BP-14 Initial Rate Proposal

Power Risk and Market Price Study

November 2012

BP-14-E-BPA-04

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POWER RISK AND MARKET PRICE STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability

FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	IntercontinentalExchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NCP	Non-Coincidental Peak
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)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)

Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning 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
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
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
PRS	Power Rates Study
PS	BPA Power Services
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
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement

RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
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
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION

The Bonneville Power Administration's (BPA) business environment is replete with uncertainty that a rigorous ratesetting process must consider. The objective of the risk study is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on Power Services' (PS) net revenue (total revenue less total expenses) and cash flow. The risk study is meant to ensure that power rates are set high enough that the probability that BPA can meet its cash obligations is at least as high as required by BPA's Treasury Payment Probability (TPP) standard. This evaluation is carried out in two distinct steps: a risk assessment step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which risk mitigation tools are assessed with respect to their ability to recover power costs given these uncertainties. The risk assessment estimates both the central tendency of risks and the potential variability of those risks. Both of these elements are used in the ratemaking process.

In this study the words "risk" and "uncertainty" are used in similar ways. Generally, each can have both up-side and down-side possibilities—that is, both beneficial and harmful impacts on BPA objectives. The BPA objectives that may be affected by the risks considered in this study are generally BPA's financial objectives.

1.1 Purpose of the Power Risk and Market Price Study

The Power Risk and Market Price Study (Study) characterizes the market price and PS net revenue distributions and demonstrates that the rates and risk mitigation tools together meet BPA's standard for financial risk tolerance—the TPP standard. This Study presents the natural gas price forecast, the electricity market price forecast, the quantitative and qualitative analysis of risks to PS net revenue, and tools for mitigating those risks, and establishes the adequacy of those tools for meeting BPA's TPP standard.

1.1.1 BPA's Treasury Payment Probability 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 meeting 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. This 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, not the probability for a single year. 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/Finance/FinancialInformation/FinancialPlan/Documents/10-year-bp-financial-plan.pdf; the 2008 updated Financial Plan is available at http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Documents/BPA-financial-plan.pdf.

By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e (a)(2)(A). Therefore, TPP is a prospective measure of BPA's overall ability to meet its financial obligations.

The following items (explained in more detail in section 3 of this Study) are included in the calculation of TPP:

(1) *Starting PS Reserves (Starting Financial Reserves Available for Risk Attributed to PS).* Financial reserves comprise cash and investment instruments held in the BPA Fund and the deferred borrowing balance. Financial reserves available for risk do not include funds held for others. For example, amounts in the BPA Fund that were collected from customers after BPA stopped making payments for Residential Exchange benefits in FY 2007 that will be distributed eventually are excluded. Deferred borrowing amounts exist when planned borrowing has not yet been completed. When the borrowing is completed, cash in the BPA Fund is increased and the deferred borrowing balance is reduced by the same amount, leaving financial reserves unchanged.

(2) *Planned Net Revenues for Risk.* PNRR is the final component of the revenue requirement that may be added to annual expenses. PNRR is needed only when the risk mitigation provided by starting financial reserves and other risk mitigation tools is not sufficient to meet the TPP standard.

(3) *BPA's Treasury Facility.* The Treasury Facility is an arrangement that BPA has with the US Treasury, allowing BPA to borrow up to $750 million on a short-term basis. The full $750 million in the Treasury Facility is considered to be available for the liquidity needs associated with PS. The Treasury Facility functions somewhat like additional financial reserves.

(4) *Within-year Liquidity Need.* The within-year liquidity need is an amount of cash or short-term borrowing capability that must be set aside for meeting within-year liquidity needs (or risks). The $300M amount assumed for setting the BP-12 rates

has been increased to $320M for the BP-14 Initial Proposal to provide assurance that BPA will have sufficient liquidity to meet up to $20M of possible outstanding margin calls required by BPA's trading of financial instruments.

(5) *Liquidity Reserves Level.* The liquidity reserves level is the amount of PS Reserves that is allocated for meeting the within-year liquidity need. For this Study, the liquidity reserves level is $0.

(6) *Liquidity Borrowing Level.* The liquidity borrowing level is the amount of the Treasury Facility set aside to meet the within-year liquidity need. For this Study, the liquidity borrowing level is $320 million. This leaves $430 million of the Treasury Facility available for year-to-year liquidity needs (*i.e.*, TPP needs).

(7) *Cost Recovery Adjustment Clause.* The CRAC is an upward adjustment to the applicable power and transmission rates. The adjustment would be applied to rates charged for service beginning in October following the fiscal year in which PS Accumulated Net Revenue (ANR) falls below the CRAC threshold. The threshold is set at the ANR equivalent of $0 in financial reserves available for risk attributed to PS.

(8) *Dividend Distribution Clause.* The DDC is a downward adjustment to the applicable power and transmission rates. The adjustment would be applied to rates charged for service beginning in October following the fiscal year in which ANR is above the DDC threshold. The threshold is set at the ANR equivalent of $750 million in financial reserves available for risk attributed to PS.

1.1.2 How Risk and Market Price Results Are Used

The main result from the risk assessment and mitigation process is the TPP calculation. If this number is 95 percent or higher, then the rates and risk mitigation tools meet BPA's TPP standard. The results also include the thresholds and caps for the CRAC and the DDC. These values are incorporated in the General Rate Schedule Provisions (GRSPs), BP-14-E-BPA-09, and will be applied in later calculations outside the ratesetting process for determining whether a CRAC or DDC will be applied to certain power and transmission rates for FY 2014 or FY 2015.

Forecasts of electricity market prices are used in the Power Rates Study, BP-14-E-BPA-01, for:

(a) Prices for surplus sales and balancing purchases
(b) Prices for augmentation purchases
(c) Load Shaping rates
(d) Load Shaping True-up rate
(e) Resource Shaping rates
(f) Resource Support Service rates
(g) Shaping the Demand rate for each of PF, IP, NR
(h) Priority Firm Power (PF) Tier 2 Balancing Credit
(i) PF Unused RHWM Credit
(j) Scaling PF Tier 1 Equivalent rates
(k) Scaling Priority Firm Melded rates
(l) Balancing Augmentation Credit
(m) Scaling Industrial Firm Power (IP) energy rates
(n) Scaling New Resources Firm Power (NR) energy rates
(o) Energy Shaping Service of NLSL True-Up rate

The electricity market price forecast also is used in the Generation Inputs Study, BP-14-E-BPA-05, to compute the variable cost component of generation input capacity; in section 2 of this Study for the risk assessment; and for setting the Average System Costs (ASCs) (which occur in separate ASC processes) that are used in ratesetting.

1.2 Overview of the Risk Assessment and Mitigation

The risk study uses a set of models, shown in Figure 1. These models are further described throughout the course of the Study.

1.2.1 Risk Mitigation Objectives

The following policy objectives guide the development of the risk mitigation package :

(a) Create a rate design and risk mitigation package that meets BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability.

(b) Produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the aging infrastructure.

(c) Set lower, but adjustable, effective rates rather than higher, more stable rates.

(d) Include in the risk mitigation package only those elements that can be relied upon.

(e) Do not let financial reserve levels build up to unnecessarily high levels.

(f) Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation.

(g) Rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.

It is important to understand that these objectives are not completely independent and may sometimes conflict with each other; thus, BPA must create a balance among these objectives when developing its overall risk mitigation strategy.

1.2.2 Quantitative and Qualitative Risk Assessment and Mitigation

This Study distinguishes between quantitative and qualitative perspectives of risk. The quantitative risk assessment is a set of quantitative risk simulations that are modeled using a Monte Carlo approach, a statistical technique in which deterministic analysis is performed on a distribution of inputs, resulting in a distribution of outputs suitable for analysis. The output from the quantitative risk assessment is a set of 3,200 possible financial results (net revenues) for each of the two years in the rate period (fiscal years (FY) 2014–2015) and for the year preceding the rate period (FY 2013). The models used in the quantitative risk assessment are covered in section 2 of this Study.

The 3,200 games from the quantitative risk assessment are used in the quantitative risk mitigation step to determine if BPA's financial risk standard, the 95 percent TPP standard, has been met. The model used for the quantitative risk mitigation step is covered in section 3 of this Study.

BPA faces some risks that are incorporated into the risk assessment and mitigation in qualitative rather than quantitative ways. For the most part, the qualitative risk assessment comprises logical assessments of possible events that could have significant financial consequences for BPA. The qualitative risk mitigation describes measures BPA has put in place, or responses BPA would make, to these events, and then presents logical analyses of whether any significant residual financial risk remains for BPA after taking into account the existing or newly adopted mitigation measures. The qualitative risk assessment is covered in section 4 of this Study.

All of these analyses work together so that BPA develops rates that recover all of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

1.2.2.1 Overview of Quantitative Risk Assessment

The quantitative risk assessment is performed using models that quantify uncertainty. There is uncertainty in market prices, reflecting the uncertainty inherent in the fundamental drivers; *e.g.*, the natural gas price. There is uncertainty in the amount of surplus power that BPA will have for secondary sales. There is uncertainty in the costs faced by BPA beyond those expenses related to operation of the system; *e.g.*, fish and wildlife-related expenses. These uncertainties affect the PS net revenue.

Projections of market prices for electricity are used for many aspects of setting power rates, including the quantitative analysis of risk, presented in section 2 of the Study. This Study explains the data used for constructing the probabilistic market price forecast and how those data are used in generating the PS net revenue forecast.

1.2.2.2 Overview of Quantitative Risk Mitigation

Financial reserves is BPA's primary tool for managing the financial risks it faces. Since the WP-02 rate proceeding, BPA has included cost recovery adjustment clauses that can adjust power rates between rate proceedings. These clauses add additional risk mitigation to that provided by financial reserves. In this rate proceeding, the CRAC, DDC, and *N*ational Marine

Fisheries Service, *F*ederal Columbia River Power System, *B*iological Opinion (NFB) Mechanisms will apply to certain Transmission rates for Ancillary and Control Area Services. When financial reserves available for risk plus the additional revenue earned through the CRAC do not provide sufficient risk mitigation to meet the 95 percent TPP standard, PNRR is added to the revenue requirement. This increases power rates, which generate additional reserves. This Study documents the risk mitigation package included in the BP-14 power rates. See section 1.2.1 for a discussion of the main policy objectives considered when developing this risk mitigation package.

1.2.2.3 Overview of Qualitative Risk Assessment and Mitigation

Financial uncertainty that is not quantitatively modeled, and any mitigation measures for these risks, are described in section 4 of this Study. There are three primary categories of qualitative risks in this Study: Federal Columbia River Power System (FCRPS) Biological Opinion risks; risks associated with Tier 2 rate design; and risks associated with Resource Support Services (RSS). Biological Opinion risks are mitigated through the NFB Mechanisms described in this Study and GRSP II.N, BP-14-E-BPA-09.

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2. QUANTITATIVE RISK ASSESSMENT

2.1 Introduction

This section describes those uncertainties pertaining to Power Services, and hence BPA's financial risk in the context of setting power rates. Section 3 describes how BPA determines whether its risk mitigation measures are sufficient to meet the TPP standard given the risks detailed in this section.

Variability in PS net revenue, a product of uncertainty in both power generation and market prices, is substantial. In addition, BPA also considers uncertainty in (1) customer load; (2) Columbia Generating Station (CGS) output; (3) wind generation; (4) system augmentation costs; (5) PS transmission and ancillary services expenses; and (6) 4(h)(10)(C) credits. The effects of these risk factors on PS net revenue are quantified herein.

PS also faces risks not directly related to the operation of the power system. These non-operating risks are modeled in the Non-Operating Risk Model (NORM). These risks include the potential for CGS, Corps of Engineers (USACE), or U.S. Bureau of Reclamation (USBR) Operations & Maintenance (O&M) spending to differ from their forecasts. NORM also accounts for variability in interest rate expense . NORM also models variability in net revenues, including uncertainty due to possible court orders related to the 2008 FCRPS BiOp and uncertainty in the length of the CGS refueling outages in FY 2013 and FY 2015.

2.2 Study Models

BPA traditionally models risks using Monte Carlo simulation. Accordingly, AURORAxmp, NORM, and ToolKit each run 3,200 iterations, or games. AURORAxmp estimates electricity prices, and those prices in turn serve as inputs to numerous other studies, including this Study. RevSim combines Federal system generation with prices from AURORAxmp, as well as 4(h)(10)(c) credits and other revenues and expenses to produce 3,200 values for net revenue. The output of this process is combined with the distribution of output from NORM and provided to ToolKit, which calculates TPP. If TPP is below the 95 percent standard required by BPA's 10-Year Financial Plan, then one of several risk mitigation tools may be adjusted until the standard is met. These options include (1) raising the CRAC threshold, which makes it more likely that the CRAC will trigger; (2) increasing the cap on the annual revenue the CRAC can collect; and/or (3) adding PNRR to the revenue requirement. This study continues this traditional approach.

2.2.1 @RISK Computer Software

NORM is maintained in Microsoft Excel with the add-in risk simulation computer package @RISK, a product of Palisade Corporation, Ithaca, NY. @RISK allows analysts to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the probability distribution that reflects the specific risk, providing the necessary parameters that describe the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately quantifying risk are not developed in @RISK but in analyses external to @RISK.

2.2.2 R Statistical Software

The risk models used in AURORAxmp were developed in R (www.r-project.org). R is an open-source statistical software environment that compiles on several platforms. It is released under the GNU GPL (GNU General Public License) and is free software. R supports the development of risk models through an object-oriented, full procedural scripting environment. That is, it provides an interface for managing proprietary risk models, and has a native random number generator useful for sampling distributions from any kernel. For the various risk models, the historical data is processed in R, the risk models are calibrated, and the risk distributions for input into AURORAxmp are generated in a unified environment.

2.2.3 AURORAxmp

AURORAxmp (version 11.1.1001) is used to forecast electricity market prices. For all assumptions other than those explicitly enumerated in section 2.3 of this Study, the model uses data provided by the developer, EPIS Inc. AURORAxmp uses a linear program to minimize the cost of meeting load in the Western Electricity Coordinating Council (WECC), subject to a number of operating constraints. Given the solution (specifically, an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This approximates the price of electricity by assuming all resources are centrally dispatched, the equivalent of cost-minimization in production theory, and that the marginal cost of electricity approximates the price.

2.2.3.1 Operating Risk Models

Uncertainty in each of the following variables is modeled as independent:

(a) WECC loads

(b) Natural Gas Price

(c) Regional Hydroelectric Generation

(d) Pacific Northwest (PNW) Hourly Wind Generation

(e) CGS Generation

(f) PNW Hourly Intertie Availability

(g) PS Transmission and Ancillary Services Expenses

Each model uses historical data to calibrate a statistical model. The model can then, by Monte Carlo, generate a distribution of outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to AURORAxmp. Where applicable, that game also serves as input to RevSim. The prices from AURORA, combined with the generation and expenses from RevSim, constitute one net revenue game. It is important to note that each risk model may not generate 3,200 games, and where necessary bootstrap is used to produce a full distribution of 3,200 games. Each of the 3,200 draws from the joint distribution is identified uniquely, which guarantees coordination between AURORAxmp prices and RevSim inventory levels.

2.2.3.2 Revenue Simulation Model (RevSim)

RevSim calculates surplus energy revenue, balancing purchase expenses, system augmentation purchase expenses, and 4(h)(10)(C) credits for use in the Rate Analysis Model (RAM2014). It also simulates PS operating net revenue for use in ToolKit. Inputs to RevSim include the output of certain risk models discussed above (to the extent that they affect generation) and prices from AURORAxmp. RevSim also uses deterministic monthly load and resource data; revenue and expenses from RAM2014; and non-varying revenue and expenses from the Power Revenue Requirement Study, BP-14-E-BPA-02 , and section 2 of the Power Rates Study, BP-14-E-BPA-01.

RevSim uses the monthly risk data generated by the risk models and the monthly electricity prices estimated by AURORAxmp to compute surplus energy revenues, balancing purchase power expenses, system augmentation expenses, and section 4(h)(10)(C) credits for each of 3,200 games. The results are used in the revenue forecast and the calculation of power rates in RAM2014. The monthly flat surplus energy values calculated by RevSim for all 3,200 games per fiscal year are inputs to the PS Transmission and Ancillary Services Expense Risk Model, which calculates the average PS transmission and ancillary services expenses included in the Power Revenue Requirement Study, BP-14-E-BPA-02. The transmission expense forecasts from the PS Transmission and Ancillary Services Expense Risk Model are input into RevSim for use in calculating net revenue risk.

Expenses associated with the purchase of system augmentation are estimated using two approaches, one applying to the calculation of rates in RAM2014 and another determining net revenue provided to the ToolKit model. Each of these approaches is discussed in detail in section 2.6.2 of this Study.

RevSim uses the risk data generated by the various risk models and the monthly electricity market prices estimated by AURORAxmp to calculate 3,200 net revenue outcomes for each fiscal year during the rate period. This process yields a distribution of 6,400 annual net revenues. These are input into ToolKit, which evaluates whether a given risk mitigation package achieves BPA's 95 percent TPP standard for the two-year rate period. Figure 1 shows the processes and interactions among the models and studies.

2.2.4 Non-Operating Risk Model

NORM is an analytical risk tool that quantifies the impacts of non-operating risks in the ratesetting process. It was first used in ratesetting in the WP-02 rate proceeding. NORM models PS non-operating risks and risks around corporate costs covered by power rates. TS risks are not included in the analysis. In addition, NORM models some changes in revenue and some changes in cash flow. While the operating risk models and RevSim are used to quantify operating risks such as variability in economic conditions, load, and generating resource capability, NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the PS revenue requirement. NORM models the accrual impacts of the included risks, as well as Accrual-to-Cash (ATC) adjustments, which translate the net revenue impacts into cash flow impacts. NORM supplies 3,200 games (or iterations) of net revenue and cash flow impacts of the risks that it models. The outputs from NORM, along with the outputs from RevSim, are passed to the ToolKit model to assess the TPP.

2.2.4.1 NORM Methodology

NORM follows BPA's traditional approach to modeling risks, which uses Monte Carlo simulation. 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 probability distribution based on input specifications for that uncertainty. After all of the games are run, the results can be analyzed and summarized or passed to other tools.

2.2.4.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, subject matter experts were interviewed for each capital and expense item modeled. The subject matter experts were asked to assess the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. In some instances, the subject matter experts provided a complete probability distribution.

2.3 AURORAxmp Model Inputs

AURORAxmp produces a single electricity price forecast as a function of its inputs. That is, to produce a given number of price forecasts requires that AURORAxmp be run that same number of times, using different inputs. Risk models provide inputs to AURORAxmp, and the resulting distribution of market price forecasts represents a quantitative measure of market price risk. As mentioned, 3,200 independent games from the joint distribution of the risk models serve as the basis for the 3,200 market price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute market price forecast. The following subsections describe the various inputs and risk models used in AURORAxmp.

2.3.1 Natural Gas Prices Used in AURORAxmp

The price of natural gas is the predominant factor in determining the dispatch cost of a natural gas generator. When natural gas-fired resources are the marginal unit (the least-cost available generator to supply an incremental unit of energy), the price of natural gas determines the price of electricity. As natural gas prices rise, so does the dispatch cost of a natural gas-fired generator. To the extent that natural gas plants constitute the marginal generator, this translates into an increase in the market price for electricity.

2.3.1.1 Methodology for Deriving AURORAxmp Zone Natural Gas Prices

Each natural gas plant modeled in AURORAxmp operates using fuel priced at a natural gas hub according to the zone in which it is located. Each zone is a geographic subset of the WECC, detailed in Figure 2. The following describes how AURORAxmp derives natural gas prices in each zone.

The foundation of natural gas prices in AURORAxmp is the price at Henry Hub, a trading hub near Erath, Louisiana. Cash prices at Henry Hub are the primary reference point for the North American natural gas market.

Though Henry Hub is the point of reference for natural gas markets, AURORAxmp uses prices for 11 gas trading hubs in the WECC. The prices at hubs other than Henry are derived using their basis differentials, or the differences in prices between Henry Hub and the hub in question. Basis differentials reflect differences in the regional costs of supplying gas to meet demand, after accounting for pipeline constraints and pipeline costs. The 11 western hubs represent three major supply basins that are the source for most of the natural gas delivered in the western United States as well as western regional demand areas.

Sumas, Washington, is the primary hub for delivery of gas from the Western Canada Sedimentary Basin to western Washington and western Oregon. The Opal, Wyoming, hub represents the collection of Rocky Mountain supply basins that supply gas to the Pacific Northwest and California. The San Juan Basin has its own hub that primarily delivers gas to southern California. AECO, the primary trading hub in Alberta, Canada, is the primary benchmark for Canadian gas prices. Kingsgate is the hub that is associated with the demand center in Spokane, Washington. Two eastern Oregon hub locations, Stanfield and Malin, are included because major pipelines intersect at those locations. Pacific Gas and Electric (PG&E) Citygate represents demand centers in Northern California. Finally, Topock, Arizona; Ehrenberg, Arizona; and the Southern California Border represent intermediary locations between the San Juan Basin and demand centers in Southern California. Figure 3. For purposes of the basis differential forecast, the same price is used for each of these three hubs, as they are relatively specific to Southern California markets. The forecast of basis differentials is derived from historical price differences between Henry Hub and each of the other 11 trading hubs, along with projections of regional supply and demand.

The final step is to estimate the basis differential between each of the western trading hubs and its associated AURORAxmp zone. Sumas, AECO, Kingsgate, Stanfield, Malin, and PG&E Citygate are all associated with the Pacific Northwest, Northern California, and Canadian zones. Opal is associated with the Montana, Idaho South, Wyoming, and Utah zones. San Juan, Topock, Ehrenberg, and the Southern California Border are all associated with the Nevada, Southern California, Arizona, and New Mexico zones.

2.3.1.2 Recent Natural Gas Market Fundamentals

Henry Hub prices held around $4.00 from 2010 until late 2011 when they started to decline, eventually hitting a low of $1.82 in April 2012 (Figure 4), a level previously considered unrealistically low. The following section discusses natural gas supply and demand fundamentals in order to interpret these recent price trends and the current state of the natural gas market.

The supply outlook for domestic natural gas continues to be robust due to continuing exploitation of large shale gas deposits across the United States. Over the past few years, the prevalence of horizontal drilling and hydraulic fracturing techniques has enabled the production of natural gas where traditional vertical drilling was not cost effective, leading to ample, geographically diverse supply and steady declines in prices. Drilling technology continues to advance in virtually every area of exploration and production. Improvements in supply basin analysis have enabled producers to find the “sweet spots” of various shale plays with increased accuracy, resulting in higher initial production rates, while the time and cost to place a drilling rig has decreased. Utilization of multi-stage fracturing has also improved well productivity, with 20-plus stages of fracturing a common occurrence in new wells. And the same technology that unleashed the recent gas boom has also contributed to a dramatic rise in domestic oil production, given the presence of oil in certain shale plays that can now be produced at significant rates of return.

Demand for natural gas over the past year has been affected by an extremely warm winter, reducing demand in residential/commercial heating as well as power generation. The winter gas season of November 2011-March 2012 ranks as the warmest in the last 50 years by NOAA (Figure 5), and weak seasonal demand led to a record level of gas in storage, at around 2.3 trillion cubic feet (tcf), or around 800 billion cubic feet (bcf) greater than last year. The unprecedented storage levels raised concerns about operational flexibility at storage facilities both at the beginning and end of injection season; most importantly, the perceived maximum allowable storage level of approximately 4.1 tcf. At the end of 2011, market forecasters were considering that if production in 2012 continued to grow at the rate of the previous year, gas in storage would almost certainly reach the maximum level (Figure 6), at which point all production would need to be either taken to market or shut in, precipitating a collapse in gas prices to around $1. Anticipation of such an event was the primary contributor to the price nadir in the spring of 2012, which encouraged producers to reduce active drilling of new wells. The demand situation turned around when a hot summer throughout most of the nation buoyed gas demand and helped to alleviate the storage surplus through the injection season, such that by the end of October, working gas in storage totaled 3.843 tcf, only 153 bcf above that of last year (Figure 7). With reduced fear of storage congestion pricing and incremental demand from the weather, the Henry Hub price found support in the mid to high $2 level throughout the summer and has recovered to above $3 in recent months.

2.3.1.3 Henry Hub Forecast

The average of the monthly forecast of Henry Hub prices is $4.08/MMBtu (million British thermal units) during FY 2014 and $4.35/MMBtu during FY 2015 (Table 1).

Prices in the FY 2014-2015 rate period are expected to increase further from current levels due to a slow rebalancing of the gas market. The rig count has been in steady decline since 2011 but dropped off dramatically as prices fell during the winter of 2011-2012. As of October 19, 2012, there are only 427 gas rigs operating, compared to 811 at the beginning of 2012 and 1,606 at the all time high in 2008. It is clear that producers have been exercising “drilling rationalization” by attempting to cut production in an unfavorable price environment. It is expected that the reduction in rig counts should lead to flat or slightly declining production in 2013, which should tighten supply relative to demand and move prices up from current levels. Assuming there is not another record warm winter that drastically affects gas demand and again raises the specter of storage congestion, gas prices should slowly rise and approach the long-term marginal cost of production of natural gas, historically represented by the Haynesville shale basin at around $4.50-$5/MMBtu.

However, many factors will limit the upside risk for gas prices. First and foremost, despite the drop in rigs over the past year, gas production remains stubbornly resilient. While current domestic production in the lower 48 states has started to plateau, it is still expected to surpass the record levels of last year. The 2012 year-to-date average is around 65 bcf per day (bcf/d), a 2.5 cf/d increase year over year. There are many explanations for the continued strength in gas supply. First, although the dropoff in rigs is profound, the rig count is a lagging indicator of production by 6-9 months. The current flat production trend is best seen as a result of the rig declines near the first quarter of 2012. All else being equal, one would assume a production decline will occur in 2013 as the remainder of the rig dropoff is felt in the supply picture. But this assumption is significantly complicated by the rise in rigs drilling for oil, where natural gas is produced concurrently. The percentage share of gas rigs versus oil rigs has continued to decline (Figure 8) to 23 percent in October 2012 compared to 46 percent a year earlier. Given the prices and high rates of return for globally fungible oil, the "associated gas" produced from oil drilling is essentially free; that is, the well is profitable to drill even at a natural gas price of $0. The classification of "gas" or "oil" rig is somewhat murky, as are accurate statistics regarding the supply of associated gas. But it is probable that an ever-growing share of natural gas production is relatively inelastic to its market price, which would partially offset production declines from a reduction in dry gas drilling.

In addition to enabling the recent oil production boom, the aforementioned advances in drilling technology mean that producers are able to mobilize a rig and begin production within days, not weeks. If prices rise to an attractive level such that more gas can be profitably taken to market, the supply response should be quicker than in the past, limiting prolonged upside risk to prices. Finally, there is evidence that land lease terms such as the "held by production" clause that necessitated active production of gas to retain the lease, along with other contractual obligations, favorable portfolio hedges and joint venture investments, encouraged or mandated producers to continue drilling even in an unfavorable economic environment. While these contracts are expected to diminish after 2012, contract terms agreed to five years ago are undoubtedly a contributing factor to the economically irrational production strength of the past year.

The low price environment has helped increase demand for natural gas by increased amounts of coal-to-gas switching, where utilities decide to run gas generators as opposed to coal generators based on lower variable cost. The sub-$3 prices in most of 2012 to date made natural gas competitive with Powder River Basin coal, among the cheapest coal used for power generation. This trend continued throughout 2012, but note that summer demand this year was substantially higher than last, meaning intrinsic demand for power generation in general, and not coal-to-gas switching, was primarily responsible for demand growth during the summer months. As prices gradually rose in the shoulder season, the amount of switching reduced accordingly, indicating that gas demand due to switching is extremely sensitive to price and starts to fall off as the fuel cost for gas approaches that of Central Appalachian coal used in most East Coast generators. Conversely, significant downward movements in the Powder River Basin (PRB) and Central Appalachian (CAPP) price during this year (Figure 9) as well as news that some generator owners were renegotiating long term coal and rail contracts, highlighted the tension in the coal markets resulting from loss of market share.

Because the relationship between gas and coal is so dynamic, sustained demand has to come from new sources of natural gas consumption. U.S. electricity demand is expected to grow at a modest rate of 0.9 percent per year during FY 2014-2015 according to the Energy Information Administration. The gradual but slow recovery in domestic manufacturing, as well as investments in gas and natural gas liquids processing plants in the petrochemical and agricultural sectors, are expected to boost industrial demand. But any potential game-changing demand opportunity lies further in the future. The most concrete area is the exportation of liquefied natural gas (LNG), for which a few projects in the United States and Canada are on track to begin in 2016. The opportunity to capture the high LNG price premium in Asia and Europe should increase demand, but this will be limited by processing capacity at the export facilities as well as potential political headwinds, should prices rise dramatically. Plans to convert heavy-duty vehicles to run on compressed natural gas (CNGs) are in progress, but infrastructure limitations and general long time horizons should mitigate enthusiasm about natural gas vehicles as a big source of future demand.

While the debate over hydraulic fracturing and water contamination has brought natural gas policy to the national conversation, most policy actions have taken place at the state level. A New York state moratorium on fracking was passed in 2010 but is currently facing the possibility of repeal. Drilling regulations in Texas focus on fracking fluid disclosures and are not expected to have a noticeable impact on drilling costs. The EPA has recently announced pending natural gas regulations, but the focus is wastewater disposal as opposed to groundwater contamination or emissions. The Cross State Air Pollution Rule (CSAPR), which was forecast to have a large positive impact on gas demand due to mandated coal retirements across the United States, has been delayed by adverse court rulings, and future implementation of the law is uncertain. In fact, the low gas prices of the past year had the same effect as many of the proposed coal regulations: decreased coal-fired generation and a corresponding increase in gas demand.

In summary, the rate period gas price outlook still appears bound between the $3 and $5 range. Above $5, many more basins would provide attractive rates of return, and the resulting responsiveness of supply should provide relief to the market. Below $3, coal-to-gas switching increases, and even extremely cost-effective plays such as the Marcellus shale in Pennsylvania become unprofitable, encouraging a supply correction. The price recovery during 2012, albeit assisted by hot summer weather, is evidence that the sub $2 prices were a reaction to a possible storage congestion situation resulting from a rare and extremely mild winter season. Barring similar weather events in the near future, the combination of flat supply and slowly rising demand should prevent prices from declining to the levels seen in 2012 to date.

In the long term there are a few major points of uncertainty. The abundance of associated gas and decreasing drilling costs call into question the historically assumed $4.50-$5 long-term marginal cost of production in the current marginal supply basin of the Haynesville Shale in Arkansas and Louisiana. Recent estimates have been forecasting a lower level of around $3.00-$3.50, which would significantly alter the long-term supply and demand equilibrium price of natural gas. Additionally, shale gas could easily become a global resource, as basins similar to those in the United States exist around the globe. Such a global market would blunt the effect of domestic LNG exports on gas demand. On the other hand, the sizable investments being made now in gas units and processing plants will contribute to increased demand for the power generation and industrial sectors, which could spur prices upward.

2.3.1.4 The Basis Differential Forecast

Table 1 shows the basis differential forecast for the 11 trading hubs in the western U.S. used by AURORAxmp.

A number of factors will influence the Western gas markets and the price of natural gas at regional trading hubs. The Ruby pipeline and connecting hubs located at Opal, Wyoming, and Malin, Oregon, went online in July 2011 and provide approximately 1.5 bcf/d of capacity from the Rocky Mountain producing basins to West Coast demand markets. With demand for Rockies supply under pressure from significant production growth in the Marcellus, a competitor for the mid-continent demand historically served by Rockies gas flowing east on the REX pipeline, Ruby provides an important outlet for Rockies gas to flow to the premium California markets. Because the variable cost of transportation on Ruby is very low, the basis differentials between Opal and Malin have shrunk in recent years, from 21 cents in 2010 to 6 cents through August 2012, and are forecast to stabilize around 11 cents during FY 2014-2015.

Northwest basis differentials are expected to remain fairly stable. Seasonal volatility is expected to moderate somewhat at Sumas hub, as cheaper Canadian gas and pipeline expansions such as Ruby and planned I-5 corridor projects allow more avenues for Rockies gas to reach the Pacific Northwest during the winter peak demand season. The constraints at Sumas do present some upside seasonal price risk, but yearly Canadian imports through this hub have been trending downward over time. Figure 10. The expected greater availability of Rockies supply should help meet demand in the region. Sumas basis is forecast to hold around a 13-cent discount to Henry Hub in FY 2014 and 14 cents in FY 2015. Stanfield, Kingsgate, and AECO hubs should also stay relatively steady in FY 2014-2015. Downward price pressure on Canadian gas is very likely in the long term, but current Western Canadian Sedimentary Basin supply has reduced in response to the low price environment, which should prevent negative basis from increasing further during the medium term.

In the California markets, PG&E Citygate remains one of the country's premium gas hubs, a status propagated in 2012 due to the extended San Onofre Nuclear Generating Station (SONGS) outage. That outage took over 2000 MW of generating capacity off the California grid, resulting in an increased demand for natural gas. Uncertainty about the return of the SONGS units, as well as around the Clean Air Resources Board (CARB) policy implementation of a carbon allowance market scheduled for 2013, provide some upside price risk from the 17- and 18-cent premium level assumed for FY 2014 and 2015. Should the SONGS units fail to return, or if other nuclear or coal units are retired due to regulatory or policy actions, natural gas will be the logical fuel to meet that demand.

The three Southern California hubs are priced in relation to the San Juan supply basin, where production has been resilient due to increasing oil drilling in the area, which was previously known mostly for conventional dry gas production. These bases are expected to hold steady through FY 2014-2015, with a small 10-cent premium between San Juan and the Southern California border.

2.3.1.5 Natural Gas Price Risk

Uncertainty regarding the price of natural gas is fundamental in evaluating electricity market price risk. Again, to the extent that natural gas-fired generators deliver the marginal unit of electricity, the price of natural gas largely determines the market price of electricity. Furthermore, as an energy commodity, the price of natural gas is expected to fluctuate, and that volatility is an important source of market uncertainty.

The natural gas risk model simulates daily natural gas prices and generates a distribution of 875 natural gas price forecasts. Because AURORAxmp treats all dollar-denominated inputs as measured in real 2008 dollars, so does the natural gas risk model. Model parameters are estimated using historical Henry Hub natural gas prices. Once estimated, the parameters serve as the basis for simulated possible future Henry Hub price streams.

The model also constrains the minimum price to $1. Furthermore, because RAM2014 and the TPP calculations use only monthly electricity prices from AURORAxmp, and the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices, the distribution of simulated natural gas prices is aggregated by month prior to being input into AURORAxmp. The mean, median, 5th, and 95th percentiles of the forecast distribution are reported in Table 2.

2.3.2 Load Forecasts Used in AURORAxmp

This Study uses the West Interconnect topology, which comprises 31 zones. It is one of the default zone topologies supplied with the AURORAxmp model and requires a load forecast for each zone.

2.3.2.1 Load Forecast

AURORAxmp uses a WECC-wide, long-term load forecast as the base load forecast. Default AURORAxmp forecasts are used for areas outside the United States. BPA produced a monthly load forecast for each balancing authority in the WECC through 2032. As AURORAxmp uses a cut-plane topology (see Figure 2) that does not correspond to the WECC balancing authorities, it is necessary to map the balancing authority load forecast onto the AURORAxmp zones. See Documentation Table 1. The forecast by balancing authority is in Documentation Table 2.

2.3.2.2 Load Risk Model

The load risk model uses a combination of three statistical methods to generate annual, monthly, and hourly load risk distributions that, when combined, constitute an hourly load forecast for use in AURORAxmp. When referring to the load model, this Study is referring to the combination of these models.

2.3.2.3 Yearly Load Model

The annual load model addresses variability in loads created by long-term economic patterns. That is, it incorporates variability at the yearly level and captures business cycles and other departures from forecast that do not have impacts measurable at the sub-yearly level. The model is calibrated using historical annual loads for each control area in the WECC, as aggregated into the AURORAxmp zones defined in the West Interconnect topology. Furthermore, it assumes that load growth at the annual level is correlated across regions, as defined by the Pacific Northwest; California including Baja; Canada; and the Desert Southwest (which constitutes all AURORAxmp areas not listed in the other three). It also assumes that load growth is correlated perfectly within them. This assumption guarantees that zones within each of these regions will follow similar annual variability patterns.

The model takes as given the history of annual loads at the balancing authority level, as given in FERC Form 714 filings from 1993 to 2011 and aggregated into the regions described above. The model estimates the load in each region using a time series econometric model. Once the model is estimated, the parameters of the model are used to generate simulated load growth patterns for each AURORAxmp zone.

2.3.2.4 Monthly Load Risk

Monthly load variability accounts for seasonal uncertainty in load patterns. The risk posed to BPA revenue reflected through price variability due to seasonal load variations is potentially substantial. Unseasonably hot summers in California, the Pacific Northwest, or the inland Southwest have the potential to exert substantial pressure on prices at Mid-C and, as such, are an important component of price risk.

In addition to an annual load forecast produced in average megawatts, AURORAxmp requires factors for each month of a forecast year that, upon multiplication by the annual load forecast, yield the monthly load, also in average megawatts. As such, the monthly load risk is represented by a distribution of vectors of 12 factors with a mean of one. The monthly load risk model generates a distribution of series of these factors for the duration of the forecast period.

The monthly load model takes as given the historical monthly load for each AURORAxmp zone, normalized by their annual average and centered on zero. These historical load factors, which average to zero for any given year, constitute the observations used to calibrate a statistical model that generates a distribution of monthly load factors.

2.3.3 Hourly Load Risk

Hourly load risk embodies short-term price risk as would be expected during cold-snaps, warm spells, and other short-term phenomena. While this form of risk may not exert substantial pressure on monthly average prices, it generates variability within months, and constitutes a form of risk that would not be captured in long-term business cycles or seasonal trends as reflected in the monthly and annual load risk models.

The hourly load model takes as inputs hourly loads for each AURORAxmp zone from 2002 to 2011. The model groups these hourly load observations by week and month, and each group of week-long hourly load observations constitutes a sample for its respective month. It then normalizes the historical hourly loads by their monthly averages, so that the sample space is comprised of hourly factors with an average of 1, and then uses a simple bootstrap with replacement approach to draw sets of week-long, hourly observations from each month. Each draw thus constitutes 9,072 hours (54 weeks), with an average of 1. The model repeats this process 50 times, which generates 50 year-long hourly load factor time series. These 50 draws are assigned randomly to the 3,200 AURORAxmp runs.

2.3.4 Hydroelectric Generation

Hydroelectric generation is a primary driver of Mid-Columbia electricity prices in AURORAxmp because it represents a substantial portion of the average generation in the region. Thus, fluctuations in its output can have a substantial effect on the marginal generator.

2.3.4.1 PNW Hydro Generation Risk

The PNW hydroelectric generation risk factor reflects uncertainty regarding the timing and volume of streamflows. Given streamflows, HYDSIM computes PNW hydroelectric generation amounts in average monthly values. See Power Loads and Resources Study, BP-14-E-BPA-03, section 3.2, for a description of HYDSIM. HYDSIM produces 80 records of PNW monthly hydroelectric generation, each one year long, based on actual water conditions in the region from 1929 through 2008 as applied to the current hydro development and operational constraints. For each of the 3,200 games, the model samples one of the 80 water years for the first year of the rate period (FY 2014) from a discrete uniform probability distribution using R, the software described in section 2.2.1. The model then selects the next historical water year for the following year of the rate period, FY 2015 *(e.g.,* if the model uses 1929 for FY 2014, then it selects 1930 for FY 2015). Should the model sample 2008 for fiscal 2014, it uses 1929 for FY 2015. The model repeats this process for each of the 3,200 games and guarantees a uniform distribution over the 80 water years. The resulting 3,200 water year combinations become AURORAxmp inputs.

2.3.4.2 British Columbia (BC) Hydro Generation Risk

BC hydroelectric generation risk reflects uncertainty in the timing and volume of streamflows and the impacts on monthly hydroelectric generation in BC. The risk model uses historical generation data from the same time period as the 80 water year HYDSIM study. The source of this information is Statistics Canada, a publication produced by the Canadian government.

A inimal amount of interpolation is done to fill missing values. Because the installed capacity of the hydroelectric generators varies over the 80 years, the model normalizes the historical generation data into capacity factors (hydroelectric generation ÷ sum of capacity). Historical capacity factors of the BC hydro system follow an evident trend. To treat this problem, the model adjusts them. It then matches each of these 80 water year, adjusted records to the corresponding record from the 80 water year HYDSIM record. They are sampled exactly as described in section 2.3.4.1

2.3.4.3 California Hydro Generation Risk

California hydroelectric generation risk reflects uncertainty with respect to the timing and volume of streamflows and the impacts on monthly hydroelectric generation in California. Historical generation data from the same 80 year history as the HYDSIM study was available through the California Energy Commission (CEC), the Federal Power Commission, and the Energy Information Agency (EIA). Again, a minimal amount of interpolation is used to replace missing values. Because installed capacity of the hydroelectric generators varies over the observed period, the model normalizes the data into capacity factors. As with the BC data, the model de-trends the data and normalizes it around the last year from the historical record. These historical water years are paired with the HYDSIM water years and distributed over the 3,200 games in exactly the same way.

2.3.4.4 Hydro Shaping

AURORAxmp uses an algorithm to dispatch hydro generation. This algorithm produces an hourly hydroelectric generation value that depends on average daily and hourly load, the average monthly hydro generation (provided by HYDSIM), and the output of any resource defined as "must run." Several constraints give the user control over minimum and maximum generation levels, the degree of hydro shaping (*i.e.*, the extent to which it follows load), and so on. AURORAxmp uses the default hydro shaping logic, with one exception.

Output from AURORAxmp suggests that its hydro shaping algorithm generates a diurnal generation pattern that is inappropriate during high water. That is, the ratio of HLH generation to LLH generation is too high. It is recognized that high water compromises the ability of the hydro system to shape hydro between on- and off-peak hours. AURORAxmp limits minimum generation to 44 percent of nameplate capacity during May and June, but operations data suggest that this system minimum generation can be as high as 75 percent of nameplate capacity during high water months. To address this difference, a separate model is used to implement the minimum generation constraints. These constraints generally restrict the minimum generation to a higher percentage of nameplate capacity than default AURORAxmp settings and reflect observed constraints to the degree to which the system can more realistically shape hydroelectric generation.

To implement this ratio in AURORAxmp, the model limits the minimum hydro generation in each month to the expected ratio of minimum generation to nameplate capacity based on an econometric model.

2.3.5 Hourly Shape of Wind Generation

AURORAxmp models wind generation as a must-run resource with a minimum capacity of 70 percent. This assumption implies that, for any given hour, AURORAxmp dispatches 70 percent of the available capacity independent of economic fundamentals and the remaining 30 percent as needed. However, because AURORAxmp dispatches wind at -$0.01, it always dispatches wind to its full available capacity. Wind is dispatched at -$0.01 because it preserves a dispatch order in which hydro is curtailed before wind, given the $0.00 price for hydro. The current amount of wind generation operating in the PNW is just over 7,486 MW. The large amount of wind in the PNW (and the rest of the WECC) affects the market price forecast at Mid-C by changing the generating resource used to determine the marginal price. Modeling wind generation on an hourly basis better captures the operational impacts that changes in wind generation can have on the marginal resource compared to using average monthly wind generation values. The hourly granularity for wind generation allows the price forecast to more accurately reflect the economic decision faced by thermal generators. Each hour they must decide whether to operate in a volatile market in which the marginal price can be below the cost of running the thermal generator, but start-up and shut-off constraints could prevent the generator from shutting down.

2.3.5.1 PNW Hourly Wind Generation Risk

The PNW Hourly Wind Generation Risk Model simulates the uncertainty in wind generation output that is derived by averaging the observed output of the BPA wind fleet every five minutes for each hour and converting the data into hourly capacity factors. The source of these data is BPA's external Web site, www.bpa.gov. The data cover the period from 2006 through 2009. The model samples this data, with replacement, using a k-nearest-neighbor algorithm (also called a local bootstrap), a procedure that creates an artificial time series to represent a possible wind-generation time series. Through this process, the model creates 30 time series that include 8,784 hours to create a complete wind year. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select AURORAxmp zones. This approach captures potential variations in annual, monthly, and hourly wind generation.

2.3.6 Thermal Plant Generation

The thermal generation units in AURORAxmp often drive the marginal unit price, whether the units are natural gas, coal, or nuclear. With the exception of CGS generation, operation of thermal resources in AURORAxmp is based on the EPIS-supplied database labeled North American DB 2012-02.

2.3.6.1 Columbia Generating Station Generation Risk

The CGS Generation Risk Model simulates monthly variability in the output of CGS such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Power Loads and Resources Study, BP-14-FS-BPA-03, section 3.1.3. The simulated results vary from the maximum output of the plant to zero output. The frequency distribution of the simulated CGS output is negatively skewed: the median is higher than the mean. The shape of the frequency distribution reflects the reality that thermal plants like CGS typically operate at output levels higher than average output levels, but occasional forced outages result in lower monthly average output levels. The output of the model feeds both RevSim (see section 2.5 of this Study) and AURORAxmp, where the results of the model are converted into equivalent forced outage rates and applied to the nameplate capacity of CGS for each of 3,200 games. The simulated frequency distribution for CGS output for October 2013 is shown in Figure 1 of the Documentation.

2.3.7 Generation Additions due to WECC-Wide Renewable Portfolio Standards (RPS)

As a result of RPS standards, renewable resource additions have been substantial during recent years. The timing of incentives and structure of markets for Renewable Energy Credits (RECs) spawned a surge in renewable resource additions well in advance of need and somewhat independent of economic fundamentals. Two sources of data are used to quantify this growth.

First, the draft Midterm Assessment of the Sixth Northwest Conservation and Electric Power Plan released by the Northwest Power and Conservation Council uses a resource build forecast. This midterm assessment is a work in progress and represents the most current expectation of future additions. It is critical to note that the addition of renewable resources in this report does not account for the dynamic nature of incentive structures, or state requirements and as such does not capture resource builds in advance of need. Second, to accommodate this shortcoming, and assuming that the additional wind in the PNW results from the availability of the Production Tax Credits (PTC) and RPS standards, the forecast size of the BPA balancing authority area wind fleet, as provided by BPA Transmission Services, is embedded in the resource build forecast from the Council. This modification is detailed in the Generation Inputs Study, BP-14-E-BPA-05, section 2.3.2. These sources are merged, which guarantees a forecast that is consistent with the Power Loads and Resources Study, BP-14-E-BPA-03, and captures generation likely to be added due to the PTC and to fulfill RPS requirements in areas both within and outside the Pacific Northwest. The WECC-wide resource additions are available in Documentation Figure 2.

2.3.8 Transmission Capacity Availability

In AURORAxmp, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 2 shows the AURORAxmp representation of the major transmission interconnections for the West Interconnect topology. The transmission path ratings for the California-Oregon Intertie (COI), the Direct Current Intertie (DC Intertie), and the British Columbia Intertie (BC Intertie) are based on historical intertie reports posted on the BPA OASIS Web site from 2003 through 2009. The ratings for the rest of the interconnections are based on the EPIS-supplied database labeled North American DB 2012-02.

2.3.8.1 PNW Hourly Intertie Availability Risk

PNW hourly intertie risk represents uncertainty in the availability of transmission capacity on each of three interties that connect the PNW with other regions in the WECC: AC Intertie, DC ntertie, and BC Intertie. This risk is modeled in the PNW hourly intertie risk model using the common statistical technique of sampling, with replacement from observed data for FY 2003–2009. These data are observed pairs of transmission ratings and the duration of those ratings. To create a one-year record, the model samples 8,784 historical pairs of observations.

The mode accounts for seasonal differences in transmission availability by sampling months independently. The model generates 200 sampled records for each of the three interties and implements them as a limit on the maximum path rating used in AURORAxmp.

For each of 3,200 games, each intertie has a single record that is independently selected from the associated set of 200 records. The outage rate is applied to the Link Capacity Shape, a factor that determines the amount of power that can be moved between zones in AURORAxmp for the associated intertie. By using this method, quantification of this risk results in the average of the simulated outcomes being equal to the expected path ratings in the historical record.

2.4 Market Price Forecasts Produced By AURORAxmp

Two electricity price forecasts are created using AURORAxmp. The market price forecast uses hydro generation data for all 80 water years, and the critical water forecast uses hydro generation for only the critical water year, 1937. Table 3 shows the FY 2014 through FY 2015 monthly average, HLH, and LLH prices from the market price forecast. Table 4 shows the FY 2014 and FY 2015 average, HLH, and LLH prices of the critical water forecast. Table 5 shows the flat annual prices for each forecast. The mean, median, 5th and 95th percentiles of the market price run are in Documentation Figures 3 and 4. The same information for the critical water run is in Documentation Figures 5 and 6.

2.5 Inputs to RevSim

As noted earlier, RevSim calculates surplus energy revenues, balancing and augmentation power purchase expenses, and 4(h)(10)(C) credits that are used by RAM2014. It also determines, by simulation, PS operating net revenue risk, used by the ToolKit Model. Inputs to RevSim include risk data simulated by various risk models (see section 2.2.3.1) and market prices calculated by AURORAxmp, along with deterministic monthly data from other rate development studies.

2.5.1 Deterministic Data

Deterministic data are data provided as single forecast values, as opposed to data presented as a distribution of many values.

2.5.1.1 Loads and Resources

Monthly HLH and LLH load and resource data are provided by the Power Loads and Resources Study, BP-14-E-BPA-03. A summary of these load and resource data in the form of monthly energy for FY 2014–2015 is provided in the Power Loads and Resources Study Documentation, BP-14-E-BPA-03A, Table 4.1.1.

2.5.1.2 Miscellaneous Revenues

Miscellaneous revenues represent estimated revenues from contract administration, late fees, interest on late payments, and mitigation payments. These revenues are not subject to change through BPA's rate process. See Power Rates Study, BP-14-E-BPA-01, section 4.2.

2.5.1.3 Composite, Load Shaping, and Demand Revenue

Composite, non-Slice, load shaping, and demand revenues are provided by RAM2014. Consistent with the Tiered Rate Methodology (TRM), composite and non-Slice revenues do not vary in the RevSim revenue simulation, but load shaping and demand revenues do vary. The load shaping billing determinants and load shaping rates from RAM2014 are input to RevSim to facilitate the calculation of changes in load shaping revenue. Demand billing determinants and rates from RAM2014 are input to RevSim to facilitate the calculation of changes in demand revenue. Power Rates Study Documentation, BP-14-E-BPA-01A,Table 2.5.5.

2.5.2 Risk Data

Uncertainty around the deterministic data provided to RevSim must be considered in the determination of TPP in ToolKit. Specifically, the uncertainty considered in RevSim is called "operational" uncertainty, as opposed to non-operational uncertainty considered in NORM. Uncertainty in the deterministic data is represented by "risk data" or a distribution of many values.

Operational risks represented as input data to RevSim are Federal hydro generation risk, PS load risk, CGS generation risk, PS wind generation risk, PS transmission and ancillary services expense risk, and electricity price risk. These inputs are reflected in the risk distributions for surplus sales revenues, balancing purchase expenses, 4(h)(10)(C) credits, system augmentation expenses, and PS net revenues calculated by RevSim and provided to ToolKit.

2.5.2.1 Federal Hydro Generation Risk

The Federal hydro generation risk factor reflects the uncertainty that the timing and volume of streamflows have on monthly Federal hydro generation under specified hydro operation requirements. Federal hydro generation risk is accounted for in RevSim by inputting hydro generation estimates from the HYDSIM model and adjusting these results to account for efficiency losses associated with standing ready to provide balancing reserve capacity, which is discussed below.

For FY 2014–2015, average monthly hydro generation risk is accounted for based on hydro generation estimates from the HYDSIM model for monthly streamflow patterns experienced from October 1928 through September 2008 (also referred to as the 80 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 960 months of the 80 water years. This analysis by HYDSIM is referred to as a continuous study. See the Power Loads and Resources Study, BP-14-E-BPA-03, section 3, regarding HYDSIM, continuous study, and 80 water years.

For each of the 80 water years, monthly HLH and LLH energy splits for the Federal system hydro generation are developed for each year of the rate period based on HOSS analyses that incorporate results from HYDSIM hydro regulation studies. *Id*. These monthly HLH and LLH regulated hydro generation estimates are combined with monthly HLH and LLH independent hydro generation estimates developed from historical data to yield total monthly Federal HLH and LLH hydro generation. *Id*.

Monthly values for Federal hydro generation for each of the 80 historical water years are provided in the Documentation, Table 3 for FY 2014 and Table 4 for FY 2015. Monthly values for Federal hydro HLH generation ratios for each of the 80 historical water years are provided in the Documentation, Table 5 for FY 2014 and Table 6 for FY 2015.

Adjustments are made to the average monthly hydro generation in the 80 water year data to represent efficiency losses associated with standing ready to provide balancing reserve capacity for both load and wind variability. Generation Inputs Study, BP-14-E-BPA-05, section 3.

A significant factor in these adjustments is the shift of hydro generation from HLH to LLH. The generation adjustments are reported in terms of HLH, LLH, and flat energy adjustments in the Documentation, Tables 7–9 for FY 2014 and Tables 10–12 for FY 2015. These generation data are added to the values presented in Documentation Tables 3–4 to yield the final monthly Federal hydro generation for each of the 80 water years.

These monthly Federal hydro generation data are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on PS surplus energy revenues, balancing power purchases, transmission and ancillary services expenses, and net revenues for 3,200 two-year simulations (FY 2014–2015).

The water year sequences developed for each game for PNW hydro generation are also used for Federal hydro generation, resulting in a consistent set of PNW and Federal hydro generation being used for each game in AURORAxmp and RevSim. See section 2.3.4.1 of this Study regarding the development of water year sequences for PNW hydro generation.

2.5.2.2 BPA Load Risk

The BPA load risk factor represents the impacts that variability in the economy and temperature can have on PS revenues and expenses. Under the TRM, fluctuations in customer loads and revenues are considered as changes in Tier 1 loads, specifically through the load shaping and demand charges. Load fluctuations are also reflected as changes in surplus energy revenues and balancing power purchase expenses. The level of regional economic activity affects the annual amount of load placed on BPA. Fluctuations in load due to weather conditions cause monthly variations in loads, especially during the winter and summer when heating and cooling loads are highest. BPA annual load growth variability and monthly load variability due to weather are derived from PNW load variability simulated in the WECC Load Risk Model. See section 2.3.2.4 of this Study for further details regarding the WECC Load Risk Model. BPA load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

While the WECC Load Risk Model considers WECC-wide loads for AURORAxmp, only the PNW component of the load risk is applied to BPA loads for the revenue simulation.

2.5.2.3 CGS Generation Risk

The CGS generation risk factor reflects the impact that variability in the output of CGS has on the amount of PS surplus energy sales and balancing power purchases estimated by RevSim. CGS generation risk is modeled in the CGS Generation Risk Model. The methodology used in quantifying CGS generation risk is described in section 2.3.6.1 of this Study; it also has an impact on prices estimated by AURORAxmp.

2.5.2.4 PS Wind Generation Risk

The PS wind generation risk factor reflects the uncertainty in the amount and value of the energy generated by the portions of Condon, Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects that are under contract to BPA.

The risk of the wind generation output is calculated in RevSim based on the differences between the monthly weighted average purchase prices for all the output contracts between wind generators and BPA and the wholesale electricity prices at which BPA can sell the amount of variable energy produced. The output contracts specify that BPA pays for only the amount of energy produced. The risk of the value of the wind generation is computed in RevSim in the following manner: (1) subtract from expenses the expected monthly payments for the expected output from all the wind projects; (2) on a game-by-game basis, compute the monthly payments for the output from all the wind projects; and (3) on a game-by-game basis, compute the revenues associated with the wind generation from all the projects.

The PNW wind generation model is described in section 2.3.5.1. Since the PNW wind generation model includes the output of wind projects that do not serve BPA loads, the results of the PNW wind model are scaled such that the average wind generation output is equal to the forecast wind generation in the Loads and Resources Study, BP-14-E-BPA-03.

The simulated monthly wind generation results are specified in terms of flat energy. Results shown in Documentation Figure 7 are the monthly flat energy output for all wind projects during FY 2014–2015 at the 5th, 50th, and 95th percentiles. These monthly flat energy values are input into RevSim, where they are converted into monthly HLH and LLH energy values by applying HLH and LLH shaping factors that are associated with these wind projects. The source of these HLH and LLH shaping factors is the data used to compute the monthly HLH and LLH wind generation values included under Renewable Resources in the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.3.

Results shown in Documentation Tables 13–14 report information from which the value of wind generation during FY 2014–2015 can be observed at expected monthly flat energy output levels and variable monthly electricity prices. Total deterministic wind generation purchase costs and total revenues earned from the sale of all wind generation at average, median, 5th percentile, and 95th percentile electricity prices estimated by AURORAxmp are provided, with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

2.5.2.5 PS Transmission and Ancillary Services Expense Risk

The PS transmission and ancillary services expense risk represents the uncertainty in PS transmission and ancillary services expenses, relative to the expected expenses included in the power revenue requirement, which has an annual average expense of $98.5 million during FY 2014 and $97.9 million during FY 2015. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A**.** This risk is modeled in the PS Transmission and Ancillary Services Expense Risk Model.

The modeling of this risk is based on comparisons between monthly firm transmission capacity that PS has under contract, the amount of existing firm contract sales, and the variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that PS has under contract, which must be paid for whether or not it is used. Because PS has more firm transmission capacity under contract than it has firm contract sales, the probability distribution for these expenses is asymmetrical. This asymmetry occurs because PS does not incur the costs of purchasing additional transmission capacity until the amount of surplus energy sales exceeds the amount of residual firm transmission capacity after serving all firm sales.

Under conditions in which PS sells more energy than it has firm transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions in which PS sells less energy than it has firm transmission rights, transmission and ancillary services expenses will remain unchanged.

Results shown in Documentation Figures 8 and 9 indicate how FY 2014–2015 transmission and ancillary service expenses vary depending on the amount of surplus energy sales. In these figures, the PS transmission and ancillary services expenses do not fall below $80.7 million in FY 2014 and $77.7 million in FY 2015, regardless of the amount of surplus energy sales, because PS must pay for the take-or-pay firm transmission capacity it has under contract.

Results shown in Documentation Figures 10 and 11 reflect the probability distributions for transmission and ancillary service expenses during FY 2014–2015. These figures indicate how often transmission and ancillary service expenses fall within various expense ranges.

2.5.2.6 Electricity Price Risk (Market Price and Critical Water AURORAxmp Runs)

As noted in section 2.4, two runs of the AURORAxmp model are used in this Study. One run uses hydro generation for all 80 water years, referred to as the market price run. The other run uses only hydro generation for the critical water year, 1937, and is referred to as the critical water run. The market price run produces 3,200 games of monthly HLH and LLH prices for FY 2014–2015. The critical water run produces 3,200 games of monthly HLH and LLH prices for FY 2014–2015.

Prices from the Market Price run are used by RevSim to develop surplus sales revenues, balancing power purchase expenses, and 4(h)(10)(C) credits for FY 2014-2015. These values are provided to RAM2014 to develop rates for FY 2014–2015.

Expenses for system augmentation purchases for FY 2014–2015 use both the Market Price run and the Critical Water run; these expenses are provided to RAM2014.

2.6 RevSim Model Outputs

RevSim model outputs are provided to RAM2014, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-14-E-BPA-01.

2.6.1 4(h)(10)(C) Credits

The 4(h)(10)(C) credit risk is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. The 4(h)(10)(C) credit is the method by which BPA implements section 4(h)(10)(C) of the Northwest Power Act. Section 4(h)(10)(C) allows BPA to allocate its expenditures for system-wide fish and wildlife mitigation activities to various purposes. The credit reimburses BPA for its expenditures allocated to the non-power purposes of the Federal hydro projects. BPA reduces its annual Treasury payment by the amount of the credit. This Study estimates the amount of 4(h)(10)(C) credits available for each of the 80 water years for FY 2014–2015 by summing the costs of the operating impacts on the hydro system (power purchases) and the expenses and capital costs associated with BPA's fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent is the percentage of the FCRPS attributed to non-power purposes).

Operating impact costs are calculated for each of the 80 water years in RevSim for FY 2014-2015 by multiplying spot market electricity prices from AURORAxmp by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. The amount of power purchases that qualifies for 4(h)(10)(C) credits is derived outside of RevSim and is used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to derive the amount of power purchases associated with the 4(h)(10)(C) credits is contained in the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.3. Tables 2.11.1 and 2.11.2 in the Power Loads and Resources Documentation contain the 4(h)(10)(C) power purchase amounts for FY 2014–2015 respectively.

The direct program expenses and capital costs for FY 2014–2015 do not vary by water volume and timing and are documented in the Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, sections 3 and 4. A summary of the costs included in the 4(h)(10)(C) calculation and the resulting credit for each fiscal year are shown in this Study's Documentation Table 15.

Results shown in Documentation Figures 12 and 13 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2014–2015. The average 4(h)(10)(C) credit for the 3,200 games is $95.3 million for FY 2014 and $92.4 million for FY 2015. These values are included in the revenue forecast component of the Power Rates Study, BP-14-E-BPA-01.

The 4(h)(10)(C) credit for each of the 3,200 games is included in the net revenue provided to the ToolKit.

2.6.2 System Augmentation Costs

System augmentation costs for FY 2014–2015 are calculated using two different methods, one for the deterministic value provided to RAM2014 and a second for the variable costs included in the net revenue calculated in RevSim and provided to the ToolKit.

For the rate period, the deterministic value provided to RAM2014 is calculated by multiplying the system augmentation amount (aMW) by the average AURORAxmp price from the critical water run. The system augmentation amount is provided by RAM2014. A summary of this calculation is shown in Documentation Table 16.

The system augmentation costs included in the net revenue provided to the ToolKit represent the uncertainty in the cost of system augmentation purchases not made prior to setting rates. The uncertainty in the cost of system augmentation considers electricity price risk associated with meeting that need. For each game, these variable cost values replace the deterministic values for system augmentation costs provided to RAM2014.

To determine system augmentation cost risk, augmentation need (aMW) is divided into two categories. The first category assumes that CGS is operating at the forecast level of output in a non-planned-outage year for the entire rate period. This category is referred to as system augmentation not needed due to CGS planned outages (Category 1). The second category of system augmentation need is the need to replace the CGS output during planned outages. This category of system augmentation need is referred to as system augmentation need due to CGS planned outages (Category 2) and is relevant for only FY 2015 in this rate period.

System augmentation not due to CGS planned outages is further divided into two categories. Fifty percent of the Category 1 augmentation is priced using the market price run, and the remaining 50 percent is priced using the critical water run. The entire amount of system augmentation due to CGS planned outages is priced at market prices from the market price run.

For FY 2014, a year without a planned CGS outage, all system augmentation would be classified as Category 1 augmentation need, 50 percent of which is met with purchases at market prices and the remaining 50 percent at prices from the Critical Water run. For FY 2015, a year with a planned CGS outage, the total system augmentation need is made up of both Category 1 and Category 2 augmentation needs. Fifty percent of the Category 1 augmentation need is met with purchases at prices from the critical water run, and the remaining 50 percent of the Category 1 augmentation need and all the Category 2 augmentation need are met at prices from the market price run.

RevSim calculates the total system augmentation cost risk associated with each of the 3,200 games per fiscal year by summing the system augmentation costs computed by these two approaches. Documentation Table 17 presents sample calculations based on the methodology used to calculate system augmentation cost risk in RevSim for FY 2014–2015.

2.6.3 Surplus Energy Sales/Revenues and Balancing Power Purchases/Expenses

RevSim calculates surplus energy sales and revenue under various load, resource, and market price conditions. A key attribute of RevSim is that each month is divided into two time periods, Heavy Load Hours and Light Load Hours. For each simulation, RevSim calculates Power Services' HLH and LLH load and resource condition and determines HLH and LLH surplus energy sales and balancing power purchases. This calculation accounts for the winter hedging purchases described in the Power Loads & Resources Study, BP-14-E-BPA-03, section 3.1.4.

Transmission losses on BPA's transmission system are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent.

Electricity prices estimated by AURORAxmp from the Market Price run are applied to the surplus energy sales and balancing power purchase amounts to determine surplus energy revenues and balancing power purchase expenses. These HLH and LLH revenues and expenses are then combined with other revenues and expenses to calculate PS operating net revenues.

Surplus energy revenues and balancing purchase expenses for FY 2014–2015 are provided to RAM2014. These revenues and expenses are based on the median net secondary revenue (surplus energy revenue less balancing purchase expense) of the 3,200 games. The surplus energy sales and balancing power purchases passed to RAM2014, both measured in annual average megawatts, are the arithmetic means of these quantities over the 3,200 games for each fiscal year.

In a data set with an even number of values, the median value is the mean of the two middle values. Because these two middle games have specific qualities *(i.e.,* load, resources, prices, and monthly shape) that may not be representative of the study as a whole, the mean of more than two middle games was used to smooth out any particular features of individual games. To avoid specific games distorting the results, the mean of 320 games was used. The values for secondary sales revenues and balancing purchases expenses passed to RAM2014 are the arithmetic means of the secondary sales revenues and balancing purchases expenses (calculated and reported separately to RAM2014) for the 320 middle games as measured by net secondary revenue (160 above the median net secondary revenue and 160 below). Documentation Tables 18 and 19 provide summary calculations of the secondary sales revenues and balancing purchase expenses provided to RAM2014 for FY 2014–2015. Documentation Tables 20 and 21 provide monthly values for the secondary sales revenues and balancing purchase expenses provided to RAM2014 for FY 2014–2015.

Secondary sales revenues and balancing purchase expenses for FY 2014–2015 (based on the median approach described above) are shown in Documentation Table 22.

2.6.4 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2014 to calculate PNRR and, ultimately, rates that provide BPA with a 95 percent TPP for the two-year rate period. The PS net revenue simulated in each RevSim run depends on the revenue components developed by RAM2014, which in turn depend on the level of PNRR assumed when RAM2014 is run. RevSim simulates intermediate sets of net revenue during this iterative process. The final set of PS net revenue from RevSim is the set that yields a 95 percent TPP without requiring additional PNRR.

Using 3,200 games of net revenue risk data simulated by RevSim and NORM and mathematical descriptions of the CRAC and DDC, the ToolKit produces 3,200 games of cashflow and annual ending reserve levels. From these games, the ToolKit calculates TPP, and then analysts can change the amounts of PNRR in order to achieve TPP targets.

A statistical summary of the annual net revenue for FY 2014–2015 simulated by RevSim using rates with $0 million in PNRR is reported in Table 6. PS net revenue over the rate period averages $3.5 million/year. This amount represents only the operating net revenues calculated in RevSim. It does not reflect additional net revenue adjustments in the ToolKit model due to the output from NORM, interest earned on financial reserves, or the impacts of the CRAC and DDC. Also, the average net revenue in Table 6 will differ from the net revenue shown in the Power Revenue Requirement Study, BP-14-E-BPA-02, Table 1, which shows the results of a deterministic forecast, which does not account for system augmentation risk.

2.7 Inputs to NORM

The primary source of risk estimates in NORM is the judgment of subject matter experts who have the most knowledge of how the expenses, and occasionally the revenue, associated with the sources of uncertainty might vary from the forecasts embedded in the baseline assumptions of the rate case. When available, historical data are used in the modeling of risks in NORM.

2.7.1 CGS Operations and Maintenance (O&M)

CGS O&M uncertainty is modeled for Base O&M and Nuclear Electric Insurance Limited (NEIL) Insurance Premiums. NORM captures uncertainty around Base O&M and NEIL insurance costs. For Base O&M, NORM distributes the minimum and maximum based subject matter expert estimation of deviations from the expected value. The Revenue Requirement amounts for CGS O&M for FY 2013, FY 2014, and FY 2015 are $338.2 million, $312.9 million, and $355.7 million, respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. NORM models the maximum O&M expense in each year as 5 percent greater than forecast and the minimum as 5 percent less than forecast.

For NEIL insurance premiums, risk is modeled around forecast gross premiums and distributions based on the level of earnings on the NEIL fund. Historically, member utilities have received annual distributions based on the level of these earnings; the net premiums they pay are lower as a result. During FY 2013–2015 BPA does not anticipate receiving any distributions; therefore, the minimum and maximum deviations from expected are $0 for FY 2013 through FY 2015.

The distributions for CGS O&M are shown in Documentation Figure 14.

2.7.2 Corps of Engineers and Bureau of Reclamation O&M

For Corps and Reclamation O&M, NORM models uncertainty around the following:

(a) Additional costs if a security event occurs or if the security threat level increases

(b) Additional costs if a fish event occurs

(c) Additional extraordinary maintenance

(d) Base O&M (for Reclamation only)

Historically, Reclamation has under-run its O&M budget. Therefore, NORM includes a probability distribution around future Reclamation Base O&M expenditures that places a higher probability on Reclamation under-running its budget than over-running it. The forecast for FY 2013 for Reclamation's O&M is $132.4 million. The forecasts for Reclamation's O&M budget included in the Revenue Requirement are $140.6 million in FY 2014 and $143 million in FY 2015. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. In the distributions for each year, the minimum possible values are $2 million less than each forecast, and the maximum possible values are $1 million more than each forecast. The most likely values are $500,000 less than the forecasts.

For additional security costs, NORM assumes for FY 2013 through FY 2015 that there is a 2 percent probability that an event will occur that leads to a requirement for additional security at the Corps and Reclamation facilities. The additional annual cost if an event were to occur is the same for both the Corps and Reclamation at $3 million each.

Additional fish environmental costs are modeled similarly, with a 2 percent probability that an event that requires additional annual expenditures of $2 million each for both the Corps and Reclamation will occur in FY 2013 through FY 2015.

For additional hydro system needs, NORM models the uncertainty that additional repair and maintenance costs at the Federal hydro projects could be incurred and the probability that an outage event could occur.

The distributions for total Corps and Reclamation O&M are shown in Documentation Figure 15.

2.7.3 Conservation Expense

For this expense item, NORM models uncertainty around Conservation Acquisition and Low-Income and Tribal Weatherization. Conservation acquisition expense is modeled for each year from FY 2013 through FY 2015 using a Program Evaluation and Review Technique (PERT) distribution. A PERT distribution is a type of beta distribution for which minimum, most likely, and maximum values are specified. Conservation acquisition expense is modeled with a minimum value of 95 percent of the amount in the revenue requirement, a most likely value equal to the amount, and a maximum value of 105 percent of the amount. The amount for FY 2013 for conservation acquisition expense is $16 million. The forecasts are $16.4 million and $16.8 million in FY 2014 and FY 2015 respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. The distribution for conservation acquisition is shown in Documentation Figure 16.

Low-income and tribal weatherization expense variability is not modeled for FY 2013 through FY 2015. These expenses are expected to be equal to the revenue requirement amount for this period.

2.7.4 Spokane Settlement

Within the rate period, legislation enacting a settlement with the Spokane Tribe, similar to the settlement with the Colville Tribes, could pass. For FY 2014 and FY 2015, the payment to the Spokane Tribe would equal 25 percent of the payments made to the Colville Tribes. This payment amount is calculated from the forecast payments to the Colville Tribes of $21.4 million in FY 2014 and $21.9 million FY 2015. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A.

NORM includes an assumption of a 45 percent probability that the legislation will pass, with an equal probability (22.5 percent) of the payments beginning in each year of the rate period. The distributions for Spokane Settlement payments are shown in Documentation Figure 17.

2.7.5 Power Services Transmission Acquisition and Ancillary Services

For this cost item, NORM models uncertainty around Third-Party General Transfer Agreement (GTA) Wheeling and Third-Party Transmission and Ancillary Services expenses. NORM models third-party GTA wheeling cost for each year from FY 2013 through FY 2015 with a PERT distribution with a minimum value of 95 percent of the revenue requirement amount, a most likely value of the revenue requirement amount, and a maximum value of 105 percent of the revenue requirement amount. The forecast for FY 2013 for third-party GTA wheeling is $52.9 million. The revenue requirement amounts are $55.5 million in FY 2014 and $56.6 million in FY 2015. Power Revenue Requirement Study Documentation, BP-14-E-

BPA-02A, Table 3A. Figure 18 of the Documentation shows the distribution for third-party GTA wheeling.

The cost of third-party transmission and ancillary services is not anticipated to have substantial variability in FY 2013, and thus risk was not modeled for that year. For FY 2014 and FY 2015, a PERT distribution was utilized with minimum value of 95 percent of the revenue requirement amount, a most likely value of the revenue requirement amount, and a maximum value of 105 percent of the revenue requirement amount. The amount in the revenue requirement for FY 2013 for third-party transmission and ancillary services is $2.2 million. The amounts in the revenue requirement are $2.3 million for FY 2014 and FY 2015. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A.

2.7.6 Power Services Internal Operations Expenses

For this item, NORM models uncertainty around the following expenses:

(a) PS System Operations
(b) PS Scheduling
(c) PS Marketing and Business Support
(d) Civil Service Retirement System (CSRS) Additional Post-Retirement Contribution
(e) PS allocation of Corporate G&A

The individual expenses that comprise PS System Operations are modeled with PERT distributions. In the distributions, minimum values are 5 percent lower than the forecasts; most-likely values are the forecasts; and maximum values are 5 percent higher than the forecasts. This same procedure is utilized for the individual expenses that comprise PS Scheduling and the individual expenses that comprise PS Marketing and Business Support. The CSRS Additional

Post-Retirement Contribution is expected to equal the forecast amount. The revenue requirement amounts for Power Services Internal Operations Expenses for FY 2013, FY 2014, and FY 2015 are $159.11 million, $165.5 million, and $170.7 million, respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A.

Figure 19 of the Documentation shows the distributions for total Internal Operations Costs, including Corporate G&A.

2.7.7 Fish & Wildlife Expenses

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

2.7.7.1 BPA Direct Program Costs for Fish and Wildlife Expenses

The costs of BPA's Direct Program for fish and wildlife are uncertain, in large part because the actual pace of implementation cannot be known, and there is a chance that program components will not be implemented as planned. This does not reflect any uncertainty in BPA's commitment to the plans; it is merely a realistic understanding that it can take time to start and implement programs, and the expenses of the programs may not be incurred in the fiscal years in which BPA plans for them to be incurred. The uncertainty in fish and wildlife expenses is modeled using PERT distributions. For FY 2013, the most likely expense deviation is 3 percent above the revenue requirement, with a minimum (maximum under-run) value of 1.5 percent lower than forecast, and maximum values of 3 percent higher than forecast. For FY 2014 and FY 2015, the most likely expense deviation from the revenue requirement amounts is $0, the minimum (maximum under-run) is 1.5 percent lower than the most likely figure, and the maximum is 3 percent higher than the most-likely figure. The revenue requirement amounts for BPA's Direct

Program for fish and wildlife for FY 2013, FY 2014, and FY 2015 are $242.9 million, $254 million, and $260 million, respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. Figure 20 of the Documentation illustrates the distributions for the BPA Direct Program expense.

2.7.7.2 USF&W Service Lower Snake River Hatcheries Expenses

Uncertainty in the expenses for the USF&W Service Lower Snake River Hatcheries is modeled as a symmetric PERT distribution with a most likely deviation from the revenue requirement of $0, a minimum value of $3 million less than the revenue requirement, and a maximum value of $3 million above the revenue requirement. The expected value deviation is $0. The revenue requirement amounts for USF&W Service Lower Snake River Hatcheries for FY 2013, FY 2014, and FY 2015 are $29.9 million, $30.7 million, and $31.7 million, respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. Figure 21 of the Documentation shows the distributions for risk over the Lower Snake River Hatcheries expense.

2.7.7.3 Bureau of Reclamation Leavenworth Complex O&M Expenses

NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using the same symmetric PERT distribution for all three years, FY 2013 through FY 2015. The most likely value for the deviation from the revenue requirement is $0; the minimum value (maximum under-run) is 3 percent lower than most likely; and the maximum value is set to the most-likely value. This results in an expected value net revenue impact of $0 for each of the three years. The revenue requirement amounts for Bureau of Reclamation Leavenworth Complex O&M for FY 2013, FY 2014, and FY 2015 are included in the Bureau's O&M budget, which is discussed in section 2.7.2 of this Study. Figure 22 of the Documentation shows the distributions for Leavenworth Complex O&M expense.

2.7.7.4 Corps of Engineers Fish Passage Facilities Expenses

NORM models uncertainty of the cost of the fish passage facilities for the Corps using the same symmetric PERT distribution for all three years, FY 2013 through FY 2015. The most likely value for the deviation from the revenue requirement is $0; the minimum value for cost (maximum under-run) is $3 million lower than most likely; and the maximum value is $3 million higher than the most-likely cost. This results in an expected value impact on net revenue of $0 for each of the three years. The revenue requirement amounts for Corps of Engineers Fish Passage Facilities Expenses for FY 2013, FY 2014, and FY 2015 are included in the Corps's O&M budget, which is discussed in section 2.7.2 of this Study. Figure 23 of the Documentation shows the distributions for Fish Passage Facilities expense.

2.7.8 Court-Ordered Spill Risk

NORM models the uncertainty that BPA will be subject to a court order related to the 2008 FCRPS BiOp, or a subsequent FCRPS BiOp, requiring BPA to spill water at FCRPS projects at levels different than those assumed in the hydro studies used for ratesetting. Power Loads and Resources Study, BP-14-E-BPA-03. Increased spill requirements would result in decreased generation and revenue. A BiOp-related court order would be an NFB event, which would increase the maximum amount that the CRAC can recover (the CRAC Cap). Section 4.2.

NORM assumes that if court-ordered spill is required in FY 2014 or FY 2015, the spill requirements will be the same as those that BPA has operated under in FY 2011 and FY 2012. NORM applies 3,200 games of monthly AURORA prices to the monthly generation difference between assumed spill and court-ordered spill, adjusted for Slice, to calculate 3,200 games of yearly revenue deviations under court-ordered spill. These deviations are calculated for FY 2013 through FY 2015. As BPA is currently subject to court-ordered spill for FY 2013, and this court-ordered spill is already assumed in the net revenue distributions generated by RevSim, NORM applies a 100 percent probability of court-ordered spill to FY 2013. NORM applies a 95 percent probability to each of FY 2014 and FY 2015.

The FY 2013 court-ordered spill revenue deviations calculated in NORM are supplied to ToolKit only as NFB Event adjustments that increase the CRAC Cap for the CRAC applicable to FY 2014. The FY 2014 and FY 2015 court-ordered spill revenue deviations are supplied to ToolKit as revenue and cash adjustments as well as adjustments to the CRAC Cap.

The Court-Ordered Spill risk results in an expected value net revenue impact in the risk assessment of $0 for FY 2013, $16.2 million for FY 2014, and $16.0 million for FY 2015. Figure 24 of the Documentation shows the distributions for Court-Ordered Spill Risk.

2.7.9 Interest Expense Risk

The impact of interest rate uncertainty on Federal and non-Federal bond interest expense is modeled in NORM by calculating interest expense in each game from simulated interest rates and forecast amounts of bond issuances. Interest rates for issuances of new and refinanced Federal and non-Federal debt are simulated for each of the three years in the study, distinguishing between year of issuance, type of debt (*e.g.*, CGS bonds or Federal bonds), and term. Revenue Requirement Study Documentation, BP-14-E-BPA-02A, section 6. The interest expense modeling is based on a forecast schedule of debt refinancing and new bond issuances. The chance of the quantity of new borrowing or refinancing of current debt varying from the forecast is not believed to be significant; therefore, no uncertainty in the amounts of incremental borrowing is modeled.

Interest rates for different types of debt and for different terms of borrowing are modeled using Gaussian probability distributions based on high, low, and most-likely rate estimates. Documentation Table 23. Correlations among different rates in each year are modeled, as are year-to-year correlations for each interest rate type. The difference in interest payments from the deterministic forecast is calculated for every game run by NORM. The distribution of variation in the Federal and non-Federal interest from the deterministic forecast is shown in Documentation Figure 25.

The impact of interest rate risk on FY 2013–2015 Federal appropriations is modeled separately in NORM. The risk of varying total interest expense for FY 2013–2015 Federal appropriations is modeled using a PERT distribution. The most-likely value for the deviation from revenue requirement numbers is $0; the minimum value (largest negative deviation) is $5 million lower than most likely; and the maximum value is $5 million higher than most likely. This results in an expected value net revenue impact of $0 for each of the three years. The revenue requirement amounts for interest on Federal Appropriations for FY 2013, FY 2014, and FY 2015 are $215.9 million, $221.9 million, and $222.7 million, respectively. Power Revenue Requirement Study Documentation, BP-14-E-BPA-02A, Table 3A. Distributions for Federal appropriations expense are shown in Documentation Figure 26.

2.7.10 CGS Refueling Outage Risk

In the spring of FY 2013 and FY 2015, CGS will be taken out of service for refueling and maintenance. There is uncertainty in the duration of these outages and thus uncertainty in the amount of replacement power BPA must purchase from the market or the amount of secondary energy available to be sold in the market.

CGS outage duration risk is modeled as deviations from expected net revenue due to variability in the duration of the planned maintenance outages in FY 2013 and FY 2015. Increases or decreases in downtime of the CGS plant result in changes in megawatthours generated. This translates to decreased or increased net revenue for Power Services in FY 2013 and FY 2015. This revenue variability is a function of plant outage duration, monthly flat AURORAxmp market prices, and monthly flat CGS energy amounts from RevSim.

The outage duration for FY 2013 is modeled with a minimum of 40 days, a maximum of 80 days, and a median of 54 days. For FY 2015, the minimum is 47 days, the maximum is 90 days, and the median is 54 days. The probability distribution of the outage durations is shown in Documentation Figure 27.

To calculate the impact of the outage on net revenue, 3,200 outage durations are simulated. The difference between the simulated duration from NORM and the deterministic duration assumed in RevSim is used to determine the number of additional days the plant is in or out of service in each month. These additional days in or out of service are then applied to the gamed CGS energy amounts from RevSim in order to calculate monthly megawatthour deviations. In order to reflect the effect of CGS generation on market prices, AURORAxmp price games and CGS outage games are aligned based on their CGS in-service amount. These prices are then multiplied by the gamed generation deviations and adjusted for Slice, resulting in a net revenue deviation. The distributions of revenue changes for FY 2013 and FY 2015 are shown in Documentation Figure 28.

2.7.11 Revenue from Sales of Variable Energy Resource Balancing Services (VERBS)

In FY 2013–2015, TS will provide VERBS to wind and other variable resource generators in BPA's balancing authority area. Generation Inputs Study, BP-14-E-BPA-05, section 10.5. TS will charge generators for VERBS based on the installed capacity of the variable energy resources. TS will obtain from PS the generation inputs needed to support these services and will pay PS for these generation inputs.

VERBS comprises three components: regulation, following, and imbalance, with separate rates applying to each. Generation Inputs Study, BP-14-E-BPA-05, section 10.5.4. The costs of supplying these services can be characterized as having three components: embedded costs, direct costs, and variable costs.

The installed capacity of wind generation in BPA's balancing authority area during the FY 2014–2015 rate period is not known with certainty. There is financial risk due to the possibility that the quantity will differ from the forecast and TS will receive either more or less revenue for VERBS than forecast. TS and PS will each bear half of the part of this risk related to the recovery of embedded and direct costs. PS will also bear the part of this risk related to the recovery of variable costs, which is offset by an equal and opposite risk to net secondary revenue, as explained below.

The variable cost calculations reflect the deoptimization of the power system that results from setting aside some system capability to support the integration into the system of variable energy resources. If less VERBS than forecast is supplied to customers, TS will receive less revenue for such services, but PS will be able to generate greater net secondary revenue than forecast. The incremental net secondary revenue is expected to be equal to and offsetting the decrease in TS revenue because the variable costs were calculated from estimates of impacts on that secondary marketing. TS will pass to PS all actual revenue from sales of VERBS to wind generators that is intended to recover the variable costs of generation inputs provided by PS, whether lower or higher than forecast. In this way, TS faces no risk due to variation in the total quantity of wind associated with the recovery of the variable costs of VERBS. PS bears the entire risk of deviations in the recovery of the variable cost component, but because this risk is offset by the corresponding impact on PS net secondary revenue, PS faces no significant financial risk. Therefore, PS does not face significant risk for the recovery of the variable costs of generation inputs.

The recovery of embedded and direct costs is subject to risk, however, and this risk will be shared equally by the two business lines. If the amount of installed wind capacity is lower than forecast for ratesetting, BPA will calculate the portion of the TS revenue shortfall that was intended to recover embedded costs of VERBS. TS payments to PS for the embedded costs of generation inputs will then be equal to the forecast amount minus half of the direct- and embedded-cost portions of the TS revenue shortfall. Similarly, if the amount of installed wind capacity exceeds the ratesetting forecast, TS payments to PS for the embedded costs of generation inputs for that year will be equal to the ratesetting forecast for that year plus half of the direct- and embedded-cost portions of the TS revenue increase.

Installed wind capacity is modeled using estimates of low, most-likely, and high quantities for FY 2014–2015, with the low and high representing the 10th and 90th percentile of capacity probability distributions. The years are modeled sequentially, such that the installed capacity drawn for one fiscal year affects the most-likely capacity for the next fiscal year, and capacity does not decrease from one year to the next. Installed capacity for each fiscal year is drawn 3,200 times. The difference between the forecast and gamed values is multiplied by the embedded-cost portion of the appropriate VERBS rates, resulting in a negative or positive financial result.

Fifty percent of the financial result of these two risks is then applied to the net revenue for both TS and PS in their risk analyses. Distributions for VERBS revenue are shown in Documentation Figure 29.

2.7.12 Operating Reserve Revenue Risk

Similar to VERBS, Operating Reserve is a service TS provides to transmission customers that relies on generation inputs from PS. Generation Inputs Study, BP-12-E-BPA-05, section 4. TS will charge customers for the Operating Reserve services they receive from TS. TS will obtain from PS the generation inputs needed to support these services and will pay PS for these generation inputs. TS will pass the actual revenue from sales of Operating Reserve products on to PS. Therefore, PS bears the revenue risks of Operating Reserve.

For FY 2014 and FY 2015, it is uncertain which regional reliability standard will be used for determining transmission customers' Spinning and Supplemental Operating Reserve requirement. *Id.* section 4.2.

Under the regional reliability standard currently in place, the Operating Reserve requirement is the greater of (1) the most severe single contingency or (2) the sum of five percent of load responsibility served by hydro generation and seven percent of load responsibility served by thermal generation.

A new regional reliability standard has been submitted to the Federal Energy Regulatory Commission (Commission) by the North American Electric Reliability Corporation (NERC). Under the new standard, the Operating Reserve requirement is the greater of (1) the most severe single contingency or (2) the sum of three percent of load and three percent of net generation. Based on the estimated timing of approval by NERC and the Commission followed by at least six months for implementation, BPA's forecast assumes that this new standard will be implemented on or before the start FY 2014–2015 rate period. *Id.*

Because a significant fraction of the generation in the BPA balancing authority area serves load outside the balancing authority area, the transfer of some Operating Reserve responsibility to load, as required under the proposed standard, would have the effect of transferring the responsibility for some Operating Reserve outside the balancing authority area. This change would reduce the amount of Operating Reserve TS needs to supply and reduce revenue from sales of Operating Reserve, reducing the revenue TS passes to PS for generation inputs. Thus, if the proposed standard is not adopted, the level of Operating Reserve revenue received will not be the lower level anticipated under the proposed standard, but a higher level based on the current standard. In that case, Operating Reserve revenue is expected to be $7 million higher than the forecast amount per year.

Since implementation of the new standard, BAL-002, requires review and approval by NERC, subsequent review and approval by the Commission, and finally a six-month implementation period within WECC, NORM assumes a 100 percent probability that FY 2013 and FY 2014 Operating Reserve revenue will be based on the current standard. NORM then assumes that the probabilities that FY 2015 Operating Reserve revenue will be based on the current standard or on

BAL-002 are each 50 percent. Distributions for Operating Reserve revenue are shown in Documentation Figure 30.

2.7.13 The Accrual-to-Cash (ATC) Adjustment

One of the inputs to the ToolKit (through NORM) is the ATC Adjustment. Most of BPA's probabilistic modeling is performed in accrual terms; that is, using impacts on net revenue. BPA's TPP standard is a measure of the probability of having enough cash to make payments to the Treasury. While cash flow and net revenue generally track each other closely, there can be significant differences in any year. For instance, the requirement to repay Federal borrowing over time is reflected in the accrual arena as depreciation of assets. Depreciation is an expense that reduces net revenue, but there is no cash inflow or outflow associated with depreciation. The same repayment requirement is reflected in the cash arena as cash payments to the Treasury to reduce the principal balance on Federal bonds and appropriations. These cash payments are not reflected anywhere on income statements. Therefore, in translating a net revenue result to a cash flow result, the impact of depreciation must be removed and the impact of cash principal payments must be added. The 3,200 ATC adjustments calculated in NORM make the changes needed to translate these accrual results (net revenue results) into the equivalent cash flows so that ToolKit can calculate reserves values in each game and thus calculate TPP.

The ATC Adjustment is modeled probabilistically in NORM. NORM uses the deterministic ATC Table, Table 7, as its starting point but includes 3,200 gamed adjustments for the Slice True-Up, based on the calculated deviations in those revenue and expense items in NORM that are subject to the True-Up.

2.8 NORM Results

The output of NORM is an Excel file containing (1) the aggregate total net revenue deltas for all of the individual risks that are modeled, (2) the associated ATC adjustments for each game, and (3) the NFB Event net revenue deltas for FY 2013, FY 2014, and FY 2015. Each run has 3,200 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in Documentation Figure 31.

3. QUANTITATIVE RISK MITIGATION

3.1 Introduction

The preceding sections of this Study describe the risks that are modeled explicitly, with the output of NORM and RevSim quantitatively portraying the financial uncertainty faced by PS in each fiscal year. This section describes the tools used to mitigate these risks, such as financial reserves and the CRAC, and how BPA evaluates the adequacy of this mitigation. The following section describes the risks that BPA has analyzed qualitatively, that is, logically rather than through modeling, and the measures for treating them.

The risk that is the primary subject of this Study is the possibility that BPA might not have sufficient cash on September 30, the last day of a fiscal year, to fully meet its obligation to the Treasury for that fiscal year. BPA's TPP standard, described in section 1.1.1, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a five percent probability of any deferrals in a two-year rate period). TPP and the ability of the rates to meet the TPP standard are measured in the ToolKit by applying the risk mitigation tools described in this section to the modeled financial risks described in the previous sections.

A second risk can be called within-year liquidity risk—the risk that, at some time within a fiscal year, BPA will not have sufficient cash to meet its immediate financial obligations (whether to the Treasury or to other creditors), even if BPA might have enough cash later in that year. In each recent rate proceeding, a need for reserves for within-year liquidity ("liquidity reserves") has been defined. This level is based on a determination of BPA's total need for liquidity and a subsequent determination of how much of that need is properly attributed to Power Services.

3.2 Risk Mitigation Tools

3.2.1 Liquidity

Cash and cash equivalents provide liquidity. For this rate proceeding, BPA has two sources of liquidity, Financial Reserves Available for Risk Attributed to PS (PS Reserves) and the Treasury Facility. These liquidity sources mitigate financial risk by serving as a temporary source of cash for meeting financial obligations during years in which net revenue and the corresponding cash flow are lower than anticipated. In years of above-expected net revenue and cash flow, financial reserves will be replenished so they will be available in later years.

3.2.1.1 PS Reserves

PS Reserves are the fundamental protection against the financial impacts of the uncertainty BPA faces in its financial reserves. For power ratesetting purposes, it is the Financial Reserves Available for Risk attributed to the generation function (PS reserves) that is considered when measuring TPP. Financial reserves available to the generation function comprise cash and investments ("Treasury Specials") held by BPA in the Bonneville Fund at the Treasury plus any deferred borrowing. Deferred borrowing refers to amounts of capital expenditures that BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts are converted to cash when needed by completing the borrowing.

As $193 million of PS reserves is considered not to be available for risk, that amount is not included in the starting financial reserves or any other part of the TPP calculation. First, PS reserves exclude financial reserves that accumulated due to the suspension of payment of 2000 REP Settlement benefits in FY 2007. This exclusion comprises $75.4 million of principal and interest that has accrued from April 2008, owed to IOUs under the 2008 Residential Exchange Interim Relief and Standstill Agreements (Contract Nos. 08PB-12438, 08PB-12439, 08PB-12441, 08PB-12442). Second, $73.8 million in funds BPA has received for previously unpaid receivables for sales into the California ISO and California PX markets during the energy crisis of 2000-2001 are excluded from PS Reserves for the time being. There remains a risk that BPA may be obligated to refund some amount for BPA's sales into these markets during the energy crisis as a result of ongoing litigation. Third, $43.9 million of funds collected from customers under contracts that obligate BPA to perform energy efficiency-related upgrades to the customers' facilities also is excluded.

3.2.1.2 The Treasury Facility

In FY 2008, BPA reached an agreement with the U.S. Treasury that made a $300 million short-term note available to BPA for up to two years to pay expenses. BPA concluded that this note can be prudently relied on as a source of liquidity. In FY 2009, BPA and the Treasury agreed to expand this facility to $750 million.

3.2.1.3 Within-Year Liquidity Need

BPA needs to maintain access to short-term liquidity for responding to within-year needs, such as uncertainty due to the unpredictable timing of cash receipts or cash payments, or known timing mismatches. An illustrative timing mismatch is the large Energy Northwest bond payment due in the spring. Priority Firm Power (PF) rates are set to recover the entire amount of this payment, but by spring BPA will have received only about half of the PF revenue that will fully recover this cost by the end of the fiscal year. In the BP-12 rate proceeding, BPA assumed that $300 million of liquidity was needed for within-year needs associated with PS. The Within-Year Liquidity Need amount has been increased for the BP-14 Initial Proposal to provide a high level of assurance that BPA will have sufficient liquidity to meet outstanding margin calls required by BPA's new practice of trading financial instruments. BPA may sell or buy financial products to manage the price risk of balancing sales and purchases of power. The outstanding balance of margin calls could total as much as $20 million, making for a total within-year liquidity need of $320 million.

3.2.1.4 Liquidity Reserves Level

No PS Reserves need to be set aside for within-year liquidity; *i.e.*, the Liquidity Reserves Level is $0. Thus, all PS Reserves are considered to be available for the year-to-year liquidity needed to support TPP.

3.2.1.5 Liquidity Borrowing Level

For this study, $320 million of the short-term borrowing capability provided by the Treasury Facility is considered to be available only for within-year liquidity needs, fully meeting the need for short-term liquidity. Thus, $430 million of the Treasury Facility is considered to be available for year-to-year liquidity for TPP.

3.2.1.6 Net Reserves

The concept of "Net Reserves" is used in this Study. Net Reserves simplifies the discussion of the above sources of liquidity by combining the two discrete sources into a single measure. Net Reserves is the amount of PS Reserves above zero, less any balance on the Treasury Facility. In each individual Monte Carlo game in the ToolKit, either PS Reserves are $0 or higher and the balance on the Treasury Facility is $0, or PS Reserves are $0 and the balance on the Treasury Facility is $0 or higher. In a single game, PS Reserves and the balance on the Treasury Facility will not both be above $0. This is because the ToolKit models a positive outstanding balance on the Treasury Facility if and only if PS Reserves are depleted. This clear-cut relationship does not hold for expected values calculated from a set of multiple games, though: it is mathematically possible for the expected value of ending reserves attributed to PS to be above zero and for the expected value of the outstanding balance on the Treasury Facility to be above zero.

3.2.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted in rate proceedings using current projections of PS Reserves and other sources of liquidity. If the TPP is below the 95 percent two-year standard established in BPA's Financial Plan, then the projected reserves, along with whatever other risk mitigations are considered in the risk study, are not sufficient to reach the TPP standard. This is typically corrected by adding PNRR to the revenue requirement as a cost needed to be recovered by rates. This addition has the effect of increasing rates, which will increase the net cash flow, which will increase the available PS Reserves and therefore increase TPP. No PNRR is needed to meet the TPP standard; PNRR is $0 for both FY 2014 and FY 2015.

3.2.3 The Cost Recovery Adjustment Clause (CRAC)

In most power rates in effect since 1993, BPA has employed CRACs or Interim Rate Adjustments (IRAs) as upward rate adjustment mechanisms that can respond to the financial circumstances BPA experiences before the next opportunity to adjust rates in a rate proceeding. The CRAC explained here could increase rates for FY 2014 based on financial results for FY 2013. It also could increase rates for FY 2015 based on the accumulation of financial results for FY 2013 and FY 2014 (taking into account any CRAC applying to FY 2014 rates). The rates subject to the CRAC (and eligible for the DDC, section 3.2.5 below) are the Non-Slice Customer rate, the PF Melded rate, the Industrial Firm Power rate, the New Resource Firm Power rate, and the Reserves-based Ancillary and Control-Area Services rates, which are levied by Transmission Services. Power GRSP II.C, BP-14-E-BPA-09; Transmission GRSP II.H, BP-14-E-BPA-10.

3.2.3.1 Description of the CRAC

The CRAC for FY 2014 and FY 2015 is an annual upward adjustment in various power and transmission rates. The threshold for triggering the CRAC is an amount of Power Services Accumulated Net Revenue (ANR) accumulated since the end of FY 2012. The ANR threshold values are calibrated to be equivalent to $0 in PS net reserves. The CRAC will recover 100 percent of the first $100 million that ANR is below the threshold. Any amount beyond $100 million will be collected at 50 percent, up to the CRAC annual limit on total collection, or cap, of $300 million. For example, at an equivalent of negative $100 million in reserves at the end of the fiscal year, $100 million will be collected in the next year. At the equivalent of negative $150 million, $125 million will be collected ($100 million plus one-half of the next $50 million). The CRAC will be implemented only if the amount of the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2014 rates will be made in July 2013; the corresponding calculations for possible adjustments to FY 2015 rates will be made in September 2014. A forecast of the year-end Power Services ANR will be made based on the results of the Third Quarter Review and then compared to the thresholds for the CRAC and the DDC. Section 3.2.5. If this ANR forecast is below the CRAC threshold, an upward rate adjustment will be calculated for the duration of the upcoming fiscal year. If the forecast is above the threshold for the DDC, a downward rate adjustment will be calculated to distribute dividends to applicable rates for the duration of the upcoming fiscal year. See Table 8.

3.2.3.2 Administrator's Discretion to Reduce the CRAC

BPA's CRAC methodology includes a process that allows BPA to look ahead to the remaining fiscal year(s) of the rate period and determine whether the calculated CRAC amount could be reduced without causing the PS TPP to fall short of BPA's TPP standard. 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 and the requirement to restore liquidity tools, such as the Treasury Facility, if they are used. This requirement protects the TPP standard but provides for lower rates if BPA determines that not all of the additional revenue is needed to meet the TPP standard or to restore liquidity tools.

A CRAC that is calculated for FY 2014 may be reduced from the calculated amount as long as the two-year TPP for FY 2014–2015 remains at or above 95 percent. BPA may adjust the parameters *(i.e.*, the Cap and Threshold) for the CRAC applicable to FY 2015 to maintain the FY 2014–2015 TPP. A CRAC that is calculated for FY 2015 may be reduced from the calculated amount as long as the one-year TPP for FY 2015 would still be at or above 97.5 percent. These reductions may not be made if they would reduce the generation of incremental revenue intended to allow repayment of any borrowing under the Treasury Facility. Because the CRAC thresholds have been set at the lowest level that allows for beginning prompt replenishment of liquidity tools if they are used, any reduction in CRAC amounts would compromise liquidity replenishment; therefore, there is effectively no Administrator's discretion for the CRACs that could apply to rates in FY 2014 or FY 2015.

3.2.4 The NFB Adjustment

NFB (NMFS [National Marine Fisheries Service] FCRPS [Federal Columbia River Power System] BiOp [Biological Opinion]) risks are risks arising from litigation over the FCRPS BiOp. Section 4.2. Historically, NFB risks and mitigation have been treated qualitatively in ratesetting.

In this rate proceeding, one potential NFB Trigger Event, court-ordered spill related to an FCRPS BiOp, has been modeled quantitatively. See section 2.7.8. The NFB Adjustment, is modeled in the ToolKit in order to capture the impact of the NFB Adjustment in mitigating the single modeled NFB risk on CRAC cost recovery and TPP. The remainder of the NFB risks and mitigation are handled through qualitative risk assessment and mitigation. See section 4.2. The ToolKit models the NFB Adjustment as it is described in section 4.2.1.

3.2.5 Dividend Distribution Clause (DDC)

One of BPA's financial policy objectives is to ensure that reserves do not accumulate to excessive levels. See section 1.2.1. The DDC is triggered if Power Services ANR is above a threshold (instead of below, as with the CRAC), and if so, there is a downward adjustment to certain power and transmission rates. In the same way that a CRAC passes bad financial outcomes to BPA's customers, a DDC passes good financial outcomes to BPA's customers. The total distribution is capped at $1,000 million per fiscal year. The DDC will be implemented only if the amount of the DDC is greater than or equal to $5 million. See Table 9.

3.3 Overview of the ToolKit

The ToolKit is an Excel 2003 spreadsheet that is used to evaluate the ability of PS to meet BPA's TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. The ToolKit contains several parameters *(e.g.,* Starting Reserves and CRAC and DDC settings) defined within the ToolKit file itself. The ToolKit reads in data from two external files, one each from RevSim and NORM. Most of the modeling of risks is performed by the Operating Risk Models 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 *V*isual *B*asic for *A*pplications).

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 and liquidity attributable to Power Services, and thus on TPP. It registers a deferral of a Treasury payment when reserves and all sources of liquidity are exhausted in any given year. The ToolKit is run for 3,200 games or iterations. TPP is calculated by taking the number of games where a deferral did not occur in either year of the rate period and dividing by 3,200. The ToolKit calculates the TPP and other risk statistics and reports results. The ToolKit also allows analysts to calculate how much PNRR is needed in rates, if any, to meet the TPP standard. The "Main" page of the ToolKit can be found in Documentation Figure 32.

3.4 ToolKit Inputs and Assumptions

3.4.1 RevSim Results

The ToolKit reads in risk distributions generated by RevSim that are created for the current year, FY 2013, and the rate period, FY 2014–2015. TPP is measured for only the two-year rate period, but the starting Reserves Available for Risk for FY 2014 depend on events yet to unfold in FY 2013; these runs reflect that FY 2013 uncertainty. See section 2 of this Study for more detail on Operating Risk Models.

3.4.2 Non-Operating Risk Model

The ToolKit reads in NORM distributions that are created for FY 2013–2015 that reflect the uncertainty around non-operating expenses. See section 2 of this Study for more detail on NORM.

3.4.3 Treatment of Treasury Deferrals

In the event of a deferral of payment of principal to the Treasury in the ToolKit, the ToolKit assumes that BPA will track the balance of payments that have been deferred and will repay this balance to the Treasury at its first opportunity. "First opportunity" is defined for TPP calculations as the first time Power Services ends a fiscal year with more than $100 million in net reserves. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral. This is referred to as "hybrid" logic on the ToolKit main page.

3.4.4 Starting PS Reserves

The FY 2013 starting PS reserves have a known value of $217 million based upon the FY 2012 Fourth Quarter Review. Each of the 3,200 games starts with this value. See section 3.2.1.1 for a description of PS Reserves.

3.4.5 Starting ANR

The FY 2013 starting ANR value of $0 million is known from the definition of ANR as being accumulated PS net revenue since the end of FY 2012. Each of the 3,200 games starts with this value.

3.4.6 PS Liquidity Reserves Level

The PS Liquidity Reserves Level is an amount of PS Reserves set aside (*i.e.*, not available for TPP use) to provide liquidity for within-year cash flow needs. This amount is set to $0 million. See section 3.2.1.4.

3.4.7 Treasury Facility

This Study relies on all $750 million of BPA's Treasury Facility; $320 million of this is set aside for within-year liquidity needs, as described above in section 3.2.1.5, and the remaining $420 million is modeled as available to support PS TPP.

3.4.8 Interest Rate Earned on Reserves

Interest earned on the both the cash component and the Treasury Specials component of PS Reserves is 1.52 percent in FY 2013, 1.52 percent in FY 2014, and 2.60 percent in FY 2015. Interest paid on use of the Treasury Facility is 0.56 percent, 1.64 percent, and 3.42 percent for those three fiscal years.

3.4.9 Interest Credit Assumed in Net Revenue

An important feature of the ToolKit is the ability to calculate interest earned on PS reserves separately for each game. The net revenue games the ToolKit reads in from RevSim include deterministic assumptions of interest earned on reserves for each fiscal year; that is, the interest earned does not vary from game to game. To capture the risk impacts of variability in interest credit induced by variability in the level of reserves, in the TPP calculations the values embedded in the RevSim results for interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The interest credit assumptions embedded in RevSim results that are backed out are $11.50 million for FY 2013, $6.45 million for FY 2014, and $11.21 million for FY 2015.

3.4.10 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the non-linear shape of PS Reserves throughout a fiscal year. The ToolKit calculates interest earned on reserves by making the simplifying assumption that reserves change linearly from the beginning of the year to the end. It takes the average of the starting reserves and the ending reserves and multiplies that figure by the interest rate for that year. Because PS cash payments to the Treasury are not evenly spread throughout the year, but instead are heaviest in September, PS will typically earn more interest in BPA's monthly calculations than the straight-line method yields. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year. The cash timing adjustments for this Study are $4.9 million for FY 2013, $4.0 million for FY 2014, and $7.1 million for FY 2015.

3.4.11 Cash Lag for PNRR

These numbers appear in the input section of the ToolKit's main page, but they are calculated automatically. When the ToolKit calculates a change in PNRR (either a decrease, or more typically, an increase), it calculates how much of the cash generated by the increased rates would be received in the subsequent year, because September revenue is not received until October. In order to treat ToolKit-generated changes in the level of PNRR on the same basis as amounts of PNRR that have already been assumed in previous iterations of rate calculations and are already embedded in the RevSim results, the ToolKit calculates the same kind of lag for PNRR that is embedded in the RevSim output file the ToolKit reads. Because this Study does not require PNRR, there are no cash adjustments for PNRR.

3.5 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 10.

3.5.1 TPP

The two-year TPP is 99.25 percent. In 3,200 games, there are no deferrals for FY 2013 or FY 2014. There are 23 deferrals for FY 2015, with the expected value of the amount deferred equal to $0.29 million. The mean size of deferrals when they occur is $38.4 million.

3.5.2 Ending PS Reserves

Known starting PS Reserves for FY 2013 are $217 million. The expected values of ending net reserves are $181 million for FY 2013, $176 million for FY 2014, and $168 million for FY 2015. Over 3,200 games, the range of ending FY 2015 net reserves is from negative $430 million to $1,190 million. The rate adjustment mechanisms would produce a CRAC of $265 million or a DDC of $440 million in these extreme cases if the FY 2016 rates include mechanisms comparable to those included in the FY 2014–2015 rates. The 50-percent confidence interval for ending net reserves for FY 2015 is negative $70 million to $384 million. ToolKit summary statistics for reserves and liquidity can be found in Documentation Figure 33 and Table 26.

3.5.3 CRAC and DDC

For FY 2014, the CRAC triggers 393 times (12 percent), yielding an expected value of $8 million of CRAC revenue in that year, with an average CRAC size of $66 million over only those games when the CRAC triggers. The NFB Adjustment results in additional CRAC recovery in 93 of the 393 CRAC games (3 percent of the 3,200-game total), yielding $0.2 million of the $8 million expected value CRAC recovery. For FY 2015, the CRAC triggers 764 times (24 percent), yielding an expected value of $23 million of CRAC revenue in that year, with an average CRAC size of $98 million over only those games when the CRAC triggers. The NFB adjustment results in additional CRAC recovery in 348 of the 764 CRAC games (11 percent of the 3,200-game total), yielding $0.9 million of the $24 million expected value CRAC recovery.

The DDC does not trigger in any of the 3,200 games for FY 2014. For FY 2015, the DDC triggers 19 times (1 percent), yielding an expected value of $0.4 million of dividend distributions in that year, with an average DDC size of $60 million over only those games when the DDC triggers.

4. QUALITATIVE RISK ASSESSMENT AND MITIGATION

4.1 Introduction

The qualitative risk assessment described here is a logical analysis of the potential impacts of risks that have been identified (but not included in the quantitative risk assessment), given the risk mitigation measures that have been created—largely terms and conditions that define how possible risk events would be treated. If this logical analysis indicates that significant financial risk remains in spite of the risk mitigation measures, additional risk treatment might be necessary. The three categories of risk analyzed here are financial risks to BPA arising from legislation over the FCRPS Biological Opinion, financial risks to BPA or to Tier 1 costs arising from BPA's provision of service at Tier 2 rates, and financial risks to BPA or to Tier 1 costs arising from BPA's provision of Resource Support Services.

4.2 FCRPS Biological Opinion Risks

Certainty that it can cover its fish and wildlife program costs is an extremely important objective for BPA. Because of pending and possible litigation over BPA's FCRPS fish and wildlife obligations, it is impossible to determine now with any certainty the approach to fish recovery and the associated costs that BPA will ultimately be required to implement during the rate period, FY 2014–2015.

The possibilities for FY 2014–2015 are many and mostly unknowable at this time and, as a result, probabilities cannot be estimated for any particular scenario that might be created. Because the uncertainty is open-ended, it is necessary to have an equally open-ended adjustment mechanism to ensure that BPA can fund its fish and wildlife obligations despite the uncertainty.

This Study includes two related features that help to mitigate the financial risk to BPA and its stakeholders caused by uncertainty over future fish and wildlife obligations under the FCRPS BiOp and their financial impacts. These are the NFB Adjustment and the Emergency NFB Surcharge, collectively referred to as the NFB Mechanisms. NFB stands for the *N*ational Marines Fisheries Service *F*ederal Columbia River Power System *B*iological Opinion. Implementation details for the NFB Mechanisms are given in GRSP II.N, BP-12-E-BPA-09.

These NFB Mechanisms will take effect should certain events, called trigger events, occur. An NFB Trigger Event is one of the following events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those in the most recent Power rate final studies, as modified, prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries,* CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by NOAA Fisheries Service, or any appeal thereof ("Litigation")

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation

(3) A new FCRPS BiOp

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation

(5) Actions or measures ultimately required under the 2010 Supplemental BiOp that differ from the 2010 Supplemental BiOp implementation forecast in the rate case

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

4.2.1 The NFB Adjustment

The NFB Adjustment adjusts the CRAC for any year in the rate period if one or more NFB Trigger Events with financial effects occurred in the previous year (unless one or more Emergency NFB Surcharges in the previous year completely collected additional revenue equal to the financial effects). The adjustment allows the CRAC to collect more revenue under specific conditions. The NFB Adjustment could modify the CRAC Cap applicable to rates for FY 2014 or FY 2015. While the NFB Adjustment increases the revenue the CRAC can collect, it does not necessarily result in higher revenue collected. If the NFB Adjustment triggers but Power Services ANR is above the CRAC threshold specified in the GRSPs, there will be no adjustment to rates, because the CRAC will not trigger.

4.2.2 The Emergency NFB Surcharge

The Emergency NFB Surcharge results in nearly immediate increases in net revenue for PS if (a) an NFB Trigger Event occurs, and (b) BPA is in a "Cash Crunch" and cannot prudently wait until the next year to collect incremental net revenue. A Cash Crunch is defined to exist when BPA calculates that the within-year Agency TPP (*i.e.*, including both TS and PS) is below 80 percent. The surcharge increases net revenue by making an upward adjustment to power and transmission rates specified in GRSP II.N, BP-14-E-BPA-09.

The Emergency NFB Surcharge addresses the fact that the CRAC does not produce revenue until the year following the fiscal year in which financial effects of a Trigger Event are experienced. Thus, the financial benefit of the NFB Adjustment may be too late if BPA is in a Cash Crunch when a Trigger Event occurs. The surcharge may be implemented in FY 2014 if the events required to impose the surcharge occur in that fiscal year or in FY 2015 if the requisite events occur in that year.

4.2.3 Multiple NFB Trigger Events

There can be multiple NFB Trigger Events in one year. If BPA is not in a Cash Crunch in such a year, then there will be only one, final analysis near the end of the year that calculates the NFB Adjustment to the cap on the CRAC applicable to the next fiscal year. If BPA is in a Cash Crunch in such a year, there may be more than one Emergency NFB Surcharge calculated and applied during that year. For example, there could be more than one court order in FY 2014 that increases the financial impacts of operations in FY 2014. If BPA were in a Cash Crunch, there could be an Emergency NFB Surcharge calculated for each of the Trigger Events and applied during FY 2014. If BPA were not in a Cash Crunch in FY 2014, all of these triggering events would be included in the calculation of the single NFB Adjustment that would increase the cap on the CRAC applicable to FY 2015.

Each NFB Adjustment affects only one year. However, because the comparison used to calculate the NFB Adjustment is between the actual operation for fish and the operation assumed in the last rate case (as modified prior by previously responded-to NFB Events), it is possible for a Trigger Event to affect operations for more than one year of the rate period. For example, a decision in FY 2013 may affect operations in both FY 2013 and FY 2014. The analysis of the total financial impact during FY 2013 for adjusting the cap on the CRAC applying to FY 2014 would be separate from the analysis of the total financial impact during FY 2014 for adjusting the cap on the CRAC applying to FY 2015 (or for implementing an Emergency NFB Surcharge during FY 2014). Increases in the financial impacts during FY 2015 are not covered by the NFB

Adjustment because incorporating those increases through an NFB Adjustment would require a CRAC during FY 2016, and the rates for FY 2016 are not covered by this Study. However, financial impacts during FY 2015 are covered by the Emergency NFB Surcharge provisions applicable to FY 2015.

4.3 Risks Associated with Tier 2 Rate Design

4.3.1 Introduction

For the FY 2014–2015 rate period, BPA is establishing three Tier 2 rate alternatives, the Tier 2 Short-Term rate, the Tier 2 Load Growth Rate, and the Tier 2 VR1-2014 rate. Power Rates Study, BP-14-E-BPA-01, section 3.1.9. BPA has not made all of the necessary power purchases to meet its load obligations at the Tier 2 rate for the rate period but intends to do so by the time power deliveries begin for each fiscal year. BPA purchased one flat annual block of power from the market for delivery to BPA at the Mid-Columbia delivery point (Mid-C). *Id.,* section 3.1.7.3. The Tier 2 rates will be formula rates in order for BPA to update the cost components prior to power deliveries, to reflect the costs of additional power acquisitions. Preventing risks associated with Tier 2 from increasing costs for Tier 1 or requiring increased mitigation for Tier 1 is one of the objectives guiding the development of the risk mitigation for the FY 2014–2015 rate period. See section 1.2.1.

4.3.2 Identification and Analysis of Risks

The qualitative assessment of risks associated with Tier 2 cost recovery identified several possible events that could pose a financial risk to either BPA or Tier 1 costs:

(a) The contracted-for power is not delivered to BPA.

(b) A customer's Above-Rate Period High Water Mark (RHWM) load is lower than the amount forecast.

(c) A customer's Above-RHWM load is higher than the amount forecast.

(d) A customer does not pay for its Tier 2 service.

(e) A customer's Above-RHWM load is lower than its take-or-pay VR1-2014 rate amounts.

The following sections describe the analysis of these risks that determines whether there is any significant financial risk to BPA or Tier 1 costs.

4.3.2.1 Risk: The Contracted-for Power Is Not Delivered to BPA

BPA has executed one standard Western Systems Power Pool (WSPP) Schedule C contract for purchases made to meet a portion of its load obligations under Tier 2 rates for the rate period. The remaining purchases are expected to be codified as WSPP Schedule C contracts as well. Under the WSPP Schedule C contracts, if a supplier fails to deliver power at Mid-C, the contract provides for liquidated damages to be paid by the supplier. The liquidated damages cover the cost of any replacement power purchased by BPA to the extent the cost of the replacement power exceeds the original purchase price.

If there is a disruption in the delivery from Mid-C to the BPA point of delivery due to a transmission event, BPA will supply replacement power and pass through the cost of the replacement power to the Tier 2 purchasers by means of a Transmission Curtailment Management Service (TCMS) calculation. The Power Rates Study, BP-14-E-BPA-01, section 3.1.9, explains how the TCMS calculation is performed for service at Tier 2 rates. BPA will base the TCMS cost on the amount of megawatthours that was curtailed and the Powerdex (or its replacement) Mid-C hourly index for the hour the event occurred. Based upon BPA's past experiences, it is not anticipated that such disruptions would affect a substantial number of hours in a year. The market index is a fair, unbiased estimate of the cost of replacement power; therefore, there is no reason to believe that if such events occur in a fiscal year BPA would incur a net cost.

4.3.2.2 Risk: A Tier 2 Customer's Load is Lower than the Amount Forecast

Each customer provided BPA an election regarding its intention to meet none, some, or all of its Above-RHWM load with Tier 2-priced power from BPA. Elections were made by November 1, 2009, for FY 2014 and by September 30, 2011, for FY 2015. Using the Above-RHWM loads that were computed in the RHWM process, which concluded in September 2012, and the customers' elections, BPA has determined each customer's Above-RHWM load served at a Tier 2 rate for the BP-14 rate period. As noted in section 4.3.2.1, BPA has started making contractual commitments to purchase power sufficient to supply the necessary quantity of power at Tier 2 rates. Power purchases will be completed prior to power deliveries at Tier 2 rates under the new rates in each year.

Even if the customer's actual load is lower than the BPA forecast, the terms of the customer's Contract High Water Mark (CHWM) contract obligate the customer to continue to pay the full cost of its purchases at the Tier 2 rates. This approach protects BPA and Tier 1 purchasers from financial impacts of this event. The customer's load reduction would free up some of the power BPA has contracted for, and BPA would remarket this power. BPA would return the value of the remarketed power to the customer by charging it less through the Load Shaping rate than it would otherwise have been charged. BPA would effectively credit the customer for the unneeded power at the Load Shaping rate, which is an unbiased estimate of the market value of the power; thus, there would be no net cost to BPA.

4.3.2.3 Risk: A Tier 2 Customer's Load is Higher than the Amount Forecast

This risk is the inverse of the previous risk. If a customer's load is higher than forecast by BPA and the customer's sources of power (the sum of the quantity of power at Tier 2 rates the customer committed to purchase, its Tier 1 power, and the amount of non-BPA power the customer committed to its load) are inadequate to meet its total retail load, BPA would obtain additional power from the market and charge the customer for this power at the Load Shaping rate. The Load Shaping rate is an unbiased estimate of the market cost of the power. The customer thus retains the primary obligation to pay for the additional power, and there would be no net cost to BPA.

4.3.2.4 Risk: A Customer Does Not Pay for its Service at the Tier 2 Rate

It is not possible for a customer to be in default on its Tier 2 charges and remain in good standing for its Tier 1 service. If a customer does not pay for its service at the Tier 2 rate, it will be in arrears for its PS bill and will be subject to late payment charges. BPA may require additional forms of payment assurance if (1) BPA determines that the customer's retail rates and charges may not be adequate to provide revenue sufficient to enable the customer to make the payments required under the contract, or (2) BPA identifies in a letter to the customer that BPA has other reasonable grounds to conclude that the customer may not be able to make the payments required under the contract. If the customer does not provide payment assurance satisfactory to BPA, then BPA may terminate the CHWM contract.

4.3.2.5 Risk: A Customer's Above-RHWM Load is Lower than its Take-or-pay VR1-2014 Rate Amounts

When customers subscribed to the VR1-2014 rate, they requested specific amounts of load to be served at this rate on a take-or-pay basis for the term of the rate alternative's application (FY 2015-2019). Customers were eligible for amounts that were capped at levels based on BPA load forecasts completed the previous spring. Once customers requested an amount, however, and BPA was successful purchasing that amount, then the customers became contractually committed to that purchase amount. Above-RHWM loads are set in a separate process prior to the Initial Proposal rate case. For the first year of application of the VR1-2014 rate (FY 2015), this was done in September 2012. Based on that process, some VR1-2014 customers elected, in accordance with section 10 of the CHWM contract, to have BPA remarket amounts of their VR1-2014 purchases that are in excess of their Above-RHWM load. These customers will continue to pay the full cost of the VR1-2014 purchase they elected, and BPA will allocate the power to the Tier 2 Short-Term cost pool at a market price. The market price will be the price at which BPA purchases its remaining Tier 2 power needs from the market. This market price will then be used as the price for computing the remarketing credits BPA applies to the customers' bills. Because BPA is selling the excess VR1-2014 power at fixed prices to Short-Term customers, the revenues that will be received from Short-Term customers will equal the remarketing credits paid to VR1-2014 customers, and there is no risk to BPA.

4.4 Risks Associated with Resource Support Services Rate Design

4.4.1 Introduction

Resource Support Services (RSS) are resource-following services that help financially convert the variable, non-dispatchable output from non-Federal generating resources to a known, guaranteed shape. Operationally, BPA serves the net load placed on it after taking into consideration the variability of the customer's load and resource(s).

RSS include Secondary Crediting Service (SCS), Diurnal Flattening Service (DFS), and Forced Outage Reserve Service (FORS). The customers that have elected to purchase RSS and their elections are listed in the Power Rates Study Documentation, BP-14-E-BPA-01A, Table 3.17

4.4.2 Identification and Analysis of Risks

The RSS pricing methodology is a value-based methodology that relies on a combination of forecast market prices and costs associated with new capacity resources rather than aiming to capture the actual cost of providing these services. Therefore, the primary risk for BPA is that the "true" value of providing these services will be more or less than the established rate. This pricing approach makes the sale of RSS no different from that of any other service or product BPA sells into the open market. Moreover, there is currently no transparent and/or liquid market for such services, which makes after-the-fact measurements of the "true" value and the price paid to BPA difficult. Furthermore, BPA does not intend to "color code" the operational decisions made by BPA. This means that BPA will not be able to measure the cost of following a customer's load separately from the cost of following its resources when a customer is taking some combination of RSS. Therefore, in addition to the difficulty in quantifying the after-the-fact value difference between the price paid and the "true" value, it would be extremely challenging, if not impossible, to measure the difference between the price received by BPA and the cost incurred by BPA.

The total forecast cost of RSS is about $3 million annually. Power Rates Study, BP-14-E-BPA-01, section 3.1.13.1. The magnitude of the risk of miscalculation of these RSS costs is not large enough to affect TPP calculations.

4.5 Qualitative Risk Assessment Results

4.5.1 Biological Opinion Risks

The financial risks deriving from possible changes to Biological Opinions are adequately mitigated by the NFB mechanisms. *See* section 4.2 in this Study and GRSP II.N.

4.5.2 Risks Associated with Tier 2 Rate Design

Tier 2 risks are adequately mitigated by the terms and conditions of service at the Tier 2 rate and BPA's credit risk policies, and no residual Tier 2 risk is borne by BPA or Tier 1.

4.5.3 Risks Associated with Resource Support Services Rate Design

BPA uses a pricing construct that is economically fair and unbiased; that is, the construct does not lead to prices for RSS that are systematically too high or systematically too low. There is not a significant financial risk that the cost would affect the Composite or Non-Slice cost pools or BPA generally, and as a consequence, there is no quantification or mitigation of RSS risks in this Initial Proposal.

Table 1: Cash Prices at Henry Hub and Basis Differentials (nominal $/MMBtu)

	FY 2014	FY 2015
Henry Hub	$4.08	$4.35
AECO	-0.37	-0.39
Kingsgate	-0.19	-0.19
Malin	-0.09	-0.08
Opal	-0.12	-0.13
PG&E	0.25	0.27
Topock/Socal/Ehrenberg	0.05	0.05
San Juan	-0.12	-0.10
Stanfield	-0.15	-0.14
Sumas	-0.03	-0.06

Table 2: Natural Gas Price Risk Model Percentiles

FY14	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14
95th %	5.52	5.70	5.86	6.22	6.11	5.87	6.00	6.14	6.27	6.41	6.04	6.05
50th %	3.70	3.92	4.17	4.27	4.15	4.04	4.12	4.14	4.19	4.22	4.12	4.06
5th %	2.54	2.68	2.85	2.87	2.84	2.79	2.86	2.85	2.91	2.93	2.81	2.83

FY15	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15
95th %	5.98	6.29	6.74	7.07	6.80	6.44	5.90	6.17	6.47	6.54	6.55	6.59
50th %	4.13	4.27	4.45	4.52	4.44	4.39	4.16	4.31	4.45	4.46	4.47	4.35
5th %	2.91	3.00	3.02	3.00	2.97	2.96	2.76	2.91	2.99	3.04	3.03	2.91

Table 3: Average Market Price from the Market Price Run for FY14/FY15

FY14	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
HLH	29.62	30.64	34.51	34.60	33.40	28.76	26.11	21.95	23.07	31.40	33.37
LLH	26.80	28.47	31.17	29.39	29.42	25.37	21.54	15.23	16.22	26.30	27.53
Average	28.41	29.71	33.08	32.37	31.69	27.31	24.15	19.07	20.13	29.21	30.87

FY15	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15
HLH	32.50	33.93	36.44	36.26	34.44	29.62	24.77	21.65	24.06	31.71	34.57
LLH	28.99	31.18	32.21	30.13	29.87	25.80	20.47	14.33	16.96	26.16	28.32
Average	31.00	32.75	34.63	33.63	32.48	27.98	22.92	18.51	21.02	29.33	31.89

Table 4: Average Market Price from AURORAxmp Critical Water Run for FY14/FY15

FY14	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14
HLH	30.75	31.93	38.11	48.96	50.28	34.46	31.48	26.09	28.43	33.72	35.67	33.18
LLH	27.46	29.71	34.67	41.08	39.28	31.94	28.46	22.27	24.61	29.54	29.54	28.42
Average	29.10	30.82	36.39	45.02	44.78	33.20	29.97	24.18	26.52	31.63	32.60	30.80

FY15	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15
HLH	33.58	35.20	40.61	50.23	52.96	36.94	31.56	27.06	30.29	35.23	36.41	35.19
LLH	29.65	32.75	36.62	42.10	40.64	34.05	28.80	22.69	26.57	30.35	30.27	29.76
Average	31.62	33.98	38.62	46.16	46.80	35.49	30.18	24.87	28.43	32.79	33.34	32.48

Table 5: Average Market Price by Fiscal Year from AURORAxmp

Average Water

	FY14	FY15
HLH	30.04	31.22
LLH	25.48	26.15
Average	28.08	29.05

Critical Water

	FY14	FY15
HLH	35.25	37.11
LLH	30.58	32.02
Average	32.92	34.56

Table 6: RevSim Net Revenue Statistics (With PNRR of $0 million)

	A	B	C
1		**FY14**	**FY15**
2		(Dollars in Thousands)	(Dollars in Thousands)
3	**Average**	$ 9,516	$ (2,543)
4	**Median**	$ 4,086	$ (2,162)
5	**Standard Deviation**	$ 174,119	$ 180,760
6			
7	**1%**	$ (307,217)	$ (347,264)
8	**2.50%**	$ (284,017)	$ (319,005)
9	**5%**	$ (263,939)	$ (297,075)
10	**10%**	$ (228,472)	$ (259,279)
11	**15%**	$ (188,931)	$ (203,445)
12	**20%**	$ (152,073)	$ (169,667)
13	**25%**	$ (120,949)	$ (138,126)
14	**30%**	$ (92,937)	$ (109,396)
15	**35%**	$ (68,650)	$ (81,699)
16	**40%**	$ (41,745)	$ (51,578)
17	**45%**	$ (19,487)	$ (26,113)
18	**50%**	$ 4,086	$ (2,162)
19	**55%**	$ 27,404	$ 20,273
20	**60%**	$ 49,112	$ 47,467
21	**65%**	$ 77,439	$ 74,820
22	**70%**	$ 105,443	$ 104,140
23	**75%**	$ 136,819	$ 130,327
24	**80%**	$ 170,883	$ 159,776
25	**85%**	$ 207,139	$ 196,748
26	**90%**	$ 244,412	$ 242,683
27	**95%**	$ 301,788	$ 293,206
28	**97.50%**	$ 345,299	$ 334,904
29	**99%**	$ 396,599	$ 379,716

Table 7: Risk Modeling Accrual To Cash Adjustments (in $Millions)

A	B	C	D	E	F
			FY 2013	FY 2014	FY 2015
1	Depreciation/Amortization		211.40	224.13	228.63
2	Interest Adjustments		(45.94)	(45.94)	(45.94)
3	ENW Direct Pay Prepaid Expense		12.41	(5.09)	(8.01)
4	All Other (see lines 10:18 below)		(10.68)	(6.33)	(1.55)
5	**Sub Total Lines 1:4**		167.20	166.76	173.13
6	Less: Scheduled Federal Debt Amortization		(181.62)	(174.66)	(179.16)
7	Less: Revenue/Reserve financing		0.00	0.00	0.00
8	**Sub Total Lines 10 :11**		(181.62)	(174.66)	(179.16)
9	**Accrual to Cash Adjustment (Lines 5 + 8)**		(14.42)	(7.90)	(6.04)
	All Other				
10	Net Slice True up lag into (out of) current year				
11	Slice Adjustment Cash Lagging out of this year		8.10	0.00	0.00
12	Slice Adjustment Cash Lagging from previous year		(3.94)	(8.10)	0.00
	NORM Slice True Up Lagging out of this year		1.36	0.37	(3.43)
	NORM Slice True Up Lagging in from previous year		0.00	(1.36)	(0.37)
13	NB Revenue and other cash lags		0.00	0.00	0.00
14	Terminated contracts & Settlements		(3.08)	(3.08)	(3.08)
15	NTSA Accrual		0.00	0.00	0.00
16	NTSA Cash Pmt		(41.66)	0.00	0.00
17	Other Miscellaneous		2.42	5.83	5.32
18	Cash Receipts from FY12 Revenue		26.12	0.00	0.00
19	**TOTAL All Other**		(10.68)	(6.33)	(1.55)

1/ Rows 6–8 are no longer required since the basis for the accrual to cash adjustments is no longer Modified Net Revenue, but Net Revenue.

Table 8: CRAC Annual Thresholds and Caps
[Dollars in Millions]

A	B	C	D	E
ANR Calculated at End of Fiscal Year	**CRAC Applied to Fiscal Year**	**CRAC Threshold as Measured in ANR**	**Approx. Threshold as Measured in PS Reserves**	**Maximum CRAC Recovery Amount (CRAC Cap)***
2013	2014	-$202.9	$0	$300
2014	2015	-$195.5	$0	$300

* The CRAC Cap may be modified by NFB Adjustments

Table 9: DDC Thresholds and Caps
[Dollars in Millions]

A	B	C	D	E
ANR Calculated at End of Fiscal Year	**DDC Applied to Fiscal Year**	**DDC Threshold as Measured in ANR**	**Approx. Threshold as Measured in PS Reserves**	**Maximum DDC Recovery Amount (DDC Cap)**
2013	2014	$547.1	$750	$1,000
2014	2015	$554.5	$750	$1,000

Table 10: ToolKit Summary Statistics

[Dollars in Millions]			
Two Year TPP	99.25%		
	FY 2013	**FY 2014**	**FY 2015**
PNRR	-	$0.0	$0.0
CRAC Frequency	0%	12%	24%
Expected Value CRAC Revenue	n / a	$65.6	$97.5
DDC Frequency	0%	0%	1%
Expected Value DDC Payout	n / a	n / a	$60.4
Treasury Deferral Frequency	0.0%	0.0%	0.7%
Expected Value Treasury Deferral	$0.0	$0.0	$0.3
Average End-of-Year Net Reserves	$181.5	$175.8	$168.0
Net Reserves, 5th percentile	($66.9)	($201.6)	($304.7)
Net Reserves, 25th percentile	$66.4	$7.9	($69.9)
Net Reserves, 50th percentile	$185.7	$173.9	$162.8
Net Reserves, 75th percentile	$292.2	$332.4	$383.5
Net Reserves, 95th percentile	$427.9	$560.8	$684.8

Figure 1: Risk Assessment Information Flow

Figure 2: AURORAxmp Zonal Topology

Figure 3: Basis Locations

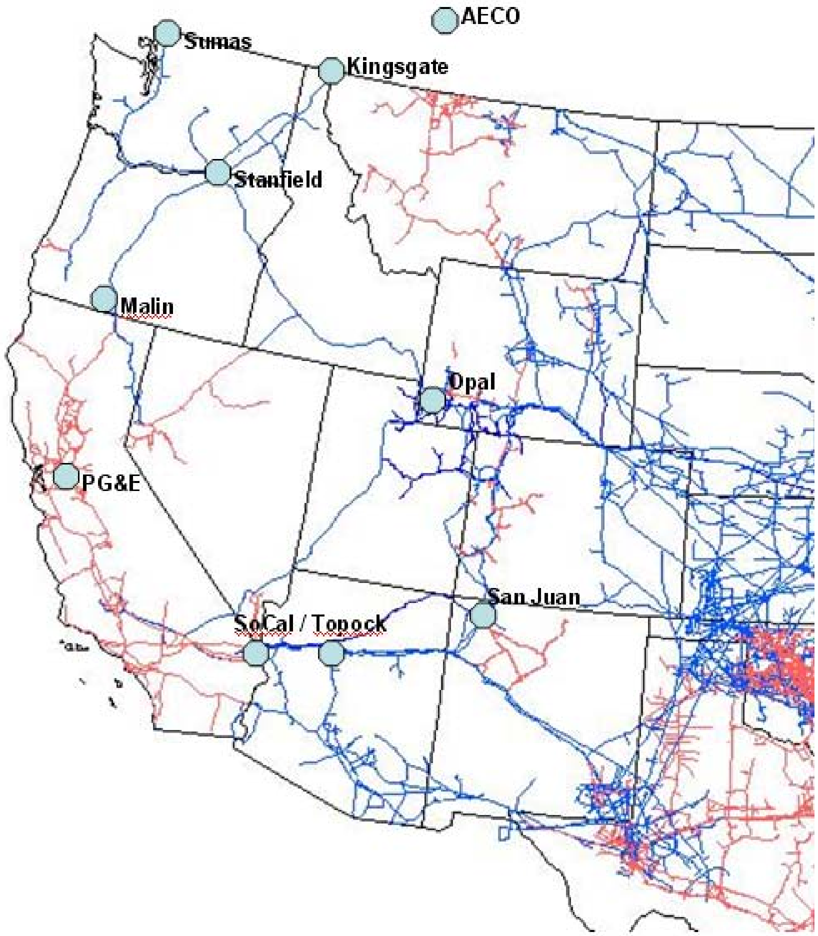


Figure 4: 2012 Henry Hub Gas prices

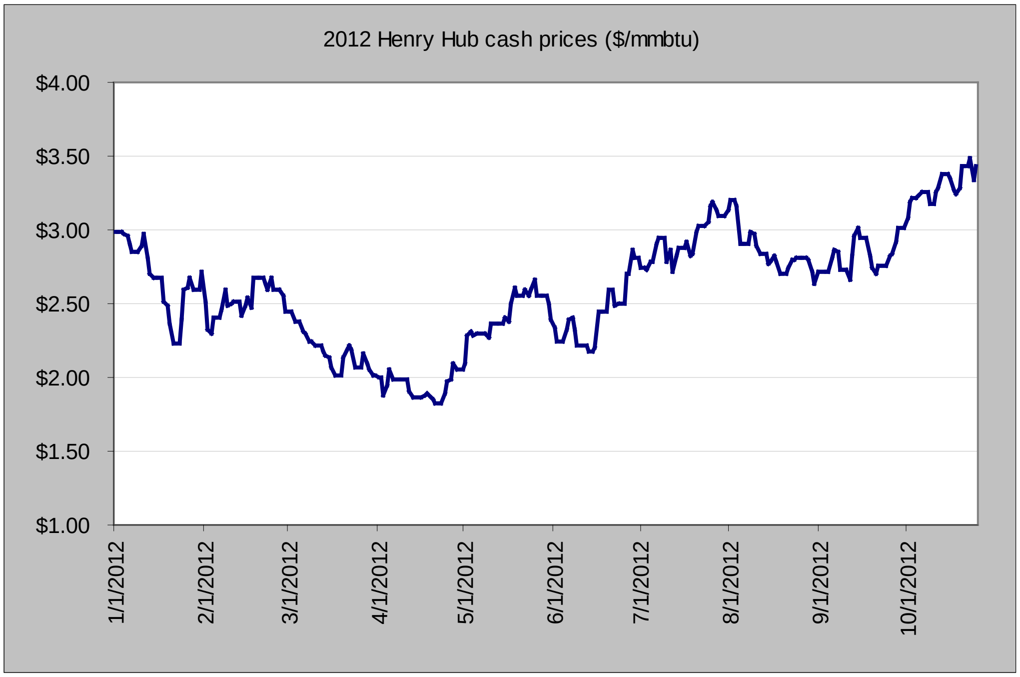


Figure 5: Winter 2011-12 statistics

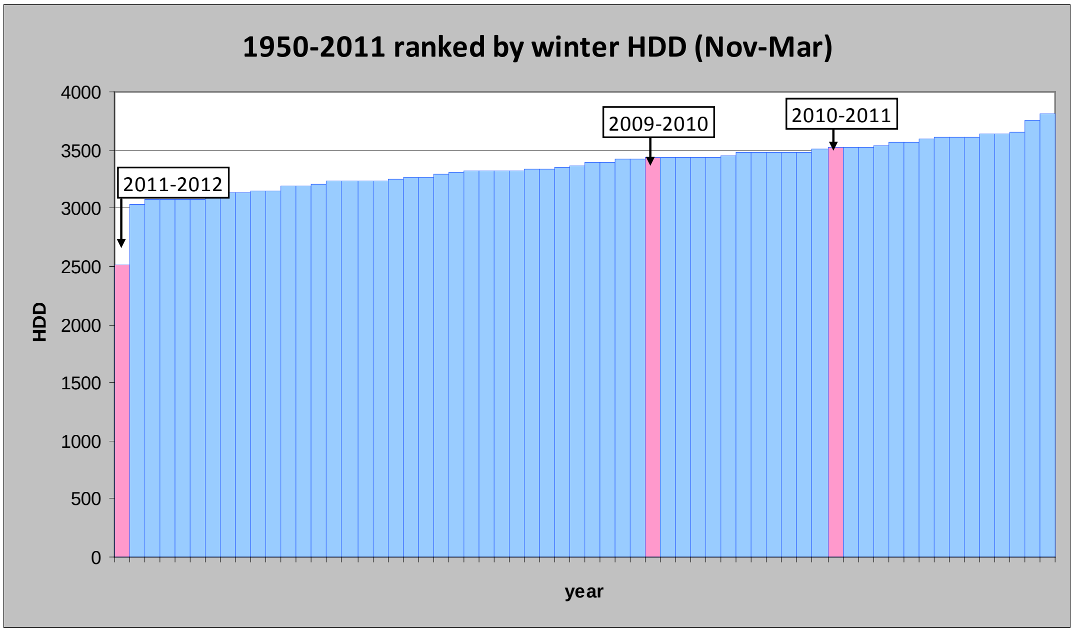


Figure 6: Natural Gas Storage trend, ca. April 2012

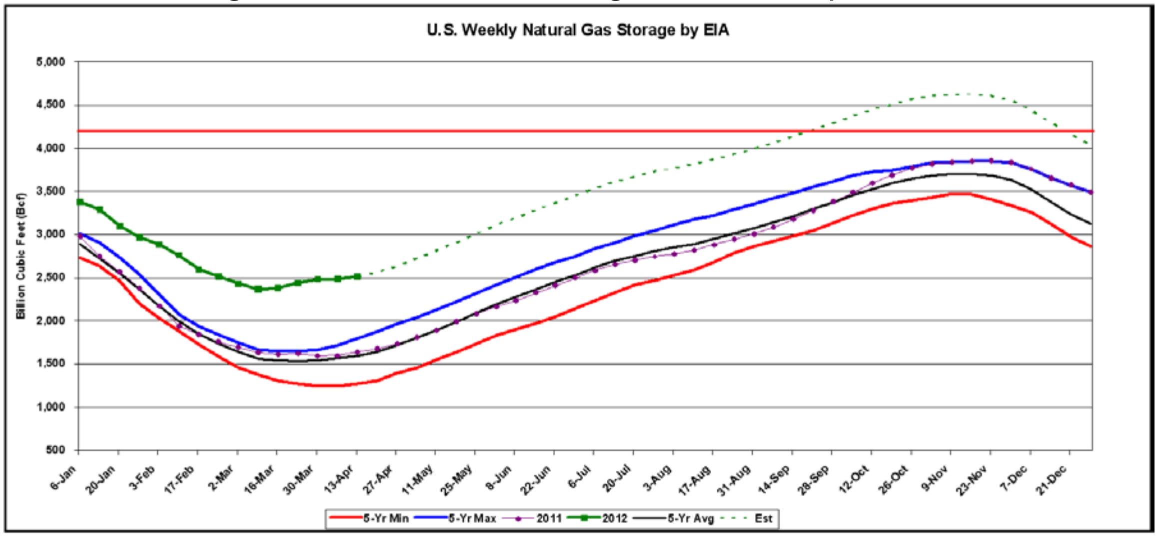


Figure 7: Natural Gas Storage trend, October 19, 2012

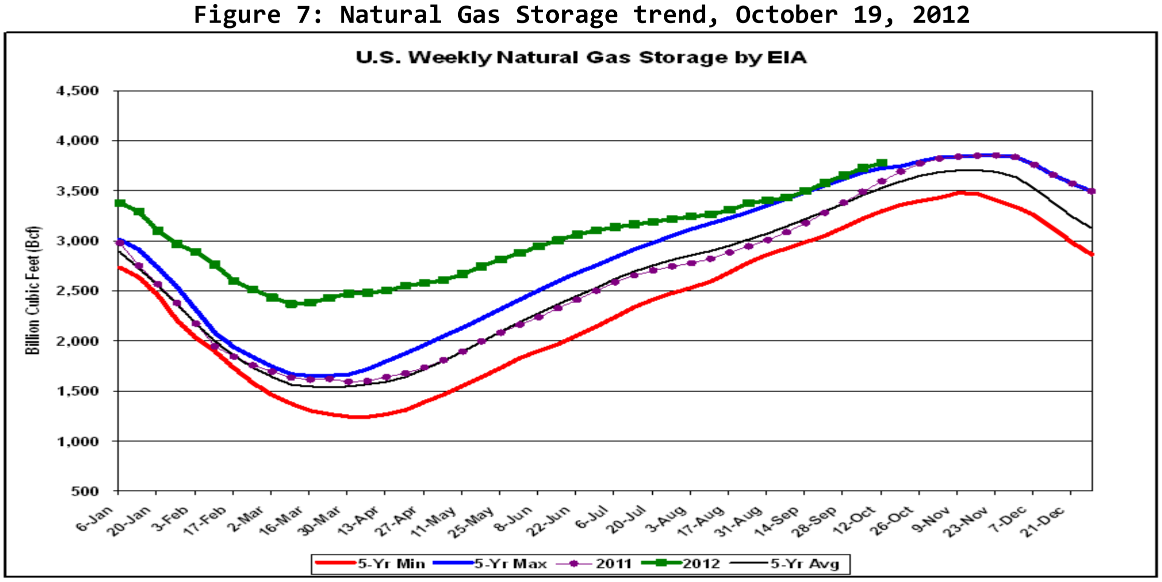


Figure 8: Rig Counts and Production

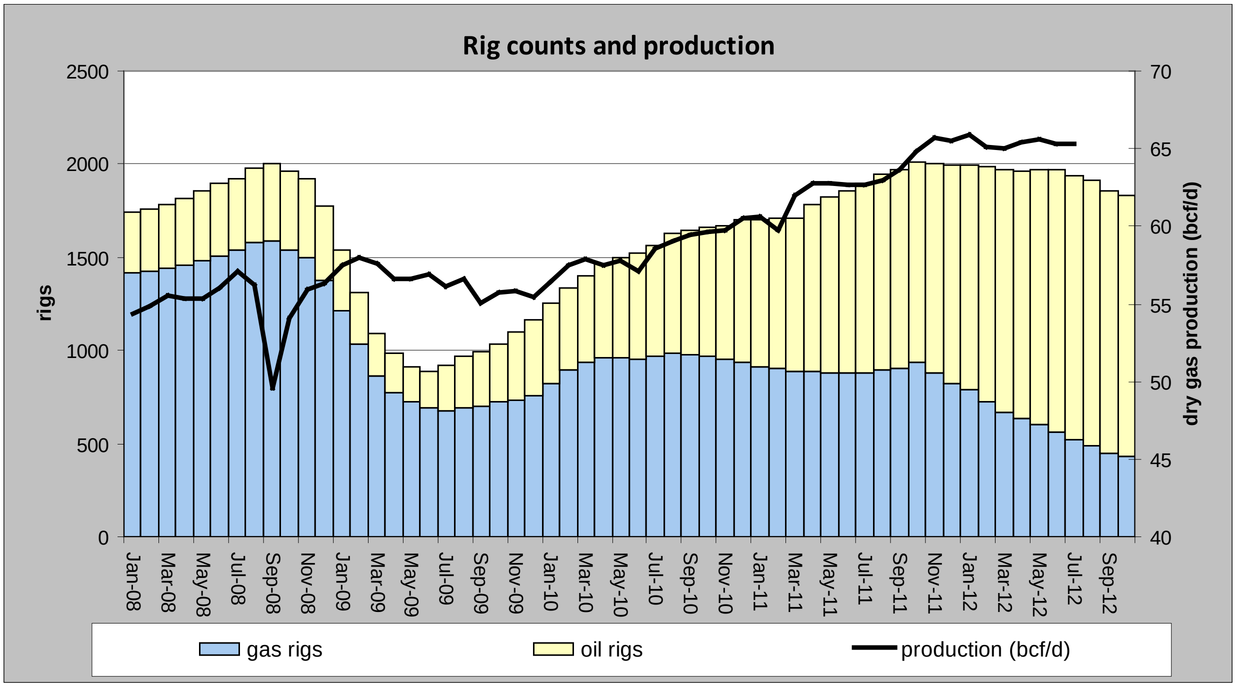
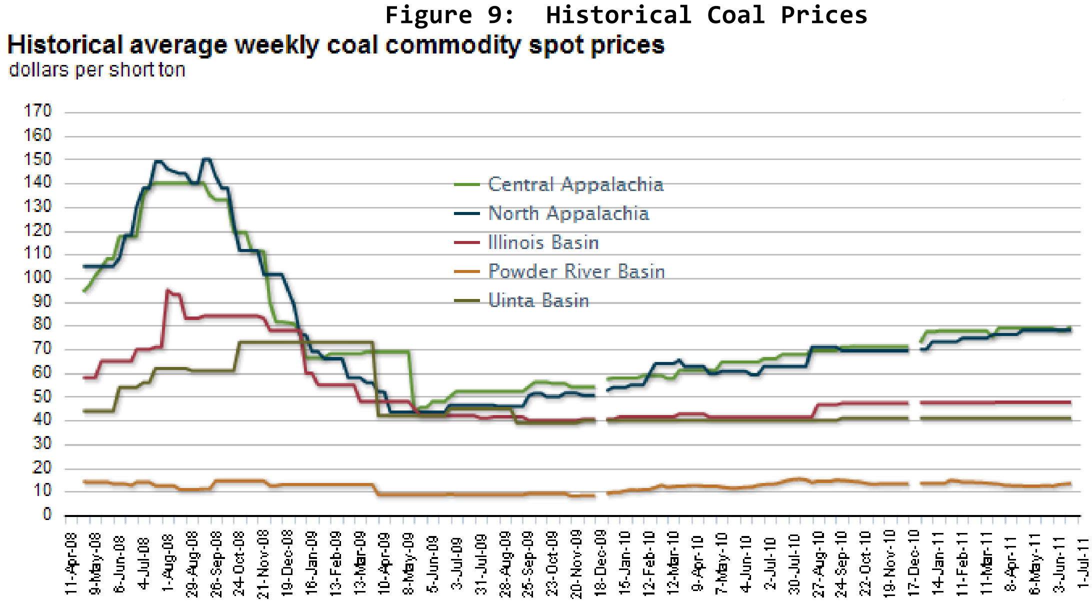
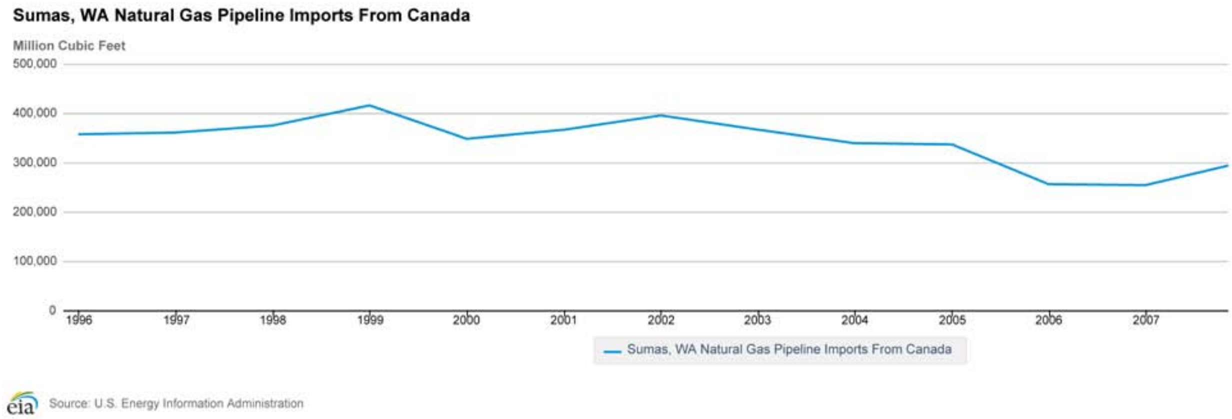


Figure 9: Historical Coal Prices



Source: EIA, with permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."

Figure 10: Sumas Imports


Sumas, WA Natural Gas Pipeline Imports From Canada
Million Cubic Feet
500,000
400,000
300,000
200,000
100,000
0
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
Sumas, WA Natural Gas Pipeline Imports From Canada
eia
Source: U.S. Energy Information Administration

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