baseline Revenues (non-Slice) revenue to BPA on loads subject to LB CRAC before application of LB CRAC
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
SACA	Slice Augmentation Cost Analysis
SALESMAYAUG	Sales of Existing Augmentation Quantity
SALENEWAUG	Sales of New Augmentation Quantity
Slice	Slice of the System product
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
STREAM	Short-Term Evaluation and Analysis Model
TAAC	Total Adjusted Augmentation Costs
TAC	Targeted Adjustment Charge
TAUGC	Total Augmentation Cost
TACUL	Targeted Adjustment Charge for Uncommitted Loads
TARR	Total Augmentation Resale Revenue
TCAAP	Total Cost of Acquisition Pre-Purchases
TPP	Treasury Payment Probability
TPPA	Total Pre-Purchase Cost
TREVwLBC	Total Revenues with LB CRAC
TREVw/oLBC	Total Revenues without LB CRAC
TREVw/LBC	Total Revenues with LB CRAC
WPBA	Western Power Business Area
WSCC	Western Systems Coordinating Council

CHAPTER 1: OVERVIEW

1.1 Background

1.1.1 Development of 2002 Wholesale Power Rates. On May 15, 2000, Bonneville Power Administration (BPA) published its 2002 Final Power Rate Proposal (May Proposal), Administrator's Final Record of Decision (May ROD) concluding the Section 7(i) proceeding to develop Wholesale Power Rates, and associated General Rate Schedule Provisions (GRSPs), for Fiscal Years (FY) 2002–2006. On July 6, 2000, BPA submitted for filing to the Federal Energy Regulatory Commission (FERC) the proposed rate adjustments for its Wholesale Power Rates pursuant to Section 7(a)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. §839(a)(2). On August 4, 2000, BPA filed a motion with FERC requesting that FERC stay for 30 days any determination regarding the adequacy of the rate filing. This motion was precipitated by events in the wholesale power market, which resulted in unacceptable financial risks to BPA if FERC approved BPA's rate proposal as submitted. As described below, these rates were developed to implement the goals adopted by BPA in the Subscription Strategy. The rates included risk mitigation tools to deal with the many uncertainties facing BPA and the region over the next rate period. It is now clear that the risk mitigation package is not sufficient to deal with those risks.

On December 12, 2000, BPA filed its 2002 Amended Power Rate Proposal (Amended Proposal). The Amended Proposal contained a three-phased Cost Recovery Adjustment Clause (CRAC) that was designed to address the increased load and higher and more volatile market that BPA was facing. Since that time several significant events have occurred that have caused BPA to file this 2002 Supplemental Amended Power Rate Proposal (Supplemental Proposal). The market price forecast for the rate period and the forecasted level of reserves BPA will have at the start of the rate period have both changed dramatically. These forecasts will be updated prior to the issuance of a final Record of Decision (ROD). The updates normally do not produce a material impact on the rate levels. As described in the testimony of Conger, *et al*., WP-02-E-BPA-71 the market price forecast of $48.37/megawatthour (MWh) in the Amended Proposal has now risen to a range of $200-$240/MWh in FY 2002 and declines to a range of $40-$60/MWh in FY 2006. Similarly the expected value of BPA's starting of reserves at the beginning of the rate period has declined from $929 million forecasted in the Amended Proposal to $309 million. In addition, BPA and the Parties engaged in a series of settlement discussions that have attempted to resolve most of the issues in this proceeding. As a result of these discussions, BPA, together with virtually all of the rate case parties that represent nearly all of the individual public utility customers, all the Investor-Owned Utilities (IOUs), and the state utility commissions, have reached an agreement (Partial Settlement Agreement) regarding how BPA should address the cost recovery problem it faces. As a consequence, BPA is proposing to modify the Amended Proposal to incorporate the Partial Settlement Agreement reached between the parties.

1.1.2 The Nature of the Problem. BPA's proposed amendments to the GRSPs continued to be necessary because market prices are expected to be much higher and more volatile than assumed in the May Proposal and Amended Proposal. BPA's cost-based rates are now further below market price expectations for the FY 2002-2006 rate period than was the case in the Amended Proposal.

As a result of higher and more volatile market prices, BPA still expects much greater demand for service from customers, demand that BPA is required to serve and that exceeds the generating capability of the Federal Columbia River Power System (FCRPS). BPA still expects loads will exceed the May Proposal forecast by an additional 1,518 average megawatts (aMW). *See* Appendix to Chapter 2, *infra*. To meet this increased load obligation, BPA will need to make substantially greater power purchases (augmentation purchases) in the market at substantially higher and more uncertain prices than anticipated in revenue requirements for the May Proposal. Moreover, the difficulty of forecasting the expense of serving the increased load obligations is magnified by the fact that prices are escalating in an extraordinarily volatile market and the uncertainity of any load response to these higher market prices.

Absent a change to the Amended Proposal, Treasury Payment Probability (TPP) would be significantly reduced. By law, BPA's payments to Treasury are the lowest priority of revenue application, meaning that such payments are the first to be missed if reserves are insufficient to pay all bills on time. For this reason, BPA expresses its cost recovery goal in terms of probability of being able to make all Treasury payments during the rate period in full and on time. A TPP that is too low reflects an unacceptable degree of financial risk for BPA and the Treasury. The load obligations that BPA expects to meet through market purchases in a currently escalating and volatile market environment have decreased TPP to just such an unacceptable level.

As in the May and Amended Proposals, this Supplemental Proposal continues to implement the Fish and Wildlife Funding Principles (Principles). WP-02-E-BPA-13, at 7. Among other provisions, the Principles call for a TPP goal of 88 percent and an acceptable range of 80-88 percent for the five-year, 2002-2006 rate period. The rates and risk mitigation tools were initially developed to achieve the TPP goal of 88 percent in full. After the Amended Proposal, increases in uncertainty surrounding augmentation purchase costs, as stated earlier, drove the TPP estimate to below 80 percent.

1.2 Developing a Solution

BPA's proposal continues to deal with this cost recovery problem by amending certain risk mitigation tools contained in the 2002 GRSPs, which apply to the base rates. BPA views this approach as a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. BPA understands that the parties to the Partial Settlement Agreement also support the changes outlined in this Supplemental Proposal as an acceptable means of solving the cost recovery problem outlined in the Amended Proposal and in Section 1.1.2.

1.2.1 Implementing Subscription Goals. The May Proposal was designed to implement the decisions made in BPA's Subscription Strategy. The Subscription Strategy was the result of a lengthy three-year public process that began with the Comprehensive Regional Review. The Subscription Strategy was fundamentally a blueprint for how BPA should go about filling the void that would be left after the vast majority of its contracts expire in 2001. The Subscription Strategy provided a structure around which BPA could offer new contracts and meet its statutory obligations while responding to the myriad of changes that had occurred since enactment of the Northwest Power Act.

Changes in the utility environment due to deregulation of the wholesale power market that began in the 1990s forced BPA to become more competitive and to unbundle its power products consistent with the open access to transmission and the more competitive climate in the wholesale power markets. The Subscription Strategy also mapped out a general plan for how the benefits of the FCRPS would be distributed in this new climate, consistent with the requirements and obligations created by the Northwest Power Act. In part, this meant attempting to strike a delicate balance between a wide range of competing interests, including customer groups, governmental entities, tribal representatives, and public interest groups.
In sum, the Subscription Strategy reflected the varied and complex interests in the Pacific Northwest and laid the groundwork for an equitable distribution of the benefits of the FCRPS

consistent with legal requirements. The goals of the four principles of the Subscription Strategy are:

- Promote the spread of the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region.
- Avoid rate increases through a creative and business-like response to markets and additional aggressive cost reductions.
- Fulfill BPA's fish and wildlife obligations while assuring a high level of Treasury payment.
- Provide market incentives for the valuation of conservation and renewable resources.

The primary purpose of this proceeding is to determine how to deal effectively with the cost recovery risk associated with higher and more uncertain purchase power costs. As noted earlier, this increased uncertainty is being caused by rising prices in a volatile market and high load obligations. However, this phase of the proceeding begins, as did the initial phase and the Amended Proposal, with the basic assumption that a solution to the problem should, as much as possible, be designed to preserve the basic principles underlying the Subscription Strategy. The basic framework that has been developed over a period of several years reflects a wide range of public processes, and is predicated on the input of all regional interests and stakeholders. It continues to provide reasonable direction and structure for the rights and corresponding obligations that have been embodied in signed contracts, for service beginning October 1, 2001.

BPA recognizes that the goals of Subscription, primarily the avoidance of rate increases, cannot be fully maintained in light of the dramatic increase in the wholesale electricity market and the deterioration of BPA's financial situation. However, BPA is attempting to minimize the impact of these changes on its customers by seeking to minimize costs for augmenting its power system, and by returning those savings to the customers through the proposed Dividend Distribution

Clause (DDC). In addition, the structure of the Load-Based Cost Recovery Adjustment (LB CRAC) allows it to drop if BPA's augmentation cost drop.

1.2.2 Meeting Treasury Payment Probability Goal. BPA is required to set rates to recover its costs. *See* WP-02-FS-BPA-02, at 55-58. Risk mitigation tools were developed in the May Proposal to achieve the TPP goal of 88 percent, and to satisfy Fish and Wildlife Funding Principle No. 4. Principle No. 4 states "[g]iven the range of potential fish and wildlife costs, Bonneville will design rates and contracts which will position Bonneville to achieve similarly high Treasury payment probability for the post-2006 period by building financial reserve levels and through other mechanisms." *See* WP-02-FS-BPA-02A, at 344. In the Amended Proposal, the TPP was reduced to 83.4 percent which is still within the range of 80-88 percent. The problem still at hand is a cost recovery problem. Therefore BPA is still proposing to modify the risk mitigation tools so that revenues are sufficient for a timely recovery of costs. At a minimum, this means having a TPP within the allowable range called for in the Principles, and meeting Principle No. 4.

In the Amended Proposal the primary means of achieving an acceptable TPP level was a redesign of the CRAC and commensurate changes to the Slice payment for augmentation costs. However, with the continued increases in market prices and the deterioration of starting reserve levels, the TPP based on the Amended Proposal dropped below the allowable range. Adjustments to the Amended Proposal are necessary to bring the TPP level within an acceptable range.

1.2.3 Maintaining Regional Benefits. All of BPA's regional customers have signed either a Subscription contract or a Residential Exchange settlement agreement prior to the October 31, 2000, contract-signing deadline.[*] The Subscription contracts translated the Subscription Strategy into product offerings and formalized the proposed distribution of power and benefits developed through the Subscription Strategy. The May Proposal established the price for the products purchased under those contracts. The contracts, as written, have been responsive to the market transformation that has taken place under FERC restructuring and are different from previous contracts. The May Proposal contained rates that are designed to fit the products being offered. As was the case with the Amended Proposal, this Supplemental Proposal preserves the proposed May rates except for the specific changes noted below.

1.3 Summary of Proposal

1.3.1 Three-Component Cost Recovery Adjustment Clause. In the May ROD, BPA proposed a single CRAC that triggered upon accumulated net revenues (ANR) dropping to pre-identified levels. The Amended Proposal had a three-component CRAC, with each component designed to deal with a different aspect of the problem. The three components are referred to as the LB CRAC, Financial-Based CRAC (FB CRAC), and Safety-Net CRAC (SN CRAC). *See* Chapter 5, *infra*. This Supplemental Proposal retains the concept of the three component CRAC but redesigns the components to better address the changing nature of the cost recovery problem and to conform to the partial settlement reached with the parties.

In the Amended Proposal, the LB CRAC was designed to address some but not all of the cost recovery problem created by increased augmentation load. Part of the cost recovery obligation for this load obligation resided with FB CRAC. Through the discussions with the parties, it became apparent that many parties preferred to place all of the costs associated with augmentation purchases on the LB CRAC and not rely on the FB CRAC for part of the solution

[*] BPA offered its IOU customers a Settlement Agreement as an alternative to the benefits under the standard Residential Power Sales Agreement. Customers who did not sign contracts prior to the close of the signing window may still do so but they will be subject to the Targeted Adjustment Charge.

to this problem. Many parties expressed concern that the contingent nature of the FB CRAC presented rate setting problems for them. Therefore, the LB CRAC has been redesigned to fully address the problem of augmentation costs exceeding the May Proposal forecast. Because there is tremendous volatility in the market, and the price forecast is currently high in the near term, trending downward through the period of the rate case, the LB CRAC redesign includes changes to allow it to adjust either up or down to ensure that customers pay the actual cost of augmentation. As in the May Proposal, the LB CRAC will be based on aMW amounts in contracts already signed by customers. The load projection derived from these contracts and used for the LB CRAC will provide an indication of how much load BPA will actually be required to serve in the upcoming rate period. However, to the extent that loads are greater than BPA's May Forecast or in the event there is a load response to the increase in prices, the LB CRAC now will be adjusted every six months to reflect these changes. The price of the augmentation will be covered through a forecast of augmentation costs and every six months will be adjusted based upon actual augmentation purchases and a forward price for the balance of the augmentation need. There would then be an after-the-fact true-up of the forecast based upon any additional augmentation purchases, corresponding changes to the forward prices, and changes in augmentation needs. Therefore, BPA's exposure to market risk due to augmentation purchases required to serve load is effectively mitigated by the LB CRAC.

Because the LB CRAC has accounted for essentially all of the cost of augmentation, the FB CRAC can be modified to address the risks that the single CRAC in the May Proposal was designed to address. BPA will modify the FB CRAC design to be similar to the CRAC contained in the May Proposal, with two changes. In the event the FB CRAC triggers in the first year of the rate period (2002), the amounts collected will not be capped, but rather BPA will be allowed to collect the amount that would have restored FY 2002 net revenues to the threshold level. The timing of the FB CRAC has also been changed to allow it to affect rates for a 12-month period starting at the beginning of the fiscal year instead of the middle.

The SN CRAC provides BPA with a tool to temporarily adjust the amounts collected under the FB CRAC upward in the event that BPA misses, or forecasts missing, a payment to Treasury or another creditor, even considering implementation of the LB CRAC and the FB CRAC. The SN CRAC would likely not trigger soon enough to avoid an initial deferral, but would help to avoid a second deferral. This Supplemental Proposal calls for a 7(i) process to implement the SN CRAC.

1.3.2 Slice. The Slice of the System product (Slice) was offered as part of BPA's Subscription Strategy. The Slice Methodology in the May Proposal was tied to the Market forecast. The May Proposal used a fixed market price forecast of $28.10/MWh to price augmentation purchases for the rate period. Because of the changes in the wholesale power market, pricing the augmentation purchases at a fixed market price would result in Slice purchasers not paying their proportionate share of the augmentation costs, either higher or lower, depending on the actual cost of augmentation. The financial impacts of purchasing the unanticipated augmentation in a market where prices are significantly higher and more volatile are not accounted for in the May Proposal.

In the Amended Proposal, BPA proposed adjustments to the Slice purchasers bill that would make certain that the proportionate share of BPA's augmentation costs were covered. In this Supplemental Proposal, BPA is proposing that the Slice rate be subject to the LB CRAC to ensure that Slice purchasers proportionately share the additional financial risk associated with the increased augmentation requirements, market prices, and market volatility. To avoid burdening Slice purchasers with risks that they have assumed directly through the purchase of the product, the after-the-fact true-up for augmentation costs for Slice customers will be different from that for non-Slice customers. With Slice there would only be an after-the-fact true-up for augmentation purchases made 120 days prior to the month in question and no corresponding update for changes in the forward strip price. This difference is due to the hydro risk and obligation to balance its own system that Slice purchasers assume directly. Slice will continue to be exempt from the FB and SN CRACs because Slice purchasers assume a proportionate share of BPA's financial risks and receive a proportionate share of the benefits of the Federal system through the product design.

1.3.3 Investor-Owned Utilities Residential Exchange Program Settlement. The Investor-Owned Utilities Residential Exchange Settlements (REP Settlement) with regional IOUs provide benefits in the form of both power and cash. The monetary portion of the benefits is calculated based on the difference between the Residential Load or Priority Firm Power (PF)-Exchange Subscription rate and BPA's rate case market price forecast. Originally, BPA adopted $28.10/MWh as the five-year flat block price forecast for monetary benefit component of REP Settlements. After reconsidering the appropriateness of that number, given the escalating and volatile market now being experienced, in the Amended Proposal BPA revised that number to $34.1/MWh. BPA is now proposing to calculate the financial aspect of the settlements using $38/MWh for the monetary benefits component of the REP Settlement. In consultation with various Parties, in order to preserve the overall balance between the different aspects of this Supplemental Proposal, raising the financial component of the settlement to $38/MWh was seen as an appropriate adjustment. In addition, the financial component of the settlement benefits will be exempt from the FB CRAC and LB CRAC but will be subject to the SN CRAC. *See* Chapter 5, *infra.* Both the power deliveries and the financial portion of the settlement will be used to determine the IOU share of distributions under the DDC.

1.3.4 Early Signers. On August 1, 2000, BPA temporarily suspended the signing of any new power contracts because of the uncertainty created by the projections of increased loads and greater market volatility. Prior to that date, BPA and a number of its customers had already signed new Subscription power contracts for the upcoming rate period that would price power at the PF-02 rate. The timing of the contract signing does not provide a sufficient basis to exempt these contracts from the application of the three-component CRAC in this proposal. However, Pre-Subscription and certain other Firm Power Products and Services sales, including extra-regional surplus sales and approximately 70 aMW of Irrigation Mitigation sales, will not be subject to the CRACs. This is consistent with the Amended Proposal.

1.3.5 Changes to the Dividend Distribution Clause. BPA is proposing to redesign the DDC to make it an automatic redistribution to the customers based upon achieving certain reserve levels. As in the Amended Proposal, the DDC will not be available in the first year (FY 2002) of the rate period. In the subsequent years the DDC will trigger if BPA has the accumulated net revenue equivalent to ending reserve levels of $1.7 billion in FY 2003, $1.5 billion in FY 2004, $1.2 billion in FY 2005, and $1.2 in FY 2006. The ending reserve levels will be adjusted to the extent that BPA has unspent but agreed-to funds to mitigate impacts of a power system emergency on fish and wildlife, or unspent funds for BPA's current year fish and wildlife direct program. Unlike the May Proposal, this redesign of the DDC will not require any evaluation of the TPP. However, the first $15 million will continue to be allocated to qualifying Conservation and Renewable purposes. And, as mentioned above, the financial portion of the REP Settlement will share in distributions under the DDC.

1.4 Market Price Forecast

In the Amended Proposal, BPA used a risk adjusted market price forecast of $48.37/MWh produced by the AURORA model in its Risk Model Analysis. In the Supplemental Proposal

BPA is proposing to use prices on the forward market, for the first two years of the rate period, rather than relying on AURORA for price forecasts for the entire rate period. AURORA has not been able to model the price levels currently in the market. BPA believes that the current market prices are difficult to model in AURORA due to a combination of supply and demand responses that have materialized in the forward markets that are impossible to quantify and model in AURORA. As a consequence, the prices modeled in AURORA during the first two years of the rate period have been replaced with prices reflecting current market reality for that time period. This is more fully explained in Chapter 2, *infra*.

1.5 Organization of Study

This study amends several of the final studies, documentation, and/or testimony of the Amended Proposal. Each chapter cites the specific study that is being amended.

The Appendix contains the revised GRSPs.

CHAPTER 2: RISK ANALYSIS

2.1 Introduction

2.1.1 Background. In the 2002 Amended Power Rate Proposal (Amended Proposal), Bonneville Power Administration (BPA) performed the Risk Analysis Study in order to ensure that BPA had a high probability of making its annual Treasury payments on time and in full over the five-year rate period (*see* WP-02-FS-BPA-58). Since the Amended Proposal, BPA's risk exposure due to uncertainty in the amount and cost of System Augmentation has substantially increased primarily due to higher, more volatile forecasted electricity prices and potential load responses to the magnitude of BPA's rates. Given the considerable uncertainty in electricity prices and the loads that could be placed on BPA, BPA and many of its customers revised how BPA mitigates its risk exposure in the Partial Settlement Agreement. Under the Partial Settlement Agreement, BPA's rates vary depending on the amount and price of actual System Augmentation purchases. Given the substantial uncertainty in the amount and price of actual System Augmentation, the Risk Analysis Study was expanded to assess the impact that various load and market price scenarios would have on BPA's rates.

2.1.2 Overview. In order to ensure that BPA has a high probability of making its annual Treasury payments on time and in full during the rate period, BPA performs the Risk Analysis Study. In this study, BPA identifies key risks, models the relationships among the risks, and then analyzes their impacts on net revenues (revenues minus expenses). BPA subsequently evaluates the impact that certain risk mitigation measures have on reducing net revenue risk in order to develop rates that cover all costs and ensure a high probability of making Treasury payments on time and in full during the rate period.

In the 2002 Supplemental Amended Power Rate Proposal (Supplemental Proposal), BPA is analyzing rates over a range of prices and loads so that it achieves between 80 and 88 percent probability that all Treasury payments will be made on time and in full over the five-year rate period. To accomplish this task, it was necessary to quantify and then mitigate key operating and non-operating risks. The first step in this process was the Risk Analysis Study, which identified key risk factors, modeled the relationship among the risk factors, and determined their impacts on net revenues.

The Risk Analysis Study focuses upon two classes of risks and their impacts on BPA's revenues and expenses. The first class of risks is comprised of operating risks. These risks include variations in spot market electricity prices, loads, and generating resource capability (including hydro generation under alternative hydro operations associated with the 13 Fish and Wildlife Alternatives). These operating risks are modeled in Risk Analysis Model (RiskMod) to quantify their impact on net revenues. The spot market electricity prices used in the net revenue computations in RiskMod are estimated by the AURORA model. These models are fully described in the Risk Analysis Study and Study Documentation, WP-02-FS-BPA-03, WP-02-FS-BPA-03A, and the Marginal Cost Analysis Study and Study Documentation, WP-02-FS-BPA-04, WP-02-FS-BPA-04A.

The second class of risks are non-operating risks. These risks include uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 Fish and Wildlife Alternatives identified in the Fish and Wildlife Funding Principles (Principles). This class of non-operating risks also includes uncertainty in achieving cost reductions identified in the Cost Review recommendations, costs associated with business line separation, costs associated with conservation and renewables, and interest rates. These risk are modeled in the Non-Operating

Risk Model (NORM). *See* Risk Analysis Study and Study Documentation, WP-02-FS-BPA-03/03A.

The output from RiskMod and NORM are combined to develop a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to meet BPA's Treasury Payment Probability (TPP) standard.

The ToolKit Model assesses the impact of the net revenue deviations on cash reserve levels, calculates the probability that BPA will make its Treasury payments on time and in full, and determines the combination of risk mitigation tools (*e.g.,* Cost Recovery Adjustment Clause (CRAC) trigger levels and amounts)) that are needed to meet BPA's 80 to 88 percent TPP goal.

2.2 Changes in the Risk Analysis Study

2.2.1 Overview of Changes in the Risk Analysis Study. The Risk Analysis Study for the Supplemental Proposal incorporates several changes from the Risk Analysis Study performed for the Amended Proposal that was filed in December of 2000. The changes include the following: (1) modeling changes in RiskMod; (2) revised loads and resources; and (3) revised methodology for forecasting Heavy Load Hour (HLH) and Light Load Hour (LLH) monthly electricity prices and price variability for Fiscal Year (FY) 2002 and 2003.

2.2.2 Modeling Changes in Risk Analysis Model. RiskMod was modified for the Supplemental Proposal in response to terms in the Partial Settlement Agreement that both the Slice and Full and Partial Requirements customers rates would be trued-up for both the quantity and price of actual System Augmentation purchases. Under the terms of the Partial Settlement Agreement, variations in Full and Partial Requirements load were included in the calculation of

System Augmentation purchases. Thus, under the Partial Settlement Agreement, the Rate Case parties would bear the risk of the amount and price of System Augmentation purchases, including the costs of serving the load growth and load variability of the Full and Partial Requirements load. These terms of the Partial Settlement Agreement were modeled in RiskMod by computing the cost of all unpurchased System Augmentation costs using fixed, average monthly flat energy prices and removing the variability in loads of the Full and Partial Requirements customers. The shape of the unpurchased System Augmentation was defined by the shape of the "Initial estimate of augmentation need" provided in Table C of Appendix 2 in Chapter 5 of the 2002 Supplemental Power Rate Proposal Study Documentation (WP-02-E-BPA-69). These modifications removed the risk of the amount and price of System Augmentation purchases from the net revenue risk estimated by RiskMod.

In order to analyze the rate impacts of the substantial uncertainty in the amount of System Augmentation purchases that BPA will actually have to make, RiskMod was modified to quantify the impact of various amounts of generic load BPA might have to serve. The change in revenues from different loads was calculated using a weighted average of the Priority Firm Power (PF) and Industrial Firm Power (IP) rate (before CRAC) of $22.1/megawatthour (MWh). Both changes in loads and the associated changes in System Augmentation purchases were incorporated in terms of monthly shaped, flat energy.

In response to the Partial Settlement Agreement, the Slice Revenue Requirement in RiskMod was modified from the Amended Proposal. The calculation of the costs associated with the Inventory Solution for the Slice Revenue Requirement were removed from the logic in RiskMod and incorporated in the ToolKit model.

For the Supplemental Proposal, RiskMod was modified to cap 4(H)(10)(c) credits at the amount of the annual Treasury Payments for FY 2002–2006, which are $690 million, $670 million, $700 million, $769 million, and $755 million. In the Amended Proposal, there were no 4(H)(10)(c) credit caps in RiskMod. Additionally, BPA revised the expected Fish Cost Contingency Fund (FCCF) reserve at the start of FY 2002 to a point forecast of $167 million, reflecting that BPA likely will be accessing the FCCF reserve in FY 2001. In the Amended Proposal, BPA had an expected FCCF reserve at the start of FY 2002 of $286.7 million, based on various amounts of FCCF credits for each of the 50 Water Years. The FCCF reserve at the start of FY 2001 was $325 million.

Finally, the expected amount of energy that BPA will have stored in Non-Treaty Storage at the start of FY 2002 was modified in RiskMod from 2,858 megawatt (MW)/month to 1,000 MW/month, reflecting the impact of dry weather conditions in FY 2001.

All the changes made in RiskMod for the Risk Analysis Study were also incorporated in RiskMod when performing risk analyses in support of the Cost Shift Analysis that assumes no sales of the Slice product. This risk analysis is referred to as the No-Slice Risk Analysis and is described in Chapter 3 of this Study.

2.2.3 Revisions in Loads and Resources. For the Supplemental Proposal, BPA did not update its sales forecast from the sales forecast that was used in the Amended Proposal. Because of the uncertainty in the load that will be placed on BPA depending on the amount and price of System Augmentation purchases, BPA chose in the Supplemental Proposal to perform risk analyses using two levels of load (which impacts the amount of System Augmentation) and System Augmentation purchase prices. The load scenarios analyzed were the loads used in the Amended

Proposal and a load reduction of 1,500 average megawatt (aMW) from the loads used in the Amended Proposal.

Resources used in the Supplemental Proposal are identical to those used in the Risk Analysis Study for the Amended Proposal, except for actual System Augmentation purchases. Actual System Augmentation purchases used in RiskMod for the Amended Proposal amounted to 917 aMW/year at a cost of $242.9 million/year ($30.20/MWh) and were based on all purchases as of October 23, 2000. *See* Tables 2-3 and 2-4 in the 2002 Amended Power Rate Proposal Study Documentation, WP-02-E-BPA-60. Actual System Augmentation purchases used in RiskMod for the Supplemental Proposal amount to 1,048 aMW/year at a cost of $280.5 million/year ($30.55/MWh) and were based on all purchases as of January 1, 2001. *See* Table 2-1 and Table 2-2 in this study.

2.2.4 Changes in the Risk Simulation Models. For the Supplemental Proposal, the Forward Market Price Simulator was developed in the @ Risk computer software. This risk model simulates market price uncertainty using inputted monthly forward market electricity prices and annual electricity price volatilities that are converted to monthly electricity price volatilities. The simulated electricity prices reflect a lognormal distribution under this methodology. These simulated electricity prices formed the basis for calibrating the FY 2002 and 2003 electricity prices estimated by AURORA in the Amended Proposal to current market conditions. *See* Section 2.2.7 of this study for a description of the methodology employed.

The monthly forward market electricity prices for FY 2002 and 2003 were collected from over-the-counter price quotes from dealers/brokers for the Mid-Columbia delivery point. These monthly flat energy price quotes reflect the prices at which these dealers/brokers would have been willing to sell/buy typically either 25 or 50 aMW. The price quotes were assembled on

Table 2-1: System Augmentation Purchases as of January 1, 2001

	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Avg.
Flat Purchases (aMW)	1,025	1,025	1,025	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,016**
HLH Energy Purchases (aMW)	1,025	1,025	1,025	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,016**
LLH Energy Purchases (aMW)	1,025	1,025	1,025	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,016**

	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Avg.
Flat Purchases (aMW)	1,314	1,314	1,313	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,088**
HLH Energy Purchases (aMW)	1,335	1,335	1,335	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,093**
LLH Energy Purchases (aMW)	1,285	1,285	1,285	1,285	1,285	1,285	735	335	335	1,285	1,285	1,285	**1,081**

	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Avg.
Flat Purchases (aMW)	1,285	1,285	1,285	1,185	1,185	1,185	635	235	235	1,185	1,185	1,185	**1,006**
HLH Energy Purchases (aMW)	1,285	1,285	1,285	1,185	1,185	1,185	635	235	235	1,185	1,185	1,185	**1,006**
LLH Energy Purchases (aMW)	1,285	1,285	1,285	1,185	1,185	1,185	635	235	235	1,185	1,185	1,185	**1,006**

	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Avg.
Flat Purchases (aMW)	1,258	1,383	1,409	1,388	1,393	1,317	771	367	463	1,473	1,453	1,448	**1,177**
HLH Energy Purchases (aMW)	1,312	1,531	1,568	1,540	1,549	1,416	873	466	587	1,585	1,585	1,585	**1,300**
LLH Energy Purchases (aMW)	1,185	1,185	1,197	1,185	1,185	1,185	635	235	298	1,323	1,277	1,266	**1,013**

	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Avg.
Flat Purchases (aMW)	1,412	1,382	1,409	963	967	892	546	342	438	1,048	1,028	1,023	**954**
HLH Energy Purchases (aMW)	1,562	1,530	1,568	1,115	1,123	991	648	441	562	1,160	1,160	1,160	**1,085**
LLH Energy Purchases (aMW)	1,212	1,185	1,197	760	760	760	410	210	273	898	852	841	**780**

5-Year Average

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg.
Flat Purchases (aMW)	1,259	1,278	1,288	1,221	1,223	1,193	684	323	361	1,255	1,247	1,245	1,048
HLH Energy Purchases (aMW)	1,304	1,341	1,356	1,282	1,285	1,233	725	362	411	1,300	1,300	1,300	1,100
LLH Energy Purchases (aMW)	1,198	1,193	1,198	1,140	1,140	1,140	630	270	295	1,195	1,177	1,172	979

Table 2-2: System Augmentation Expenses as of January 1, 2001

	FY2002	FY2003	FY2004	FY2005	FY2006	Average
System Augmentation Expenses ($Million)	266.8	288.2	267.6	316.3	263.7	280.5

February 8, 2001, but were still indicative of general price levels for the period at the time of the publishing of the Supplemental Proposal.

Electricity price volatilities were calculated from both historical electricity prices and currently traded option premiums. Under both these approaches, the natural logarithm of percentage changes in prices are assumed to be normally distributed. The electricity price volatilities calculated from currently traded option premiums are referred to as implied price volatilities. These implied price volatilities were derived using the Black model, which is a slight variation of the better known Black-Scholes model. For the Supplemental Proposal, BPA used implied price volatilities in the Forward Market Price Simulator to simulate monthly electricity prices.

The monthly forward market flat energy prices and the implied price volatilities used in the Forward Market Price Simulator for FY 2002 and 2003 are shown in Table 2-3 and Table 2-4. The annual average flat energy prices quoted by dealers/brokers averaged $210.00/MWh in FY 2002 and $115.00/MWh in FY 2003. Statistical information for the simulated monthly forward market prices for FY 2002 and 2003 are reported in Table 2-5 and Table 2-6.

2.2.5 Changes in the Non-Operating Risk Model. For the Supplemental Proposal, no changes were made to NORM since the Amended Proposal

2.2.6 Changes in the Natural Gas Price Forecast. For the Supplemental Proposal, the natural gas price forecast was not revised.

2.2.7 Changes in AURORA. For the Supplemental Proposal, BPA did not update prices from AURORA. For the Supplemental Proposal, BPA used the same monthly electricity prices and price risk estimates from AURORA for FY 2004-2006 as in the Amended Proposal and BPA

Table 2-3: Inputs to the Forward Market Price Simulator for FY 2002

Date 2/14/01

Price Inputs	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02
Expected Spot Prices ($/MWh)	$324.03	$312.78	$311.88	$238.87	$212.14	$180.16	$126.71	$124.89	$124.97	$179.16	$228.83	$156.53
Implied Spot Volatility (Monthly)	33.20%	36.08%	34.93%	34.06%	32.62%	25.98%	24.54%	23.96%	20.21%	21.07%	21.65%	21.65%
Implied Volatility (Annual)	115.00%	125.00%	121.00%	118.00%	113.00%	90.00%	85.00%	83.00%	70.00%	73.00%	75.00%	75.00%

Table 2-4: Inputs to the Forward Market Price Simulator for FY 2003

Date 2/14/01

Price Inputs	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Expected Spot Prices ($/MWh)	$150.00	$145.22	$145.13	$144.60	$127.97	$107.76	$75.05	$73.71	$73.72	$107.38	$136.44	$94.14
Implied Spot Volatility (Monthly)	27.42%	29.73%	28.81%	28.12%	26.96%	21.65%	20.50%	20.03%	17.03%	17.72%	18.19%	18.19%
Implied Volatility (Annual)	95.00%	103.00%	99.80%	97.40%	93.40%	75.00%	71.00%	69.40%	59.00%	61.40%	63.00%	63.00%

Table 2-5: Statistics for Simulated Monthly Forward Market Prices, FY 2002 ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	323.07	308.51	324.40	235.81	213.04	185.31	128.54	123.79	123.74	180.01	232.17	156.49	**211.24**
Minimum	7.29	7.57	6.68	4.75	3.35	7.65	5.77	4.76	6.49	10.00	11.03	7.41	
Maximum	3,895.50	3,811.75	9,161.92	3,641.66	3,765.66	3,549.85	2,042.57	1,160.01	831.95	2,154.24	3,535.59	1,875.29	
Standard Deviation	391.30	431.04	642.15	357.37	344.09	269.06	166.84	138.51	113.57	201.20	297.44	188.24	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	41.18	26.66	24.59	17.91	16.36	23.25	17.42	16.54	23.14	27.87	32.04	20.31
10%	57.59	39.95	37.95	27.55	24.99	33.51	24.73	23.77	31.21	38.82	44.74	28.97
15%	73.63	52.85	50.67	36.52	33.13	42.30	30.93	29.77	38.02	48.35	56.28	36.79
20%	89.20	65.77	63.20	45.80	40.92	50.84	37.32	35.85	44.66	57.41	67.46	44.29
25%	104.81	79.44	76.39	55.41	50.00	59.94	43.44	42.04	51.05	66.44	78.43	51.94
30%	121.25	93.10	90.31	66.30	59.76	69.04	50.00	48.49	57.70	76.07	90.82	59.99
35%	139.10	109.12	106.03	77.76	69.58	78.75	56.95	55.64	64.87	85.85	102.72	68.17
40%	158.02	126.89	122.25	90.38	81.12	89.09	64.53	62.95	72.13	96.82	116.75	77.18
45%	178.76	145.61	141.25	105.27	93.96	101.11	72.83	70.96	80.35	108.59	131.55	87.25
50%	202.15	167.92	163.18	121.56	109.25	113.75	81.52	79.81	88.72	121.33	147.35	99.00
55%	228.77	193.72	189.14	141.05	126.31	128.44	92.08	89.48	98.89	135.70	165.60	111.21
60%	257.09	222.56	218.48	162.79	146.04	144.71	103.70	100.86	109.14	151.74	187.32	125.63
65%	294.18	257.90	251.85	189.30	169.38	164.47	117.00	114.31	121.89	169.34	211.66	142.14
70%	336.38	300.44	294.41	222.56	197.78	186.91	133.42	130.82	137.21	191.91	241.53	162.35
75%	387.99	352.66	350.89	263.74	235.47	216.24	152.95	150.19	154.83	218.36	275.86	188.73
80%	456.86	425.67	422.82	323.61	286.91	253.38	179.09	175.79	177.26	254.31	323.03	221.48
85%	549.86	528.00	527.52	400.44	356.77	303.29	214.54	211.34	206.87	301.70	386.64	264.86
90%	690.52	697.28	689.55	533.23	477.80	387.33	267.38	264.90	252.37	375.70	487.13	335.35
95%	975.54	1,017.44	1,049.22	800.86	705.61	545.07	380.40	370.89	337.29	504.14	671.76	466.10

Table 2-6: Statistics for Simulated Monthly Forward Market Prices, FY 2003 ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	148.96	141.03	156.43	141.34	128.63	112.54	76.65	72.81	72.77	108.05	138.95	94.10	**116.02**
Minimum	0.98	1.20	1.20	1.24	0.93	2.68	2.14	1.83	2.67	4.42	5.00	3.50	
Maximum	3,069.86	2,680.91	7,306.82	3,116.29	3,170.20	3,038.38	1,628.26	834.22	578.66	1,561.53	2,519.01	1,290.81	
Standard Deviation	264.28	268.90	470.83	276.06	265.62	213.60	123.46	94.21	75.85	138.15	202.31	124.61	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	8.99	5.71	5.77	5.92	5.83	9.57	7.48	7.33	10.93	13.53	15.78	10.29
10%	13.82	9.43	9.73	9.84	9.52	14.54	11.11	10.98	15.22	19.43	22.63	15.04
15%	18.93	13.34	13.80	13.72	13.20	18.99	14.31	14.10	18.94	24.70	28.98	19.41
20%	24.21	17.49	18.02	17.92	16.85	23.44	17.69	17.35	22.64	29.80	35.23	23.66
25%	29.77	22.10	22.64	22.42	21.26	28.30	21.01	20.72	26.26	34.95	41.45	28.05
30%	35.89	26.91	27.71	27.71	26.14	33.28	24.63	24.29	30.07	40.52	48.55	32.71
35%	42.80	32.76	33.64	33.44	31.17	38.70	28.52	28.31	34.24	46.24	55.45	37.49
40%	50.40	39.50	39.94	39.92	37.23	44.57	32.85	32.48	38.51	52.73	63.65	42.81
45%	59.04	46.84	47.54	47.79	44.14	51.53	37.66	37.12	43.41	59.77	72.40	48.80
50%	69.12	55.90	56.59	56.62	52.56	58.97	42.78	42.30	48.44	67.47	81.82	55.85
55%	81.00	66.73	67.63	67.47	62.18	67.78	49.09	48.05	54.64	76.24	92.80	63.23
60%	94.07	79.26	80.48	79.89	73.55	77.70	56.14	54.91	60.94	86.13	105.99	72.02
65%	111.82	95.15	95.54	95.44	87.33	89.97	64.34	63.12	68.88	97.10	120.92	82.16
70%	132.79	114.97	115.35	115.51	104.51	104.17	74.63	73.36	78.54	111.32	139.41	94.70
75%	159.46	140.24	142.56	141.10	127.90	123.11	87.09	85.56	89.79	128.18	160.90	111.21
80%	196.62	177.07	178.54	179.59	160.79	147.62	104.08	101.96	104.31	151.39	190.76	131.93
85%	249.36	231.28	233.17	230.86	206.94	181.39	127.65	125.18	123.78	182.45	231.57	159.70
90%	333.93	326.46	322.14	323.58	290.24	240.05	163.69	160.99	154.29	231.85	297.08	205.45
95%	520.10	521.50	534.61	522.66	455.88	355.06	243.80	234.22	212.78	319.65	420.14	291.99

estimated monthly electricity prices and price risk for FY 2002 and 2003 using a different methodology described in Section 2.2.4 above.

For FY 2002 and 2003, BPA developed an algorithm that calibrates the monthly prices estimated by AURORA in the Amended Proposal to current monthly forward market electricity prices, price volatilities, and price distribution shape (lognormal). The monthly electricity prices the AURORA prices were calibrated to were the market prices simulated by the Forward Market Price Simulator, which is discussed in Section 2.2.4 of this study.

The following algorithm was utilized to calibrate the AURORA prices:

Modified Prices = (P*PL) * ((P*PL)/PPL)^EXP(PWF)

Where:
P= AURORA prices
PL= Price Level Factor
PPL= Average P*PL (for all prices)
EXP= base of the natural logarithm (e) raised to the power of a number (PWF)
PWF= Power Factor

The calibration process involved the following steps:

1. Sorting the prices from the Forward Market Price Simulator and AURORA from lowest to highest.
2. Modifying the AURORA prices using the algorithm specified above.
3. Comparing the differences between the modified AURORA prices and the simulated prices
4. Modifying the Price Level Factor and the Power Factor in the algorithm to calibrate prices.

Criteria used in comparing and calibrating the monthly flat energy AURORA prices to the monthly flat energy simulated prices were average prices, standard deviation of prices, squares of differences in prices, and graphical comparisons over the range of prices. The objective of the calibration process was to derive monthly combinations of Price Level Factors and Power Factors that yielded similar average prices and standard deviation of prices while minimizing the squares of differences in prices (least squares approach).

Table 2-7 and Table 2-8 contain the statistical information for the FY 2002 and 2003 calibrated prices. These results can be compared to the statistical information on the prices simulated by the Forward Market Price Simulator contained in Table 2-5 and Table 2-6, which was provided previously in this study. For illustrative purposes, results from the calibration process for October 2001 are provided in Table 2-9.

Given the algorithm and the combinations of monthly Price Level Factors and Power Factors derived during the calibration process, equations were developed in RiskMod that modified the FY 2002 and 2003 monthly HLH and LLH prices estimated by AURORA for the Amended Proposal. Due to there being more hours in HLHs than LLHs, modest changes were subsequently made in RiskMod to the Price Level Factors to yield the targeted flat energy prices.

Due to uncertainty in electricity prices, risk analyses were performed using alternative sets of prices in FY 2002 and 2003. The alternative sets of forward market electricity prices were developed by uniformly scaling both the FY 2002 and 2003 calibrated prices either upward or downward by the same proportion. The magnitude of these scaling factors was based on raising the calibrated FY 2002 prices to a specified annual average flat energy price. The FY 2002 annual flat energy prices analyzed (for which the scaling factors were also applied to FY 2003) were \$315/MWh, \$210/MWh, and \$140/MWh.

Table 2-7: Statistics for Calibrated Monthly Forward Market Prices, FY 2002 ($/MWh)

Statistics	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Average**
Average	322.14	315.24	309.83	238.41	213.79	184.76	128.00	126.05	126.63	178.02	224.64	152.95	**210.04**
Minimum	30.57	13.86	8.77	25.49	5.84	3.11	2.16	0.27	4.16	4.33	1.68	2.31	
Maximum	4,072.89	4,718.21	3,962.15	2,107.14	2,320.54	1,351.21	962.04	1,393.37	1,555.57	974.96	1,615.60	1,892.05	
Median	192.44	169.19	167.27	107.20	98.27	130.38	101.24	86.75	93.67	119.63	139.97	96.78	
Standard Deviation	416.58	454.60	422.09	314.06	304.66	192.51	122.14	144.79	141.26	174.28	239.62	183.74	

	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
5%	70.53	34.75	25.07	51.73	31.72	41.30	31.32	5.17	15.93	12.68	17.21	20.22
10%	89.69	48.78	37.93	57.96	40.79	52.32	36.26	9.15	25.91	21.41	29.98	25.26
15%	105.13	57.82	50.22	63.94	47.99	62.27	39.99	13.31	33.59	31.98	41.84	31.56
20%	111.53	73.27	62.77	70.22	54.17	69.38	44.88	20.14	38.49	39.61	52.72	37.96
25%	122.22	84.68	73.71	76.47	61.98	78.49	52.35	29.68	46.10	48.55	64.60	44.71
30%	132.41	95.31	87.50	82.05	67.36	85.90	60.08	39.41	53.59	60.59	76.31	52.85
35%	145.20	104.35	104.62	87.04	75.68	95.54	67.75	54.26	64.19	81.79	86.84	63.38
40%	155.73	122.40	124.87	93.45	82.88	108.57	74.46	63.13	74.83	88.86	102.64	71.51
45%	179.16	146.42	145.41	100.45	89.41	119.30	91.87	75.20	83.60	103.19	116.37	80.37
50%	192.44	169.19	167.27	107.20	98.27	130.38	101.24	86.75	93.67	119.63	139.97	96.78
55%	206.63	196.57	194.45	114.91	110.04	142.89	112.17	101.65	105.99	141.17	160.76	111.72
60%	233.63	214.81	228.31	122.52	128.36	157.11	118.50	123.90	114.55	167.56	189.93	127.74
65%	268.21	259.00	262.08	134.19	150.56	166.81	126.12	137.93	126.21	197.86	222.01	148.02
70%	293.67	311.99	326.66	151.66	174.03	186.84	138.31	152.60	138.60	237.02	267.01	161.05
75%	346.86	364.74	369.58	188.63	203.64	201.75	145.65	173.01	153.07	252.42	326.93	190.56
80%	439.47	434.23	472.61	315.74	285.77	235.31	174.53	194.21	184.68	288.66	363.58	231.65
85%	500.01	528.76	586.31	496.75	388.14	277.37	200.55	217.92	210.92	324.28	413.61	276.11
90%	678.22	757.30	709.75	672.02	551.24	338.53	244.74	264.85	243.03	374.28	527.91	330.68
95%	943.13	1,062.58	1,056.87	891.12	766.26	579.45	355.73	378.87	328.17	556.58	700.69	452.64

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Table 2-8: Statistics for Calibrated Monthly Forward Market Prices, FY 2003 ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	147.97	144.99	145.34	143.12	124.94	104.38	77.50	72.34	70.59	108.44	136.34	96.74	**114.39**
Minimum	14.26	5.88	4.21	8.06	4.20	1.12	0.15	0.17	2.56	0.42	1.88	2.10	
Maximum	3,170.61	4,063.12	2,517.09	1,729.61	4,209.81	1,586.19	1,612.06	1,556.33	521.62	817.22	1,018.44	693.23	
Median	82.84	54.48	50.31	67.67	67.86	67.30	34.63	41.20	47.23	67.81	74.78	50.72	
Standard D	273.49	328.93	269.45	233.84	301.78	137.35	138.19	115.03	78.91	131.52	163.16	119.67	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	29.16	12.33	9.08	22.02	18.15	17.42	1.17	1.88	7.34	4.12	7.88	7.04
10%	36.96	15.61	12.83	32.06	24.43	29.11	3.07	3.29	11.50	6.27	12.92	13.08
15%	41.30	18.46	16.44	37.70	28.43	33.86	4.78	4.15	14.72	9.93	17.86	16.68
20%	46.45	23.16	20.77	43.60	35.71	40.14	8.67	6.51	20.24	14.45	23.10	19.64
25%	53.30	26.33	22.82	47.32	41.84	45.58	12.82	9.83	23.56	18.75	30.38	23.06
30%	60.07	30.84	26.02	51.78	46.55	49.01	15.08	14.19	28.58	22.26	37.89	27.22
35%	67.31	39.14	29.71	57.15	50.33	52.13	19.48	17.98	31.22	32.10	43.26	31.85
40%	73.44	43.79	33.27	59.47	55.93	57.54	22.95	27.52	39.46	41.91	56.81	40.12
45%	80.02	49.37	44.10	63.03	60.83	63.20	28.19	31.21	41.73	49.98	65.71	46.05
50%	82.84	54.48	50.31	67.67	67.86	67.30	34.63	41.20	47.23	67.81	74.78	50.72
55%	90.28	60.96	63.45	72.94	73.29	77.51	38.81	50.92	53.39	76.94	87.66	57.47
60%	98.72	71.47	71.91	77.19	82.81	80.79	49.00	60.47	59.41	89.24	105.39	68.97
65%	112.08	84.30	90.45	84.80	93.21	87.90	60.88	71.24	66.43	100.77	122.66	83.42
70%	125.89	108.34	113.09	95.41	102.81	98.81	76.19	85.54	72.71	119.83	148.73	97.72
75%	135.64	128.35	142.53	106.12	116.10	113.23	91.02	98.29	79.32	145.08	180.98	126.21
80%	155.96	166.59	193.68	136.88	135.11	126.67	112.19	113.91	96.96	168.73	208.29	148.31
85%	180.15	205.43	241.35	198.56	160.07	143.29	137.36	137.78	122.94	207.65	251.80	184.98
90%	244.48	310.84	330.16	320.25	204.94	196.56	175.51	167.40	155.07	272.67	336.90	241.81
95%	367.93	504.95	609.81	561.54	303.55	314.09	278.99	222.17	198.83	373.25	515.12	337.36

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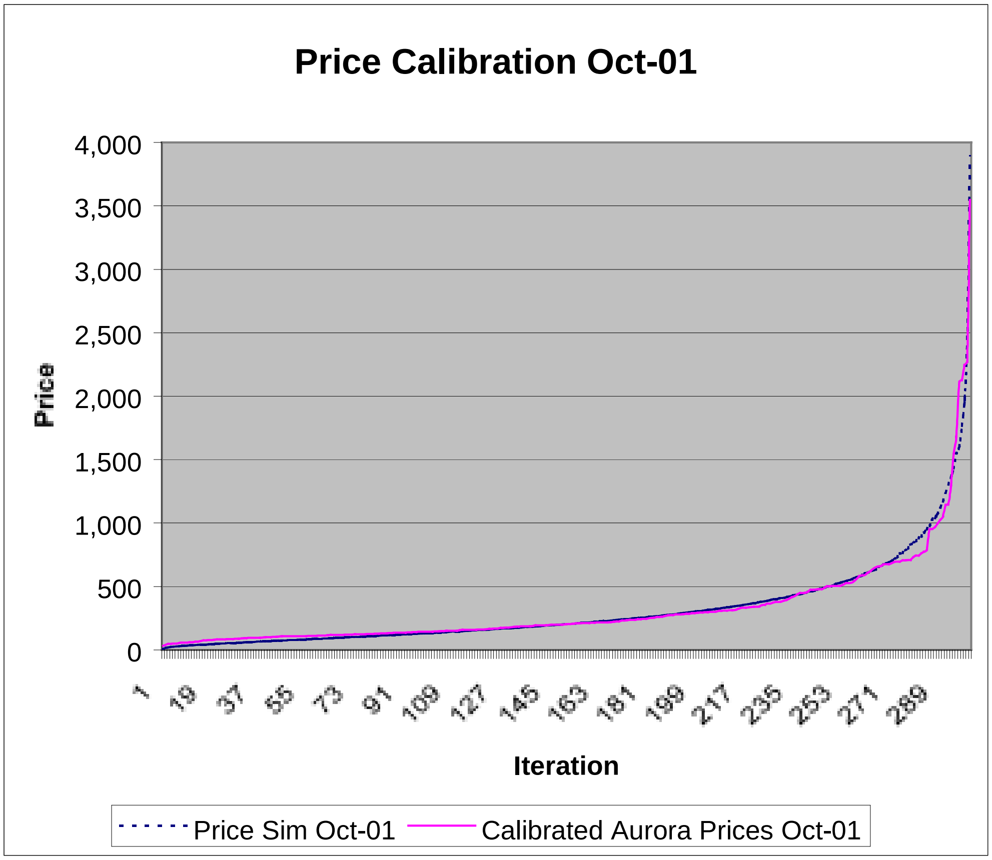
Table 2-9: Example of the Price Calibration Process



Price Factor	**5.2**
Power Factor	**1.5**
Sim Avg Price	**323.07**
Sim Price Stdev	**391.30**
Fitted Avg Price	**324.25**
Fitted Price Stdev	**380.22**

2.2.8 Results from Risk Analysis Model. Summaries of the average annual net revenues for all 18 Fish and Wildlife Scenarios for FY 2002-2006 from RiskMod for the three different electricity price and two different load levels are reported in Table 2-10 through Table 2-15. The prices in these tables are reported in terms of annual flat energy prices in FY 2002. The net revenues reported in these tables do not include revenues from the Load-Based (LB) CRAC, Financial-Based (FB) CRAC, and interest earned on cash reserves, which are computed in the ToolKit model.

The net revenue risk estimated by RiskMod is an input into the ToolKit Model. The Toolkit Model uses the net revenue risk estimated by RiskMod, the net revenue risk estimated by the NORM model, and additional adjustments to net revenues from the LB CRAC, FB CRAC, and interest earned on cash reserves to calculate the TPP.

If requested, BPA will make available on CD an electronic copy of RiskMod and NORM with the associated input and output data for the Risk Analysis Study. If requested, BPA will also provide a hard copy.

Table 2-10: Net Revenue Summary, Slice = 2000 MW ($ Thousand) (FY '02 Avg. Price = $140, Load Reduction = 0 MW)						
Alternative	**FY 2002**	**FY 2003**	**FY 2004**	**FY 2005**	**FY 2006**	**5 Yr Average**
1 - In-River (low)	-2,104,971	-1,007,157	-249,548	-231,881	-273,752	-773,462
2 - In-River (hi) CWA	-2,057,176	-977,401	-208,265	-188,637	-228,793	-732,055
3 - Exp Trns	-2,085,958	-994,038	-239,811	-221,318	-263,287	-760,883
4 - Exp Trns (low)	-2,121,843	-977,288	-239,549	-221,556	-262,849	-764,617
5 - TrnsPlus	-2,104,971	-1,007,157	-249,548	-231,881	-273,752	-773,462
6 - TrnsPlus CWA	-2,104,971	-1,007,157	-249,548	-231,881	-273,752	-773,462
7 - 2 LSN	-2,337,762	-1,138,414	-337,880	-328,620	-367,894	-902,114
8 - 4 LSN	-2,429,943	-1,190,450	-372,223	-366,589	-404,764	-952,794
9 - LSN & JDA	-2,433,176	-1,191,840	-372,393	-366,340	-404,703	-953,690
10 - JDA	-2,104,971	-1,007,157	-249,548	-231,881	-273,752	-773,462
11 - JDA Spillway	-2,104,971	-1,007,157	-249,548	-231,881	-273,752	-773,462
12 - LSN JDA Spillway	-2,433,252	-1,193,225	-374,067	-368,301	-406,532	-955,075
13 - LSN & JDA CWA	-2,678,030	-1,329,960	-457,011	-460,677	-497,448	-1,084,625
14 - 2 LSN - Adj	-2,122,613	-1,017,179	-256,411	-239,303	-281,099	-783,321
15 - 4 LSN - Adj	-2,123,544	-1,017,717	-256,784	-239,705	-281,493	-783,848
16 - LSN & JDA - Adj	-2,121,100	-1,016,569	-255,876	-238,748	-280,567	-782,572
17 - LSN JDA Spillway - Adj	-2,123,926	-1,018,133	-257,037	-239,993	-281,781	-784,174
18 - LSN & JDA CWA - Adj	-2,374,285	-1,160,066	-349,835	-342,093	-381,368	-921,530
Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.						

Table 2-11: Net Revenue Summary, Slice = 2000 MW ($ Thousand) (FY '02 Avg. Price = $140, Load Reduction = 1500 MW)						
Alternative	**FY 2002**	**FY 2003**	**FY 2004**	**FY 2005**	**FY 2006**	**5 Yr Average**
1 - In-River (low)	-499,205	-265,448	83,329	148,363	100,818	-86,428
2 - In-River (hi) CWA	-451,410	-235,692	124,612	191,614	145,776	-45,020
3 - Exp Trns	-480,192	-252,329	93,066	158,924	111,281	-73,850
4 - Exp Trns (low)	-516,077	-235,578	93,328	158,749	111,737	-77,568
5 - TrnsPlus	-499,205	-265,448	83,329	148,363	100,818	-86,428
6 - TrnsPlus CWA	-499,205	-265,448	83,329	148,363	100,818	-86,428
7 - 2 LSN	-731,996	-396,704	-5,003	51,624	6,662	-215,083
8 - 4 LSN	-824,177	-448,740	-39,346	13,653	-30,226	-265,767
9 - LSN & JDA	-827,410	-450,131	-39,516	13,904	-30,168	-266,664
10 - JDA	-499,205	-265,448	83,329	148,363	100,818	-86,428
11 - JDA Spillway	-499,205	-265,448	83,329	148,363	100,818	-86,428
12 - LSN JDA Spillway	-827,486	-451,516	-41,190	11,943	-31,998	-268,049
13 - LSN & JDA CWA	-1,072,264	-588,251	-124,134	-80,423	-122,921	-397,599
14 - 2 LSN - Adj	-516,847	-275,470	76,467	140,941	93,470	-96,288
15 - 4 LSN - Adj	-517,778	-276,008	76,093	140,539	93,077	-96,815
16 - LSN & JDA - Adj	-515,334	-274,859	77,001	141,496	94,002	-95,539
17 - LSN JDA Spillway - Adj	-518,160	-276,423	75,840	140,251	92,788	-97,141
18 - LSN & JDA CWA - Adj	-768,519	-418,357	-16,958	38,154	-6,816	-234,499
Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.						

Table 2-12: Net Revenue Summary, Slice = 2000 MW ($ Thousand)

(FY '02 Avg. Price = $210, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-3,298,654	-1,579,748	-246,546	-230,204	-272,656	-1,125,561
2 - In-River (hi) CWA	-3,229,179	-1,537,610	-205,661	-186,912	-227,796	-1,077,431
3 - Exp Trns	-3,270,009	-1,560,156	-236,846	-219,705	-262,177	-1,109,779
4 - Exp Trns (low)	-3,317,581	-1,533,036	-235,346	-220,319	-261,737	-1,113,604
5 - TrnsPlus	-3,298,654	-1,579,748	-246,546	-230,204	-272,656	-1,125,561
6 - TrnsPlus CWA	-3,298,654	-1,579,748	-246,546	-230,204	-272,656	-1,125,561
7 - 2 LSN	-3,652,551	-1,780,429	-334,987	-327,663	-366,833	-1,292,493
8 - 4 LSN	-3,792,551	-1,860,369	-369,250	-365,580	-403,570	-1,358,264
9 - LSN & JDA	-3,797,663	-1,863,134	-369,450	-365,288	-403,492	-1,359,805
10 - JDA	-3,298,654	-1,579,748	-246,546	-230,204	-272,656	-1,125,561
11 - JDA Spillway	-3,298,654	-1,579,748	-246,546	-230,204	-272,656	-1,125,561
12 - LSN JDA Spillway	-3,797,614	-1,864,815	-371,105	-367,278	-405,340	-1,361,230
13 - LSN & JDA CWA	-4,172,560	-2,075,214	-454,041	-459,185	-496,001	-1,531,400
14 - 2 LSN - Adj	-3,325,515	-1,595,017	-253,426	-237,696	-279,984	-1,138,328
15 - 4 LSN - Adj	-3,326,911	-1,595,824	-253,800	-238,098	-280,378	-1,139,002
16 - LSN & JDA - Adj	-3,323,282	-1,594,108	-252,896	-237,149	-279,453	-1,137,378
17 - LSN JDA Spillway - Adj	-3,327,500	-1,596,447	-254,058	-238,391	-280,667	-1,139,413
18 - LSN & JDA CWA - Adj	-3,708,415	-1,813,749	-346,993	-341,104	-380,401	-1,318,132

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-13: Net Revenue Summary, Slice = 2000 MW ($ Thousand)

(FY '02 Avg. Price = $210, Load Reduction = 1500 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-744,808	-325,811	86,331	150,040	101,915	-146,467
2 - In-River (hi) CWA	-675,333	-283,674	127,217	193,339	146,774	-98,335
3 - Exp Trns	-716,162	-306,220	96,031	160,537	112,391	-130,685
4 - Exp Trns (low)	-763,735	-279,100	97,531	159,987	112,848	-134,494
5 - TrnsPlus	-744,808	-325,811	86,331	150,040	101,915	-146,467
6 - TrnsPlus CWA	-744,808	-325,811	86,331	150,040	101,915	-146,467
7 - 2 LSN	-1,098,705	-526,493	-2,110	52,580	7,723	-313,401
8 - 4 LSN	-1,238,705	-606,433	-36,373	14,663	-29,032	-379,176
9 - LSN & JDA	-1,243,817	-609,197	-36,573	14,956	-28,957	-380,718
10 - JDA	-744,808	-325,811	86,331	150,040	101,915	-146,467
11 - JDA Spillway	-744,808	-325,811	86,331	150,040	101,915	-146,467
12 - LSN JDA Spillway	-1,243,768	-610,879	-38,228	12,967	-30,806	-382,143
13 - LSN & JDA CWA	-1,618,714	-821,278	-121,164	-78,931	-121,474	-552,312
14 - 2 LSN - Adj	-771,669	-341,081	79,451	142,548	94,585	-159,233
15 - 4 LSN - Adj	-773,065	-341,888	79,077	142,146	94,191	-159,908
16 - LSN & JDA - Adj	-769,435	-340,172	79,981	143,095	95,116	-158,283
17 - LSN JDA Spillway - Adj	-773,654	-342,511	78,819	141,853	93,902	-160,318
18 - LSN & JDA CWA - Adj	-1,154,569	-559,813	-14,116	39,143	-5,848	-339,041

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-14: Net Revenue Summary, Slice = 2000 MW ($ Thousand)

(FY '02 Avg. Price = $315, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-5,101,286	-2,464,187	-243,619	-228,862	-271,470	-1,661,885
2 - In-River (hi) CWA	-4,999,928	-2,404,320	-202,900	-185,679	-226,027	-1,603,771
3 - Exp Trns	-5,058,107	-2,434,570	-234,078	-218,377	-261,014	-1,641,229
4 - Exp Trns (low)	-5,120,997	-2,391,104	-232,126	-218,840	-259,744	-1,644,562
5 - TrnsPlus	-5,101,286	-2,464,187	-243,619	-228,862	-271,470	-1,661,885
6 - TrnsPlus CWA	-5,101,286	-2,464,187	-243,619	-228,862	-271,470	-1,661,885
7 - 2 LSN	-5,639,616	-2,770,085	-332,488	-326,173	-365,352	-1,886,743
8 - 4 LSN	-5,852,568	-2,891,945	-366,984	-364,178	-401,923	-1,975,520
9 - LSN & JDA	-5,860,429	-2,896,282	-367,164	-363,909	-401,857	-1,977,928
10 - JDA	-5,101,286	-2,464,187	-243,619	-228,862	-271,470	-1,661,885
11 - JDA Spillway	-5,101,286	-2,464,187	-243,619	-228,862	-271,470	-1,661,885
12 - LSN JDA Spillway	-5,860,213	-2,898,747	-368,847	-365,881	-403,701	-1,979,478
13 - LSN & JDA CWA	-6,431,574	-3,219,131	-452,207	-458,127	-494,621	-2,211,132
14 - 2 LSN - Adj	-5,142,030	-2,487,485	-250,535	-236,331	-278,800	-1,679,036
15 - 4 LSN - Adj	-5,144,124	-2,488,695	-250,909	-236,732	-279,193	-1,679,931
16 - LSN & JDA - Adj	-5,138,725	-2,486,165	-250,006	-235,783	-278,265	-1,677,789
17 - LSN JDA Spillway - Adj	-5,145,033	-2,489,650	-251,167	-237,026	-279,480	-1,680,471
18 - LSN & JDA CWA - Adj	-5,725,625	-2,820,763	-344,535	-339,644	-378,754	-1,921,864

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-15: Net Revenue Summary, Slice = 2000 MW ($ Thousand)

(FY '02 Avg. Price = $315, Load Reduction = 1500 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-1,125,320	-432,349	89,258	151,382	103,100	-242,786
2 - In-River (hi) CWA	-1,023,961	-372,481	129,977	194,572	148,542	-184,670
3 - Exp Trns	-1,082,141	-402,732	98,799	161,865	113,554	-222,131
4 - Exp Trns (low)	-1,145,031	-359,266	100,751	161,465	114,841	-225,448
5 - TrnsPlus	-1,125,320	-432,349	89,258	151,382	103,100	-242,786
6 - TrnsPlus CWA	-1,125,320	-432,349	89,258	151,382	103,100	-242,786
7 - 2 LSN	-1,663,650	-738,247	389	54,070	9,204	-467,647
8 - 4 LSN	-1,876,601	-860,106	-34,107	16,065	-27,385	-556,427
9 - LSN & JDA	-1,884,463	-864,444	-34,287	16,335	-27,322	-558,836
10 - JDA	-1,125,320	-432,349	89,258	151,382	103,100	-242,786
11 - JDA Spillway	-1,125,320	-432,349	89,258	151,382	103,100	-242,786
12 - LSN JDA Spillway	-1,884,246	-866,909	-35,970	14,363	-29,168	-560,386
13 - LSN & JDA CWA	-2,455,608	-1,187,293	-119,330	-77,873	-120,094	-792,040
14 - 2 LSN - Adj	-1,166,064	-455,647	82,342	143,913	95,770	-259,937
15 - 4 LSN - Adj	-1,168,158	-456,857	81,968	143,512	95,376	-260,832
16 - LSN & JDA - Adj	-1,162,759	-454,327	82,871	144,461	96,304	-258,690
17 - LSN JDA Spillway - Adj	-1,169,066	-457,812	81,710	143,218	95,088	-261,372
18 - LSN & JDA CWA - Adj	-1,749,659	-788,925	-11,658	40,603	-4,201	-502,768

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

CHAPTER 3: NO-SLICE RISK ANALYSIS

3.1 Introduction

For the Supplemental Proposal, Bonneville Power Administration (BPA) performed various risk analyses in support of the Cost-Shift Analysis in Chapter 5. The risk analyses for the Cost-Shift Analysis were performed using a sales forecast that reflected BPA's sales at the Priority Firm Power rate assuming no sales of the Slice product under various specified load and market price scenarios. This assessment, consisting of a set of alternative risk analyses, will be referred to as the No-Slice Risk Analysis.

The Cost-Shift Analysis was performed by comparing results from the ToolKit model using net revenue risk quantified by Risk Analysis Model (RiskMod) and the Non-Operating Risk Model (NORM) for the Risk Analysis Study in Chapter 2, and the No-Slice Risk Analysis in this chapter. Comparisons of the differences in the results were made to assess whether or not there is a Cost-Shift between the Slice purchasers and the non-Slice purchasers. *See* Chapter 5 of this study.

3.2 Differences From the Risk Analysis Study

3.2.1 Overview. The No-Slice Risk Analysis used the same version of RiskMod and NORM for Fiscal Year (FY) 2002-2006 as the Risk Analysis Study, in Chapter 2. The same input data were used in NORM and RiskMod, except that a public agency sales forecast was input into RiskMod that did not include any sales of the Slice product. Public agency sales are higher in the No-Slice Risk Analysis due to BPA having to serve more load growth, resulting in an increase in the amount of System Augmentation purchases. Also, for the No-Slice Risk Analysis in RiskMod, BPA receives all, not a share, of the output of the Federal System and BPA pays all, not a share, of the variable non-operating expenses in the NORM for FY 2002-2006.

3.2.2 Revisions in Loads. For the No-Slice Risk Analysis, the expected sales for the Slice customers are based on the expected product that each customer would buy as an alternative to Slice. The total sales were calculated by summing individual customer sales forecasts. Sales for non-Slice customers were forecasted to be the same in both the Slice and No-Slice cases. The sales forecast used in the No-Slice Risk Analysis for the Supplemental Proposal is the same sales forecast used in the Amended Proposal.

3.2.3 Results from Risk Analysis Model. Summaries of the average annual net revenues for all 18 fish and wildlife scenarios for FY 2002-2006 from RiskMod for the No-Slice Risk Analysis for three different electricity price and two different load levels are reported in Table 3-1 through Table 3-6. The prices in these tables are reported in terms of annual flat energy prices in FY 2002. The alternative prices and loads used in these analyses are the same as those used in Chapter 2 of this Study. The net revenues reported in the tables do not include revenues from the Load-Based (LB) Cost Recovery Adjustment Clause (CRAC), Financial-Based (FB) CRAC, and interest earned on cash reserves, which are computed in the ToolKit model.

If requested, BPA will make available, on CD, an electronic copy of RiskMod and NORM with the associated input and output data for the No-Slice Risk Analysis. If requested, BPA will also provide a hard copy.

Table 3-1: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $140, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-2,068,996	-1,048,111	-189,649	-178,381	-223,569	-741,741
2 - In-River (hi) CWA	-2,002,623	-1,007,164	-132,006	-118,361	-160,506	-684,132
3 - Exp Trns	-2,042,400	-1,029,744	-175,846	-163,569	-209,075	-724,127
4 - Exp Trns (low)	-2,092,690	-1,008,160	-177,570	-166,158	-210,436	-731,003
5 - TrnsPlus	-2,068,996	-1,048,111	-189,649	-178,381	-223,569	-741,741
6 - TrnsPlus CWA	-2,068,996	-1,048,111	-189,649	-178,381	-223,569	-741,741
7 - 2 LSN	-2,394,400	-1,231,739	-312,947	-314,272	-355,412	-921,754
8 - 4 LSN	-2,522,662	-1,303,912	-360,894	-367,023	-407,080	-992,314
9 - LSN & JDA	-2,527,697	-1,306,332	-361,058	-366,588	-407,072	-993,750
10 - JDA	-2,068,996	-1,048,111	-189,649	-178,381	-223,569	-741,741
11 - JDA Spillway	-2,068,996	-1,048,111	-189,649	-178,381	-223,569	-741,741
12 - LSN JDA Spillway	-2,527,595	-1,307,817	-363,395	-369,455	-409,573	-995,567
13 - LSN & JDA CWA	-2,869,011	-1,499,901	-479,398	-498,788	-535,881	-1,176,596
14 - 2 LSN - Adj	-2,093,693	-1,062,099	-199,307	-188,803	-233,821	-755,545
15 - 4 LSN - Adj	-2,094,996	-1,062,846	-199,831	-189,367	-234,370	-756,282
16 - LSN & JDA - Adj	-2,091,614	-1,061,245	-198,583	-188,033	-233,089	-754,513
17 - LSN JDA Spillway - Adj	-2,095,537	-1,063,426	-200,200	-189,774	-234,778	-756,743
18 - LSN & JDA CWA - Adj	-2,445,781	-1,261,610	-329,854	-333,115	-374,686	-949,009

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 3-2: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $140, Load Reduction = 1500 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-463,230	-306,402	143,228	201,828	150,983	-54,719
2 - In-River (hi) CWA	-396,857	-265,455	200,871	261,858	214,039	2,891
3 - Exp Trns	-436,634	-288,035	157,031	216,638	165,470	-37,106
4 - Exp Trns (low)	-486,923	-266,451	155,307	214,126	164,129	-43,963
5 - TrnsPlus	-463,230	-306,402	143,228	201,828	150,983	-54,719
6 - TrnsPlus CWA	-463,230	-306,402	143,228	201,828	150,983	-54,719
7 - 2 LSN	-788,634	-490,030	19,930	65,938	19,106	-234,738
8 - 4 LSN	-916,896	-562,203	-28,017	13,190	-32,576	-305,300
9 - LSN & JDA	-921,931	-564,623	-28,181	13,626	-32,569	-306,736
10 - JDA	-463,230	-306,402	143,228	201,828	150,983	-54,719
11 - JDA Spillway	-463,230	-306,402	143,228	201,828	150,983	-54,719
12 - LSN JDA Spillway	-921,829	-566,108	-30,518	10,757	-35,090	-308,557
13 - LSN & JDA CWA	-1,263,245	-758,192	-146,521	-118,554	-161,390	-489,580
14 - 2 LSN - Adj	-487,926	-320,390	133,570	191,405	140,727	-68,523
15 - 4 LSN - Adj	-489,230	-321,137	133,046	190,841	140,179	-69,260
16 - LSN & JDA - Adj	-485,848	-319,536	134,294	192,175	141,460	-67,491
17 - LSN JDA Spillway - Adj	-489,771	-321,717	132,677	190,434	139,771	-69,721
18 - LSN & JDA CWA - Adj	-840,015	-519,901	3,023	47,102	-162	-261,991

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 3-3: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $210, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-3,206,770	-1,598,425	-185,466	-176,042	-222,041	-1,077,749
2 - In-River (hi) CWA	-3,110,302	-1,540,484	-128,375	-115,957	-159,115	-1,010,847
3 - Exp Trns	-3,166,701	-1,570,996	-171,713	-161,320	-207,527	-1,055,651
4 - Exp Trns (low)	-3,233,414	-1,535,839	-171,710	-164,433	-208,886	-1,062,857
5 - TrnsPlus	-3,206,770	-1,598,425	-185,466	-176,042	-222,041	-1,077,749
6 - TrnsPlus CWA	-3,206,770	-1,598,425	-185,466	-176,042	-222,041	-1,077,749
7 - 2 LSN	-3,701,443	-1,879,159	-308,914	-312,939	-353,933	-1,311,278
8 - 4 LSN	-3,896,245	-1,990,048	-356,750	-365,616	-405,416	-1,402,815
9 - LSN & JDA	-3,904,163	-1,994,624	-356,956	-365,121	-405,384	-1,405,250
10 - JDA	-3,206,770	-1,598,425	-185,466	-176,042	-222,041	-1,077,749
11 - JDA Spillway	-3,206,770	-1,598,425	-185,466	-176,042	-222,041	-1,077,749
12 - LSN JDA Spillway	-3,903,785	-1,996,300	-359,265	-368,028	-407,911	-1,407,058
13 - LSN & JDA CWA	-4,426,751	-2,291,808	-475,259	-496,708	-533,864	-1,644,878
14 - 2 LSN - Adj	-3,244,370	-1,619,736	-195,147	-186,563	-232,267	-1,095,617
15 - 4 LSN - Adj	-3,246,325	-1,620,857	-195,671	-187,127	-232,816	-1,096,559
16 - LSN & JDA - Adj	-3,241,303	-1,618,464	-194,429	-185,804	-231,536	-1,094,307
17 - LSN JDA Spillway - Adj	-3,247,159	-1,621,726	-196,046	-187,540	-233,225	-1,097,139
18 - LSN & JDA CWA - Adj	-3,780,018	-1,925,138	-325,892	-331,736	-373,337	-1,347,224

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 3-4: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $210, Load Reduction = 1500 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-652,924	-344,489	147,411	204,167	152,511	-98,665
2 - In-River (hi) CWA	-556,456	-286,548	204,502	264,262	215,430	-31,762
3 - Exp Trns	-612,855	-317,060	161,164	218,887	167,017	-76,569
4 - Exp Trns (low)	-679,568	-281,903	161,167	215,851	165,679	-83,755
5 - TrnsPlus	-652,924	-344,489	147,411	204,167	152,511	-98,665
6 - TrnsPlus CWA	-652,924	-344,489	147,411	204,167	152,511	-98,665
7 - 2 LSN	-1,147,597	-625,223	23,963	67,272	20,585	-332,200
8 - 4 LSN	-1,342,398	-736,112	-23,873	14,596	-30,912	-423,740
9 - LSN & JDA	-1,350,317	-740,688	-24,079	15,092	-30,881	-426,174
10 - JDA	-652,924	-344,489	147,411	204,167	152,511	-98,665
11 - JDA Spillway	-652,924	-344,489	147,411	204,167	152,511	-98,665
12 - LSN JDA Spillway	-1,349,939	-742,364	-26,388	12,184	-33,428	-427,987
13 - LSN & JDA CWA	-1,872,905	-1,037,871	-142,382	-116,474	-159,373	-665,801
14 - 2 LSN - Adj	-690,523	-365,800	137,730	193,645	142,281	-116,533
15 - 4 LSN - Adj	-692,479	-366,921	137,206	193,082	141,733	-117,476
16 - LSN & JDA - Adj	-687,457	-364,528	138,448	194,403	143,012	-115,224
17 - LSN JDA Spillway - Adj	-693,312	-367,790	136,831	192,668	141,324	-118,056
18 - LSN & JDA CWA - Adj	-1,226,172	-671,202	6,985	48,481	1,187	-368,144

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 3-5: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $315, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-4,930,310	-2,454,401	-181,385	-174,172	-220,388	-1,592,131
2 - In-River (hi) CWA	-4,789,586	-2,372,145	-124,527	-114,238	-156,650	-1,511,429
3 - Exp Trns	-4,869,911	-2,412,937	-167,855	-159,468	-205,905	-1,563,215
4 - Exp Trns (low)	-4,958,177	-2,356,319	-167,222	-162,372	-206,108	-1,570,040
5 - TrnsPlus	-4,930,310	-2,454,401	-181,385	-174,172	-220,388	-1,592,131
6 - TrnsPlus CWA	-4,930,310	-2,454,401	-181,385	-174,172	-220,388	-1,592,131
7 - 2 LSN	-5,682,753	-2,882,300	-305,431	-310,861	-351,868	-1,906,643
8 - 4 LSN	-5,979,069	-3,051,350	-353,591	-363,661	-403,120	-2,030,158
9 - LSN & JDA	-5,991,216	-3,058,481	-353,770	-363,198	-403,105	-2,033,954
10 - JDA	-4,930,310	-2,454,401	-181,385	-174,172	-220,388	-1,592,131
11 - JDA Spillway	-4,930,310	-2,454,401	-181,385	-174,172	-220,388	-1,592,131
12 - LSN JDA Spillway	-5,990,449	-3,060,914	-356,117	-366,082	-405,627	-2,035,838
13 - LSN & JDA CWA	-6,787,365	-3,510,849	-472,702	-495,234	-531,940	-2,359,618
14 - 2 LSN - Adj	-4,987,339	-2,486,917	-191,117	-184,660	-230,616	-1,616,130
15 - 4 LSN - Adj	-4,990,272	-2,488,598	-191,641	-185,224	-231,164	-1,617,380
16 - LSN & JDA - Adj	-4,982,803	-2,485,070	-190,399	-183,900	-229,880	-1,614,411
17 - LSN JDA Spillway - Adj	-4,991,557	-2,489,931	-192,017	-185,638	-231,571	-1,618,143
18 - LSN & JDA CWA - Adj	-5,803,699	-2,952,241	-322,466	-329,701	-371,042	-1,955,830

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 3-6: Net Revenue Summary, Slice = 0 MW ($ Thousand)

(FY '02 Avg. Price = $315, Load Reduction = 1500 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-954,344	-422,563	151,492	206,037	154,164	-173,043
2 - In-River (hi) CWA	-813,620	-340,306	208,350	265,981	217,895	-92,340
3 - Exp Trns	-893,945	-381,099	165,022	220,739	168,639	-144,129
4 - Exp Trns (low)	-982,211	-324,481	165,655	217,912	168,457	-150,933
5 - TrnsPlus	-954,344	-422,563	151,492	206,037	154,164	-173,043
6 - TrnsPlus CWA	-954,344	-422,563	151,492	206,037	154,164	-173,043
7 - 2 LSN	-1,706,787	-850,462	27,446	69,349	22,650	-487,561
8 - 4 LSN	-2,003,102	-1,019,512	-20,714	16,551	-28,616	-611,079
9 - LSN & JDA	-2,015,250	-1,026,643	-20,893	17,015	-28,602	-614,874
10 - JDA	-954,344	-422,563	151,492	206,037	154,164	-173,043
11 - JDA Spillway	-954,344	-422,563	151,492	206,037	154,164	-173,043
12 - LSN JDA Spillway	-2,014,483	-1,029,076	-23,240	14,131	-31,144	-616,763
13 - LSN & JDA CWA	-2,811,399	-1,479,011	-139,825	-115,000	-157,449	-940,537
14 - 2 LSN - Adj	-1,011,373	-455,078	141,760	195,548	143,933	-197,042
15 - 4 LSN - Adj	-1,014,306	-456,760	141,236	194,985	143,384	-198,292
16 - LSN & JDA - Adj	-1,006,836	-453,232	142,478	196,308	144,668	-195,323
17 - LSN JDA Spillway - Adj	-1,015,591	-458,093	140,860	194,570	142,978	-199,055
18 - LSN & JDA CWA - Adj	-1,827,733	-920,403	10,411	50,516	3,482	-536,745

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

CHAPTER 4: SLICE AUGMENTATION COST ANALYSIS

4.1 Introduction and Overview of Chapter

In the 2002 May Power Rate Proposal (May Proposal), Bonneville Power Administration (BPA) adopted an approach to the financial portion of the Investor-Owned Utilities Residential Exchange Program Settlements (REP Settlement). Because of subsequent changes to the financial portion of the REP Settlement, as described in Doubleday, *et al.*, WP-02-E-BPA-74, BPA believes that the approach described in the May Proposal is no longer appropriate to assure that Slice purchasers pay the proportionate share of the financial portion of the REP Settlement.

4.2 Purpose of the Proposed Modifications

The proposed modification is intended to assure that Slice purchasers continue to pay their proportionate share of the financial part of the REP Settlement. In order to assure this result, BPA is proposing a monthly adjustment to a Slice purchaser's bill.

4.3 Approach to the Slice Rate Calculation in the May Proposal

A basic tenet of the Slice product is that Slice purchasers pay a percentage of BPA's costs proportionate to the percentage of the Federal Columbia River Power System that the Slice purchaser elects to purchase. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 42. The costs considered by the Slice contracts are referred to collectively as the Slice Revenue Requirement. *Id.* The Slice Revenue Requirement consists of all the line items identified in the generation revenue requirement, with certain limited exceptions. Mesa, *et al.*, WP-02-E-BPA-32, at 5. The Slice Revenue Requirement includes costs associated with the financial portion of the REP Settlement.

4.4 Slice Portion of Increased Residential Exchange Program Settlement

As is presented in Chapter 6 of this study, BPA's Supplemental Proposal has the effect of increasing the value of the financial portion of the REP Settlement of the Residential Exchange Program. A proportionate share of the increased cost of the cash portion of the REP Settlement will be assessed to purchasers of the Slice product. BPA is proposing to include this as a monthly adjustment to the monthly bill for each Slice customer.

The monthly adjustment per one-percent Slice is proposed to be:
[Incremental amount of REP Settlement costs above the May Proposal/12/100] = $ per month per one-percent Slice.

CHAPTER 5: RISK MITIGATION

5.1 Introduction

This chapter describes changes to the risk mitigation tools and modeling that are incorporated in this Supplemental Proposal. Since the publication of the May 2000 Final Power Rate Proposal (May Proposal), significant changes in West Coast power markets and unanticipated system augmentation required Bonneville Power Administration (BPA) to reassess its risk profile and develop an even more robust mitigation package. As explained in Chapter 1 of this document, due to higher market prices, BPA now expects both an increase in demand and higher costs for augmentation purchases than previously projected. The combination of an unanticipated increase in loads with higher and more uncertain market prices greatly diminished the probability that the rates reflected in the May Proposal would fully recover generation function costs. Absent a change to proposed rates, Treasury Payment Probability (TPP) would be reduced to an unacceptable level.

In December 2000, BPA released the 2002 Amended Power Rate Proposal (Amended Proposal). The Amended Proposal addressed the additional risks that had materialized following the release of the May Proposal, updating forecasts of market prices and expected reserves and introducing a more robust, three-component Cost Recovery Adjustment Clause (CRAC) to mitigate risks of an increasingly volatile market. Since December, market prices have continued to rise to levels well beyond those forecast in the Fall of 2000. At the same time, the Pacific Northwest has been experiencing a drought that has left reservoirs at levels well below average. This Supplemental Proposal addresses these more recent increases in risks, adopting the same general approach as the Amended Proposal (*i.e.*, a three-component CRAC) but modifying some of the specific rate-making provisions. In order to accomplish this, several modifications have been made to the risk mitigation methodology as well as to the structure of the ToolKit model. These modifications are detailed in the text that follows.

5.2 Treasury Payment Probability

This Supplemental Proposal, like the May and Amended Proposals, is consistent with Fish and Wildlife Funding Principle (Principles) Nos. 3 and 4, which relate to BPA's TPP. Principle No. 3 states:

> "Bonneville will demonstrate a high probability of Treasury payment in full and on time over the five-year period.
>
> - A 100 percent probability of Treasury payment is not achievable, but BPA's new rates must be designed to maintain or improve TPP, even in view of the range of fish costs.
> - BPA will demonstrate a probability of Treasury payment in full and on time over the five-year rate period at least equal to the 80 percent level established in the last rate case and will seek to achieve an 88 percent level." *See* the Principles, Volume 1, Chapter 13 of Revenue Requirement Study Documentation, May Proposal, WP-02-FS-BPA-02A.

In the May Proposal, BPA designed and proposed risk mitigation tools to achieve an 88 percent TPP for the generation function. An 88 percent TPP continues to be BPA's goal. Because the design of Load-Based (LB) CRAC calls for adjustments based on actual levels of augmentation and actual market prices, this Supplemental Proposal includes a range of TPPs rather than a point estimate. Several scenarios were modeled to demonstrate the impacts of different levels of market price and load reduction on the amount of revenues to be collected. The scenarios which have been modeled result in TPPs from 82.7 percent to 85.9 percent, which still fall within the

80-88 percent range called for in the Principles. *See* Section 5.6 of this Study, and Burns, *et al.*, WP-02-E-BPA-70.

Principle No. 4 states: "Given the range of potential fish and wildlife costs, BPA will design rates and contracts which will position BPA to achieve similarly high Treasury payment probability for the post-2006 period by building financial reserve levels and through other mechanisms." Consistent with this Principle, the expected value of reserve levels at the end of Fiscal Year (FY) 2006 was $1.2 billion in the May Proposal, without modeling Dividend Distribution Clause (DDC) distributions. In the scenarios modeled for this Supplemental Proposal which include impacts of Slice loads, the expected value of ending reserves, including modeling the DDC, is $1.1 billion.

5.3 Risk Mitigation Tools

This Supplemental Proposal incorporates the same general risk mitigation tools as the May and Amended Proposals. In addition to those tools used in the development of the May Proposal, two new tools, a Load-Based (LB) CRAC and a Safety-Net (SN) CRAC, were added in the Amended Proposal to address the higher level of risk due to system augmentation and market volatility. This Supplemental Proposal contains updates and revisions to some of these tools. *See* WP-02-FS-BPA-02A, at 266-267; WP-02-E-BPA-61, at 6-9 through 6-11; WP-02-E-BPA-69, Chapter 5.

5.3.1 Fiscal Year 2002 Start of Year Financial Reserves. Starting financial reserves include cash in the Bonneville Fund and deferred borrowing balance, if any, attributable to the generation function. The risk-adjusted expected value for starting reserves is $309 million at the beginning of FY 2002; the range is from about -$500 million to about $1,200 million.

5.3.2 Credits under the Fish Cost Contingency Fund. There has been no change in terms and conditions of access from the May Proposal. The projected balance at the beginning of FY 2002 is $158 million.

5.3.3 Planned Net Revenues for Risk. There has been no change from the May Proposal. Planned Net Revenues for Risk (PNRR) averages $98 million per year and annual internal cash flows, which are available for risk, average $22.6 million per year.

5.3.4 Cost Recovery Adjustment Clauses. The CRAC is an automatic, temporary upward adjustment to posted power prices if certain conditions occur. Although the May Proposal contained a single CRAC mechanism to deal with fluctuations in BPA's financial situation, the Amended Proposal contained three CRAC mechanisms: a LB CRAC implemented if augmentation load exceeds the amount forecast in the original 2002 rate case; a Financial-Based (FB) CRAC designed to trigger if forecasted accumulated net revenues (ANR) fall below a threshold level; and a SN CRAC, triggered by a deferral or a forecasted deferral, designed to prevent further deferrals. These three CRAC mechanisms have been adjusted since the Amended proposal, as described below.

The FB and SN CRACs apply to power customers under these firm power rate schedules: Priority Firm Power (PF) Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load (RL-02), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). The CRACs do not apply to Pre-Subscription rates or Irrigation Mitigation sales. In this Supplemental Proposal, the financial portion of the Residential Exchange Settlement is subject only to the SN CRAC, and Slice purchases are not subject to the FB or SN

CRACs, but are subject to the LB CRAC and the Slice provisions for the LB CRAC true-up. *See* Section 5.7 which describes the augmentation cost recovery methodology for both LB CRAC and Slice purchases.

5.3.4.1 Load-Based Cost Recovery Adjustment Clause. The LB CRAC is a percentage rate adjustment based on BPA's cost of augmentation. It is designed to cover the net cost of augmenting BPA's system. The Amended Proposal included a flat percentage LB CRAC to be applied throughout the rate period. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been re-designed in this Supplemental Proposal to be responsive to changes in the market price of power. One LB CRAC for each FY will appear in the Final Record of Decision (ROD). The value for each LB CRAC is preliminary and is intended to provide the customer some guidance about the possible level of the LB CRAC for each six-month period.

The preliminary LB CRAC amount will be adjusted for each six-month period of the rate period, for October through March, and for April through September. Approximately 90 days before the beginning of each six-month period, there will be a public process to determine the amount of the LB CRAC adjustment for the upcoming six-month period. The adjustment will be based on updated market prices and augmentation loads and will be applied to each customer's power bill for the six-month period.

Approximately 90 days after the end of each six-month period, BPA will true-up the LB CRAC for the prior six-month period based on actual augmentation purchases during the period. *See* Section 5.7 of this Study for a detailed discussion of the mechanics of the LB CRAC and Slice adjustments.

5.3.4.2 Financial-Based Cost Recovery Adjustment Clause. In this Proposal, the FB CRAC is structured in substantially the same way as in the May Proposal, with two notable exceptions described below. In both proposals, the FB CRAC is designed to trigger when ANRs at the end of the prior year decline below a predetermined threshold. Once triggered, the FB CRAC results in a percentage rate increase for a 12-month period, to collect revenues either sufficient to get back to the threshold level or up to a cap, whichever amount is smaller. The thresholds in the May Proposal were the prior year-end ANR equivalent of $300 million in reserves for FYs 2002 and 2003, and $500 million for FYs 2004-2006. The caps were $125 million for FY 2002, $135 million for FY 2003, $150 million for FYs 2004-2005, and $175 million for FY 2006.

This Supplemental Proposal changes the FB CRAC design in the following ways. First, FY 2002 FB CRAC will be set so that it collects whatever amount of additional ANR would have been needed to raise ANR to the threshold value for that year: the annual cap on FB CRAC revenue collection for FY 2002 were removed. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same as those set in the May Proposal, and the amount collected cannot exceed the cap in those years. Second, the timing of the collection of FB CRAC has changed. In the May Proposal, it was proposed that the determination of whether the FB CRAC threshold had been reached be based on audited actual financial data available in January, and that collection be made over a 12-month period beginning in April. By contrast, the Amended Proposal called for collecting the full amount in the four months between March and June. This proposal goes back to the 12-month collection. However, collection would begin in October following an initial determination made in August after the Third Quarter Review.

The FB CRAC increase is calculated, for FY 2002, by determining the Revenue Amount (the amount to be collected under the FB CRAC) divided by the total generation revenue (not including LB CRAC) for loads subject to CRAC for the FY in which the FB CRAC implementation begins, based on the then most current revenue forecast. For FYs 2003-2006, FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC plus Slice loads for the FY in which the FB CRAC implementation begins, based on the then most current revenue forecast. Each non-Slice product's total charge for energy, demand, and load variance will be increased by this CRAC percentage amount. Rate increases under the FB CRAC will be due in 12 monthly payments from November (for the October billing period) through October of the following year.

A true-up will be made in the second half of the year, if the prior year's audited actual net revenues differed significantly from the August forecast. The adjustment will be based on the difference between the originally-calculated FB CRAC Revenue Amount and the Revenue Amount calculated using the audited actual ANR. This difference will be divided by the generation revenue (not including LB CRAC) for the loads subject to FB CRAC, as forecasted for power deliveries for April through September. The resulting percentage will be used to adjust the FB CRAC Percentage applied to each customer's bills for April through September.

5.3.4.3 Safety-Net Cost Recovery Adjustment Clause. The third component, SN CRAC, has been revised in two ways since the Amended Proposal. The threshold is now designed to trigger when BPA forecasts a 50 percent or higher probability of missing a payment to Treasury or other creditor, or upon the occurrence of a missed payment to Treasury or other creditor. If, even with implementation of the LB and FB CRACs, the threshold is reached, the SN CRAC enables posted power rates for Subscription sales to be adjusted upward through modification of FB CRAC parameters. If the SN CRAC does trigger, BPA will propose changes to the FB CRAC parameters that will, to the extent market and other risk factors allow, achieve a high probability that the remainder of Treasury payments during the rate period will be made in full.

BPA's proposal could include changes to the Revenue Amount (the amount to be collected through the FB CRAC), the duration (the length of time the FB CRAC would be in place, which could be for more than 1 year), and the timing of collection.

The second change to the SN CRAC design is that an expedited process under Section 7(i) will be conducted in which BPA will demonstrate the need for such an adjustment. At the end of the 7(i) process, the Administrator will make a final decision on the SN CRAC based on the record. The decision will be submitted to Federal Energy Regulatory Commission (FERC) for review and confirmation.

5.4 Dividend Distribution Threshold

BPA's Supplemental Proposal retains the DDC mechanism for distributing "dividends" to certain stakeholders if Audited Accumulated Net Revenues (AANR) for the prior year reach the DDC Threshold. However, the mechanics of how the DDC will operate have changed since the publication of the Amended Proposal.

As has been the case since the May Proposal, the first $15 million of AANR exceeding the threshold will be allocated to qualifying Conservation and Renewable purposes. The remainder of any excess revenues will automatically be refunded to customers, rather than having a separate public process to determine how dividends should be allocated. The threshold for any fiscal year will be adjusted upward by the following:

In the event that:

- There has been a power system emergency during the fiscal year, and BPA has agreed to provide additional funding to mitigate the impact of the emergency operations on fish and wildlife, to the extent that BPA has not spent the additional emergency-related funding during that fiscal year, the threshold for that year will be increased by that amount; and/or

- To the extent that BPA fish and wildlife direct program costs previously budgeted for expenditure in that fiscal year were not spent in that fiscal year and a need for them continues, the threshold for that year will be increased by that amount.

Due to the automatic nature of the dividend, threshold values have been raised since the May and Amended Proposals. They are now the AANR equivalent of $1.7 billion in ending reserves for FY 2002 (for distribution in FY 2003), $1.5 billion for FY 2003, and $1.2 billion for FY 2004-2005. There will be no DDC distribution in FY 2002, the first year of the rate period. In addition, the financial portion of the Exchange settlement (900 aMW) will be counted as loads and will participate in DDC distributions.

The determination of whether the AANR exceeds the DDC Threshold will be made in January, after audited actual financial data is available. The amount of dividends is the difference between AANR and the threshold (as adjusted). The first $15 million will go to qualifying Conservation and Renewables Discount (C&R Discount) participants. The remaining amount (Power Customer DDC Amount) will be converted to a percentage by dividing it by the DDC Customer Revenue Amount, which is the total revenues paid to BPA by customers eligible for the DDC since the beginning of the rate period or the last DDC distribution, whichever is later. These revenues will include the financial portion of the Residential Exchange Settlement at the applicable Residential Load (RL) rate. This percentage will be applied to the DDC Customer Revenue Amount for each power customer subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers during the 12-month period beginning in May.

5.5 ToolKit and Generation Risk Mitigation Modeling

The ToolKit model is used to determine the probability of making all planned Treasury payments during the five-year rate period given the risks identified in two other models, Risk Analysis Model (RiskMod) and Non-Operating Risk Model (NORM), and the risk mitigation tools. Specifically, ToolKit receives two streams of net revenues and sums these to arrive at a distribution that reflects both operating and non-operating risks. RiskMod produces the stream of net revenues reflecting operating risk, whereas NORM produces the stream of net revenues reflecting non-operating risks. *See* Risk Analysis Study and Documentation, WP-02-E-BPA-03 and, WP-02-E-BPA-03A for a description of RiskMod and NORM and the 2002 Final Power Rate Proposal Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 268-270 for a fuller description of the modeling system.

Another version of the ToolKit model is used to produce a distribution of net revenues for the remaining year of the current rate period (FY 2001). This version uses the output of the Short-Term Evaluation and Analysis Model (STREAM) model used in the 1996 Rate Case to assess operating risks for FY 2001, and a current rate period version of NORM to assess the potential impact of two non-operating risks in FY 2001. For the Supplemental Proposal, the output of STREAM was modified to better reflect BPA's current outlook.

For the Supplemental Proposal, ToolKit was calibrated to a lower FY 2002 starting reserves value than in the May Proposal. In December, a new set of 300 starting reserves values were generated by ToolKit, calibrated to forecasts reported in BPA's Third Quarter Review for FY 2000. New values for the Supplemental Proposal were derived by operating the version of the current period ToolKit used for the Amended Proposal, but subtracting $600 million from the net revenues for FY 2001 in each of the 300 games. Additionally, the $50 million deferral floor was turned off so that the FY 2002-2006 ToolKit would be reading reserves values that could include negative cash balances, for example if BPA exercised a note with Treasury to cover cash requirements and needed to pay off the note. It is this amount that the uncapped FY 2002 FB CRAC would have to pay off to reestablish a $300 million ending reserves level. FY 2002 starting reserve balances in the 3,900 games averaged $308.7 million.

- Both the RiskMod and NORM distributions for the FY 2002-2006 period were modified to reflect two sets of changes from the May Proposal. First, because the percentage of system output to be purchased by Slice customers is now known fairly well, the net revenues deviation in both RiskMod and NORM were adjusted to reflect the 28.29 percent of operating and non-operating risks absorbed by the Slice customers. The net revenues developed in RiskMod also reflected a revised forecast of market prices, and larger system augmentation required to meet the loads placed on BPA by customers who have signed subscription contracts.

- Two components of CRAC were modeled in ToolKit.
  1. The LB CRAC is designed to cover the net cost of augmenting BPA's system to meet the additional 1,518 aMW of load placement. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been designed to be responsive to changes in the market price of power. The internal logic of the ToolKit was modified in order to model the LB CRAC as it is currently designed. New inputs were added: the annual market price weighted by BPA's monthly augmentation need; the net costs of acquiring that augmentation; and the revenue bases for the FB and LB CRACs. Additional outputs were calculated to show statistics on the LB and FB CRACs.

2. The FB CRAC is structured and modeled in substantially the same way as in the May Proposal with two notable exceptions. First, the annual cap on new revenue collection for FY 2002 was removed: ToolKit now models FY 2002 FB CRAC so that it collects whatever amount of additional revenues are needed to raise reserves to the $300 million threshold value for that year, and the amount to be collected is not reduced by the fraction that Slice load makes up of the total Slice loads and loads subject to the FB CRAC. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same. Second, the ToolKit reflects the change in the timing of the collection of FB CRAC. Collection would begin in October following an initial determination, based on forecasts, made in August after the Third Quarter Review.

- Because the value of the Investor-Owned Utility Residential Exchange Program Settlement (REP Settlement) has been revised to reflect a market price of $38 rather than $28.1 per megawatthour (MWh), an additional annual expense of $56 million was entered, representing the additional costs less the 28.29 percent share of that expense that would be paid by Slice customers.

- SN CRAC was not modeled in ToolKit because its parameters will not be fully defined until it triggers and therefore cannot be modeled. Additionally, if it could be modeled, it would not significantly affect the calculation of TPP as TPP has historically been defined. TPP reflects the probability that no Treasury payments ill be missed during the five-year rate period. The SN CRAC is not likely to trigger in time to prevent a missed Treasury payment, but is instead more likely to help avoid a second miss.

Because the DDC is now designed to operate automatically, these thresholds can be modeled straightforwardly in ToolKit as a “reverse CRAC.” The DDC is modeled so that it triggers when cash reserves exceed $1.7 billion in FY 2003, $1.5 billion in FY 2004, and $1.2 billion in FY 2005-2006. There will be no DDC distribution in FY 2002, the first year of the rate period.

When implemented, the DDC will be triggered by actual ANR values comparable to the threshold expressed in terms of cash. These AANR equivalents have been recalibrated based on updated financial data. The threshold is $1,110 million for the end of FY 2002 (*i.e.,* for possible distribution starting in FY 2003), $852 million for the end of FY 2003, $519 million for the end of FY 2004, and $519 for the end of FY 2005.

5.6 Risk Mitigation ToolKit Results

For the Supplemental Proposal, ToolKit was run a total of 12 times. This was done to demonstrate the impacts of different levels of market price and load reduction on the amount of revenues to be collected under the LB CRAC and to demonstrate that the Supplemental Proposal does not shift additional costs to non-Slice customers. The Slice Cost Shift Analysis is presented in Section 5.8 below. The table below makes comparisons of the relative rate impacts of the LB CRAC, the FB CRAC, and the DDC on Slice and non-Slice customers given the six different combinations of FY 2002 price levels and load reduction assumptions.

Table 5-1: Treasury Payment Probability Analyses

ToolKit run	*1*	*2*	*3*	*4*	*5*	*6*
FY 2002 market price	140	140	210	210	315	315
Load reduction (relative to Amended Proposal)	0	1500	0	1500	0	1500
Treasury Payment Probability	82.7%	82.7%	85.1%	85.1%	85.9%	85.9%
Expected value ending 2006 reserves	1,045	1,046	1,116	1,117	1,156	1,157
2002 net augmentation cost	2,635	1,029	4,180	1,626	6,497	2,521
2002-2006 total net augmentation cost	5,194	1,760	7,485	2,591	10,933	3,839
2002 augmentation rate impact, Slice	161%	76%	255%	121%	396%	187%
2002 augmentation rate impact, non-Slice	161%	76%	255%	121%	396%	187%
2002 augm. + FB CRAC impact, non-Slice	172%	92%	267%	136%	408%	202%
2002-2006 ave augm. rate impact, Slice	63%	26%	91%	38%	133%	57%
2002-2006 ave augm. rate impact, non-Slice	63%	26%	91%	38%	133%	57%
2002-2006 ave augm. + FB CRAC impact, non-Slice	67%	31%	94%	43%	136%	61%
2002-2006 augm. + FB CRAC + DDC impact, non-Slice	59%	21%	79%	23%	108%	25%
2002-2006 ave frequency of FB CRAC	27%	27%	22%	22%	20%	20%

Table 5-1 makes comparisons of the relative rate impacts of the LB CRAC, the FB CRAC, and the DDC on Slice and non-Slice customers given the different FY 2002 price levels and load reduction assumptions. The table summarizes the results of running ToolKit for six distinct combinations of conditions;

	sets of			load			Slice			ToolKit
3	market	X	**2**	reduction	X	**2**	sales	=	**12**	Alternatives
	prices			levels			levels			

Where:

- market price levels for FY 2002 are set at $140, $210, and $315/MWh;
- load reduction levels are either 0 or 1,500 aMW; and
- the Slice sales levels are with or without Slice.

The table compares Five-Year TPP, first year rate increase due to LB and FB CRAC, average rate increase due LB and FB CRAC, average rate increase due to LB and FB CRAC including the offsetting effects of the DDC, and FY 2006 average ending reserves. These values are reported for 'Slice' (2000) and 'without Slice' (0) Options for each of six specific market price/load reduction combinations. (Note: Unlike the May and Amended Proposals, the ToolKit runs represented in the tables reflect the effects of the DDC.) Attachments 2-13 to this documentation present the summary ToolKit outputs for each of the 12 Alternatives modeled.

5.7. Load-Based Cost Recovery Adjustment Clause Methodology

5.7.1 Introduction and Overview. This section describes BPA's LB CRAC Methodology (Proposed Methodology) for the Supplemental Proposal. The Proposed Methodology describes how BPA is proposing to recover augmentation costs on loads subject to the LB CRAC which includes Slice.

Section 5.7.2 addresses the rationale for the proposed changes. Section 5.7.3 summarizes the approach to recovering augmentation costs in the May and Amended Proposals. Section 5.7.4 explains how BPA will determine the Monthly Augmentation Amounts (AAMT). Section 5.7.5 describes BPA's Proposed Methodology. Section 5.7.6 elaborates on BPA's proposed approach to determining the amount of over- or under-collection of augmentation costs from application of the LB CRAC.

5.7.2 Purpose of the Proposed Modifications. In the May Proposal, BPA used the five-year flat block forecast of $28.10/MWh to calculate BPA's augmentation costs. Using a price forecast has the inherent problem of being an imprecise approximation of prices, since the actual prices will rarely reflect the forecast of prices. In the May Proposal, BPA was willing to accept the risk associated with using a price forecast in calculating augmentation costs because the power market was perceived to be relatively stable. However, because the wholesale power market is significantly higher and more volatile than it was when the forecast in the May Proposal was developed, the use of a forecast to price the augmentation presents a significantly greater financial risk for BPA. These market changes are described in Conger, *et al.*, WP-02-E-BPA-71. BPA is now proposing a methodology that will allow for biannual changes in rates subject to LB CRAC to provide a method that will more directly allow augmentation costs to be reflected in rates from all purchasers' loads subject to the LB CRAC. This approach is a redesign of both the LB CRAC and Slice Augmentation Cost methodology that appeared in the Amended Proposal.

5.7.3 Approach to Augmentation Cost Recovery in the May Proposal and the Amended Proposal. In the May Proposal, BPA included expected augmentation costs in the revenue requirements contained in that proposal. In turn, the base rates reflected these augmentation revenue requirements. BPA's Amended Proposal proposed a series of CRAC mechanisms for non-Slice purchasers. In that proposal, increments in augmentation costs in excess of those included in the May Proposal would have been covered by these CRAC mechanisms for non-Slice purchasers. A separate method was proposed to recover the proportionate share of BPA's augmentation costs from Slice purchasers.

In this Supplemental Proposal, BPA is modifying the LB CRAC and Slice augmentation methodology so that they are very similar in design. Through a series of biannual adjustments to the forecast of augmentation costs and after-the-fact true-up adjustments to the forecast based upon subsequent events, BPA is attempting to deal with the risks associated with augmentation expenses in the current market. The major difference between the treatment of the Slice and non-Slice customers will be the manner in which the after-the-fact true-up is conducted. Because Slice purchasers assume certain risks and take on certain obligations directly through the purchase of the product, the manner in which the adjustment is made is reflected in this Supplemental Proposal.

5.7.4 Establishing the Monthly Augmentation Amount. The Monthly Augmentation Amount (AAMT) is the amount of augmentation that BPA proposes to use to calculate the LB CRAC percentage. Table 5-2 shows the AAMT that will be used to determine the LB CRACs that will appear in the Final ROD. For a given month, the AAMT is a constant for all hours in that month.

Table 5-2: Preliminary Monthly Acquisition Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2002	2209	2508	2754	2783	2725	2460	2905	3258	3200	2322	2321	2228
FY 2003	2099	2380	2615	2550	2489	2229	2652	3009	2966	2082	2079	1990
FY 2004	1854	2141	2364	2432	2383	2119	2572	2928	2884	2002	2003	1917
FY 2005	1902	2056	2275	2338	2276	2062	2511	2866	2795	1853	1859	1774
FY 2006	1725	2035	2253	2663	2601	2388	2615	2775	2701	2158	2163	2077

Over the rate period, BPA will determine if the AAMT amounts needed are different from those in Table 5-2. Documentation and additional explanation for the calculation of the numbers in Table 5-2 is contained in WP-02-E-BPA-69.

5.7.5 Proposed Methodology. The discussion in this section describes the calculations BPA is proposing to determine the LB CRAC.

5.7.5.1 Application. The LB CRAC applies to the following rate schedules: The LB CRAC applies to power customers under these firm power rate schedules: PF Preference, Exchange Program, and Exchange Subscription, Industrial Firm Power (IP-02), including under the IPTAC and Cost-Based Index Rate, Residential Load (RL-02), New Resource Firm Power (NR-02), and Subscription purchases under FPS. The CRAC does not apply to Pre-Subscription rates, the financial portion of the Residential Exchange Settlement, or Irrigation Mitigation sales. The LB CRAC does apply to Slice purchases.

The LB CRAC will apply to a purchaser's bill for purchasers under these rate schedules. The first LB CRAC will apply to the six-month period beginning October 2001 and the last LB CRAC will apply to the six-month period beginning April 2006.

5.7.5.2 Process. An LB CRAC percent for each FY will be presented in the Final ROD. These LB CRAC percent will be referred to as the preliminary LB CRAC percent. Each is intended to provide the customer some guidance about the possible level of the LB CRAC percent for the future six-month periods in the rate period. Each preliminary LB CRAC percent will be established using the methodology described in WP-02-E-BPA-68.

On or about 90 days prior to the beginning of each six-month period, BPA will establish the LB CRAC percent for the upcoming six-month period. The LB CRAC percent will be determined using the methodology described in WP-02-E-BPA-68. When BPA develops the LB CRAC percent, BPA will determine what data require updating from that used to set the LB CRAC percents in the Final ROD.

Approximately 90 days after the end of the most recent six-month period, BPA will determine what over- or under-collection of augmentation costs occurred during the most recently completed six-month period. This determination will be made using the methodology described in WP-02-E-BPA-68. As a part of reaching this determination, BPA will determine what data require updating from that used to set the LB CRAC percent.

5.7.5.3 Calculations that are performed both before the beginning of a six-month period and after the end of the same six-month period. This section describes BPA's proposed approach to calculations that are both a part of determining the LB CRAC percent before the beginning of a six-month period as well as the determination of whether actual LB CRAC revenues collected during the six-month period are in excess of actual Net Augmentation Cost (NAC) or fall short of actual NAC for the six-month period.

5.7.5.3.1 Determining the Monthly Augmentation Cost. While AAMT is flat for a given month (but may vary in amount between months), the cost of meeting this AAMT will likely vary by diurnal period within a month.

5.7.5.3.1.1 Determining the Total Cost of Acquisition Pre-Purchases. BPA will maintain records of Acquisition Pre-Purchases (APP) made to meet the AAMT for the month. These data will be maintained in MWh, megawatt (MW), and/or aMW (and their associated costs) for each month separately for Heavy Load Hours (HLH) and Light Load Hours (LLH) and their associated costs.

As BPA makes acquisitions to meet AAMT, the shape of the augmentation and cost, by diurnal period by month, are noted for the term of the acquisition. Acquisitions made at least 120 days in advance of the month in which an LB CRAC takes effect are included in the augmentation tally, irrespective of the duration of that augmentation purchase.

Here are several examples.

Example 1: In May 2001, BPA enters into an acquisition for 100 MW HLH power for six months at $200/MWh.

This acquisition would be entered into the augmentation totals in the June 2001 calculation of the LB CRAC percent that will apply for the six-month period beginning October 2001.

Example 2: BPA enters into an acquisition on May 30, 2001, for 500 aMW for 12 hours at a price of $500/MWh for delivery in October 2001.

These costs will be treated exactly the same as those in Example 1.

Example 3: BPA enters into an acquisition on June 30, 2001, of 100 aMW HLH power at $120/MWh for a 12-month period beginning November 1, 2001.

Since this purchase was not made 120 days prior to October 1, 2000, the cost of this pre-purchase will not appear in the costs used to determine the LB CRAC percent that will apply beginning October 1, 2001. The cost of this pre-purchase does qualify as an APP for meeting AAMT used to determine the LB CRAC percent that will be applied beginning April 1, 2002 and October 1, 2002. After-the-fact, they will be included in the costs used to determine the LB CRAC revenue over- or under-recovery for the following periods: (a) October 1, 2001–March 30, 2002; (b) April 1, 2002–September 30, 2002; and (c) October 1, 2002–March 30, 2003.

After the close of a six-month period, BPA will determine what the diurnal augmentation cost (DIURNALAC) would have been had the cut-off for a purchase to be considered an APP was 120-days before each separate month rather than 120-days before the six-month period. This determination will affect the calculation of DIURNALAC.

In addition, BPA will also calculate DIURNALAC using a rule of five days before the end of the month rather than 120 days before the end of the month. This separate determination of DIURNALAC will enter into the Total Cost of Acquisition Pre-Purchases (TCAPP) that is used in determining the over- or under-collection of costs only from non-Slice purchasers, and this is discussed further in Section 5.7.6.3.

5.7.5.3.1.2 Determining the Diurnal Augmentation Costs. One of the following equations will be used to determine the augmentation costs for each separate diurnal period. The three equations are as follows:

1. If APP > AAMT, Then DIURNALAC = (AAMT/APP) * TCAPP
2. If APP = AAMT, Then DIURNALAC = TCAPP
3. If APP < AAMT, Then DIURNALAC = TCAPP + [(AAMT-APP) * PRICE * Hours]

Where:

AAMT = Augmentation Amount (aMW)
APP = Acquisition Pre-Purchases (aMW)
TCAPP = Total Cost of Acquisition Pre-Purchase ($$)
DIURNALAC = Diurnal Acquisition Cost ($$)
PRICE = Price established 120 days prior to the month.

Example: *Calculate the diurnal cost of meeting AAMT for October 2001 to determine the LB CRAC percent to go into effect on October 1, 2001. Assume that by June 1, 2001: BPA has entered into agreements for 1,000 aMW HLH power for six months at $200/MWh and 500 aMW of LLH purchases at $120/MWh also for six months. AAMT equals 2,209 aMW for October 2001. Five-day price is $60/MWh on HLH and $40 on LLH. The 120-day price for HLH is $80/MWh and $60/MWh for LLH.*

This acquisition would be entered into the augmentation totals for the October 2001 calculation that is a part of the LB CRAC percent for the six-month period beginning October 2001. Here, APP for HLH = 1,000 and APP for LLH = 500. CAPP for HLH = 100*200 *HLH Hours, and CAPP for LLH = 500*120 *LLH Hours. These amounts and costs will be input into formula 3 above for both HLH and LLH since AAMT = 2,209 aMW is greater than the APP for both HLH and LLH. Since the HLH and LLH APP<AAMT, the difference between APP and AAMT is priced at the Price established at the end of May.

This same procedural will be performed for each diurnal period for each month. All of the separate DIURNALAC for a six-month period will then be summed to determine the Total Pre-Purchase Cost (TCAPP) for the six-month period.

In this example, the five-day Price for Augmentation not pre-purchased (PRICE) was not used. When DIURNALAC is determined before the beginning of a six-month period, the 120-day PRICE will be used. When these calculations are being performed after the close of that same six-month period, the 120-day PRICE will again first be used. This set of DIURNALAC will be used in subsequent steps for determining the amount of augmentation costs Slice and non-Slice cover. Then, after the amount of Slice and non-Slice LB CRAC revenue over- or under-payment has been established, a separate analysis will be performed using the five-day price in place of the 120-day price in this above example. This amount of DIURNALAC will then result in a different amount of TAUGC in the next step.

5.7.5.3.1.3 Calculating the Total Augmentation Cost. The TAUGC is the sum of TPPC and all monthly option or monthly load buydown costs. When TAUGC is calculated before the beginning of the upcoming six-month period, one TAUGC will be determined using the 120-day rule for determining what qualifies as an APP and the 120-day PRICE for equation 3 in Section 5.7.5.3.1.2.

After the close of this same six-month period, a new TAUGC will be determined that will be used in determining the amount of LB CRAC revenue over- or under-collection from both Slice and non-Slice. When this TAUGC is determined, the 120-day rule will again be used. A separate TAUGC will also be determined using a five-day rule for defining what constitutes a pre-purchase and the value for PRICE. The TAUGC that results from this replacement of the 120-day rule with the five-day rule will result in a difference between the TAUGC calculated after the close of the six-month period using the 120-day rule and the TAUGC calculated after the close of the six-month period using the five-day rule. Section 5.7.6.3 describes how this difference is assigned to non-Slice purchasers.

This difference between the after-the-fact calculation of TAUGC using the 120-day rule and the after-the-fact calculation of TAUGC using the five-day rule represents the change in cost of meeting AAMT for the six-month period. This cost change may be positive or negative. All of this cost change is an adjustment to the cost responsibility of non-Slice purchaser's and the difference between these two calculations is referred to as Difference in Net Augmentation Cost (NACDIFF) appearing in Section 5.7.6.2.

5.7.5.3.2 Calculating the Monthly Augmentation Resale Revenues. Monthly Augmentation Resale Revenues (MARR) represents a monthly amount of revenue to BPA on sales from augmentation quantities included in the May Proposal. For augmentation quantities already included in the May Proposal, as defined in Sales of Existing Augmentation Quantity (SALESMAYAUG), resale revenues are to be determined using a rate of $28.10/MWh. For augmentation quantities above those included in the May Proposal, refined as Sales of New Augmentation Quantity (SALESNEWAUG), resale revenues are to be determined using a rate of $19.10/MWh. The formula is as follows:

MARR = (SALESMAYAUG* $28.10) + (SALESNEWAUG * $19.10)

Where:

SALESMAYAUG = Resale of augmentation of 1,282 aMW not purchased by August 1, 2000, plus the amount of energy at $28.10/MWh melded into the Direct Service Industrial rate and collected through IP sales.

SALESNEWAUG = Resale of augmentation quantity above SALESMAYAUG.

Before publishing the Final ROD, BPA will determine if SALESMAYAUG and SALESNEWAUG need updating. BPA will also update these numbers when determining any actual LB CRAC revenue over- or under-collection.

SALESMAYAUG and SALESNEWAUG may vary due to load loss, including buydown. Such reductions in loads translate into reductions in acquisitions which translates into reductions in acquisition resale revenue.

5.7.5.3.3 Calculating Total Augmentation Resale Revenue. Once a MARR is determined for each month, they will be summed to determine Total Augmentation Resale Revenue (TARR) for the six-month period.

5.7.5.3.4 Calculating Net Augmentation Cost. Net Augmentation Cost (NAC) is the difference between TAUGC and TAAR, NAC = TAUGC – TARR. When this calculation is performed before the six-month period, NAC represents the amount of additional revenues BPA expects to need to collect in the upcoming six-month period. After the close of this six-month period, BPA will determine the actual amount of additional revenues required to meet actual augmentation costs for the six-month period.

5.7.5.3.5 Calculating Slice Revenues from Loads Subject to Cost Recovery Adjustment Clause and Non-Slice Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause. These amounts represent the LB CRAC revenues from loads subject to the LB CRAC. Before a six-month period, they are the revenues BPA expects to collect from the expected loads subject to the LB CRAC, at the rates in the May Proposal. After the six-month period, they are the amount of revenue BPA would receive using actual loads during the six-month period and rates from the May Proposal. All these revenue numbers are net of both the C&R Discount and the Low Density Discount (LDD).

Before the beginning of the six-month period, the values calculated for Slice Revenues from Loads Subject to CRAC (REVw/oLBC(S)) and Non-Slice Revenues from Loads Subject to the LB CRAC (REVw/oLBC(NS)) are used to determine the LB CRAC percent for the six-month period. Calculation of the LB CRAC percent must reflect BPA's best estimate of sales subject to the LB CRAC during the six-month period.

Recall that the LB CRAC percent is not recalculated after the close of the six-month period. At that point in time, BPA will determine what LB CRAC revenue over- or under-collection actually occurred during the six-month period. To make this determination, BPA must know what revenues actually were collected using the actual LB CRAC loads during the six -month period and the rates from the May Proposal. The values of REVw/oLBC(S) and REVw/oLBC(NS) are used in determining actual revenue over- or under-collection.

5.7.5.3.6 Calculating Total Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause. Total Revenues without Load-Base Cost Recovery Adjustment Clause (TREVw/oLBC) is the sum of REVw/oLBC(S) and REVw/oLBC(NS). Total Revenues with Load-Based Cost Recovery Adjustment Clause (TREVw/LBC) is the sum of REVw/LBC(S) and REVW/LBC(NS).

5.7.5.4 Calculating the Load-Based Cost Recovery Adjustment Clause Percent. This section presents the calculation of the LB CRAC percent. This calculation is only performed before the beginning of the upcoming six-month period. It is not performed as a part of the after-the-fact calculations of a six-month period because the after-the-fact calculations are performed to determine what LB CRAC over- or under-collection actually occurred during the six-month period. Determining whether there is any over- or under-collection does not depend on re-calculating the LB CRAC percent calculated before the beginning of the six-month period.

5.7.5.4.1 Calculating the Load-Based Cost Recovery Adjustment Clause Percent. One LB CRAC percent is determined by spreading the NAC across the total LB CRAC revenue received from all loads subject to the LB CRAC during the six-month period, where this revenue is determined using the rate from the May Proposal, and the forecasted loads for the six-month period (TREVw/oLBC). As a result, the LB CRAC percent represents the percent increase in revenues above the revenues BPA anticipates without the LB CRAC that is expected to be required to meet NAC.

5.7.5.4.2 Calculating the Adjustment for Slice and Non-Slice Adjusted Rates [REVRATE(S) and REVRATE(NS)]. To determine the charge to be placed on Slice and non-Slice bills to recover augmentation costs, the NAC has to first be apportioned between Slice and non-Slice purchasers. Then, the resulting apportionment is converted into a charge.

Recall that the LB CRAC percent represents the percent change in revenues required to cover the expected value of NAC. The increment in revenues required to cover NAC for Slice is then the

LB CRAC percent times the revenue expected from Slice purchaser's for the upcoming six-month period, where revenue expected from Slice is calculated using expected sales for that upcoming period and the rate in the May Proposal. The revenue estimate used in this calculation has C&R Discount and any LDD subtracted. The Slice rate from the May Proposal is then added to this increment in revenue and the result is the forecasted amount of total revenue required from Slice to cover the Slice portion of the expected NAC for the upcoming six-month period. This amount is then divided by 100, and the result is the new Slice rate in dollars per 1 percent Slice.

The non-Slice calculation is similar. First, the LB CRAC percent is multiplied by the revenue expected from non-Slice purchaser's for the upcoming six-month period calculated using expected sales for that upcoming period and the rates in the May Proposal. The revenue estimate used in this calculation has C&R Discount and any LDD subtracted. Next, the forecasted revenues from non-Slice sales, including C&R Discount and any LDD, are added to the increment in revenue from non-Slice sales. This sum is then the forecast of the new amount of revenues required from non-Slice for the six-month period. This new revenue amount is then divided by the forecast of non-Slice revenues for the six-month period using forecasted loads and rates from the May Proposal but including C&R Discount and LDD. This ratio results in a percentage multiplier that is then applied to rates in the May Proposal. The product of this percentage multiplier to the rates in the May Proposal results in new rates to be applied to non-Slice loads subject to the LB CRAC in the upcoming six-month period.

5.7.5.4.3 Adjusting a Purchaser's Bill. For both Slice and non-Slice, the adjusted rates replace the rates from the May Proposal that would have otherwise appeared on the purchaser's bill for loads subject to the LB CRAC.

5.7.6 Calculating the Amount of Over- or Under-Recovery of Augmentation Costs through the Load-Based Cost Recovery Adjustment Clause. The calculation in this section is performed only once, after the end of the most recently completed six-month period, and the result is the amount of money that is to be either refunded to or collected from individual Slice and non-Slice purchasers. Determining the amount of over- or under-collection and adjusting the purchaser's bill is a four-step process. Each step is discussed below.

5.7.6.1 Calculate the Load-Based Cost Recovery Adjustment Clause revenues that were actually collected during the six-month period separately for Slice and Non-Slice. The result of this step is the actual amount of LB CRAC revenue collected from purchasers for the recently completed six-month period. This is done separately for Slice as a group and non-Slice as a group. For example, the actual amount of LB CRAC revenue received by BPA for Slice is the difference between the revenue received on loads during the six-month period (with the LB CRAC applied) and the revenue that would have been received using the actual loads subject to LB CRAC for the six-month period and the rates without the LB CRAC applied. For purposes of this calculation, the load amounts do not vary between the with LB CRAC case and the without LB CRAC case. Keeping the load amounts the same, BPA is able to identify the amount of revenue received from Slice purchasers that is attributable to the LB CRAC, referred to as Revenues Actually Received by BPA from the LB CRAC (Slice) (LBCREVREC(S)). This same procedure is performed for non-Slice to determine Revenues Actually Received by BPA from the LB CRAC (non-Slice) (LBCREVREC(NS)).

5.7.6.2 Calculate the Load-Based Cost Recovery Adjustment Clause revenues that are needed to cover the actual augmentation costs, divided between Slice and Non-Slice based on actual Load-Based Cost Recovery Adjustment Clause Revenues. It is likely that the amount of revenue actually collected from the LB CRAC (determined in the previous step) will not equal the amount of LB CRAC revenue that is actually required to cover actual NAC for the six-month period. Before this determination can be made, it is necessary to determine how much LB CRAC revenue was actually required to cover the actual NAC for the most recently completed six-month period. This calculation will be performed separately for Slice and non-Slice purchasers of loads subject to the LB CRAC.

Since BPA will, by the time this step is reached, have determined the actual NAC as part of the calculations for the most recently completed six-month period, it is this value of NAC that is then apportioned between Slice and non-Slice purchasers. This step performs this apportionment.

To determine the amount of actual NAC to apportion to Slice actual NAC is multiplied by the ratio of: (a) revenue received from Slice purchaser's using actual loads for the six-month period and Slice rate with the LB CRAC applied divided by total revenue received from load subject to the LB CRAC from both Slice and non-Slice using actual loads for the six-month period; and (b) rates with the LB CRAC applied. The result of this calculation is referred to in the General Rate Schedule Provisions (GRSPs) as Actual LB CRAC Revenue Required (Slice) (ACTUALLBCREVREQ(S)). This same calculation is performed separately for non-Slice and the result is referred to as Actual LB CRAC Revenue Required (non-Slice) (ACTUALLBCREVREQ(NS)).

After these calculations are performed, these is one additional adjustment that is made to the value of ACTUALLBCREVREQ(NS). This is the calculation referred to in Section 5.7.5.3.4 where after the close of a six-month period one NAC is determined using the 120-day rule and a separate NAC is determined using the five-day rule. The difference between these two calculations, referred to in the GRSPs as Difference in Net Augmentation Cost (NACDIFF), is added to the value for ACTUALLBCREVREQ(NS).

With the completion of these calculations the amount of revenue actually required from Slice purchaser's as a group and non-Slice purchaser's as a group has been determined.

5.7.6.3 Calculate the difference between the actual Load-Based Cost Recovery Adjustment Clause revenue received and the actual Load-Based Cost Recovery Adjustment Clause revenue required to cover actual augmentation costs. In this step, the difference between the LB CRAC revenue actually collected and the LB CRAC revenue that is actually required to cover NAC for the six-month period just ended are compared. If the actual LB CRAC revenue collected exceeds what is required, purchasers of products subject to the LB CRAC will receive a refund. If the actual LB CRAC revenue collected is less than the revenue required, purchasers of products subject to the LB CRAC will be face additional charges. This over- or under-collection of LB CRAC revenues will be apportioned to individual purchaser's to determine the actual adjustment to each purchaser's bill.

5.7.6.4 Adjusting a Purchaser's Bill. There will be a separate line item on the bill for a refund or additional charges to cover actual augmentation costs. The same method is applied to both Slice and non-Slice when determining the amount of any refund or charge.

In 5.7.6.3, the amount of any over- or under-recovery was apportioned between Slice purchasers as a group, and non-Slice purchasers as a group. These separate revenue over- or under-collection amounts for Slice and non-Slice must now be apportioned to individual purchasers of Slice and non-Slice. The "apportionment factor" that will be used is the ratio of the revenues actually collected from a specific Slice customer the LB CRAC revenues received from all Slice customers. In this calculation, the revenues collected from a specific customer are determined using the customer's actual loads subject to the LB CRAC for the six-month period and the rates with the LB CRAC, and subtracting out any C&R Discount or LDD credits. The LB CRAC revenues received from all Slice customers is simply the sum of the revenues collected from individual customers, as that is defined in this section. This same calculation is also performed for each non-Slice customer.

Any over- or under-collection adjustments to an individual customer's bill will appear as a separate line item in the month following finalization of these calculations by BPA, which will occur on or about 90 days after the close of the six-month period for which these calculations are performed.

5.8 Slice Cost-Shift Analysis

An important design criterion of the Slice product has been that the availability and purchase of Slice products must not shift any costs or risks to non-Slice customers or to the Treasury. To ensure that BPA's Supplemental Proposal has not increased the costs or risks for other customers or for Treasury in light of the changed power market outlook, BPA compared several statistics for six pairs of cases.

The first case in each pair is a "Slice Case," which is BPA's Supplemental Proposal. In this case the Slice sales are 2,000 aMW. The second case in each pair is a "No-Slice Case," in which estimates of the products BPA's preference customers would choose if Slice were not available are made.

We are describing the Supplemental Proposal through the use of a set of analyses instead of a single analysis because of the design of the LB CRAC. The LB CRAC in this Proposal is a formula rather than a percentage fixed in the Final ROD. The formula is based on BPA's net cost of augmentation, which depends on the remaining augmentation need (*i.e.*, the augmentation need for which BPA does not have purchases in place) and a market-based forward indicator of future power prices. In today's electricity world, both of those are highly volatile. To avoid basing another proposal on a single estimate of forward prices and remaining augmentation, BPA is presenting a proposal developed with its customers in which the LB CRAC will adjust to market prices and BPA's augmentation needs. Since we cannot predict what the forward prices and remaining augmentation needs will be, we are presenting a range of possibilities to illustrate the way in which the LB CRAC and FB CRAC will work to mitigate augmentation costs and financial risks respectively.

Two levels of augmentation load quantity are considered: one in which there is no load reduction from the amounts forecast in BPA's Amended Proposal, and one in which total firm load is 1,500 aMW lower. Three different market levels are considered: one is a medium case corresponding to forward prices as of late January and early February 2001; to show the impacts of higher prices, one market level has been set to be 50 percent higher for 2002 and 2003; and to show the impacts of lower prices, the third market level uses prices two-thirds of the levels of the first one for 2002 and 2003. In all three market levels the market prices for 2004 through 2006 are the same as the Aurora prices BPA used in its Amended Proposal.

Two augmentation load levels and three market levels yield six combinations; thus, the six pairs of Slice/No-Slice runs in the cost shift study.

5.8.1. Summary of the Analysis. The "No-Slice Case" is a risk analysis that assumes there is no Slice offered and that Slice customers would purchase other requirements products from

BPA. On a customer-specific basis, BPA has estimated what products the Slice customers would have chosen in the absence of Slice (*See* Conger, *et al.*, WP-02-E-BPA-71, Chapter 3).

In the No-Slice cases, BPA's total loads are higher over the five-year period by approximately 93 aMW (*See* Conger, *et al.*, WP-02-E-BAP-71). This load increase is the result of some Slice customers selecting other requirements products that provide for load growth (Slice does not provide for load growth). This increases the magnitude of the LB CRAC revenue amount and also changes the load basis over which the LB CRAC is spread in comparison to the Slice cases.

The non-operating risks are different between the two cases. As in the Amended Proposal, in the Supplemental Proposal Slice customers are modeled as absorbing 28.29 percent of the non-operating risks (*See* Chapter 2.5 of WP-02-E-BPA-67). In the No-Slice Case, BPA faces 100 percent of the non-operating risks. In the No-Slice Case, the non-operating risk values are identical to those of the May Proposal. The market prices used in the two risk analyses are the same as are the base rates. BPA determined whether shifts of costs or risks to non-Slice customers occurred by examining the whether the costs faced by non-Slice customers are higher in the Slice case than in the No-Slice Case in each pair of cases. However, BPA is also concerned about the potential impact on TPP between the No-Slice Case and the Amended Proposal, and the risk analysis also included this issue by examining whether the TPP is lower in the Slice case than in the No-Slice Case for each pair of cases.

Since the base rates for non-Slice customers are the same in the Slice and No-Slice cases, BPA compared payments for the FB and LB CRACs in the two analyses to determine if there are any cost shifts to non-Slice customers. If the sum of the expected value of the two CRAC percentage increases is higher with Slice than without, it would indicate that the offering of the Slice product, with the changes in the risk mitigation and augmentation described in the Supplemental Proposal, causes non-Slice customers to pay more, and therefore a cost shift has occurred.

Following from this, the expected value of the total revenue the non-Slice customers would have to pay with and without Slice is the one of the best estimates of the cost of power for non-Slice customers. The other statistic that can be looked at is the average net rate increase non-Slice customers face, taking into account the expected value of DDC distributions. Since the financial portion of the IOU settlement is also eligible for the DDC, the revenue basis over which the DDC is spread differs from the revenue basis of the FB CRAC. Since the first $15 million of each year's DDC distribution, if any, is pledged to conservation and renewables, this has been taken into account.

BPA has long used the TPP as the measure of risk to the Treasury, BPA's primary long-term creditor. As long as the Slice case has a five-year TPP as high as the TPP of the No-Slice Case, BPA considers that the risk to Treasury is no higher with Slice than without.

5.8.2 Results of the Six Pairs of Slice/No-Slice Cases. Six pairs of cases are presented in Table 5.8-1. For each combination of load reduction level and market price, the left of the two sets of results is for the Slice case, and the right set is the No-Slice Case. In each of the six cases, the expected value of the total of the FB CRAC percentage and the LB CRAC percentage is no higher in the Slice case than in the No-Slice Case. In each of the six cases, the TPP is no lower in the Slice case than in the No-Slice Case.

Table 5-3: Cost Shift Analysis Summary

		No Load Reduction Slice Product Sales		**1500 MW Load Red** Slice Product Sales	
		2000 aMW	0 aMW	2000 aMW	0 aMW
Ave 2002 Market = $140	TPP (5-year)	82.7 %	77.6 %	82.7 %	77.4 %
	1st yr. rate increase	172%	179%	92%	93%
	Ave rate increase	67%	71%	31%	33%
	Ave rate inc w/DDC	59%	61%	21%	21%
	Ave 2006 End Res	$1045	$1124	$1046	$1116
Ave 2002 Market = $210	TPP (5-year)	85.1 %	80.6 %	85.1 %	79.9%
	1st yr rate increase	267%	279%	136%	141%
	Ave rate increase	94%	100%	43%	44%
	Ave rate inc w/DDC	79%	82%	23%	24%
	Ave 2006 End Res	$1116	$1178	$1117	$1112
Ave 2002 Market = $315	TPP (5-year)	85.9 %	81.1%	85.9 %	80.5 %
	1st yr rate increase	408%	430%	202%	213%
	Ave rate increase	136%	145%	61%	65%
	Ave rate inc w/DDC	108%	114%	25%	29%
	Ave 2006 End Res	$1156	$1204	$1140	$1142

Notes for Table 5-3

Ave 2002 Market: The 2002 and 2003 markets vary; 2004 through 2006 are the same in all cases. Calendar-weighted average prices: $140, $76, $46, $50, $49; $210, $114, $46, $50, $49; $315, $172, $46, $50, $49.

Load Reduction: "No Reduction" means full amount of augmentation is needed; "1,500 Reduction" means that load has been reduced by 1,500 MW of unspecified load at no additional cost.

Slice product sales: in the "0" case, Slice is not offered, and Slice load is converted to other PF products according to Account Executive estimates and customer feedback. Increased load growth in the 0 Slice case adds an average of 94 MW to that case, increasing augmentation needs and net costs.

TPP: The TPP is estimated without quantification of the risks of mismatch between the LB CRAC revenues and the actual augmentation costs, and without estimation of the timing of cash flows of the LB CRAC revenues.

Starting 2002 Reserves: The 2001 ending reserves are allowed to be negative, reflecting possible use of Treasury note (expected value = $309 million).

FB CRAC for 2002 collects enough to make up for any shortfall (below $300 million) in beginning 2002 reserves. It triggers 46 percent of the time in all 12 cases.

Slice/non-Slice Allocation of Net Augmentation Cost: Allocated across all revenues, per BPA (Customer proposal calls for dividing Slice/non-Slice shares by MW, not revenues).

Cost Shift Conclusions: Offering the Slice product under this proposal does not cause a shift of costs or risks to non-Slice Customers or to the Treasury.

This analysis shows that the offering of the Slice product does not shift costs to non-Slice customers, and does not shift risk to the Treasury (or to taxpayers). The treatment of Slice in the Supplemental Proposal passes the ‘no cost shift, no risk shift’ test.

CHAPTER 6: INVESTOR-OWNED UTILITY RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT

6.1 Introduction

The purpose of this chapter is to present Bonneville Power Administration's (BPA) changes to the May Proposal for calculating the financial aspect of the Investor-Owned Utility Residential Exchange Program Settlements (REP Settlements). Section 6.2 presents the background of BPA's May Proposal regarding the REP Settlement. Section 6.3 presents BPA's revisions to the May Proposal for the REP Settlement.

6.2 Bonneville Power Administration's 2002 Final Power Rate Proposal for the Monetary Portion of Investor-Owned Utility Residential Exchange Program Settlements

BPA's Subscription Strategy proposed that REP Settlements with the Investor-Owned Utilities (IOUs) would be comprised of two types of benefits: power sales at the Residential Load (RL) or Priority Firm Power (PF) Exchange Subscription rate, and monetary benefits. Any monetary benefits would reflect the difference between the market price of power forecasted in BPA's rate case and the rate used to make such Subscription sales to the IOUs. BPA's May Proposal addressed the issue of the market forecast that would be used in calculating monetary benefits.

In the May Proposal, BPA developed price forecasts to be used in: (1) designing rates; (2) determining surplus revenue; (3) calculating the cash component of the proposed settlement of the REP with regional IOUs; (4) estimating the cost of augmenting the Federal Base System (FBS) with five-year flat block purchases; and (5) developing BPA's Cost Recovery Adjustment Clause (CRAC) analyses. For designing rates, BPA relied on the Marginal Cost Analysis (MCA), which uses the AURORA model. The MCA is described in detail in the testimony of Anderson, *et al*., WP-02-E-BPA-16. The testimony of Keep, *et al*., WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA used a forecast of prices based on the MCA but with adjustments. Oliver, *et al*., WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger, *et al.*, WP-02-E-BPA-15. BPA developed a five-year flat block price forecast for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat block purchases. Oliver, *et al*., WP-02-E-BPA-20, at 2.

As noted above, BPA developed a five-year flat block price forecast for two purposes. *Id*. The first purpose was for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id*. The Power Subscription Strategy, at 8-9, states:

> BPA's strategy is that IOUs may agree to a settlement of the Residential Exchange Program in which they would be able to purchase a specified amount of power under subscription for their residential and small farm consumers at a rate approximately equivalent to the PF Preference rate. . .
>
> In subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of Federal power for the 2002–2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is most cost-effective for BPA.
>
> . . . Any cash payment will reflect the difference between the market price of power forecast in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period . . .

Id. at 2-3. The other forecasts developed in BPA's May Proposal were not appropriate for estimating advance purchases of five-year flat block energy. *Id*. at 3. Therefore, a separate forecast was developed for this purpose. *Id*.

The second purpose for this forecast was to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id.* BPA's firm obligations and firm resources are described in the Loads and Resources Study, WP-02-FS-BPA-01. Some of BPA's firm obligations are met by making purchases during the rate period on an as-needed basis, depending on generation levels, hydro conditions, and weather conditions. Oliver, *et al.*, WP-02-E-BPA-20, at 3. In addition, BPA anticipated making substantial purchases prior to the rate period for terms longer than one year to augment the FBS. *Id.* A forecast of the five-year price of the flat block power acquired in the 1999-2000 market timeframe was considered a more accurate reflection of the costs and structure of these augmentation purchases than the other price estimates (*e.g.*, AURORA price forecast). *Id.*

BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year flat block purchases. *Id.* BPA used actual market experience to derive a price estimate of five-year flat block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id.*

6.3 Supplemental Proposal for Market Price Forecast for Investor-Owned Utility Residential Exchange Program Settlements

BPA proposes to amend its May Proposal to reflect more current estimates of BPA's load obligations as well as its expectation of higher power market prices. The higher estimate of BPA's load obligations has increased BPA's forecasted amount of system augmentation purchases. BPA also believes that these greater amounts of power purchases are likely to be made at a higher average price than was initially estimated in BPA's May Proposal. These facts caused BPA to review the appropriateness of its rate case market price forecast for use in the calculation of the monetary benefits of the REP Settlement, and caused BPA to review whether

BPA's Subscription policy goals were still being satisfied. In BPA's Amended Proposal, BPA proposed a $34.1/megawatthour (MWh) forecast. BPA now proposes to use a $38/MWh market price forecast for the Fiscal Year (FY) 2002-2006 rate period as its five-year forward flat block price forecast.

The Subscription Strategy states that BPA would use a rate case market price forecast as one of the elements in the calculation of monetary benefits for the REP Settlement. A fixed price forecast was used to limit BPA's risk and to establish a known benefit amount. In BPA's May Proposal, BPA previously identified a market price forecast that averaged $28.1/MWh for FY 2002 to 2006. While not used in BPA's May Proposal for the determination of monetary benefits, BPA also developed other market price forecasts in its May Proposal. One such forecast is the risk-adjusted average market price forecast. The risk-adjusted average market price forecast is the average spot market price for all hours of the year estimated by AURORA to quantify BPA's operating risk in RiskMod for the Risk Analysis Study. This forecast is $34.1/MWh. In BPA's Amended Proposal, BPA proposed the use of this forecast for the calculation of the financial benefits in the IOUs' REP Settlements. Upon further review, however, given the total settlement package proposed by a large number of BPA's customers, and given recent changes in the power market, BPA now proposes to adjust its $34.1/MWh five-year flat block forecast to $38/MWh. BPA believes, given the total settlement package, that this $38/MWh price forecast is more appropriate for use as the five-year flat block price forecast than the $28.1/MWh forecast or the $34.1/MWh forecast.

Use of the $38/MWh market price forecast recognizes that BPA faces increased amounts of augmentation purchases and will not make all of the purchases prior to the start of the five-year rate period. BPA has also proposed that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits under the REP Settlements, should be exempt from the proposed Load-Based (LB) and Financial-Based (FB) CRACs. BPA chose to protect the monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed LB and FB CRACs.