

2010 BPA Rate Case
Wholesale Power Rate Initial Proposal

**RISK ANALYSIS AND
MITIGATION
STUDY**

February 2009

WP-10-E-BPA-04



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RISK ANALYSIS AND MITIGATION STUDY

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal Base System
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet
kcfs	thousand (kilo) cubic feet per second

K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA _r	megavolt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (formerly National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission

NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert

TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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1. INTRODUCTION

BPA's environment is filled with numerous uncertainties, and thus the ratesetting process must take into account a wide spectrum of risks. The objective of the risk analysis is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on Power Services' (PS) net revenue (total revenues less total expenses). This is carried out in two distinct steps: a risk analysis step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which different risk mitigation tools are tested to assess their ability to recover power costs in the face of this uncertainty.

1.1 BPA's Treasury Payment Probability (TPP) Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of being able to meet its payment obligations to the U.S. Treasury (Treasury). 1993 Final Rate Proposal Administrator's Record of Decision (ROD), WP-93-A-02, at 72. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. The TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the entire rate period, rather than setting numerical goals for year-to-year performance. The 10-Year Financial Plan was updated July 31, 2008, and remains in effect. The original 10-Year Financial Plan is available at http://www.bpa.gov/corporate/Finance/financial%5Fplan/10-year_BPA_Financial_Plan.pdf; the 2008 updated Financial Plan is available at http://www.bpa.gov/corporate/Finance/financial_plan/BPA_Financial_Plan.pdf.

1 By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning
2 that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all
3 bills on time. TPP is therefore a prospective measure of BPA's overall ability to meet its
4 financial obligations.

6 **1.2 Risk Mitigation Objectives**

7 BPA's policy objectives for the risk mitigation package, *see* Bliven and Lefler, WP-10-E-BPA-
8 10, include the following five objectives:

- 9 1) A rate design that meets BPA's financial standards, including meeting the 95
10 percent two-year TPP;
- 11 2) Lowest possible rates, consistent with sound business principles, including
12 statutory obligations;
- 13 3) Lower, but adjustable, effective rates rather than higher but stable rates;
- 14 4) A risk package that includes only those elements BPA believes can be relied
15 upon; and
- 16 5) Reserve levels that are not built up to unnecessarily high levels.

17
18 It is important to understand that these objectives are interdependent and require BPA to balance
19 these competing objectives when developing its overall rate design strategy.

21 **1.3 Overview of the Risk Analysis**

22 Two statistical models are used in the risk analysis step for this rate proposal, the Risk Analysis
23 Model (RiskMod) and the Non-Operating Risk Model (NORM). A third model, the ToolKit, is
24 used to test the effectiveness of different risk mitigation tools in the risk mitigation step.

25 RiskMod is discussed in Section 2, NORM is discussed in Section 3, and the ToolKit is
26 discussed in Section 4. The models function together so that BPA can develop rates that cover

1 all of its costs and provide a high probability of making its Treasury payments on time and in full
2 during the rate period.

3
4 Among the uncertainties that PS must mitigate, the most financial variability is associated with
5 hydro conditions, market prices, and river operations for fish recovery. Most of the power
6 marketed by BPA is hydro-based, and annual generation is a direct function of precipitation in
7 the Columbia River basin. As a result, BPA has little control over the amount of available
8 generation from year to year. Increased wholesale market price volatility also significantly
9 changes the profile of risk and uncertainty facing PS and its stakeholders. Higher, more volatile
10 natural gas prices, a key factor in the pricing of electricity, are increasing the variability in BPA's
11 net secondary revenues from year to year. As a result, BPA faces greater uncertainty of not
12 achieving the particular level of net secondary revenues that are assumed in setting base power
13 rates. These uncertainties are discussed in section 2 and in the Risk Analysis and Mitigation
14 Study Documentation (Documentation), WP-10-BPA-E-04A, section 2.4.

15
16 Further uncertainty for BPA arises from the financial impacts of potential changes in river
17 operations for fish mitigation. As a result of ongoing litigation over the FCRPS Biological
18 Opinions (BiOps), a new BiOp may be adopted or changes in river operations or fish and
19 wildlife measures may be required that could reduce BPA's actual net revenues compared to the
20 estimates on which power rates are based.

21 22 **1.4 Overview of Risk Mitigation**

23 Financial reserves are BPA's primary tool for managing the financial risk PS faces. Given the
24 large magnitude of the financial risk, if BPA were to rely solely on financial reserves (and
25 Planned Net Revenues for Risk (PNRR) to augment financial reserves if they are insufficient) for
26 risk mitigation, power rates would need to include a large risk premium to meet BPA's TPP

1 standard. As an alternative to high, fixed PNRR, the Initial Proposal includes a risk mitigation
2 package that balances PNRR with variable rate mechanisms, relying on the Cost Recovery
3 Adjustment Clause (CRAC) and Dividend Distribution Clause (DDC) to work with PNRR to
4 achieve the TPP policy objective of 95 percent. This makes the risk mitigation package less
5 expensive on an expected value basis, because the rates can be adjusted annually to respond to
6 uncertain financial outcomes, and additional revenues would be collected only when financial
7 conditions require them. *See* section 1.3 above for discussion of policy objectives.

8
9 The following items are included in the calculation of TPP.

- 10 1) *Starting PS Reserves Available for Risk.* Financial reserves include cash in the
11 BPA Fund and the deferred borrowing balance. Reserves available for risk
12 attributed to Power were \$874.9 million at the beginning of FY 2009.
- 13 2) *Planned Net Revenues for Risk.* PNRR is the final component of the revenue
14 requirement that is added to annual expenses. PNRR is needed only when the risk
15 mitigation provided by starting financial reserves and other risk mitigation tools is
16 not sufficient to meet the TPP standard. By increasing the rate that would
17 otherwise be sufficient to meet the revenue requirement, PNRR increases rates,
18 which in turn increase financial reserves, thus increasing TPP until it meets the 95
19 percent TPP objective. PNRR in the amount of \$48 million is applied to each
20 year of the rate period.
- 21 3) *Liquidity Reserve Level.* The liquidity reserve level has been decreased from
22 \$50 million to \$0 following the completion of an agreement between BPA and the
23 Treasury that gives BPA access to a \$300 million short-term note that can be used
24 for paying expenses. A deferral of a Treasury payment is registered in the Toolkit
25 when reserves fall below this level of Liquidity Reserves defined for PS.

1 4) *Cost Recovery Adjustment Clause.* The CRAC is a downward adjustment to
2 Residential Exchange Program (REP) benefits and an upward adjustment to the
3 applicable power rates. The adjustment would be applied for power deliveries
4 beginning in October following the fiscal year in which PS Accumulated
5 Modified Net Revenues (AMNR) fall below the CRAC threshold. The AMNR
6 threshold is set at the equivalent of \$750 million in financial reserves available for
7 risk attributed to PS.

8 5) *Dividend Distribution Clause.* The DDC is an upward adjustment to REP
9 benefits and a downward adjustment to the applicable power rates. The
10 adjustment would be applied for power deliveries beginning in October following
11 the fiscal year in which AMNR is above the DDC threshold. The AMNR
12 threshold is set at the equivalent of \$1,050 million in financial reserves available
13 for risk attributed to PS.

14
15 Additional tools for responding to specific risks in the fish and wildlife arena are also included in
16 the proposed risk mitigation package, but are not modeled as part of the TPP analysis. Neither
17 the risks nor the tools that mitigate the risks are modeled. These risks are not modeled because
18 they are primarily functions of future human and legal actions, for which no objective probability
19 data exist. Since BPA is not modeling the risks, it is appropriate to develop tools for these risks
20 and then exclude the tools from the modeling. This accomplishes two important goals: 1) the
21 risks are acknowledged and treated within the rate case; and 2) TPP calculations are not
22 distorted, which would occur had the risks but not the tools been modeled, or had the tools but
23 not the risks been modeled. These tools are the following NFB (National Marine Fisheries
24 Service, Federal Columbia River Power System, Biological Opinion) mechanisms:

25 1) *The NFB Adjustment.* This adjustment increases the CRAC Cap to allow
26 recovery of increased costs or reduced revenues resulting from court-ordered

1 changes to hydro operations, court-approved settlement of FCRPS BiOp
2 litigation, and/or any increase in costs due to a new BiOp. The NFB Adjustment
3 does not directly modify rates.

- 4 2) *The Emergency NFB Surcharge.* This surcharge is a separate mechanism from
5 the NFB Adjustment, but it triggers based on the same court-related events, with
6 the added requirement that the Agency within-year TPP be less than 80 percent.
7 The Emergency NFB Surcharge addresses the fact that the CRAC does not
8 produce revenues in the same fiscal year in which financial effects of an NFB
9 trigger event occur. The Emergency NFB Surcharge is designed to recover NFB
10 costs (or lost revenues) in the same year when BPA's financial reserves are
11 precariously low.

12
13 Information regarding these features is discussed in section 4 of this Study; the Wholesale Power
14 Rate Development Study (WPRDS), WP-10-E-BPA-05; and the General Rate Schedule
15 Provisions, WP-10-E-BPA-07, sections II.D, II.F, and II.G.

2. OPERATING RISK ANALYSIS

BPA's traditional approach to modeling risks is to use Monte Carlo simulation methodology. In this technique, the models RiskMod, NORM, and ToolKit run through 3,500 games or scenarios. In each game, each of the financial uncertainties is randomly assigned a value based on input specifications for that uncertainty. After all of the games have been run, the output data of the set of games are either analyzed and summarized or passed to other tools for further analysis in the ratesetting process. This Study proposes to continue this traditional approach.

2.1 RiskMod

RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manage data referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with AURORA^{xmp®}, the Rates Analysis Model (RAM2010), and the ToolKit model during the process of performing the risk analysis documented in this Study. AURORA^{xmp®} is the computer model used to develop the market price forecast. Market Price Forecast Study, WP-10-E-BPA-03. The RAM2010 is the computer model used to calculate rates. WPRDS, WP-10-E-BPA-05, section 3. Lastly, ToolKit is the computer model used to develop the risk mitigation package that achieves BPA's TPP standard. Section 4 of this Study.

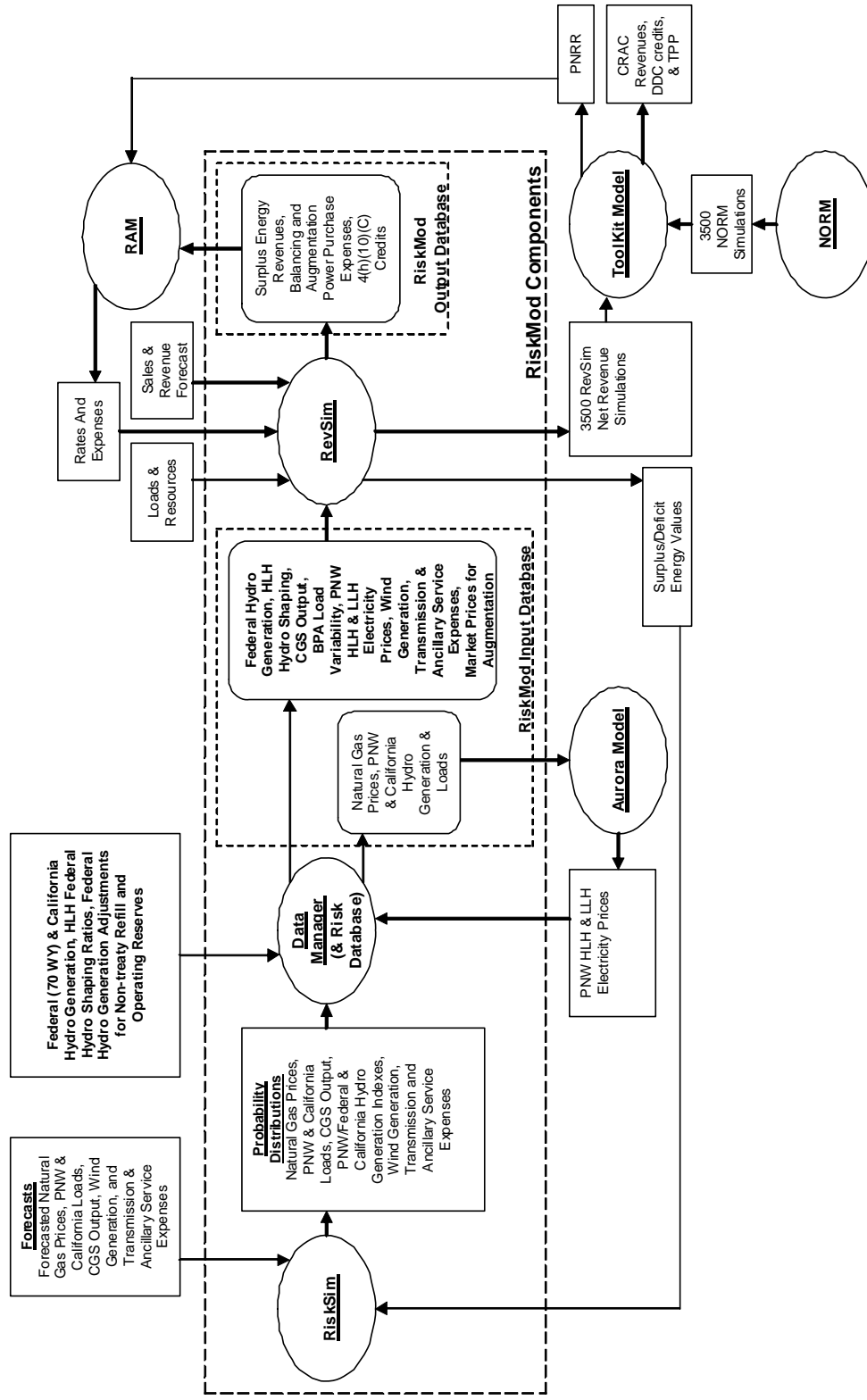
Variations in monthly loads, resources, natural gas prices, and PS transmission and ancillary service expenses are simulated in RiskSim. Monthly spot market electricity prices, based on varying loads, resources, and natural gas prices, are estimated by AURORA^{xmp®}. Data Management Procedures facilitate the formatting and movement of data that flow to and/or from RiskSim, AURORA^{xmp®}, and RevSim. To estimate net revenues, RevSim uses risk data from RiskSim, spot market electricity prices from AURORA^{xmp®}, load and resource data from the

1 Loads and Resources Study, WP-10-E-BPA-01; various revenues from the revenue forecast
2 component of the WPRDS, WP-10-E-BPA-05; and rates and expenses from the RAM2010.
3
4 Annual average surplus energy revenues, balancing and augmentation purchased power
5 expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the revenue forecast
6 and the RAM2010. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus energy values
7 from RevSim are used in the PS Transmission and Ancillary Services Expense Risk Model,
8 which calculates the average PS transmission and ancillary services expenses used in the
9 Revenue Requirement Study, WP-10-E-BPA-02. Net revenues estimated for each simulation by
10 RevSim are input into the ToolKit model to develop the risk mitigation package that achieves
11 BPA's 95.0 percent TPP standard for the two-year rate period. Graph 1 shows the processes and
12 interactions among each of the models and studies. Additional discussion on these processes and
13 interactions is provided in the Documentation, WP-10-E-BPA-04A.

14

Graph 1: RiskMod Risk Analysis Information Flow

Graph 1: RiskMod Risk Analysis Information Flow



2.2 Risk Simulation Models (RiskSim)

BPA developed risk models that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operating risks that BPA faces. Econometric modeling techniques capture the dependency of values through time. Parameters for the probability distributions were developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the revenue forecast, revenue requirement, and AURORA^{xmp®}. WPRDS, WP-10-E-BPA-05, section 4; Revenue Requirement Study, WP-10-E- BPA-02, section 4; and Market Price Forecast Study, WP-10-E-BPA-03, section 2.

The monthly outputs from these risk simulation models are accumulated into a computer file to form a risk database, which contains values lower than, higher than, or equal to the base case values used in the revenue forecast component of the WPRDS, Revenue Requirement Study, and AURORA^{xmp®}. Load, resource, and natural gas price risk data for each simulation are input into AURORA^{xmp®} to estimate monthly HLH and LLH spot market electricity prices. The prices estimated by AURORA^{xmp®} are then downloaded into the risk database, and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim. The risk models run 3,500 games to produce monthly risk data for the FY 2010-2011 rate period. Thus, each of the risk models produces 3,500 rows and 24 columns of simulated data.

2.3 @RISK Computer Software

Most of the risk simulation models developed to quantify operating risks were developed in Microsoft Excel workbooks using the add-in risk simulation computer package @RISK, which is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that reflects the specific risk, providing the

1 necessary parameters required for developing the probability distribution, and letting @RISK
2 sample values from the probability distributions based on the parameters provided. The values
3 sampled from the probability distributions reflect their relative likelihood of occurrence. The
4 parameters required for appropriately capturing risk are not developed in @RISK, but in
5 analyses external to @RISK.

7 **2.4 Operating Risk Factors**

8 In the course of doing business, BPA manages risks that are unique to operating a hydro system
9 as large as the Federal Columbia River Power System (FCRPS). The variation in hydro
10 generation due to the variation in the volume of water supply from one year to the next can be
11 substantial. BPA also faces other operating risks and variability that increase BPA's risk
12 exposure, including the following: (1) customer load variability due to changes in load growth
13 and weather; (2) Columbia Generating Station (CGS) nuclear plant generation; (3) wind
14 generation and value of output; (4) augmentation costs; (5) Power Services' transmission and
15 ancillary services expenses; (6) 4(h)(10)(C) credits; and (7) variability in electricity prices due to
16 Pacific Northwest (PNW) and California load, resource, and natural gas price variability. The
17 impacts of these risk factors on Power Services' net revenues are quantified in this Study.

18
19 One major operating risk that is not quantified in this Study is the change to hydro operations
20 that could result from litigation regarding FCRPS BiOps. What are believed to be the most
21 likely hydro operations for the rate period under the new 2008 BiOp are incorporated into the
22 hydro regulation study. Detail of the power and non-power requirements for the hydro
23 regulation study for FY 2010-2011 are presented in the Loads and Resources Study, WP-10-E-
24 BPA-01, section 2.3.2.1.1. For additional information on how BPA intends to respond to BiOp
25 uncertainty, *see* the description of the NFB Mechanisms in this Study, section 4.

1 The following is a discussion of the major risk factors included in RiskMod. Each of these risk
2 factors is used in AURORA^{xmp®}, RevSim, or both.

3 4 **2.4.1 PNW and Federal Hydro Generation Risk Factors**

5 The PNW and Federal hydro generation risk factors reflect the uncertainty that the timing and
6 volume of streamflows have on monthly PNW and Federal hydro generation under specified
7 hydro operation requirements. Federal hydro generation risk is accounted for in RevSim in two
8 ways. *See* Documentation, WP-10-E-BPA-04A, section 2.4.1.

9
10 For FY 2010-2011, hydro generation risk is accounted for by inputting monthly hydro generation
11 data estimated by the HydroSim Model for monthly streamflow patterns experienced from
12 October 1928 through September 1998 (also referred to as the 70 water years). These monthly
13 hydro generation data are developed by simulating hydro operations sequentially over all 840
14 months of the 70 water years. This analysis by HydroSim is referred to as a continuous study.
15 *See* the hydro-regulation component of the Loads and Resources Study, WP-10-E-BPA-01,
16 section 2.3.2, regarding HydroSim, continuous study, and 70 water years. Hydro generation
17 adjustments are made to each year of the 70 water year data from the continuous study for FY
18 2010-2011 to reflect the refilling of Non-Treaty Storage in Canada. Additional hydro generation
19 adjustments are made to the 70 water year data that represent efficiency losses associated with
20 standing ready to provide and deploy within-hour balancing reserves for both load and wind
21 generation variability and carrying the spinning portion of the operating reserves obligation. *See*
22 Generation Inputs Study, WP-10-E-BPA-08, section 4.

23
24 The PNW and Federal hydro generation data are used to estimate prices and revenues for 3,500
25 two-year simulations (FY 2010-2011). The monthly Federal hydro generation data are input into
26 the RevSim Model to quantify the impact that Federal hydro generation variability has on BPA's

1 net revenues. The associated monthly PNW hydro generation data are input into AURORA^{xmp®}
2 to quantify the impact that PNW hydro generation has on PNW electricity prices. Each
3 simulation uses hydro generation produced from streamflow patterns for a sequential set of two
4 water years from the continuous study for FY 2010-2011.

5
6 The initial water year (FY 2010) of the sequential set of two water years is randomly sampled
7 from 1929 through 1998 using a uniform distribution. When the end of the 70 water years is
8 reached (at the end of water year 1998), monthly hydro production data for water year 1929 is
9 subsequently used. For example, if a simulation for FY 2010-2011 starts with water year 1998,
10 the simulation uses water year 1998, as well as water year 1929, for a total of two water years.
11 This approach is used so that each of the 70 water years is sampled an equal number of times and
12 to maintain the historical relationships from year to year.

13
14 For FY 2010-2011, prices and net revenues are estimated such that each of the 70 water years is
15 sampled 50 times to produce 3,500 two-year simulations. Using the hydro-regulation data for
16 FY 2010-2011 in this continuous manner captures the dry, normal, and wet weather patterns
17 inherent in the 70 water years and the impact these patterns have on electricity prices and BPA's
18 net revenues over time.

19
20 Higher streamflows usually increase surplus energy revenues and decrease purchased power
21 expenses. Surplus energy revenues usually increase, because the revenue from the larger
22 quantities of surplus energy available for sale more than compensates for the lower market
23 prices. Conversely, lower streamflows usually decrease surplus energy revenues and increase
24 purchased power expenses. Surplus energy revenues usually decrease, because the revenues
25 from smaller quantities of surplus energy available for sale are not comparably offset by higher
26 market prices.

1
2 **2.4.2 PNW and BPA Load Risk Factor**

3 The PNW and BPA load risk factor reflects the impacts that the strength of the economy and
4 fluctuations in temperature can have on HLH and LLH spot market electricity prices and Priority
5 Firm Power (PF) loads. The level of economic activity impacts the overall annual amount of
6 load placed on BPA by its non-Slice PF customers while fluctuations in load due to weather
7 conditions cause monthly variation in loads, especially during the winter when heating loads are
8 highest. Annual load growth variability and monthly load variability due to weather for the
9 PNW (and indirectly for BPA) are simulated in the PNW Load Risk Model. Documentation,
10 WP-10-E-BPA-04A, section 2.4.2. Annual load growth variability parameters are derived from
11 historical Western Electricity Coordinating Council (WECC) load data. *Id.* Monthly load
12 variability for the PNW (and indirectly for BPA) is derived from daily load variability
13 parameters used as input data in the Power Market Decision Analysis Model (PMDAM) in the
14 1996 rate case, Marginal Cost Analysis Study, WP-96-FS-BPA-04, which is discussed in the
15 Documentation, WP-10-E-BPA-04A, section 2.4.2.

16
17 Higher firm loads due to economic and weather conditions increase PF loads and revenues,
18 increase balancing power purchase expenses, and reduce surplus energy revenues. Lower firm
19 loads reduce PF loads and revenues, decrease balancing power purchase expenses, and increase
20 surplus energy revenues. Higher spot market electricity prices increase BPA's surplus energy
21 revenues and balancing and augmentation power purchase expenses. Conversely, lower spot
22 market electricity prices decrease BPA's surplus energy revenues and balancing and
23 augmentation power purchase expenses.

1 **2.4.3 California Hydro Generation Risk Factor**

2 The California hydro generation risk factor reflects the uncertainty that the timing and volume of
3 streamflows have on monthly hydro production in a given year in California. This uncertainty
4 was derived from monthly hydro production data reported by the Energy Information
5 Administration for 1980-1997. Documentation, WP-10-E-BPA-04A, section 2.4.3.

6
7 Higher California hydro generation generally reduces the need to run thermal plants in
8 California, which results in lower prices paid by California utilities for PNW surplus energy and
9 lower prices paid by PNW utilities for purchased power from California. Conversely, lower
10 hydro generation generally increases the need to run thermal plants in California, which results
11 in higher prices paid by California utilities for PNW surplus energy and higher prices paid by
12 PNW utilities for purchased power from California.

13
14 **2.4.4 California Load Risk Factor**

15 The California load risk factor reflects the impacts that the strength of the economy and
16 fluctuations in temperature have on California loads and HLH and LLH spot market electricity
17 prices. The level of economic activity impacts the overall annual amount of loads in California,
18 while fluctuations in load due to weather conditions cause monthly variation in loads, especially
19 during the summer when cooling loads are highest. Load growth variability and load variability
20 due to weather for California are simulated in the California Load Risk Model. Documentation,
21 WP-10-E-BPA-04A, section 2.4.4. Annual load growth variability parameters are derived from
22 historical WECC load data. *Id.* Monthly load variability for California is derived from daily
23 load variability parameters used as input data in PMDAM in the 1996 rate case. Marginal Cost
24 Analysis Study, WP-96-FS-BPA-04, which is discussed in the Documentation, WP-10-E-BPA-
25 04A, section 2.4.2.

1 Higher California loads increase the need to run thermal plants in California, which results in
2 higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW
3 utilities for purchased power from California. Conversely, lower California loads decrease the
4 need to run thermal plants in California, which generally results in lower prices paid by
5 California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased
6 power from California.

8 **2.4.5 Natural Gas Price Risk Factor**

9 The natural gas price risk factor reflects the uncertainty in the costs of producing electricity from
10 gas-fired resources throughout the WECC region. Natural gas price risk is simulated in the
11 Natural Gas Price Risk Model, and the associated spot market electricity prices are estimated in
12 AURORA^{xmp®}. Documentation, WP-10-E-BPA-04A, section 2.4.5; and Market Price Forecast
13 Study, WP-10-E-BPA-03, section 3.

14
15 Higher gas prices generally increase the cost of producing electricity from gas-fired resources,
16 which increases the price of electricity on the wholesale power market. Conversely, lower gas
17 prices generally decrease the cost of producing electricity from gas-fired resources, which
18 decreases the price of electricity on the wholesale power market.

19
20 Higher gas prices tend to result in BPA earning higher surplus energy revenues and paying
21 higher purchased power expenses. Likewise, lower gas prices tend to result in BPA earning
22 lower surplus energy revenues and paying lower purchased power expenses.

24 **2.4.6 CGS Nuclear Plant Generation Risk Factor**

25 The nuclear plant generation risk factor is modeled in the CGS Nuclear Plant Risk Model and
26 reflects the uncertainty in the amount of energy generated by CGS. Documentation, WP-10-E-

1 BPA-04A, section 2.4.6. Quantification of this risk is such that the average of the simulated
2 outcomes is equal to the expected monthly CGS output specified in the Loads and Resources
3 Study, WP-10-E-BPA-01, section 2.3.3. The simulated results can vary from the output capacity
4 of the plant to zero output.

5
6 Higher CGS generation tends to increase BPA's surplus energy revenues or reduce its power
7 purchase expenses because more energy is available to sell as surplus energy or displace power
8 purchases. Lower CGS generation tends to decrease BPA's surplus energy revenues or increase
9 its power purchase expenses because less energy is available to sell as surplus energy or displace
10 power purchases.

11 12 **2.4.7 Wind Resource Risk Factor**

13 The wind resource risk factor, which is quantified in RiskSim and RevSim, reflects the
14 uncertainty in the amount and value of the energy generated by BPA's portion of Condon,
15 Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects. Documentation, WP-
16 10-E-BPA-04A, section 2.4.7. The wind generation risk is quantified in four risk simulation
17 models (the Foote Creek projects are combined and the Klondike projects are combined) such
18 that the average of the simulated monthly generation outcomes for each wind project are similar
19 to the expected monthly generation values included in the Loads and Resources Study, WP-10-
20 E-BPA-01, section 2.3.3. The risk of the value of the wind generation is calculated in RevSim
21 and is based on the differences between the purchase prices specified in output contracts that
22 wind generators have with BPA and the wholesale electricity prices at which BPA can sell the
23 amount of variable energy produced. Under its output contracts, BPA pays only for the amount
24 of energy that is produced.

1 Higher wind generation yields higher net revenues when wholesale electricity prices are higher
2 than the purchase prices specified in output contracts, and lower net revenues when wholesale
3 electricity prices are lower than the purchase prices specified in output contracts. In contrast,
4 lower wind generation yields relatively lower net revenues when wholesale electricity prices are
5 higher than the purchase prices specified in output contracts, and relatively higher net revenues
6 when wholesale electricity prices are lower than the purchase prices specified in output contracts.

7 8 **2.4.8 Augmentation Cost Risk Factor**

9 The augmentation cost risk factor reflects the uncertainty in the cost of augmentation purchases
10 that have not been acquired prior to setting rates. The uncertainty in the cost of augmentation
11 includes both the forecast deterministic need (aMW amount) and the electricity price risk
12 associated with meeting that need. For each iteration, these variable cost values replace the
13 deterministic values for augmentation costs included in the revenue requirement. Revenue
14 Requirement Study, WP-10-E-BPA-02, section 4. The expected (base case) augmentation costs
15 are calculated in RevSim using spot market electricity prices calculated by AURORA^{xmp®} under
16 1937 hydro conditions and deterministic forecast values for PNW and California natural gas
17 prices, loads, and resources (other than PNW hydro generation). The Documentation, WP-10-E-
18 BPA-04A, section 2.4.8, presents a sample calculation that uses this methodology to calculate
19 expected augmentation costs for the revenue requirement.

20
21 For the purpose of determining augmentation cost risk, augmentation need (aMW) is divided into
22 two categories. The first category of augmentation need was computed assuming CGS was
23 operating at the forecast level of output in a non-planned-outage year for the entire rate period.
24 This category is referred to as augmentation need not due to CGS planned outages (Category 1).
25 The second category of augmentation need was calculated as the augmentation amount needed to
26 replace the output of CGS during planned outages. This category of augmentation need is

1 referred to as augmentation need due to CGS planned outages (Category 2), and is relevant for
2 only FY 2011 in this rate proposal.

3
4 Two approaches are used for determining the price risk associated with augmentation need. The
5 first approach (Forecast 1) for determining the price risk associated with augmentation need is
6 the same as that used for computing secondary energy and balancing purchase price risk, where
7 3,500 games are run in AURORA^{xmp®} by altering natural gas prices, PNW and California loads,
8 and PNW and California hydro generation. PNW hydro generation for all 70 water years is used
9 in this risk run. The second approach (Forecast 2) for determining the price risk associated with
10 augmentation need is the same as the methodology used for the first approach with the exception
11 of the hydroelectric generation forecast. In the second approach (Forecast 2), only PNW
12 hydroelectric generation levels under 1937 hydro conditions are used for all 3,500 games per
13 fiscal year.

14
15 For FY 2010, a fiscal year without a planned CGS outage, there is only a Category 1
16 augmentation need. For FY 2010, this study assumes that 50 percent of the augmentation need
17 would be met at electricity prices derived under the Forecast 1 approach and the remaining 50
18 percent at electricity prices derived under the Forecast 2 approach. For FY 2011, a fiscal year
19 with planned CGS outages, the total augmentation need is made up of both Category 1 and
20 Category 2 augmentation needs. For FY 2011, this study assumes that 50 percent of the
21 Category 1 augmentation need would be met at electricity prices derived under the Forecast 1
22 approach, the remaining 50 percent of the Category 1 augmentation need would be met at
23 electricity prices derived under the Forecast 2 approach, and all the Category 2 augmentation
24 need would be met at electricity prices derived under the Forecast 1 approach.

1 RevSim calculates the total augmentation cost risk associated with each of the 3,500 games per
2 fiscal year by summing the augmentation costs computed by these two approaches. The
3 Documentation, WP-10-E-BPA-04A, section 2.4.8, presents a sample calculation that is based on
4 the methodology used to calculate augmentation cost risk in RevSim. *See* the testimony of
5 Bliven and Lefler, WP-10-E-BPA-10.

7 **2.4.9 PS Transmission and Ancillary Services Expense Risk Factor**

8 The transmission expense risk factor reflects the uncertainty in PS transmission and ancillary
9 expenses, relative to the expected expenses included in the revenue requirement. Revenue
10 Requirement Study, WP-10-E-BPA-02, section 4. The risk exposure of this factor, which is
11 computed in the Transmission Expense Risk Model, is based on variability in surplus energy
12 sales, with the probability distributions for these expenses being asymmetrical. These
13 asymmetrical results are due to how transmission and ancillary services expenses vary from the
14 cost of the fixed, take-or-pay, firm transmission capacity that PS has under contract, which must
15 be paid regardless of its use. This phenomenon reflects the fact that PS does not incur the costs
16 of purchasing additional transmission capacity until the amounts of surplus energy sales exceed
17 the amounts of residual firm transmission capacity after serving all firm sales. Documentation,
18 WP-10-E-BPA-04A, section 2.4.9.

19
20 Under conditions where PS sells more energy than it has firm transmission rights, transmission
21 and ancillary services expenses will increase. Alternatively, under conditions where PS sells less
22 energy than it has firm transmission rights, transmission expenses will remain unchanged, but
23 ancillary services expenses will decline.

1 **2.4.10 4(h)(10)(C) Credit Risk Factor**

2 The 4(h)(10)(C) credit risk factor is quantified in RevSim and reflects the uncertainty in the
3 amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. Documentation, WP-10-E-
4 BPA-04A, section 2.4.10. The 4(h)(10)(C) credit is the method by which BPA implements
5 section 4(h)(10)(C) of the Pacific Northwest Electric Power Planning and Conservation Act
6 (Northwest Power Act) that allows BPA to allocate its expenditures for system-wide fish and
7 wildlife mitigation activities to various purposes. The credit reimburses BPA for its expenditures
8 allocated to the non-power purposes of the Federal hydro projects. BPA reduces its annual
9 Treasury payment by the amount of the credit. This Study estimates the amount of the
10 4(h)(10)(C) credits that are available for each of the 70 water years for FY 2010-2011 by
11 summing the costs of the operating impacts (power purchases) and the expenses and capital costs
12 associated with BPA's fish and wildlife mitigation measures, and then multiplying the total cost
13 by 0.223 (22.3 percent is the non-power purpose percentage of the FCRPS).

14
15 The costs of the operating impacts are calculated for each of the 70 water years in RiskMod for
16 FY 2010-2011 by multiplying spot market electricity prices from AURORA^{xmp}® by the amounts
17 of power purchases (aMW) that qualify for 4(h)(10)(C) credits. The amounts of power
18 purchases (aMW) that qualify for 4(h)(10)(C) credits are derived outside of RevSim and are used
19 in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the
20 methodology used to derive the amounts of power purchases associated with the 4(h)(10)(C)
21 credits is contained in the Loads and Resources Study Documentation, WP 10-E-BPA 01,
22 section 2.1.5. The direct program expenses and capital costs for FY 2010-2011 do not vary by
23 water year and are documented in the Revenue Requirement Study, WP 10-E-BPA 02, at 5.2.1.

24
25 Higher 4(h)(10)(C) credits, which normally occur under below-average streamflow conditions
26 when the amount of power purchases that qualify for 4(h)(10)(C) credits is larger, increases net

1 revenues. Conversely, lower 4(h)(10)(C) credits, which normally occur under above-average
2 streamflow conditions when the amount of power purchases that qualify for 4(h)(10)(C) credits
3 is smaller, decreases net revenues.

4 5 **2.4.11 Revenue Simulation Model (RevSim)**

6 The RevSim module within RiskMod serves two main functions in determining rates. The first
7 function (the 70 Water Year Run) calculates surplus energy revenues, balancing and
8 augmentation purchase power expenses, and 4(h)(10)(C) credits that are used by the RAM2010
9 model. The second function (the Risk Simulation Run) simulates Power Services' operating net
10 revenue risk. Inputs to RevSim include risk data simulated by RiskSim and AURORA^{xmp®},
11 along with deterministic monthly load and resource data, monthly PF rates, and non-varying
12 revenues and expenses from the Loads and Resources Study, WP-10-E-BPA-01; section 2 of the
13 WPRDS, WP-10-E-BPA-05; and the RAM2010.

14
15 The risk data simulated by RiskSim and monthly spot market electricity prices estimated by
16 AURORA^{xmp®} are used to calculate 3,500 net revenues in RevSim for each fiscal year from
17 FY 2010-2011. This process yields a total of 7,000 annual net revenues, which are provided to
18 the ToolKit model to calculate TPP.

19 20 **2.4.12 Results from RiskMod**

21 RiskMod results are used in an iterative process with the ToolKit and the RAM2010 to calculate
22 PNRR and, ultimately, rates that provide BPA with a 95.0 percent TPP for the two-year rate
23 period. The net revenues simulated in each RiskMod run depend on the level of the rates
24 developed by the RAM2010, which in turn depend on the level of PNRR assumed when
25 RAM2010 is run. RiskMod simulates several temporary, intermediate sets of net revenues

1 during this iterative process. The final set of net revenues from RiskMod is the set that yields a
2 95.0 percent TPP without requiring additional PNRR.

3
4 Using 3,500 games of net revenue risk data simulated by RiskMod and NORM and mathematical
5 descriptions of the CRAC and DDC, the ToolKit produces 3,500 games of cash flow and annual
6 ending reserve levels. From these games, the ToolKit calculates TPP, and then analysts can
7 change the amounts of PNRR in order to achieve TPP targets.

8
9 A statistical summary of the annual net revenues for FY 2010-2011 simulated by RiskMod using
10 rates with \$48 million in PNRR is reported in Table 1. Net revenues over the rate period average
11 \$119 million/year. These values represent only the operating net revenues calculated in
12 RiskMod. They do not reflect additional net revenue adjustments in the ToolKit model due to
13 the output from NORM, interest earned on financial reserves, and the impacts of the CRAC and
14 DDC. Also, the average net revenues in Table 1 will differ from the net revenues shown in the
15 Revenue Requirement Study, WP-10-E-BPA-02, Table 1, because the latter Table 1 shows the
16 results of a deterministic forecast that does not account for the impact of risks.

Table 1: RiskMod Net Revenue Statistics (With PNRR of \$48 million)

	A	B	C
1		FY 2010	FY 2011
2		(Dollars in Thousands)	(Dollars in Thousands)
3	Average	200,626	38,294
4	Median	202,194	47,056
5	Standard Deviation	367,616	432,787
6			
7	1%	(478,571)	(843,041)
8	2.50%	(426,827)	(716,663)
9	5%	(372,795)	(643,029)
10	10%	(306,372)	(544,023)
11	15%	(226,479)	(452,746)
12	20%	(147,860)	(356,770)
13	25%	(72,225)	(276,845)
14	30%	1,067	(175,074)
15	35%	62,911	(102,609)
16	40%	112,754	(48,406)
17	45%	162,147	(3,269)
18	50%	202,194	47,056
19	55%	248,568	96,539
20	60%	296,768	146,299
21	65%	341,567	195,307
22	70%	390,368	250,333
23	75%	440,464	314,775
24	80%	502,706	380,864
25	85%	569,691	457,245
26	90%	661,077	576,038
27	95%	818,617	739,922
28	97.50%	925,716	905,567
29	99%	1,123,614	1,198,982

3. NON-OPERATING RISK

3.1 Non-Operating Risk Model (NORM)

NORM is an analytical risk tool that captures risks other than operating risks in the ratesetting process. It was first introduced and adopted in the WP-02 rate proceeding. NORM models the non-operating risks of Power and the risks of the corporate costs that are covered by Power. Transmission function risks are not included in the analysis. In addition, NORM models some changes in revenue, and some changes in cash. While RiskMod is used to quantify risks having to do with various economic, load, and generation resource capability variations, NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the Power revenue requirement. The main NORM modules model the accrual impacts of the included risks, and an accrual-to cash adjustment translates the net revenue impacts into cash impacts. NORM supplies 3,500 games (or iterations) of both net revenue and cash impacts. The outputs from NORM, along with the outputs from RiskMod are input into the ToolKit model to assess the TPP.

3.1.1 Methodology

NORM follows BPA's traditional approach to modeling risks, which uses the Monte Carlo simulation methodology. In this technique, a model runs through a number of games or iterations. In each game, each of the uncertainties is randomly assigned a value from a distribution based on input specifications for that uncertainty. After all of the games are run, the output data on the set of games can be analyzed and summarized or passed to other tools.

3.1.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, BPA risk staff interviewed subject matter experts (SMEs) for each capital and expense item modeled. The SMEs were asked for their assessment of the risks concerning their cost estimates, including the

1 possible range of outcomes and the associated probabilities of occurrence. In some instances, the
2 SMEs were able to provide a complete probability distribution. For the remaining cost items,
3 BPA risk staff used the information provided to develop the probability distributions.
4

5 **3.1.3 Inputs**

6 **3.1.3.1 CGS O&M**

7 CGS O&M consists of the following four cost elements:

- 8 1) Base O&M
 - 9 2) Nuclear fuel
 - 10 3) Decommissioning Trust Fund Contributions
 - 11 4) Nuclear Electric Insurance Limited (NEIL) Insurance Premiums
- 12

13 For the initial proposal, NORM captures uncertainty around Base O&M and NEIL insurance
14 costs only. For Base O&M, NORM assumes that the most likely outcome is the amount
15 determined in the Integrated Program Review (IPR) process. The minimum and maximum
16 values are distributed based on historical deviations of actual and forecast CGS O&M. For NEIL
17 insurance premiums, risk is modeled around the level of earnings on the NEIL fund. Member
18 utilities receive annual distributions based on the level of these earnings, which in turn lowers the
19 premiums they pay.
20

21 The distributions for CGS O&M are shown in the Documentation, WP-10-E-BPA-04B, Table
22 43. Distributions are shown for each fiscal year for FY 2010-2011, and also for the total of the
23 two years.
24

25 **3.1.3.2 Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) O&M**

26 For COE/Reclamation O&M, NORM models uncertainty around the following:

- 1 1) Additional costs if a security event occurs
- 2 2) Additional costs if a fish event occurs
- 3 3) Additional system needs
- 4 4) Additional extraordinary maintenance
- 5 5) Base O&M (for Reclamation only)

6
7 Historically, Reclamation has underrun its O&M budget. Therefore, NORM includes a
8 probability distribution around future Reclamation Base O&M expenditures, with a minimum
9 value of \$2 million less than the IPR value, and a maximum value equal to the IPR value (i.e.,
10 the value determined in the IPR process).

11
12 For additional security costs, NORM assumes a 5 percent probability that an event will occur
13 that leads to a requirement for additional security at the COE and Reclamation facilities. The
14 additional annual cost is the same for both the COE and Reclamation at \$3 million each.

15
16 Additional fish environmental costs are modeled similarly, with a 5 percent probability that an
17 event will occur requiring additional annual expenditures of \$2 million each for both the COE
18 and Reclamation.

19
20 For additional system needs, NORM models the uncertainty that additional repair and
21 maintenance costs could be incurred and the probability that an outage event will occur.

22
23 The distributions for total COE and Reclamation O&M are shown in the Documentation, WP-
24 10-E-BPA-04B, Table 44. Distributions are shown for each fiscal year for FY 2010-2011, and
25 also for the total of the two years.

1 **3.1.3.3 Colville/Spokane Settlement**

2 For the Colville settlement, the payment to the Colville Tribe equals a base annual charge, which
3 is calculated as a base annual price times the generation output from Grand Coulee. The base
4 annual charge is subject to both a floor and ceiling. NORM models the uncertainty in the price
5 per kWh paid, Consumer Price Index (CPI), and generation output from Grand Coulee.

6
7 The base annual price equals the 1995 base price of 0.747153 mills/kWh, escalated by the BPA
8 price escalator each year thereafter. The BPA price escalator equals the BPA power sales price
9 for the previous fiscal year, divided by the BPA power sales price for FY 1995, 27.14 mills/kWh.

10
11 The floor annual price is calculated as the FY 1995 floor price of 0.661414 mills/kWh escalated
12 by the combined escalator for each fiscal year thereafter. Similarly, the ceiling annual price is
13 the FY 1995 ceiling price, 0.832892 mills/kWh, escalated by the combined escalator for each
14 year thereafter. The combined escalator equals the simple average of the BPA price escalator
15 and CPI escalator for the fiscal year. The CPI escalator is the ratio of the CPI for the September
16 ending the previous fiscal year and the CPI for September 1995.

17
18 To model the variability around Grand Coulee generation, a mean and standard deviation were
19 calculated for the 50 historical water years average annual output. The mean and standard
20 deviation are used as parameters for a normal probability distribution generated by @Risk. The
21 50 years of data are provided in the Documentation, WP-10-E-BPA-04B, Table 45.

22
23 Using the data described above, NORM calculates a base annual payment to the Colville Tribe,
24 which equals the base annual price times the draw for that year's output from Grand Coulee. If
25 the base payment exceeds the ceiling, the Colville payment equals the ceiling. If the base
26 payment is below the floor, the payment is set equal to the floor, and the difference is carried

1 forward as a loan to be paid the following fiscal year. A new loan is created each year the base
2 payment is below the floor or the following year's base payment is insufficient to pay off the
3 previous year's loan.

4
5 Within the rate period, a similar settlement with the Spokane Tribe could go into effect by means
6 of legislation. NORM includes an assumption of a 60 percent probability that the legislation will
7 pass and payments to the Spokane Tribe are 60 percent likely to occur over the entire rate period.
8 The payments equal 29 percent of the payments made to the Colville Tribe.

9
10 The distributions for Colville Settlement payments are shown in the Documentation, WP-10-E-
11 BPA-04B, Table 46. Distributions are shown for each fiscal year for FY 2010-2011, and also for
12 the total of the two years. Similar graphs for the Spokane Settlement payments are shown in the
13 Documentation, WP-10-E-BPA-04B, Table 47.

14 15 **3.1.3.4 Power Services Internal Operations**

16 For this cost item, NORM models uncertainty around the following:

- 17 1) PS System Operations
- 18 2) PS Scheduling
- 19 3) PS Marketing and Business Support
- 20 4) Corporate G&A

21
22 For Corporate G&A, NORM assumes the IPR value as most likely, with a minimum value of
23 5 percent lower and a maximum value of 10 percent higher.

1 To model uncertainty around the remaining cost items, NORM creates a probability distribution
2 for each item, with a minimum that is 10 percent lower than the IPR values and a maximum that
3 is 10 percent higher.

4
5 The distributions for total Internal Operations Costs, including Corporate G&A, that are modeled
6 in NORM are shown in the Documentation, WP-10-E-BPA-04B, Table 48. Distributions are
7 shown for each fiscal year for FY 2010-2011, and also for the total of the two years.

8 9 **3.1.3.5 Fish & Wildlife Expenses**

10 NORM models uncertainty around four categories of fish and wildlife mitigation program
11 expense, as described below.

12 13 **3.1.3.5.1 BPA Direct Program Costs for Fish and Wildlife**

14 The costs of BPA's Direct Program for fish and wildlife are uncertain in large part because the
15 actual pace of implementation cannot be known, and there is a significant chance that measures
16 will not be implemented as rapidly as planned, especially in FY 2009 and 2010. This does not
17 reflect any uncertainty in BPA's commitment to the plans, merely a realistic understanding that it
18 can take time to start programs, and the expenses of the programs may not actually be incurred in
19 the fiscal years in which BPA plans for them to be incurred. This uncertainty is modeled by Pert
20 distributions with most likely expense deviation values of \$0 for all three years; minimum
21 (maximum underrun) values of -\$50 million, -\$35 million, and -\$20 million for FY 2009, 2010,
22 and 2011; and maximum values of \$10 million, \$10 million, and \$20 million for the three years,
23 respectively. This results in expected value net revenue impacts of \$6.7 million, \$4.2 million,
24 and \$0 for the three years, respectively. Graphs of the distributions for the BPA Direct Program
25 expense, along with additional descriptive statistics, are shown in the Documentation, WP-10-E-

1 BPA-04B, Table 49. Distributions are shown for each fiscal year for FY 2010-2011, and also for
2 the total of the two years.

3 4 **3.1.3.5.2 USF&W Service Lower Snake River Hatcheries**

5 Uncertainty in the costs of the USF&W Service Lower Snake River Hatcheries is modeled as a
6 symmetric Pert distribution with a most likely impact of \$0, a minimum value (largest negative
7 impact) of -\$2 million, and a maximum value of \$2 million. The expected value is \$0. Graphs
8 of the distributions for risk over the Lower Snake River Hatcheries expense are shown in the
9 Documentation, WP-10-E-BPA-04B, Table 50.

10 11 **3.1.3.5.3 Bureau of Reclamation Leavenworth Complex O&M**

12 NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using
13 the same symmetric Pert distribution for all three years, FY 2009-2011. The most likely value
14 for the deviation from revenue requirement numbers is \$0; the minimum value (largest negative
15 deviation) is -\$500 thousand; and the maximum value is \$500 thousand. This results in an
16 expected value net revenue impact of \$0 for each of the three years. Graphs of the distributions
17 for Leavenworth Complex O&M expense are shown in the Documentation, WP-10-E-BPA-04B,
18 Table 51.

19 20 **3.1.3.5.4 Corps of Engineers Fish Passage Facilities**

21 NORM models uncertainty of the cost of COE's fish passage facilities using the same symmetric
22 Pert distribution for all three years, FY 2009-2011. The most likely value for the deviation from
23 revenue requirement numbers is \$0; the minimum value (largest negative deviation) is -\$3
24 million; and the maximum value is \$3 million. This results in an expected value net revenue
25 impact of \$0 for each of the three years. Graphs of the distributions for Fish Passage Facilities
26 expense are shown in the Documentation, WP-10-E-BPA-04B, Table 52.

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3.1.3.6 BiOp Secondary Sales Risk

The 2008 FCRPS BiOp (BiOp) is incorporated into the hydro studies. Loads and Resources Study, WP-10-E-BPA-01, section 2.3.2.1.1. This BiOp includes performance standards. It may be necessary to make changes to the operational regime to meet the BiOp standards, resulting in decreased net secondary revenue. This risk continues as long as the current 2008 BiOp remains in effect (the separate risk of changes to FCRPS operations or expenses arising from litigation over either the 2004 or the 2008 FCRPS BiOp are treated with the two NFB mechanisms, described below in section 4). A Pert distribution of this risk is created and used for each of the two fiscal years in the rate period and for FY 2009. The most likely value is \$0 change, the minimum value (largest negative impact) is -\$40 million, and the maximum value is \$5 million. This results in an expected value net revenue impact of -\$5.8 million for each of the three years. Graphs of the distributions for Bi-Op Secondary Sales Risk are shown in the Documentation, WP-10-E-BPA-04B, Table 53.

3.1.3.7 Capital Expenditures

For the Initial Proposal, capital expenditure uncertainty is generally not being modeled in NORM. New capital expenditures are debt financed. This results in the net revenue effect being distributed over several years (the precise duration depends on the type of financing). A small fraction of the capital expenditure is distributed to net revenues for FY 2010 and 2011 for the calculation of TPP. Data from the WP-07 Final Proposal, and preliminary data for the Initial Proposal, show the capital expenditure risk to be insignificant in the calculation of TPP.

The one kind of capital risk that is modeled in NORM is associated with the CGS condenser replacement project for FY 2011. CGS capital additions are modeled around historical variability, with added uncertainty around the costs of the condenser replacement. This capital

1 uncertainty affects Energy Northwest (EN) debt service for the calculation of TPP. The CGS
2 debt service effect is currently modeled using a deterministic interest rate. The distribution of
3 CGS debt service is shown in the Documentation, WP-10-E-BPA-04B, Table 54.

4 5 **3.1.3.8 Interest Rate and Inflation Risk**

6 Interest rate and inflation risk is currently not being modeled in NORM. Preliminary evaluation
7 and past modeling show the effect of interest rate and inflation risk on TPP to be minimal.

8 9 **3.1.3.9 Federal Depreciation, Amortization, and Net Interest Distributions**

10 Depreciation, amortization, and net interest distribution variability are driven primarily by
11 interest rate risk. As a result, the Initial Proposal does not include this risk.

12 13 **3.1.3.10 CGS Main Condenser Replacement**

14 In 2011, EN is planning to replace the main condenser at CGS. This project is scheduled
15 concurrently with the regular CGS refueling outage, scheduled to begin April 9, 2011. During
16 this project, CGS will not be producing power. Risks of the main condenser replacement have
17 been modeled around revenue variability due to changes in the outage duration.

18
19 CGS outage duration risk is modeled as lost revenues due to variability in the duration of the
20 planned maintenance outage in 2011. Increases or decreases in down time of the CGS plant
21 result in changes in MWh generated. This translates to decreased or increased revenues for
22 Power Services. This revenue variability is a function of plant outage duration, monthly flat
23 AURORA^{xmp®} prices from the Market Price Forecast Study, WP-10-E-BPA-03, section 2.5, and
24 CGS aMW generation, documented in the Loads and Resources Study, WP-10-E-BPA-01,
25 section 2.3.3.

1 SMEs have provided outage duration estimates of a minimum of 65 days and a most likely
2 outage of 88 days. A high estimate for the outage is approximately twice the most likely
3 duration. The probability distribution of the outage duration is shown in the Documentation,
4 WP-10-E-BPA-04B, Table 55. The outage duration is effectively capped at 175 days. The
5 outage is scheduled to begin on April 9, 2011. The last day of the rate period is September 30,
6 2011, 174 days later. Any energy lost after this date would not apply to the FY 2010-2011 rates.

7
8 To calculate the revenue effect of the outage duration, for each of the 3,500 games of flat
9 monthly prices from AURORA^{xmp®}, a duration is drawn from the outage duration distribution.
10 This duration is then applied to the monthly prices multiplied by the aMW normally generated
11 by CGS when the plant is in service, multiplied by the hours in the month. This calculation
12 results in a lost revenue figure from the plant being down. The same methodology is applied
13 using the deterministic outage duration assumed in the Loads and Resources Study, WP-10-E-
14 BPA-01, section 2.3.3. This lost revenue less the lost revenue calculated using outage duration
15 variability results in 3,500 revenue changes due to the CGS outage duration. The distribution of
16 these revenue changes is shown in the Documentation, WP-10-E-BPA-04B, Table 56.

17 18 **3.1.3.11 Revenue from Sales of Services to Wind Generators**

19 In FY 2010 and 2011, TS will provide services to wind generators in the BPA balancing area.
20 TS is proposing to charge these customers on the basis of the installed MW of capacity. TS will
21 obtain from PS the generation inputs needed to support these services and will pay PS for the
22 generation inputs. PS has estimated the costs of providing the forecast quantity of generation
23 inputs to TS to meet the needs of wind generation on the BPA system. The costs can be
24 characterized as having two components, embedded costs and variable costs.

1 Since the quantity of wind generation in BPA's balancing area is not known with certainty, there
2 is a financial risk due to the possibility that the quantity will differ from the forecast, and TS will
3 receive either more or less revenue for wind services sales than forecast. TS and PS are
4 proposing that TS and PS each bear half of the part of this risk that relates to the recovery of
5 embedded costs. PS will bear the part of this risk that relates to the recovery of variable costs,
6 which is offset by risk to realization of net secondary revenues.

7
8 The variable cost calculations reflect the deoptimization of the power system that results from
9 setting aside some system capability to support installed wind capacity. *See* Bermejo, WP-10-E-
10 BPA-25. If less wind generation than forecast is actually installed, BPA (TS) will receive less
11 revenue for such services, but BPA (PS) will be able to generate greater net secondary revenues
12 than forecast. Additionally, the incremental net secondary revenue will be, within BPA's ability
13 to calculate such factors, equal to and offsetting the decrease in TS revenues. TS will pass to PS
14 all actual revenue from sales of services to wind generators that is designated to recover the
15 variable costs of generation inputs provided by PS. In this way, TS faces no risk due to variation
16 in the total quantity of wind associated with the recovery of the variable costs of generation
17 inputs. PS bears the entire risk of deviations in the recovery of the variable cost component, but
18 this risk is offset by the corresponding impact on PS net secondary revenue, so PS faces no
19 significant financial risk. Therefore, BPA does not face significant risk for the recovery of the
20 variable costs of generation inputs.

21
22 The recovery of embedded costs, however, is subject to risk, and this risk will be shared equally
23 by the two business lines, as follows. If the amount of installed wind capacity is lower than the
24 rate case forecast in a year in the rate period, BPA staff will calculate the portion of the decrease
25 in revenue TS receives that was intended to recover the embedded costs of generation inputs. TS
26 payments to PS for the embedded costs of generation inputs will then be equal to the forecast

1 amount minus half of the decrease in the embedded-cost portion of the revenue received from TS
2 wind customers. Similarly, if the amount of installed wind capacity exceeds the rate case
3 forecast for a year in the rate period, TS payments to PS for the embedded costs of generation
4 inputs for that year will be equal to the rate case forecast for that year plus half of the increase in
5 the embedded-cost portion of the revenue received from TS wind customers.

6
7 Equivalently, if the amount of installed wind capacity underruns the rate case forecast in a year
8 in the rate period, BPA staff will calculate the portion of the decrease in revenue TS receives that
9 was intended to recover the embedded costs of generation inputs. TS payments to PS for the
10 total costs of generation inputs for that year will be equal to the actual amount received by TS
11 plus half of the amount of the decrease in the embedded-cost portion of the revenue received
12 from TS wind customers. Similarly, if the amount of installed wind capacity exceeds the rate
13 case forecast for a year in the rate period, TS payments to PS for the total costs of generation
14 inputs for that year will be equal to the actual amount received by TS less half of the amount of
15 the increase in the embedded-cost portion of the revenue received from TS wind customers.

16
17 This risk is modeled using estimates of low, most likely, and high quantities of installed wind
18 capacity for FY 2010 and 2011. The low and high estimates were interpreted to represent the
19 2.5th and 97.5th percentiles. Distributions were fitted that matched those parameters. In each of
20 the games in the risk analysis, a random draw of installed wind capacity was made from the
21 distributions. If this random result was lower (higher) than the most likely forecast, then a
22 negative (positive) financial result was calculated by multiplying the difference in capacity by
23 the annual cost per installed MW for embedded costs of generation inputs. Fifty percent of the
24 financial result was then applied to the net revenues for both TS and PS in their respective risk
25 analyses. Graphs of the distributions for Services for Wind Generators revenue are shown in the
26 Documentation, WP-10-E-BPA-04B, Table 57.

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3.1.3.12 Accrual-to-Cash (ATC)

One of the inputs to the ToolKit (through NORM) is the ATC. NORM takes the deterministic values for the line items listed above and shown on Table 2 below and assigns to each a distribution. It then runs 3,500 games and feeds the results of these games into the ToolKit model. The ToolKit also accepts as input 3,500 net revenue scenarios from RiskMod. The 3,500 NORM-computed ATC adjustments make the necessary changes to convert these net revenue scenarios (accruals) into the equivalent reserves value (cash) needed by ToolKit to calculate TPP.

Because not all changes in expenses result in a similar change in cash, ATC is modeled probabilistically in NORM for this rate case. NORM uses the deterministic ATC Table (Table 2 on the following page) as its starting point, but replaces the deterministic value with the new value for each game for the following line items in the table:

- 1) Line 1: Depreciation/Amortization
- 2) Line 3: EN Direct Pay Prepaid Expense
- 3) Line 4: Slice True-up included in All Other
- 4) Line 6: EN Debt Service included in income statement
- 5) Line 8: Planned Advance Amortization of Federal Debt

Table 2: ToolKit Net Revenue to Cash Adjustments (in \$Millions)

	A	B	C	D	E	F
				FY 2009	FY 2010	FY 2011
1						
2						
3	1	Depreciation/Amortization		\$188.764	\$197.919	\$207.095
4						
5	2	Interest Adjustments		(\$45.937)	(\$45.937)	(\$45.937)
6						
7	3	ENW Direct Pay Prepaid Expense		(\$69.017)	\$17.213	(\$10.304)
8						
9	4	All Other (see lines 14 thru 21 below)		(\$3.587)	(\$15.542)	(\$7.109)
10						
11	5	Sub Total Lines 1 - 4		\$70.223	\$153.653	\$143.745
12						
13						
14	6	Add: EN Debt Service Before Refinancing		\$544.793	\$537.207	\$557.683
15	7	Adjust for Current Estimated ENW Debt Service (PBL only)		(\$438.299)	(\$537.208)	(\$557.683)
16	8	Less: Planned Advanced Amortization of Federal Debt		(\$138.000)	\$0.000	\$0.000
17	9	Sub Total Lines 6 - 8		(\$31.506)	(\$0.001)	\$0.000
18						
19	10	Less: Scheduled Federal Debt Amortization		(\$109.655)	(\$267.264)	(\$161.888)
20						
21	11	Less: Revenue/Reserve financing		\$0.000	\$0.000	\$0.000
22						
23	12	Sub Total Lines 10 - 11		(\$109.655)	(\$267.264)	(\$161.888)
24						
25	13	Accrual to Cash Adjustment (Lines 5 + 9 + 12)		(\$70.938)	(\$113.612)	(\$18.143)
26				\$0.000	\$0.000	\$0.000
27						
28	14	All Other				
29						
30	15	Net Slice True up lag into (out of) current year		\$0.232	\$0.535	\$5.660
31	16	NB Revenue and other cash lags		\$0.000	\$0.000	\$0.000
32	17	Terminated contracts & Settlements		(\$13.114)	(\$8.924)	(\$5.574)
33	18	Energy Efficiency Projects		\$7.356	(\$5.781)	(\$5.781)
34	19	Inter Company Revenue Net of Expense		\$0.000	\$0.000	\$0.000
35	20	Other Miscellaneous		\$1.939	(\$1.372)	(\$1.414)
36	21	TOTAL All Other		(\$3.587)	(\$15.542)	(\$7.109)

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3.2 Output

The output of NORM is an Excel file containing (1) the aggregate total expense deltas for all of the individual risks that are modeled, and (2) the associated ATC adjustment for each game. A typical run has 3,500 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in the Documentation, WP-10-E-BPA-04B, Table 58.

4. RISK MITIGATION

4.1 Treasury Payment Probability (TPP)

One of BPA’s policy objectives for this rate case is to meet its TPP standard. As described in Section 1 of this Study, this standard for a two-year rate period is 95.0 percent for the risks, financial reserves, and tools attributed to PS.

4.2 ToolKit Overview

The ToolKit is an Excel 2003 spreadsheet that is used to evaluate Power Services’ ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. Many of the settings are entered on the ToolKit main page (the “TK_Main” worksheet). It reads in data from two external files, one each from RiskMod and NORM. Most of the modeling of risks is performed by RiskMod and NORM, as described in sections 2 and 3 of this Study. Most of the logic for simulating the financial results in the years included in a ToolKit analysis is in VBA code (Microsoft’s *Visual Basic for Applications*). This code contains comments that document how the code works, and is a useful reference for understanding how the ToolKit functions.

More specifically, the ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to PS, and thus on TPP. It registers a deferral of a Treasury payment when these reserves fall below the level of “Liquidity Reserves” entered on the main page of the ToolKit. The Initial Proposal assumes that the amount of liquidity needed in the form of financial reserves is \$0 million. *See* Bliven and Lefler, WP-10-E-BPA-10. The ToolKit is run for 3,500 “games” or iterations. TPP is calculated by dividing the number of those games where each of the two years in the rate period ends with at least \$0 million in PS reserves by 3,500. The ToolKit calculates the TPP and

1 other risk statistics and reports results, and allows analysts to calculate how much PNRR is
2 needed, if any, to meet the TPP standard.

4 **4.3 Risk Mitigation Tools Incorporated into the Initial Proposal**

5 The preceding sections of this study describe the risks that are modeled explicitly. This section
6 describes the tools for mitigating those risks. Some of these tools are modeled and included in
7 the Initial Proposal; others are not modeled, specifically the NFB Adjustment and the Emergency
8 NFB Surcharge, but are included as part of BPA's risk mitigation package. The following
9 sections describe each of these risk mitigation tools.

11 **4.3.1 Reserves Available for Risk and PNRR**

12 **Reserves Available for Risk.** The fundamental protection against the financial impacts of the
13 uncertainty BPA faces is its financial reserves. For this rate proposal, it is the financial reserves
14 available for risk attributed to the generation function (PS reserves) that are considered when
15 measuring TPP. Financial reserves available to the generation function comprise cash and
16 investments held by the Treasury in the Bonneville Fund plus amounts of deferred borrowing.
17 Deferred borrowing refers to amounts of capital expenditures that BPA has made that authorize
18 borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred
19 borrowing amounts are converted to cash when the borrowing is completed.

20
21 PS reserves mitigate financial risk by serving as a source of cash for meeting financial
22 obligations during years in which net revenue and the corresponding cash flows are lower than
23 anticipated. In years of above-expected net revenue and cash flow, financial reserves will be
24 replenished so they will be available in later years.

1 Some financial reserves attributed to PS are not considered to be available for risk and thus are
2 not included in the starting financial reserves or any other part of the TPP calculation. In this
3 rate case, financial reserves available for risk attributed to PS exclude financial reserves that
4 BPA is holding due to the suspension of payment of REP Settlement Benefits. These funds are
5 expected to be completely distributed by a combination of REP payments to investor-owned
6 utilities (IOUs) and refunds (in the form of rate credits) to consumer-owned utilities (COUs).

7
8 **PNRR.** BPA conducts analyses of its TPP using current projections of PS financial reserves in
9 its rate cases. If the TPP is below the standard established in the 10-Year Financial Plan, then
10 the projected reserves, along with whatever other risk mitigations are considered in the analysis,
11 are not sufficient to reach the TPP standard. This is typically corrected by adding PNRR to the
12 revenue requirement as a cost needed to be recovered by rates. This has the effect of increasing
13 rates, which will increase the net cash flow, which will increase the available PS financial
14 reserves and therefore increase TPP.

15
16 Compared to most of the expenses in the revenue requirement, PNRR is an unusual cost. For
17 one thing, there is no associated expectation that cash is disbursed. For example, if BPA were
18 able to find financial instruments in the market for mitigating its hydro and market risk, it would
19 have to pay fees to counterparties in one way or another that it would not get back – there would
20 be a long-term net cost. For another, including PNRR in one rate case is likely to reduce the
21 need for PNRR or other forms of risk mitigation in subsequent rate cases. If it turns out that the
22 reserves generated by the rate increase caused by PNRR are not drawn down to pay bills in the
23 rate period under consideration, they remain available in later rate periods and will serve to
24 reduce the cost of risk mitigation that customers will pay then, all else being equal.

1 **4.3.2 The Cost Recovery Adjustment Clause (CRAC)**

2 Cost recovery adjustment clauses, or CRACs, can be powerful risk mitigation tools. In most rate
3 cases since 1993, BPA has employed CRACs or Interim Rate Adjustments (IRAs) as upward
4 rate adjustment mechanisms that respond to the financial risks BPA faces. Financial reserves
5 were the original metric used for determining whether a CRAC should trigger. BPA decided in
6 the WP-02 Final Proposal to use AMNR rather than financial reserves, because net revenues are
7 a more standard financial metric than reserves (cash). The use of AMNR is proposed to continue
8 for FY 2010-2011.

9
10 **4.3.2.1 Basic Description of the CRAC**

11 The CRAC for FY 2010-2011 is essentially the same as the CRAC for FY 2007-2009. It is an
12 annual upward adjustment in energy and load variance rates subject to the CRAC. In addition,
13 since the REP is now being implemented using the PF Exchange rate, the CRAC also creates a
14 reduction in REP benefits. The CRAC is limited to the annual collection amount – or cap – of
15 \$300 million. The threshold for triggering the CRAC is an amount of PS AMNR as accumulated
16 since the end of FY 1999. The AMNR threshold values are calibrated to be equivalent to PS
17 financial reserve levels of \$750 million.

18
19 The CRAC (and NFB Adjustment and DDC) calculations would be made shortly before the
20 beginning of each year in the rate period. A forecast of the year-end PS AMNR would be made
21 after the Third Quarter Review and then compared to the thresholds for the CRAC and the DDC.
22 If this PS AMNR forecast is below the CRAC threshold, an upward rate adjustment and a
23 downward REP benefit adjustment would be calculated for the duration of the upcoming fiscal
24 year. If the forecast is above the threshold for the DDC, a downward rate adjustment and
25 upward REP benefit adjustment would be calculated to distribute dividends to applicable rates
26 for the duration of the upcoming fiscal year.

Table 3: CRAC Annual Thresholds and Caps
[Dollars in Millions]

A	B	C	D	E
AMNR	CRAC	CRAC	Approx.	Maximum
Calculated at	Applied	Threshold as	Threshold as	CRAC Recovery
End of Fiscal	to Fiscal	Threshold as	Measured in	Amount
Year	Year	Measured in	Measured in	(CRAC Cap)*
		AMNR	PS Reserves	
2009	2010	\$14.3	\$750	\$300
2010	2011	\$140.6	\$750	\$300

* The CRAC Cap may be modified by NFB Adjustments

4.3.2.1.1 Administrator’s Discretion to Adjust the CRAC

The CRAC methodology would include a process that allows the Administrator to look ahead to the remaining fiscal year(s) of the rate period and determine whether any or all of the CRAC is needed to help BPA maintain its financial standing. The ability to apply discretion in the CRAC adjustment is tempered by the requirement to maintain the TPP standard for the remainder of the rate period. This requirement protects the TPP standard but provides for lower rates if the Administrator determines that s/he will not need all of the additional revenues to meet the TPP standard. A CRAC that is calculated for FY 2010 may be reduced from the calculated amount as long as the two-year TPP for FY 2010-2011 remains at or above 95.0 percent. The Administrator may adjust the parameters (i.e., the Cap and Threshold) for the CRAC applicable to FY 2011 to maintain the FY 2010-2011 TPP. A CRAC that is calculated for FY 2011 may be reduced from the calculated amount as long as the one-year TPP for FY 2011 would still be at or above 97.5 percent.

4.3.3 Dividend Distribution Clause (DDC)

One of the financial policy objectives for this rate case is to ensure that PS reserves do not accumulate to excessive levels. See Bliven and Lefler, WP-10-E-BPA-10. The DDC is triggered if PS AMNR is above (instead of below as with the CRAC) a threshold, and if so, there is a downward adjustment to rates and an upward adjustment to REP benefits. In the same way

1 that a CRAC passes bad financial outcomes to BPA’s customers, a DDC passes good financial
 2 outcomes to BPA’s customers.

3 **Table 4: DDC Thresholds**
 4 [Dollars in Millions]

5	A	B	C	D
6	AMNR		DDC	Approx.
7	Calculated at	DDC Applied	Threshold as	Threshold as
8	End of Fiscal	to Fiscal	Measured in	Measured in
9	Year	Year	AMNR	PS Reserves
10	2009	2010	\$314.3	\$1,050
11	2010	2011	\$440.6	\$1,050

12
 13 **4.4 Tools Not Modeled in the ToolKit**

14 **4.4.1 The NFB Mechanisms**

15 Being certain it can cover its fish and wildlife costs is an extremely important objective for BPA.
 16 Because of pending and possible litigation over BPA’s fish and wildlife obligations, it is
 17 impossible to determine now with any certainty the approach to fish recovery and the associated
 18 costs that BPA will ultimately be required to implement during FY 2010-2011.

19
 20 The possibilities for FY 2010-2011 are many and mostly unknowable at this time, and as a result
 21 probabilities cannot be estimated for any particular scenario that might be created. Because the
 22 uncertainty is open-ended, BPA believes it is necessary to have an equally open-ended
 23 adjustment mechanism to ensure that BPA can fund its fish and wildlife obligations despite the
 24 uncertainty. This proposal includes two related features that help to mitigate the financial risk to
 25 BPA and its stakeholders caused by uncertainty over future fish and wildlife obligations under
 26 the FCRPS BiOp and their financial impacts. These are the NFB Adjustment and the Emergency
 27 NFB Surcharge, collectively referred to as the NFB Mechanisms. The NFB Mechanisms are
 28 explained in the General Rate Schedule Provisions, WP-10-E-BPA-07, section II.G.

1 An NFB Trigger Event is one of the following four kinds of events that results in changes to
2 BPA’s FCRPS Endangered Species Act (ESA) obligations compared to those in the most recent
3 Power rate Final Proposal as modified prior to this Trigger Event:

- 4 1) A court order in *National Wildlife Federation vs. National Marine Fisheries*,
5 CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by
6 NMFS (now known as NOAA Fisheries Service), or any appeal thereof
7 (“Litigation”)
- 8 2) An agreement (whether or not approved by the Court) that results in the resolution
9 of issues in, or the withdrawal of parties from, the Litigation
- 10 3) A new FCRPS BiOp
- 11 4) A BPA commitment to implement Recovery Plans under the ESA that results in
12 the resolution of issues in, or the withdrawal of parties from, the Litigation

13
14 The NFB Mechanisms protect the financial viability of BPA and its financial resources from the
15 potentially large impact of changes in the operation of the Columbia River hydro system or in
16 fish and wildlife program costs that are directly related to FCRPS BiOp litigation (as specified
17 above).

18 19 **4.4.1.1 The NFB Adjustment**

20 The NFB Adjustment would result in an upward adjustment to the CRAC Cap for any year in the
21 rate period if one or more NFB Trigger Events with financial effects occurs in the previous year
22 (unless one or more Emergency NFB Surcharges in the previous year completely collected
23 additional revenue equal to the financial effects). The NFB Adjustment could modify the CRAC
24 Cap applicable to rates for FY 2010 or 2011 based on changes in modified net revenue in
25 FY 2009 or 2010.

1 While the NFB Adjustment increases the Cap on the amount the CRAC can collect, it does not
2 necessarily increase the amount of revenue collected. If the NFB Adjustment triggers but PS
3 AMNR is above the threshold, there will be no adjustment to rates, because the CRAC will not
4 trigger at all. If the NFB Adjustment triggers and PS AMNR is below the threshold, but not by
5 more than \$300 million, the CRAC will trigger for an amount that is below the original Cap. On
6 the other hand, if PS AMNR is more than \$300 million below the threshold, the NFB Adjustment
7 will allow BPA to recover more than the \$300 million Cap.

8
9 As a result of the Partial Resolution of Issues in the WP-07 rate proceeding, BPA and parties
10 agreed that any revenues above \$300 million resulting from the NFB Adjustment to the Cap
11 should be collected over a different revenue basis than regular CRAC revenues. BPA is
12 proposing to continue this treatment in the Initial Proposal. CRAC revenue amounts below the
13 original CRAC Cap (before the NFB Adjustment Calculation) would be collected from LLH and
14 HLH energy and Load Variance rates. CRAC revenue amounts in excess of the CRAC Cap as
15 shown in Table 3, would be collected from LLH and HLH energy, Load Variance and Demand
16 rates proportionally under the firm power rate schedules subject to the CRAC. As a result,
17 CRAC revenue amounts for the financial impacts of the NFB Adjustment would be spread over a
18 larger basis than the CRAC, thus lowering the percentage adjustment to the rates. This
19 difference produces a complexity in the CRAC adjustment in that it would require two
20 percentages to be applied to applicable rates if the NFB Adjustment triggers in a year that the
21 CRAC Amount is greater than the original Cap amount of \$300 million.

22 23 **4.4.1.2 The Emergency NFB Surcharge**

24 The Emergency NFB Surcharge results in nearly immediate increases in net revenue for PS if (a)
25 an NFB Trigger Event occurs, and (b) BPA is in a “Cash Crunch” and cannot prudently wait
26 until the next year to collect incremental net revenue. A Cash Crunch is defined to exist when

1 BPA calculates that the within-year Agency TPP (i.e., including both TS and PS) is below
2 80 percent. The Surcharge increases net revenue by making an upward adjustment to specified
3 Power rates and reductions in REP benefits.

4
5 The Emergency NFB Surcharge addresses the fact that the CRAC does not produce revenues
6 until the year following the fiscal year in which Financial Effects of a Trigger Event are
7 experienced. Thus, the financial benefit of the NFB Adjustment may be too late if BPA is in a
8 Cash Crunch when a Trigger Event occurs. For the WP-10 rates, the Surcharge may be
9 implemented in FY 2010 if the events required to impose the Surcharge occur in that fiscal year
10 or in FY 2011 if the requisite events occur in that year.

11 12 **4.4.1.3 Multiple NFB Trigger Events**

13 There can be multiple NFB Trigger Events in one year. If BPA is not in a Cash Crunch in such a
14 year, then there will be only one final analysis per year that calculates the NFB Adjustment to the
15 Cap on the CRAC applicable to the next fiscal year. If BPA is in a Cash Crunch in such a year,
16 there may be more than one Emergency NFB Surcharge calculated and applied during that year.
17 For example, there could be more than one court order in FY 2010 that increases the financial
18 impacts of operations in FY 2010. If BPA were in a Cash Crunch, there could be an Emergency
19 NFB Surcharge calculated for each of the Trigger Events and applied during FY 2010. If BPA
20 were not in a Cash Crunch in FY 2010, both of these triggering events would be included in the
21 calculation of the single NFB Adjustment that would increase the Cap on the CRAC applicable
22 to FY 2011.

23
24 Each NFB Adjustment affects only one year. However, since the comparison used to calculate
25 the NFB Adjustment is between the actual operation for fish and the operation assumed in the
26 rate case (as modified prior to a Trigger Event), it is possible for a Trigger Event to affect

1 operations for more than one year of the rate period. For example, a decision in FY 2009 may
2 affect operations in both FY 2009 and FY 2010. The analysis of the total financial impact during
3 FY 2009 for adjusting the Cap on the CRAC applying to FY 2010 would be separate from the
4 analysis of the total financial impact during FY 2010 for adjusting the Cap on the CRAC
5 applying to FY 2011 (or for implementing an Emergency NFB Surcharge during FY 2010).
6 Increases in the financial impacts during FY 2011 are not covered by the NFB Adjustment in the
7 proposed rates, because incorporating those increases through an NFB Adjustment would require
8 a CRAC during FY 2012, and the rates for FY 2012 are not covered by this rate case. However,
9 financial impacts during FY 2011 are covered by the Emergency NFB Surcharge provisions
10 applicable to FY 2011 in the proposed rates.

11 12 **4.4.2 Liquidity Tools**

13 BPA has relied on financial reserves for mitigating two types of financial risk that are related but
14 can be usefully distinguished. The risk that is the primary subject of the Risk Analysis and
15 Mitigation Study is that BPA might not have sufficient cash on September 30 to make full
16 payments to the Treasury. BPA's TPP standard, described in the introductory section of this
17 Study, defines a way to measure this risk (TPP) and a standard that reflects the Agency's
18 tolerance for this risk (95 percent for a two-year rate period). The second risk can be called
19 liquidity risk – the risk that, at some time within a fiscal year, BPA will not have sufficient cash
20 to meet its immediate financial obligations (whether to the Treasury or to other creditors).

21
22 Financial reserves have served as one of BPA's main tools for mitigating Treasury payment risk,
23 and also for mitigating liquidity risk. In each recent rate case, BPA has defined a need for
24 reserves for liquidity ("liquidity reserves," formerly known as "working capital"). This level is
25 based on a determination of BPA's total need for liquidity, and a subsequent determination of

1 how much of that need is properly attributed to PS. During FY 2009, BPA is continuing to work
2 on more accurate assessments of its total liquidity need.

3 4 **4.4.2.1 Direct Pay of EN Budget**

5 BPA is proposing to continue the “Direct Pay” method of funding Energy Northwest’s cash
6 needs.

7 8 **4.4.2.2 Flexible PF Rate Program**

9 During the WP-07 rate case, BPA and its customers developed and later implemented the
10 Flexible PF Rate Program as part of an endeavor to identify additional sources of liquidity. The
11 Flexible PF Rate Program allows BPA to increase the amount payable by participating customers
12 for power service in a given month and thereafter reduce the amount payable for power service
13 from such customers in subsequent months. The program is intended to increase BPA’s liquidity
14 by shaping power revenues to cover extraordinary cash flow requirements. The Initial Proposal
15 is neither proposing to continue nor proposing to discontinue the Flexible PF Rate Program at
16 this time. *See* Bliven and Lefler, WP-10-E-BPA-10.

17 18 **4.4.2.3 Treasury Note**

19 In FY 2008, BPA reached an agreement with the Treasury that makes a \$300 million short-term
20 note available to the Administrator for up to three years that can be used to pay expenses. BPA’s
21 Finance and Risk staffs have concluded that this note can be prudently relied on as a source of
22 liquidity. *See* Bliven and Lefler, WP-10-E-BPA-10.

23 24 **4.4.2.4 The Net Impact on the Liquidity Reserve Level**

25 At the time of the development of the WP-10 Initial Proposal, BPA had not made a new
26 determination of its total need for liquidity nor the amount of liquidity needed to be supplied by

1 PS. Therefore, the most recent determination, from the WP-07 Final Proposal, is being used for
2 this Proposal. That determination was that with EN Direct Pay, PS needed \$175 million of
3 liquidity. Since the new Treasury expense note is larger than that amount, and TS does not
4 currently need to rely on the Treasury note for additional liquidity, staff are proposing that no PS
5 reserves need to be set aside to provide liquidity (i.e., liquidity reserves = \$0). BPA will
6 continue to study this issue during FY 2009, and may have a different assessment of the needs
7 for liquidity for PS and a different assessment of the sources of liquidity available for meeting
8 the PS needs for liquidity that will be included in the Final Proposal.

9 10 **4.5 ToolKit Modifications and Changes in TPP Modeling**

11 Changes in risk mitigation since the WP-07 rate case and since the WP-07 Supplemental rate
12 case are reflected in changes in how the ToolKit models TPP. The following sections cover
13 areas where the risk mitigation tools in the Initial Proposal differ from the WP-07 or WP-07
14 Supplemental risk mitigation tools.

15 16 **4.5.1 IOU REP Settlement Benefits Replaced by REP Program**

17 The 2000 REP Settlement that was modeled in the WP-07 rate proceeding risk analysis was
18 overturned by the U.S. Court of Appeals for the Ninth Circuit in May, 2007. Like the WP-07
19 Supplemental rate proceeding, the Initial Proposal contains provisions for the operation of a
20 traditional REP rather than the REP Settlement terms that were used in the WP-07 Final
21 Proposal. For risk mitigation, this is relevant mainly in how the CRAC and DDC would be
22 calculated.

23
24 BPA has participated in extensive discussions with IOUs, COUs, and other parties about how to
25 resume the operation of the REP. These discussions have, among other things, culminated in
26 some decisions by BPA about the REP that guided the design of the CRAC and DDC with

1 regard to REP benefits. *See generally* 2007 Supplemental Wholesale Power Rate Case
2 Administrator's Final Record of Decision, WP-07-A-05. The GRSPs in the WP-07
3 Supplemental Final Proposal defined the CRAC and DDC as applying to several PF rates,
4 including the PF Exchange rate, but did not specify exactly how a CRAC or DDC would apply to
5 the PF Exchange rate. Instead of having a CRAC or DDC affect REP benefits by modifying the
6 PF Exchange rate and then recalculating benefits for each exchanging utility, staff are proposing
7 that any CRAC or DDC would be applied proportionally to all exchanging utilities' REP
8 Benefits. Staff believe this is more consistent with the extensive discussions about how to
9 implement the reconstituted REP. A portion of any CRAC or DDC would be allocated to REP
10 Benefits, and this portion would be applied as a reduction to or increase in REP Benefits in
11 proportion to the magnitude of the REP Benefits previously calculated for each exchanging
12 utility for that fiscal year. GRSPs, WP-10-E-BPA-07, sections II.D and II.F.

13
14 The RAM2010 was used to test how REP Benefits would change and how the rates subject to the
15 CRAC and DDC would change if quantities of PNRR were added or subtracted, taking into
16 account the 7(b)(2) rate test impacts and impacts on the Slice true-up. These calculations
17 showed that for a CRAC that generated an additional \$200 million of incremental net revenue for
18 BPA, reductions in REP Benefits account for 27 percent of this amount and increases in non-
19 Slice PF, IP and other rates subject to the CRAC would generate 80.5 percent of this amount.
20 These amounts total more than 100 percent because the reductions in REP Benefits would lead to
21 a decrease in Slice expense and would therefore increase the size of the True-Up BPA owes the
22 Slice customers (or decrease the size of the True-Up Slice customers owe BPA), partially
23 offsetting the net revenue benefit of the CRAC. This methodology has been used to define how
24 a CRAC or DDC would apply to REP Benefits. After the amount of incremental net revenue to
25 be recovered by a CRAC is determined, or the amount of decremental net revenue to be
26 distributed by a DDC is determined, portions allocated to REP Benefits and to non-Slice PF, IP

1 and other rates subject to the CRAC are determined: 27 percent of the incremental or
2 decremental amounts is allocated to REP Program benefits, and 80.5 percent is allocated to non-
3 Slice PF, IP and other rates subject to the CRAC. REP Benefit amounts are increased or
4 decreased proportionally across all exchanging utilities. A percentage is calculated, using the
5 most recent forecast of revenues from rates subject to the CRAC, that when applied to the
6 subject rates will produce 80.5 percent of the total CRAC or DDC amount. That percentage is
7 then applied to the subject rates for the next fiscal year.

8 9 **4.5.2 Treasury Payment Deferral Modeling**

10 In the event of a deferral of payment of principal to the Treasury in the ToolKit, the ToolKit
11 assumes that BPA will track the balance of payments that have been deferred and will repay this
12 balance to the Treasury at its first opportunity. “First opportunity” is defined for TPP
13 calculations as the first time PS ends a fiscal year with more than \$100 million above its
14 minimum liquidity level. The PS minimum liquidity level in this proposal is \$0 million (*see*
15 section 4.4.2.4), so the ToolKit is modeling the repayment as occurring as soon as possible while
16 not bringing the level of PS reserves below \$0 million at the end of the fiscal year following the
17 deferral. The same applies to subsequent fiscal years if the repayment cannot be completed in
18 the first year after the deferral.

19 20 **4.5.3 New Outputs**

21 Many of the output features that were added to the ToolKit during the WP-07 rate case are no
22 longer relevant or are no longer working properly due to lack of time to update them after
23 removing the logic that modeled the REP Settlement Agreements.

24 25 **4.5.3.1 Graphs**

26 This worksheet is not functional at this time.

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4.5.3.2 IOU REP Settlement Benefits Output

The worksheet, "IOU_Adj," is not functional at this time.

4.6 ToolKit Inputs and Assumptions

4.6.1 Risk Analysis Model (RiskMod)

RiskMod distributions are created for the current year, FY 2009, and the rate period, FY 2010-2011. TPP is measured only for the two-year rate period, but the starting reserves available for risk for FY 2010 depend on events yet to unfold in FY 2009; these runs reflect that FY 2009 uncertainty

4.6.1.1 Non-Operating Risk Model (NORM)

NORM distributions are created for the FY 2009-2011 period that reflect the uncertainty around non-operating expenses.

4.6.2 Inputs and Assumptions on the Toolkit Main Page

4.6.2.1 Starting PS Reserves Available for Risk

The FY 2009 starting PS reserves have a known value of \$874.9 million based upon the FY 2008 Fourth Quarter Review. Each of the 3,500 games starts with this value. This figure is determined from the total BPA reserves at the end of FY 2008 by excluding reserves attributed to TS. An additional computational step then excluded funds that were in the Bonneville Fund due to the cessation of the REP Settlement Agreements. At the end of FY 2008, approximately \$195 million of funds collected from rates that BPA had planned to pay to exchanging IOUs remained in the Bonneville Fund. Since these funds are expected to be completely distributed to IOUs and COUs in response to the court ruling; *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007), the funds are not considered to be available for risk.

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4.6.2.2 Starting AMNR

The FY 2009 starting AMNR value of \$69.0 million was based upon the FY 2008 Fourth Quarter Review. Each of the 3,500 games starts with this value.

4.6.2.3 Treatment of Treasury Deferrals

Treasury deferrals are treated using the “Hybrid” logic described in section 4.5.2.

4.6.2.4 Other Agency Reserves Temporarily Available

The Initial Proposal does not rely any of the reserves attributed to TS as available for use in meeting the PS TPP requirement. Therefore, cells J14:J16 are set to zero. A different assumption will be considered during the rate proceeding. *See* Bliven and Lefler, WP-10-E-BPA-10.

4.6.2.5 Interest Rate Earned on Reserves

Interest earned on PS reserves is calculated at the rate of 5.05 percent per year.

4.6.2.6 Interest Credit Assumed in the Net Revenues

A basic feature of the ToolKit is the ability to calculate interest earned on PS reserves separately for each game. The revenue requirement includes an assumption of interest earned on reserves, and that assumption is deterministic, that is, it does not vary from game to game. To capture the interest effects of this variability TPP, the revenue requirement assumptions about interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The revenue requirement amounts that are backed out are \$64.16 million, \$50.35 million, and \$49.57 million for FY 2009, FY 2010, and FY 2011, respectively.

1 **4.6.2.7 The Cash Timing Adjustment**

2 The cash timing adjustment reflects the interest credit impact of the typical shape of PS reserves
3 throughout a fiscal year. The ToolKit calculates interest earned on reserves by making the
4 simplifying assumption that reserves change linearly from the beginning of the year to the end.
5 It takes the average of the starting reserves and the ending reserves and multiplies that figure by
6 the interest rate for that year. Because PS cash payments to the Treasury are not evenly spread
7 throughout the year, but instead are heaviest in September, PS will typically earn more interest in
8 BPA's monthly calculations than the straight-line method yields. The cash timing adjustment is
9 a number from the repayment study that approximates this additional interest credit earned on
10 reserves throughout the fiscal year. The cash timing adjustments for this proposal are
11 \$7.0 million, \$11.7 million, and \$9.1 million for FY 2009, FY 2010, and FY 2011, respectively.

12
13 **4.6.2.8 Cash Lag for PNRR**

14 These numbers appear in the input section of the ToolKit's main page, but they are calculated
15 automatically. When the ToolKit calculates a change in PNRR (either a decrease, or more
16 typically, an increase), it calculates how much of the cash generated by the increased rates would
17 be received in the subsequent year, since September revenue is not received until October. In
18 order to treat ToolKit-generated changes in the level of PNRR on the same basis as amounts of
19 PNRR that have already been assumed in the rates calculation, the ToolKit calculates this lag for
20 PNRR that is embedded in the RiskMod output file the ToolKit reads. For the Initial Proposal,
21 \$48 million of PNRR was embedded in the RiskMod output for each of the two years in the rate
22 period. The ToolKit calculates that one-twelfth of this revenue is received as cash one year later.
23 For FY 2010, this means that cash will be lower than net revenue by one-twelfth of \$48 million,
24 or \$4 million, and cell K15 therefore contains -4. For FY 2011, the \$4 million in cash lagging in
25 from FY 2010 revenue balances the \$4 million of FY 2011 revenue that lags into FY 2012,

1 outside the time scope of this analysis. Therefore, the total cash adjustment for PNRR lag for
2 FY 2011 is \$0.

3 4 **4.6.2.9 Other Cash Adjustments**

5 There are no adjustments of this type in the Initial Proposal.

6 7 **4.6.3 Inputs on the ToolKit “IOU_Data” Sheet**

8 These numbers are not used at this time.

9 10 **4.7 ToolKit Output**

11 **4.7.1 TPP**

12 The two-year TPP is 95.0 percent. Only one deferral was registered for FY 2009. There were 23
13 in FY 2010, and 163 in 2011. The expected value of deferred Treasury payments was
14 \$0.4 million in FY 2010, for an average of \$62 million per deferral. In FY 2011, the expected
15 value of the amount deferred was \$8.9 million, for an average of \$195 million per deferral.

16 17 **4.7.2 Ending PS Reserves**

18 Known starting PS reserves for FY 2009 were \$874.9 million. The expected values of ending
19 reserves for FY 2009 through 2011 were \$695 million, \$860 million, and \$865 million. Over
20 3,500 games, the range of ending FY 2011 reserves was from \$0 (indicating a deferral) to \$2,906
21 million (which would result in a DDC for FY 2012 if the WP-12 rate case includes a DDC
22 comparable to that of the WP-07, WP-07 Supplemental, or WP-10 rate proposals). The
23 50 percent confidence interval for ending reserves was \$542 to 862 million for FY 2009, \$563 to
24 1,123 million for FY 2010, and \$465 to 1,204 million for FY 2012.

1 **4.7.3 CRAC and DDC**

2 The CRAC triggered 2,051 times in FY 2010 (59 percent), with an average of \$181 million per
3 triggering, yielding an expected value of \$106 million of CRAC revenue for that year. It
4 triggered 1,395 times in FY 2011 (40 percent), with an average of \$208 million per triggering,
5 and an expected value of \$83 million of revenue for that year. The CRAC was at its maximum
6 (\$300 million) 535 times in FY 2010 (26 percent of the times it triggered) and 609 times in
7 FY 2011 (44 percent of the times it triggered).

8
9 The DDC triggered 211 times in FY 2010 (6 percent), with an average size of \$104 million,
10 yielding an expected value of \$6 million for that year. In FY 2011, the DDC triggered
11 1,094 times (31 percent), yielding an average of \$265 million per triggering, and an expected
12 value of \$83 million of dividend distributions for the year.

13
14 **4.7.4 Other ToolKit Results**

15 Other ToolKit results are shown in the Documentation, WP-10-E-BPA-04B, TK Main.

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DOE/BP-3987 • February 2009 • 1C