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

2012 BPA Final Rate Proposal

Power Risk and Market Price Study

July 2011

BP-12-FS-BPA-04

POWER RISK AND MARKET PRICE STUDY

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TABLES

FIGURES

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COMMONLY USED ACRONYMS AND SHORT FORMS

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
Commission	Federal Energy Regulatory Commission
COSA	Cost of Service Analysis
COU	consumer-owned utility
Corps or USACE	U.S. Army Corps of Engineers
Council	Northwest Power and Conservation Council
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
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	Hydro Simulation (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
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
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
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance

OMB	Office of Management and Budget
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)
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 or Corps	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
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION

Bonneville Power Administration's (BPA) business environment is filled with numerous uncertainties, and thus the ratesetting process must take into account a wide spectrum of risks. The objective of the risk analysis is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on Power Services' (PS) net revenue (total revenue less total expenses) and cashflow. The risk analysis is designed 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 analysis 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 tested to assess their ability to recover power costs in the face of these uncertainties. The risk analysis 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. A "risk" in this study does not signify the possibility of harm but rather the possibility of an event occurring that has an impact on a BPA objective. 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 purpose of the Power Risk and Market Price Study (Study) is to establish the market price distributions and to demonstrate that the rate and risk package meets BPA's standard for financial risk tolerance—the TPP standard. This study presents the gas price forecast, the electricity market price forecast, the analysis of risks to Power Services' (PS) net revenue, the tools for mitigating those risks, and the evaluation of 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/corporate/Finance/financial%5Fplan/10-year_BPA_Financial_Plan.pdf; the 2008 updated Financial Plan is available at http://www.bpa.gov/corporate/Finance/financial_plan/BPA_Financial_Plan.pdf.

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. 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 Reserves Available for Risk Attributed to Power.* 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. Also excluded are funds collected from customers under a contract that obligates BPA to perform energy efficiency-related upgrades to the customers' facilities.

(2) *Planned Net Revenues for Risk.* PNRR is the final component of the revenue requirement that is 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.* During the WP-10 rate proceeding, BPA and the Treasury reached an agreement that expanded the existing Treasury Facility from $300 million to $750 million. Three hundred million dollars is reserved for within-year liquidity (#4 below), leaving $450 million available for PS TPP support, functioning somewhat like additional financial reserves.

(4) *Liquidity Reserve Level.* The liquidity reserve level is an amount of reserves available for risk that is allocated for meeting within-year liquidity needs (or risks). In the WP-07 rate proceeding, BPA determined that the amount of liquidity needed for responding to within-year issues related to PS is $300 million. For this Study, the liquidity reserves level is set at $0 because the $300 million of within-year liquidity is provided by a portion of the Treasury Facility.

(5) *Reserves Attributed to Transmission, Temporarily Available for Supporting PS TPP.* Reliance on a portion of reserves attributed to Transmission Services (TS) was proposed and evaluated in the BP-12 rate proceeding. No reserves attributed to TS are relied upon for risk mitigation in setting the BP-12 power rates.

(6) *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.

(7) *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 analysis 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-12-A-02B, 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 2012 or FY 2013.

Forecasts of electricity market prices are used in the Power Rates Study, BP-12-FS-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;

(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) Scaling Industrial Firm Power (IP) rates;

(m) Balancing Augmentation Credit; and

(n) Scaling New Resources Firm Power (NR) rates.

The electricity market price forecast also is used in the Generation Inputs Study, BP-12-FS-BPA-05, to compute the variable cost component of generation input capacity, in section 2 of this Study for the risk analysis, and for setting the Average System Costs (ASCs) that are used in ratesetting (which occurs in the separate ASC process).

1.2 Overview of the Risk Analysis

The risk analysis is accomplished using a set of models, as shown in Figure 1. These models are further described throughout the course of the Study.

1.2.1 Risk Mitigation Objectives

BPA's policy objectives that guide the development of the risk mitigation package are the following:

(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; and

(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 Analysis and Mitigation

This Study distinguishes between quantitative and qualitative perspectives on risk. The quantitative risk analysis is primarily a set of quantitative risk simulations that are modeled using a Monte Carlo, or gaming, approach. The output from the quantitative risk analysis is a set of 3,500 possible financial results (net revenues) for each of the two years in the rate period (fiscal years (FY) 2012–2013) and for the year preceding the rate period (FY 2011). The models used in the quantitative risk analysis are covered in section 2 of this Study.

The 3,500 games from the quantitative risk analysis are then 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 test is covered in section 3 of this Study.

BPA faces some risks that are incorporated into the risk analysis and mitigation in qualitative rather than quantitative ways. For the most part, the qualitative risk analysis comprises verbal descriptions 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 analysis is covered in section 4 of this Study.

All of these analyses work together so that BPA can develop 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 Analysis

The quantitative risk analysis is performed using a number of models that quantify uncertainty. There is uncertainty in market prices, which reflects the uncertainty inherent in the fundamental drivers; *e.g.,* the natural gas price. There is uncertainty in the inventory BPA will have for secondary sales. There is uncertainty in the costs faced by BPA beyond operating expenses; *e.g.,* fish and wildlife-related expenses. These uncertainties impact 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 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 cases. These clauses add additional risk mitigation to that provided by financial reserves. In this rate proceeding, for the first time, 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 the power rate, which generates additional reserves. This Study documents the risk mitigation package included in the BP-12 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 Analysis 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.K, BP-12-A-02B.

2. QUANTITATIVE RISK ANALYSIS

2.1 Introduction

This section describes the uncertainties creating financial risk for PS that are modeled in setting power rates. Section 3 describes how BPA determines whether its risk mitigation measures are adequate to meet the TPP standard when the risks described in this section are taken into account.

The variability in PS net revenue from precipitation-driven hydro generation, compounded by variability in market prices, is substantial. PS also faces other operating risks and variability that increase its risk exposure, including the following: (1) customer load variability due to changes in load growth and weather; (2) Columbia Generating Station (CGS) generation; (3) amount of wind generation and value of the output; (4) system augmentation costs; (5) PS transmission and ancillary services expenses; and (6) 4(h)(10)(C) credits. The impacts of these risk factors on PS net revenue are quantified in this section 2.

PS also faces risks that are not directly related to the operation of the power system, and these non-operating risks are also modeled in this Study 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 vary from the forecasts. NORM also accounts for interest rate variability and interest rate expense variability due to uncertainty over the rate of progress on capital-funded projects. Uncertainty in net revenue due to the effect of implementing Biological Opinion performance standards and the uncertainty in the length of the CGS outage in FY 2011 for refueling and condenser replacement are also modeled in NORM. The CGS outage is scheduled to be completed in FY 2011, prior to the beginning of the rate period. Modeling of the outage is important because the length of the outage during FY 2011 will affect the financial reserves available at the start of the rate period, and the outage could extend into the rate period, affecting net revenue.

2.2 Study Models

BPA traditionally models risks using a Monte Carlo simulation methodology. In this technique, the models AURORAxmp, RiskMod, NORM, and ToolKit each run through 3,500 iterations, or games. The AURORAxmp model calculates variable electricity prices that are used in several studies, including this Power Risk and Market Price Study. These electricity prices are passed to RiskMod. In each game, each of the uncertainties modeled in RiskMod and NORM is randomly assigned a value based on input specifications for that uncertainty. After all of the games are run, the output data—the set of games from RiskMod and NORM—are passed to ToolKit. ToolKit then calculates TPP. If TPP is below the 95 percent standard required by BPA's 10-Year Financial Plan, risk mitigation must be strengthened by (1) raising the CRAC threshold, which will make the CRAC trigger more often; (2) increasing the cap on the annual revenue the CRAC can generate; and/or (3) adding PNRR to the revenue requirement. This analysis continues this traditional approach.

2.2.1 @RISK Computer Software

Several of the risk simulation models in RiskMod and NORM are developed in Microsoft Excel workbooks 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 AURORAxmp

The AURORAxmp model is used for forecasting electricity market prices. For this Study, AURORAxmp version 10.1.1001 is used. The data supplied by the developer, EPIS, Inc., with this version of AURORAxmp are used for all assumptions except those explicitly described in section 2.3 of this Study. AURORAxmp assumes a competitive market pricing structure as the fundamental mechanism underlying its estimates of the wholesale electric energy market clearing prices. Two fundamental inferences for electric energy pricing in a competitive market follow from economic theory. First, the price in any hour approximates the variable cost of the marginal generating resource, such as coal- or gas-fired generation. Second, the long-term average price gravitates toward the full cost of a new resource, where the cost includes both the fixed and variable components. A couple of factors complicate these general principles. When resources are being acquired to meet regulatory obligations, such as Renewable Portfolio Standards (RPS), the costs of these resources can be above the long-term average price. Further, if resources are seen as particularly risky based on potential future regulation, such as possible regulation of carbon dioxide emissions that would affect the costs of coal-based resources, the variable cost uncertainty and potential unanticipated capital costs for regulation-based upgrades will discourage investment in these resources.

2.2.3 RiskMod

RiskMod comprises a set of risk simulation models, collectively referred to as RiskSim, and a model that calculates net revenue and net revenue risk, referred to as RevSim. RiskMod interacts with AURORAxmp, the 2012 Rate Analysis Model (RAM2012), and the ToolKit during the process of performing the risk analysis documented in this Study.

2.2.3.1 Risk Simulation Models (RiskSim)

Risk simulation models use logic, econometrics, and probability distributions to quantify PS's ordinary operating risks. Econometric modeling techniques capture the dependency of values through time. Parameters for the probability distributions are developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and represent deviations from the base case values used in the revenue forecast and the revenue requirement. Power Rates Study, BP-12-FS-BPA-01, section 4, and Power Revenue Requirement Study Documentation, BP-12-FS- BPA-02A. The following risk simulation models are included in RiskSim:

(a) Natural Gas Price Risk Model;

(b) Pacific Northwest (PNW) Load Risk Model;

(c) California Load Risk Model;

(d) PNW Hourly Wind Generation Risk Model;

(e) CGS Generation Risk Model;

(f) PNW Hourly Intertie Availability Risk Model;

(g) PS Wind Generation Risk Model; and

(h) PS Transmission and Ancillary Services Expense Risk Model.

The risk simulation models generate monthly and/or hourly values that may be lower than, higher than, or equal to the base case values used in the Power Rates Study, BP-12-FS-BPA-01, Power Revenue Requirement Study, BP-12-FS-BPA-02, and AURORAxmp. The risk models produce 3,500 games, each of which contains monthly and/or hourly risk data spanning FY 2012–2017. These data are downloaded into databases that are read by AURORAxmp and RevSim so that the models use data that are consistent on a game-by-game basis.

2.2.3.2 Revenue Simulation Model (RevSim)

The RevSim module within RiskMod calculates surplus energy revenue, balancing and system augmentation purchase power expenses, and 4(h)(10)(C) credits that are used by the RAM2012 model. It also simulates PS operating net revenue used by the ToolKit. Inputs to RevSim include risk data simulated by RiskSim and AURORAxmp, along with deterministic monthly load and resource data, revenue and expenses from the RAM2012 model, and non-varying revenue and expenses from the Power Loads and Resources Study, BP-12-FS-BPA-03, and section 2 of the Power Rates Study, BP-12-FS-BPA-01. The RevSim module accounts for winter hedging purchases.

RevSim uses the monthly risk data simulated by RiskSim and the monthly variable 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 3,500 games per fiscal year. The results are used in the revenue forecast and the calculation of power rates in RAM2012. The monthly flat surplus energy values calculated by RevSim for all 3,500 games per fiscal year are used in 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-12-FS-BPA-02. The risk data 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 determined using two approaches, one for the calculation of rates in RAM2012 and another for the determination of 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 simulated by RiskSim and the monthly variable electricity market prices estimated by AURORAxmp to calculate 3,500 net revenue outcomes for each fiscal year for FY 2012–2013. This process yields a total of 7,000 possible annual net revenue amounts, which are passed to the ToolKit to test whether the 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)

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 cashflow. While RiskMod is 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. The main NORM modules model the accrual impacts of the included risks, and an accrual-to-cash adjustment translates the net revenue impacts into cashflow impacts. NORM supplies 3,500 games (or iterations) of net revenue and cashflow impacts of the risks that it models. The outputs from NORM, along with the outputs from RiskMod, 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 a Monte Carlo simulation methodology. In this technique, a model runs through a number of games or iterations. In each game, each of the uncertainties is randomly assigned a value from a 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

The AURORAxmp model provides a deterministic, or single, electricity price forecast that does not account for any uncertainties if the user makes no modifications to the model as delivered from its developer, EPIS, Inc. In order to produce risk-informed market prices, risk models external to AURORAxmp are used to incorporate risk into the development of the electricity market price forecast. Outputs from these risk models are used as inputs to AURORAxmp to produce 3,500 market price outputs. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices produced form the basis for the market price forecast. The following subsections of this Study describe the various inputs and risk models used when operating AURORAxmp for the purpose of producing electricity price forecasts for this rate proceeding.

2.3.1 Natural Gas Prices Used in AURORAxmp

When natural-gas-fired resources are the marginal unit (the unit that would supply the next megawatt of energy if the demand is 1 MW larger), the price of natural gas determines the variable cost for that generator. Higher natural gas prices generally increase the cost of producing electricity, which in turn increases the price of electricity on the wholesale power market. Conversely, lower gas prices generally decrease the cost of producing electricity, which in turn decreases the price of electricity on the wholesale power market.

2.3.1.1 Methodology for Deriving AURORAxmp Zone Natural Gas Prices

AURORAxmp calculates electricity market prices based upon natural gas price forecasts for each AURORAxmp zone, each of which is a geographic subset of the Western Electricity Coordinating Council (WECC) region, detailed in Figure 2. A three-step process is used to derive the natural gas price forecast for each zone.

The first step is to forecast natural gas prices at Henry Hub, which is near Erath, Louisiana. Cash prices at Henry Hub are the primary reference point for the North American natural gas market and provide an appropriate foundation for developing the natural gas price forecast.

The second step is to derive basis differentials for 11 western hubs, or the differences in prices between Henry Hub and the 11 western natural gas trading hubs used by AURORAxmp. Basis differentials reflect differences in the regional costs of supplying gas to meet demand, after accounting for pipeline constraints and pipeline costs. These 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. The forecast also includes eight other hubs representing natural gas markets or pipeline intersections. 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. The hub associated with each zone is the one that is the primary source of marginal gas supply in that zone; that is, the hub that most impacts prices in the local 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 Natural Gas Market Fundamentals

The defining characteristic of the U.S. natural gas market in recent years has been increasing supply driven by a substantial increase in production from domestic shale gas deposits. Horizontal drilling, a method in which wells are drilled downward and then curved sideways, has allowed access to a much greater underground area than traditional vertical wells. Hydraulic fracturing ("fracking"), the injection of water and other materials at extremely high pressures, is used in horizontal wells to break apart shale rock and extract natural gas where traditional vertical drilling was not cost-effective. Substantial shale gas deposits have been known but largely unexploited for many years. However, recent advances in technology have enabled significant increases in efficient and low-cost production. In addition, many shale gas leases, known as "held by production" leases, require companies to retain an active drill in order to retain drilling rights. The result has been an overwhelming increase in gas supply, even in the face of falling prices, as producers rushed to take advantage of this newly available source of domestic natural gas.

Current domestic production in the lower 48 states is at an all-time high (Figure 4), with a 2011 year-to-date average of over 60 billion cubic feet per day (bcf/d). Additionally, this record production is occurring despite a steep decline in the overall number of drilling rigs since 2008, primarily because production rates from horizontal wells are eclipsing those of traditional vertical or directional wells. Levels of natural gas in storage reached record highs in late 2010, and while increased withdrawals due to winter temperatures left end-of-winter storage levels below the five-year average, the most recent available storage figure of 2,354 Bcf is only 64 Bcf less than the five-year average, and given current levels of production, the storage level is expected to surpass the five-year average as the year progresses (Figure 5).

On the demand side, there has been a marked increase in demand for gas by the residential, commercial, power generation, and industrial sectors in 2010 and early 2011 compared to 2009, even as the overall economic recovery remains slow (Figure 6). The low price of gas encouraged coal-to-gas switching, raising demand for gas used for electric generation. In addition, cold weather during the winter of 2010–2011 contributed to increased residential heating demand, and improving economic conditions have brought industrial demand for gas close to 2008 levels. However, the increased demand for natural gas was not enough to substantially lift prices during 2010, and so far in 2011, due to high levels of production and gas in storage, which exert downward pressure on the natural gas price.

2.3.1.3 Henry Hub Forecast

The average of the monthly forecast Henry Hub prices is $4.22/MMBtu (Million British Thermal Units) during FY 2012 and $4.67/MMBtu during FY 2013 (Table 1).

During 2011, the economy has continued to slowly recover while supply has remained high. Gas-only rig counts started to show a definitive downward trend during early 2011 (Figure 9), but given the increased prevalence of horizontal wells, production is likely to remain at high levels during the remainder of 2011 despite an unfavorable price environment for producers. In fact, production has continued to increase despite the drop in number of rigs that has occurred since late 2010. There is no apparent opportunity for an increase in near-term demand sufficient to provide meaningful upward pressure on prices. Even if production falls or demand increases, the ample amount of gas in storage (Figure 5) should prevent prices from rising quickly. This conclusion is consistent with the fact that prices remained persistently low in the spring and summer of 2010, despite a very hot summer (Figure 7) in which gas demand for power production increased throughout most of the nation. Under such conditions, prices continued to fall below the $4/MMBtu range and showed no immediate signs of price recovery. Similarly, a very cold winter and occasional supply disruptions due to extreme weather conditions failed to buoy prices beyond the mid-$4/MMBtu range, establishing a relatively tight range for Henry Hub prices over the past two years regardless of seasonal variation in demand.

For FY 2012–2013, natural gas prices are forecast to increase relative to FY 2010 and FY 2011. Increased demand is expected to put upward pressure on gas prices. Power generation demand is expected to increase as utilities reduce output from coal-fired plants and increase output from natural gas-fired plants at an accelerated rate. A near-term reduction of output from coal-fired plants due to policy actions such as a tax on carbon or pending EPA emissions regulations is less likely due to the uncertainty around the timing of adopting or implementing such policies. However, sustained low natural gas prices are expected to make natural gas more competitive with coal on price alone. Supply disruptions in the coal market, such as the recent floods in Australia, combined with a functioning export market and burgeoning demand in China and other overseas markets, have contributed to a rise in the price of most domestically produced coal (Figure 10) and further encouraged the use of natural gas. The overall economic picture should continue to gradually improve, resulting in additional gas demand in the industrial sector.

At the same time, several circumstances on the supply side could lead to a decrease in production. Many "held by production" leases will expire, potentially reducing unusually high production despite an unfavorable price environment. Also, horizontal drilling techniques are proving to be viable to extract oil and natural gas liquids (NGLs, hydrocarbons other than methane) at relatively low costs. Because the prices for these commodities are currently much higher than prices for dry natural gas (methane), producers have an incentive to alter their investments from production of dry gas to that of oil or NGLs (Figure 11). As evidence, note that the gas-only share of the rig count has dropped from 64 percent to 46 percent from the beginning of 2010 to June 2011, while the oil share has risen from 35 percent to 53 percent in the same time period (1 percent of rigs were not drilling for gas or oil), with a dramatic rebalancing of the rig share occurring since the beginning of calendar year (CY) 2011 (Figure 11).

On the policy side, while national climate change legislation appears less likely in the near term, recent pipeline accidents and scrutiny over the risks of hydraulic fracturing are expected to result in a tougher regulatory environment, as has been seen recently with state drilling restrictions and moratoria, such as legislation in New York, fracking fluid disclosure legislation in Texas, and the heavy accident fines proposed for PG&E in the wake of the deadly explosion in San Bruno, California. Increased regulation will likely result in a higher marginal cost of production and a higher fixed cost for producers considering entering the market, both of which put upward pressure on natural gas prices either at Henry Hub or regional bases. Nevertheless, the upward pressure on natural gas prices over the next few years likely will be largely muted due to the abundant supply of gas available at low prices, even after considering these influences on supply and demand.

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.

The record production from domestic shale gas deposits has affected all hubs in North America. Domestic shale gas resources are geographically diverse. The Marcellus Shale formation, which spans most of Pennsylvania and portions of nearby states, is one of the largest shale deposits in the United States and lies in close proximity to East Coast demand centers. Similarly, there are vast amounts of shale gas in the southern Haynesville Shale formation which is primarily in Louisiana, the central corridor of the United States, the Rocky Mountains, and Canada. Seasonal volatility in basis differentials is expected to decrease over time. This volatility is usually driven by weather or transportation distance and should be partially mitigated by the proximity of active supply basins and regional gas storage to major demand centers. Daily volatility in basis differentials, primarily driven by pipeline constraints, is also expected to decrease over the medium to long term as new pipelines are constructed and the implications of shale-driven supply mature in the market.

A number of factors affect the basis differential forecast in the WECC region, most notably the expected July 2011 completion of the Ruby Pipeline. This pipeline will connect hubs located at

Opal, Wyoming and Malin, Oregon (Figure 8), and provide 1.5 bcf/d of capacity from the Rocky Mountain producing basins to West Coast demand markets. The addition of this major pipeline is expected to increase capacity such that the historically negative Opal basis differential will decrease in the short term, with Opal prices moving closer to Henry Hub prices immediately after the Ruby Pipeline goes online.

However, in the longer term, the Opal basis will likely move further into negative territory as production in the Marcellus Shale increases, which will reduce the amount of Rocky Mountain gas that can economically be delivered eastward. The Malin basis is expected to move closer to the Opal basis during this time period as the low variable cost of transportation on the Ruby Pipeline takes effect. While there was a 28-cent difference between Malin and Opal prices in 2010 and a 14-cent difference during the first five months of 2011, the differential between these two hubs is expected to shrink to 10 cents by FY 2013.

The Sumas, AECO, Stanfield, and Kingsgate bases are expected to remain relatively steady over the next few years. The advent of Ruby should not have any immediate effects on Western Canadian prices as intermediary pipeline constraints between Malin and Pacific Northwest demand centers persist and keep Canadian gas competitive with Rockies in the Pacific Northwest market. In the long term, future pipeline expansions should continue to reduce seasonal pipeline constraints and cause shrinking basis differentials between some of these hubs. However, there is still considerable uncertainty in the Western supply market outlook. Recent exploration in the Niobrara basin in the Rockies could presage increased production, which would further displace Canadian gas. Canadian production in general is expected to be less competitive with North American gas as a result of the shale boom, and it is possible that a large number of Canadian rigs could switch to oil, as has been occurring in the lower 48 states. Material change in Rockies or Canadian supply could alter the relationships among western hubs. On a long-term basis, Canadian gas is expected to be displaced in greater amounts, which will increase the negative basis differential to Henry for all of the above hubs.

Prices at the California hubs of PG&E, Topock, Ehrenberg, Southern California Border, and the associated producing San Juan Basin are expected to increase relative to Henry Hub because of expected production decreases in the San Juan Basin and the Midcontinent area. There are many basins in this area containing vertical wells that have been in production for many years, as well as mature shale fields dominated by dry gas production. With producers increasingly turning to more cost-effective shale gas fields and the extraction of more valuable oil and NGLs, production in this area is expected to decrease because drilling in these primary dry gas basins, regardless of type of well, will be relatively more expensive and less profitable. Combined with expected demand growth in California markets, the result will be steady upward pressure on basis at the above California market hubs.

2.3.1.5 Natural Gas Price Risk

The natural gas price risk factor reflects the uncertainty in natural gas prices, which affects the costs of producing electricity from gas-fired resources throughout the WECC region. The Natural Gas Price Risk Model simulates various monthly natural gas price patterns (in real 2008 dollars) through time using a forecast-reverting, random-walk technique. The random-walk technique simulates various monthly natural gas price patterns through time, with the starting point for simulating a price in a given month being the price from the previous month. The forecast-reverting technique, used in conjunction with the random-walk technique, allows the modeler to specify parameter values that control the otherwise uncontrollable variability that results from using the random-walk technique. These parameter values are calibrated such that the simulated variability in natural gas prices over time is consistent with the variability reflected in the historical natural gas price data. This model simulates uncertainty around the monthly

Henry Hub natural gas price forecast (converted to real 2008 dollars) previously discussed in this section. The monthly simulated natural gas prices in real 2008 dollars are used in AURORAxmp, where they are converted into nominal dollars.

Additional information input into the Natural Gas Price Risk Model includes a constraint on the minimum natural gas price, which is $1.75/MMBtu in real 2008 dollars, and month-to-month price volatilities for natural gas prices at Henry Hub. The month-to-month price volatilities are computed based on historical monthly spot market gas prices at Henry Hub from December 1990 through December 2010, computed in real 2008 dollars. These month-to-month price volatilities are derived as follows: (1) all the natural log (ln) price ratio changes from one month to the next for December 1990 through December 2010 are calculated; these are commonly referred to as "returns" and calculated as ln(price at time t/price at time t-1); (2) all the returns are accumulated, by month, for each of the 12 months in a year; and (3) the standard deviations of all the returns from one month to the next are calculated for each month. Power Risk and Market Price Study Documentation (Documentation), BP-12-FS-BPA-04A, Table 1. Using a similar approach with annual price data, cumulative annual price volatilities over several years are computed to quantify how much annual prices could deviate in the future from the natural gas price forecast.

Comparisons between the average and median prices for the monthly and annual historical price data indicate that average prices are greater than median prices. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. These asymmetrical differences are accounted for in this study by modeling natural gas price risk in lognormal probability distributions that differ in skew depending on the size of the differences.

The monthly and annual one-year volatility figures are substantial, with the annual price volatility being 32.9 percent. Documentation, Table 2. The annual price volatility reflects how much natural gas prices can vary from a gas price forecast made at the beginning of CY 2011.

Table 2 of the Documentation contains the cumulative annual price returns (the natural log of the ratio of two annual prices) for one through seven years' duration and the derivation of the associated cumulative annual price volatilities. The cumulative annual price returns for one through seven years' duration are derived from the historical price data by computing all the annual price returns over one-year through seven-year increments and calculating the associated standard deviations to yield the cumulative annual price volatilities. These values are computed so that the simulated prices over various time periods are calibrated to particular values rather than moving through time in an unconstrained manner. For calibration purposes, the simulated cumulative annual price volatilities are calibrated, using forecast reversion factors, to the historical average annual price volatilities over one through three years for CY 2011–2013 and four through seven years for CY 2014–2017. The calibration process is performed in Excel using Goal Seek, a linear optimization routine, to calculate the forecast reversion factors.

The forecast-reverting, random-walk algorithm used to simulate natural gas price risk is reported in Figure 12. Results from the Natural Gas Price Risk Model on a monthly basis over time are shown in the Documentation, Figure 1, for the 5th, 50th, and 95th percentiles. As noted in this figure, simulation of gas price variability began in May 2011.

The prices in Documentation Figure 1 include month-specific price level adjustments that perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast, both reflected in real 2008 dollars. These adjustments are made based on median prices rather than average simulated prices because the natural gas price forecast represents BPA's assessment that there is a 50 percent probability that natural gas prices could go higher or lower than forecast. Because the monthly price level adjustments are applied to all simulated prices for that month, such adjustments do not alter the simulated price volatilities.

2.3.2 Load Forecasts Used in AURORAxmp

AURORAxmp uses load forecasts for each zone in the model to determine the dispatch of resources and the import and export of electricity between zones. This Study uses the consolidated WECC topology, one of the default zone topologies supplied with the AURORAxmp model.

2.3.2.1 Base-Year Load Forecast

The EPIS-supplied AURORAxmp database labeled North American DB 2010-01 is used to derive the base-year load forecast for the WECC region.

2.3.2.2 Average Annual Growth Rate

The EPIS-supplied AURORAxmp database North American DB 2010-01 is used to derive the average annual growth rate forecast for loads in the WECC. The model uses the forecast growth rate in conjunction with the base-year load forecast to compute the load in each zone for the year following the base year.

2.3.2.3 Monthly and Hourly Load Shaping Factors

The EPIS-supplied AURORAxmp database North American DB 2010-01 is used to derive the monthly and hourly load shaping factors. The model uses these factors to convert the annual WECC-wide load forecast into a monthly and hourly load forecast. AURORAxmp multiplies the monthly shaping factor by the annual load forecast to derive the monthly load forecast. AURORAxmp uses an analogous process to convert the monthly load forecast into an hourly load forecast.

2.3.2.4 PNW Load Risk

The PNW load risk factor reflects the impact that economic and weather conditions can have on PNW loads and HLH and LLH electricity market prices. The level of economic activity affects the overall annual amount of electricity load in the Pacific Northwest. Fluctuations in electricity use due to weather conditions cause monthly variation in load, especially during the winter, when heating loads are higher, and summer, when cooling loads are higher. The PNW Load Risk Model simulates both the annual load growth variability due to economic conditions and monthly load variability due to weather conditions for the Pacific Northwest (and indirectly BPA). This model simulates monthly PNW load variability around the forecast load data used in AURORAxmp.

Annual PNW (and indirectly BPA, as discussed in section 2.5.2.2) load growth risk is modeled to simulate various load patterns through time using a forecast-reverting, random-walk technique. See section 2.3.1.5 of this Study for a description of the forecast-reverting, random-walk technique. Load growth variability is incorporated into the PNW Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of zero and a standard deviation of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year.

The cumulative annual PNW load growth standard deviations used in the PNW Load Risk Model are reported in the Documentation, Table 3. These standard deviation values are derived from historical annual WECC load data for the Northwest Power Pool (NWPP) Area for CY 1985-2008 that were modified by removing historical annual loads for BPA's direct-service industrial customers (DSIs) for CY 1985-2008. The source for the historical annual DSI loads is metered data that includes all DSI loads served by both Federal and non-Federal purchases, except for DSI loads served by Chelan PUD at the Alcoa aluminum smelter located in

Wenatchee, Washington. Variability in monthly loads due to load growth risk is derived by multiplying variable annual loads by deterministic monthly load shape factors.

Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth. These monthly PNW load standard deviations due to weather are derived from historical hourly load data filed by every balancing authority in the Pacific Northwest with the Commission on Form 714 from 1993 to 2005. The impact of load growth on these data is removed by taking a ratio of the monthly average load to the annual average load and computing the standard deviation of these values for each month.

In order for the PNW Load Risk Model to simulate the cumulative annual load growth standard deviations reflected in the historical data over various time durations, forecast-reversion factors are derived so that the simulated cumulative annual load growth standard deviations for CY 2010–2017 are calibrated to the values calculated from the historical data. The calibration process is performed in Excel using Goal Seek to calculate the forecast reversion factors. The forecast-reverting, random-walk algorithm used to simulate PNW load risk is reported in Figure 13. Documentation Figure 2 shows the simulated PNW loads at the 5th, 50th, and 95th percentiles.

2.3.2.5 California Load Risk

The California load risk factor reflects the impact that economic and weather conditions have on California loads, which affects HLH and LLH electricity market prices. The level of economic activity affects the overall annual amount of electricity load in California, while fluctuations in weather conditions cause monthly variation in load, especially during the summer, when cooling loads are highest. The California Load Risk Model simulates the annual load growth variability due to economic conditions and monthly load variability due to weather conditions for California. This model simulates monthly California load variability around the forecast load data using the same methodology as used to simulate PNW load variability, as explained in section 2.3.2.4.

The data sources used to calculate the cumulative annual load standard deviations and monthly variability for California are identical to those used for the PNW; however, the cumulative annual load standard deviations for California are developed using WECC load data from a shorter time period, CY 1987–ther are derived from historical hourly load data filed by every balancing authority in California with the Commission on Form 714 from 1993 through 2005. The impact of load growth is removed from this historical California load data in the same manner as it is removed from the historical PNW load data. See section 2.3.2.4.

The same game-by-game values sampled from standard normal probability distributions when simulating annual load growth variability for the PNW are used when simulating the annual load growth variability for California. This approach incorporates into the risk analysis the fact that annual PNW (after removing the impact of DSI loads) and California loads are highly positively correlated (0.982), as indicated in Table 3 of the Documentation. Conversely, the random draws used in simulating monthly load variability due to weather for California are sampled independently of those sampled for the PNW. The forecast-reverting, random-walk algorithm used to simulate California load risk is reported in Figure 13. Figure 3 of the Documentation shows the simulated California loads at the 5th, 50th, and 95th percentiles.

2.3.3 Hydroelectric Generation

Hydroelectric generation is a primary driver of electricity prices in AURORAxmp because it has a significant impact on the marginal unit operating on any hour. The marginal unit is the generator that would supply the next megawatt of power if the demand was 1 MW higher, as described in section 2.2.2.

2.3.3.1 PNW Hydro Generation Risk

For the purposes of this risk, the Pacific Northwest is defined as Oregon, Washington, Idaho, and Montana. The PNW hydroelectric generation risk factor reflects the uncertainty of the timing and volume of streamflows and the impact of streamflows on monthly hydroelectric generation in a given year. These PNW hydro generation amounts are computed by the HYDSIM model. See Power Loads and Resources Study, BP-12-FS-BPA-03, section 3.2, for a description of HYDSIM. The HYDSIM model produces 70 records of PNW monthly hydroelectric generation, each one year long, based on actual water conditions in the region from 1929 through 1998. For each of the 3,500 games, one of the 70 water years for the first year of the rate period (FY 2012) is sampled from a discrete uniform probability distribution using the @RISK software, as described in section 2.2.1. The model then selects the next historical water year for the next year of the rate period, FY 2013 *(e.g.*, if the model uses 1929 for FY 2012, then it selects 1930 for FY 2013) and continues this process through FY 2017. The model repeats this process for each of the 3,500 games. The resulting 3,500 water year combinations become AURORAxmp inputs.

2.3.3.2 British Columbia (BC) Hydro Generation Risk

The BC hydroelectric generation risk factor reflects the uncertainty of the timing and volume of streamflows and its impact on monthly hydroelectric generation in BC in a given year. Historical generation data over the same time period as the 70 historical water years used in the HYDSIM model was the basis for modeling this risk. The source of this information is primarily from Statistics Canada, a publication produced by the Canadian government. A minimal amount of interpolation is done to estimate values for some missing data so that a complete 70-water-year record is created. Because the installed capacity of the hydroelectric generators varied over the 70 years, the historical generation data are normalized into capacity factors (hydroelectric generation/sum of capacity). Current expected output of BC hydroelectric generators is projected from the historical data using a trend adjustment technique. The trend adjustment is accomplished by fitting a linear trend line to the historical capacity factor time series and adjusting the capacity factors by the difference between the fit of the line for any given year and the last year of the data collected. Each of these 70 water-year trend-adjusted records is matched, by water year, with each of the 70 water-year records of the PNW hydroelectric generation from HYDSIM and jointly sampled for the 3,500 games using the technique described in section 2.3.3.1.

2.3.3.3 California Hydro Generation Risk

The California hydroelectric generation risk factor reflects the uncertainty of the timing and volume of streamflows and its impact on monthly hydroelectric generation in California in a given year. Historical generation data over the same time period as the 70 historical water years used in the HYDSIM model was the basis for modeling this risk. The publicly available sources of these data include the California Energy Commission (CEC), the Federal Power Commission, and the Energy Information Agency (EIA). A minimal amount of interpolation is done to estimate values for some missing data so that a complete 70-water-year record is created. Because installed capacity of the hydroelectric generators has varied over these 70 years, the historical generation data are normalized into capacity factors. As with the BC data, a trend adjustment is used to project current expected output of the California hydroelectric generators. Each of these 70 water-year trend-adjusted records is matched, by water year, with each of the 70 water year records of the PNW hydroelectric generation from HYDSIM and jointly sampled for the 3,500 games using the technique described in section 2.3.3.1.

2.3.4 Hourly Shape of Wind Generation

AURORAxmp models wind generation as a must-run resource, or a resource that is run regardless of economic or demand-based market signals in AURORAxmp. AURORAxmp reports a negative one dollar price for any hour in which the marginal resource is a must-run resource. Current operating PNW wind generation is just over 3,500 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.

2.3.4.1 PNW Hourly Wind Generation Risk

The PNW hourly wind generation risk factor represents the uncertainty in the power output of the regional wind fleet. The PNW Hourly Wind Generation Risk Model simulates this uncertainty, 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. These hourly capacity factors are then resampled using a k-nearest-neighbor algorithm (also called a local bootstrap), an algorithm that creates a sampled time series to represent a possible wind generation time series. Thirty sampled time series are created, with 8,784 hours sampled for each time series to represent a complete wind year. The sampled records are then randomly selected and translated into a forced outage of wind generators in the PNW zone in

AURORAxmp. Using this method, the model captures potential variations in annual, monthly, and hourly wind generation.

2.3.5 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 2010-01.

2.3.5.1 Columbia Generating Station Generation Risk

The CGS generation risk factor reflects the uncertainty regarding the amount of energy generated by CGS. The CGS Generation Risk Model simulates the 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-12-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, with the median value (the value at the 50th percentile) being higher than the average. The shape of the frequency distribution reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output. These game-by-game results are used in both RevSim (see section 2.2.3 of this Study) and AURORAxmp, with the results being converted to a forced outage rate in AURORAxmp and applied to the CGS generation for each of the 3,500 games.

The algorithm used to simulate CGS generation risk in the CGS Generation Risk Model is reported in Figure 14. The simulated frequency distribution for CGS output for October 2011 is shown in Figure 4 of the Documentation.

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

RPS requirements are expected to drive construction of qualifying renewable resources throughout the WECC region in the future. Two data sources are used to represent the likely resource additions in AURORAxmp: the Sixth Northwest Conservation and Electric Power Plan released by the Northwest Power and Conservation Council, and the forecast of the size of the wind fleet provided by BPA Transmission Services, found in the Generation Inputs Study, BP-12-FS-BPA-05, section 2.3.2. These two sources are merged to create a forecast that is consistent with the Power Loads and Resources Study, BP-12-FS-BPA-03, and captures generation likely to be added to fulfill RPS requirements in areas outside the Pacific Northwest. The WECC-wide resource additions can be seen in Figure 5 of the Documentation.

2.3.7 Transmission Capacity Availability

In AURORAxmp, transmission capacity sets the limit on the amount of electricity that can be imported and exported from one zone to another. Figure 2 shows the AURORAxmp representation of the major transmission interconnections for the WECC region. 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 Transmission Services 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 2010-01.

2.3.7.1 PNW Hourly Intertie Availability Risk

The PNW hourly intertie availability risk factor represents the uncertainty in the hourly availability of transmission capacity on three interties that connect the PNW with other regions in the WECC: COI, DC Intertie, and BC Intertie. This risk is modeled in the PNW Hourly Intertie Availability Risk Model by using the common statistical technique of sampling, with replacement, from historically (FY 2003–2009) observed pairs of transmission ratings and the duration of those ratings. To create a year-long record, the pairs are repeatedly sampled and appended to each other until the sum of the durations covers 8,784 hours.

Seasonal differences in transmission availability are accounted for by limiting the sampling to a specific month. This is done so that a pair could be sampled only if the start of the duration of the rating matches the month that would correspond to the position implied by summing previously sampled durations. This approach creates 200 sampled records for each of the three interties. These records are then represented as a percentage of the maximum path rating used in AURORAxmp.

For use with the 3,500 games, each intertie has a single record that is independently selected from the associated set of 200 records. These data are then 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 produced using AURORAxmp. The Market Price run uses hydro generation data for all 70 water years, while the Critical Water run uses hydro generation data for only the critical water year, 1937. Tables 2 through 7 show the FY 2012 through FY 2017 monthly average HLH and LLH prices from Market Price run. Table 8 shows the

FY 2012 average HLH and LLH prices of the Critical Water run. Table 9 gives the same information for FY 2013. Table 10 shows the fiscal year HLH and LLH average prices for FY 2012–2017 from the Market Price run. Table 11 gives the FY 2012 and FY 2013 annual averages of HLH and LLH for the Critical Water run.

2.5 Inputs to RevSim

As noted earlier, the RevSim module of RiskMod calculates surplus energy revenues, balancing and augmentation power purchase expenses, and 4(h)(10)(C) credits that are used by the RAM2012 model. It also determines, by simulation, PS operating net revenue risk, used by the ToolKit Model. Inputs to RevSim include risk data simulated by RiskSim 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-12-FS-BPA-03. A summary of these load and resource data in the form of monthly energy for FY 2012–2013 is provided in the Power Loads and Resources Study Documentation, BP-12-FS-BPA-03A, Table 4.1.1. These data include Federal hydro generation for water year 1937. Monthly surplus/deficit values calculated in RevSim for 1937 hydro generation must agree with the monthly Total Firm Surplus/Deficit values in the Power Loads and Resources Study Documentation, BP-12-FS-BPA-03A, Table 4.1.1, to validate the data transfer.

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-12-FS-BPA-01, section 4.2.

2.5.1.3 Composite, Load Shaping, and Demand Revenue

Composite, load shaping, and demand revenues are provided by RAM2012. Consistent with the Tiered Rate Methodology (TRM), composite 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 RAM2012 are input to RevSim to facilitate the calculation of changes in load shaping revenue. Demand billing determinants and rates from RAM2012 are input to RevSim to facilitate the calculation of changes in demand revenue. Power Rates Study Documentation, BP-12-FS-BPA-01A,Table 2.5.4.

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 2012–2013, 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 1998 (also referred to as the 70 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 840 months of the 70 water years. This analysis by HYDSIM is referred to as a continuous study. See the Power Loads and Resources Study, BP-12-FS-BPA-03, section 3, regarding HYDSIM, continuous study, and 70 water years.

For each of the 70 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 70 historical water years are provided in the Documentation, Table 4 for FY 2012 and Table 5 for FY 2013. Monthly values for Federal hydro HLH generation ratios for each of the 70 historical water years are provided in the Documentation, Table 6 for FY 2012 and Table 7 for FY 2013.

Adjustments are made to the average monthly hydro generation in the 70-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-12-FS-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 8–10 for FY 2012 and Tables 11–13 for FY 2013. These generation data are added to the values presented in Documentation Tables 4–5 to yield the final monthly Federal hydro generation for each of the 70 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 3,500 two-year simulations (FY 2012–2013).

The water year sequences developed for each game for PNW hydro generation are used for Federal hydro generation. This results in a consistent set of PNW and Federal hydro generation being used for each game. See section 2.3.3 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 reflects the impacts that the strength of the economy and fluctuations in 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 PNW Load Risk Model. See section 2.3.2.4 of this Study for further details regarding the PNW Load Risk Model. BPA load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

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 2.3.5.1 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 PS portion of Condon, Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects. The PS Wind Generation Risk Model simulates this risk such that the average of the simulated monthly generation outcomes for all these wind projects is almost identical to the combined expected monthly generation included in the Power Loads and Resources Study, BP-12-FS-BPA-03, section 3.1.3.

The risk of the wind generation value 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.

To model monthly PS wind generation risk, monthly energy output data for the wind resources that PS purchased from March 2002 through February 2010 are divided by the sum of the associated capacity of these wind resources at the time the energy was produced, yielding average capacity factors. These average capacity factors reflect the impact of additional resources being added over time. The capacity factors are sorted by month, regardless of year. This process yields eight years of monthly capacity factors, from which cumulative probability distributions of capacity factors for each month are derived. These cumulative probability distributions are input into the RiskCumul function in the @RISK computer package and used to simulate variability in capacity factors. These simulated capacity factors are multiplied by the current total capacity of the resources that PS purchases, yielding PS wind generation variability.

The simulated monthly wind generation results are specified in terms of flat energy. Documentation Figure 10 shows the monthly flat energy output for all wind projects during FY 2012–2013 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-12-FS-BPA-03, section 3.1.3.

Documentation Tables 14–15 report information from which the value of wind generation during FY 2012–2013 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 factor reflects 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 $92.9 million during FY 2012 and $89.0 million during FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, Table 3B. 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 11–12 indicate how FY 2012–2013 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 $78.9 million in FY 2012 and $76.5 million in FY 2013, 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 13–14 reflect the probability distributions for transmission and ancillary service expenses during FY 2012–2013. 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 70 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 3,500 games of monthly HLH and LLH prices for FY 2012-2017. The Critical Water run produces 3,500 games of monthly HLH and LLH prices for FY 2012–2013.

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 2012-2017. These values are provided to RAM2012 to develop rates for FY 2012–2013.

Expenses for system augmentation purchases for FY 2012-2017 use both the Market Price run and the Critical Water run; these expenses are provided to RAM 2012.

2.6 RevSim Model Outputs

RevSim model outputs are provided to RAM2012, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-12-FS-BPA-01.

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

The 4(h)(10)(C) credit risk factor is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. Documentation, Table 16. 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 70 water years for FY 2012–2013 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 70 water years in RiskMod for FY 2012-2013 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-12-FS-BPA-03, section 3.3. Table 2.11 in the Power Loads and Resources Documentation contains the 4(h)(10)(C) power purchase amounts for FY 2012–2013.

The direct program expenses and capital costs for FY 2012–2013 do not vary by water volume and timing and are documented in the Power Revenue Requirement Study Documentation, BP-12-FS-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 16.

Results shown in Documentation Figures 15–16 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2012–2013. The average 4(h)(10)(C) credit for the 3,500 games is $91.1 million for FY 2012 and $95.8 million for FY 2013. These values are included in the revenue forecast component of the Power Rates Study, BP-12-FS-BPA-01.

The 4(h)(10)(C) credit for each of the 3,500 games is included in the net revenue provided to the ToolKit.

2.6.2 System Augmentation Costs

System augmentation costs are calculated for FY 2012–2017. System augmentation costs for FY 2012–2013 are used in the BP-12 rate calculations and those for FY 2012–2017 are used in the REP-12 rate proceeding. System augmentation costs for the rate period are calculated using two different methods, one for the deterministic value provided to RAM2012 and a second for the variable costs included in the net revenue provided to the ToolKit.

For the rate period the deterministic value provided to RAM2012 is calculated by multiplying the system augmentation amount (aMW) by the average AURORAxmp price from the Critical Water run. The system augmentation amount is determined in the Power Loads and Resources Study, BP-12-FS-BPA-03, section 4. A summary of this calculation is shown in Documentation Table 17.

For FY 2014–2017, the average AURORAxmp price is the average price for the 50 games, out of a total of 3,500 games in the Market Price run, that use 1937 hydro generation data.

The system augmentation costs included in the net revenue provided to the ToolKit reflect the uncertainty in the cost of system augmentation purchases not acquired prior to setting rates. The uncertainty in the cost of system augmentation includes both the uncertainty around the forecast deterministic need (aMW amount) and the 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 RAM2012.

To determine system augmentation cost risk, augmentation need (measured in 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 2013 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 2012, 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. However, since there is a surplus under critical water conditions for FY 2012, the system augmentation need for FY 2012 is zero. For FY 2013, 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 Market Price run, and the remaining 50 percent of the Category 1 augmentation need and all the Category 2 augmentation need is met at prices from the Critical Water run.

RevSim calculates the total system augmentation cost risk associated with each of the 3,500 games per fiscal year by summing the system augmentation costs computed by these two approaches. Documentation Table 18 presents sample calculations based on the methodology used to calculate system augmentation cost risk in RevSim for FY 2012–2013.

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-12-FS-BPA-03, section 4.1.

Transmission losses on BPA's transmission system are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent. This factor excludes losses on the Southern Intertie. This loss factor is identical to the loss factor used in the Power Loads and Resources Study Documentation, BP-12-FS-BPA-03A, Table 2.12.5.

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 2012–2013 are provided to RAM2012. The surplus energy revenues and balancing purchase expenses provided to RAM2012 are based on the median net secondary revenue (surplus energy revenue less balancing purchase expense) of the 3,500 games. The surplus energy sales and balancing power purchases passed to RAM2012, both measured in annual average megawatts, are the arithmetic means of these quantities over the 3,500 games for each fiscal year.

In a dataset 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 350 games was used. The values for secondary sales revenues and balancing purchases expenses passed to RAM2012 are the arithmetic means of the secondary sales revenues and balancing purchases expenses (calculated and reported separately to RAM2012) for the 350 middle games as measured by net secondary revenue (175 above the median net secondary revenue and 175 below). Documentation Tables 19 and 20 provide summary calculations of the secondary sales revenues and balancing purchase expenses provided to RAM2012 for FY 2012–2013.

Secondary sales revenues and balancing purchase expenses for FY 2012–2013 (based on the median approach described above) are shown in Documentation Table 23.

2.6.4 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2012 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 RAM2012, which in turn depend on the level of PNRR assumed when RAM2012 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 3,500 games of net revenue risk data simulated by RevSim and NORM and mathematical descriptions of the CRAC and DDC, the ToolKit produces 3,500 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 2012–2013 simulated by RevSim using rates with $0 million in PNRR is reported in Table 12. PS net revenue over the rate period averages $26 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, and the impacts of the CRAC and DDC. Also, the average net revenue in Table 12 will differ from the net revenue shown in the

Power Revenue Requirement Study, BP-12-FS-BPA-02, Table 1, which shows the results of a deterministic forecast, one reason being that the deterministic forecast does not account for system augmentation risk.

2.7 Inputs to NORM

Historical data sets are used in the modeling of some risks modeled in NORM, but the primary method of risk estimation in NORM relies on the input 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.

2.7.1 CGS Operations and Maintenance (O&M)

CGS O&M uncertainty is modeled for:

(a) Base O&M; and

(b) Nuclear Electric Insurance Limited (NEIL) Insurance Premiums.

NORM captures uncertainty around Base O&M and NEIL insurance costs only. Based on a comparison of actual CGS O&M costs from FY 2007–2010 with those shown in the Integrated Program Review (IPR), costs were on average 0.3 percent higher than the IPR amounts. For Base O&M, NORM assumes that the most likely outcome is 0.3 percent higher than the amount determined for the Revenue Requirement Study. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. NORM distributes the minimum and maximum values based on historical deviations of actual and forecast Base O&M.

For NEIL insurance premiums, risk is modeled around forecast gross premiums and distributions based on the level of earnings on the NEIL fund. Member utilities receive annual distributions based on the level of these earnings; the net premiums they pay are lower as a result. The Revenue Requirement amounts for CGS O&M for FY 2011, FY 2012, and FY 2013 are $321.7 million, $306.4 million, and $345.9 million, respectively. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B.

The distributions for CGS O&M are shown in Documentation Figure 17.

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; and
(d) Base O&M (for Reclamation only).

Historically, Reclamation has underrun its O&M budget. Therefore, NORM includes a probability distribution around future Reclamation Base O&M expenditures that places a higher probability on Reclamation underrunning its budget than overrunning it. The forecast for FY 2011 for Reclamation's O&M is $96.1 million. The forecasts for Reclamation's O&M budget included in the Revenue Requirement are $112.0 million in FY 2012 and $119.9 million in FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B.

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 2011 that there is a 2.5 percent probability that an event will occur that leads to a requirement for additional security at the Corps and Reclamation facilities. For FY 2012 and FY 2013 it is assumed that there is a 5 percent probability that an event will occur. The FY 2011 probability is lower because NORM begins its analysis partway through FY 2011, which reduces the probability of an event occurring during that year. 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 2.5 percent probability that an event that requires additional annual expenditures of $2 million each for both the Corps and Reclamation will occur in FY 2011 and a 5 percent probability that an event with the same annual cost will occur in FY 2012 and FY 2013.

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 18.

2.7.3 Residential Exchange Program (REP)

The NORM model reflects the recently adopted 2012 REP Settlement Agreement. Residential Exchange Program Settlement Agreement Proceeding (REP-12) Administrator’s Final Record of Decision, REP-12-A-02. Variability for costs for the REP for the investor-owned utilities (IOUs) in FY 2011 and for the consumer-owned utilities (COUs) in FY 2011–2013 is modeled in NORM. For FY 2011, variability around IOU REP costs is modeled due to potential fluctuation in exchangeable residential and small farm load, with an expected value of $179.9 million, a minimum value of $10 million lower than the most likely value, and a maximum value of $10 million higher than the most likely value. It is assumed in this Study that BPA will pay the IOUs the fixed amount of REP benefits established in the 2012 REP Settlement in FY 2012 and FY 2013 and therefore, no variability is modeled. Variability of plus or minus $1 million per year is modeled for the expected payments to COUs for FY 2012 and FY 2013.

The REP variability described above is modeled using PERT distributions. A PERT distribution is a distribution in which maximum, most likely, and minimum values are defined for the distribution. The @RISK software models a distribution that best fits those maximum, most likely, and minimum values.

2.7.4 Conservation Expense

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

(a) Conservation Acquisition; and

(b) Low-Income and Tribal Weatherization.

Conservation acquisition expense is modeled for each year from FY 2011 through FY 2013 with a PERT distribution with a minimum value of 80 percent of the amount in the Revenue Requirement, a most likely value of 95 percent of the amount, and a maximum value of the amount. The amount for FY 2011 for conservation acquisition expense is $14.2 million. The forecasts are $16.0 million in both FY 2012 and FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. The distribution for conservation acquisition is shown in Documentation Figure 19.

Low-income and tribal weatherization expense is modeled for no variability for FY 2011. For FY 2012–2013, a total cost of $10.0 million for the two years combined is modeled. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. For FY 2012, a

PERT distribution with a minimum value of $4 million, a most likely value of $5 million, and a maximum value of $6 million was utilized. The amount for FY 2013 is the difference between $10 million and the amount for each game for FY 2012. The Revenue Requirement amounts for low-income and tribal weatherization are $5 million per year from FY 2011 through FY 2013. The distribution for low income and tribal weatherization cost is shown in Documentation Figure 20.

2.7.5 Colville Settlement and Possible Spokane Settlement

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

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

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

To model the variability around Grand Coulee generation, a forecast for FY 2012 output was created with mean and standard deviation calculated for the average annual output of the 70 historical water years. The mean and standard deviation are used as parameters for a normal probability distribution generated by @RISK. The 70 years of data are provided in Documentation Table 25.

Using the data described above, NORM calculates a base annual payment to the Colville Tribes, which equals the base annual price times the draw for that year's output from Grand Coulee. If the base payment exceeds the ceiling, the Colville payment equals the ceiling. If the base payment is below the floor, the payment is set equal to the floor, and the difference is carried forward as a loan to be paid the following fiscal year. A new loan is created each year the base payment is below the floor or the following year's base payment is insufficient to pay off the previous year's loan.

Within the rate period, legislation enacting a similar settlement with the Spokane Tribe could go into effect. NORM includes an assumption of a 30 percent probability that the legislation will pass, and that payments would then be made to the Spokane Tribe for each year in the rate period. The payments would equal 29 percent of the payments made to the Colville Tribes.

The forecast included in the Revenue Requirement for FY 2011 for payments to the Colville Tribes is $17.6 million. The amounts are $21.9 million in FY 2012 and $22.1 million in FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Payments to the Spokane Tribe are forecast at $0 for FY 2011–2013.

The distributions for Colville Settlement payments are shown in Documentation Figure 21. Similar graphs for the Spokane Settlement payments are shown in Documentation Figure 22.

2.7.6 Power Services Transmission Acquisition and Ancillary Services

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

(a) Third-Party General Transfer Agreement (GTA) Wheeling; and

(b) Third-Party Transmission and Ancillary Services.

NORM models third-party GTA wheeling cost for each year from FY 2011 through FY 2013 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 2011 for third-party GTA wheeling is $54.8 million. The Revenue Requirement amounts are $52.3 million in FY 2012 and $52.9 million in FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Figure 23 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 2011, and thus risk was not modeled for that year. For FY 2012 and FY 2013, 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 2011 for third-party transmission and ancillary services is $2 million. The amounts in the Revenue Requirement are $2.2 million for FY 2012 and FY 2013. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Figure 24 of the Documentation shows the distribution for third-party transmission and ancillary services.

2.7.7 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; and

(e) 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 utilizes a PERT distribution with minimum and maximum values of 7.5 percent lower and 10 percent higher than the most likely values. The most likely values are the amounts from the Revenue Requirement for each year. The Revenue Requirement amounts for Power Services Internal Operations Expenses for FY 2011, FY 2012, and FY 2013 are $146.6 million, $156.0 million, and $159.5 million, respectively. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B.

Figure 25 of the Documentation shows the distributions for total Internal Operations Costs, including Corporate G&A.

2.7.8 Fish & Wildlife Expenses

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

2.7.8.1 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 measures will not be implemented as rapidly 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 actually be incurred in the fiscal years in which BPA plans for them to be incurred. This uncertainty is modeled by PERT distributions with most likely expense deviation values of $0 from the Revenue Requirement amounts for each of the three years, minimum (maximum underrun) values of 10 percent lower than the most likely figures, and maximum values of 5 percent higher than the most likely figures. The Revenue Requirement amounts for BPA's Direct Program for fish and wildlife for FY 2011, FY 2012, and FY 2013 are $225.0 million, $237.4 million, and $241.4 million, respectively. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Figure 26 of the Documentation illustrates the distributions for the BPA Direct Program expense.

2.7.8.2 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 at $0, a minimum value of $2 million less than the Revenue Requirement, and a maximum value of $2 million above the Revenue Requirement. The expected uncertainty is $0. The Revenue Requirement amounts for USF&W Service Lower Snake River Hatcheries for FY 2011, FY 2012, and FY 2013 are $24.5 million, $28.8 million, and $29.9 million, respectively. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Figure 27 of the Documentation shows the distributions for risk over the Lower Snake River Hatcheries expense.

2.7.8.3 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 2011 through FY 2013. The most likely value for the deviation from the Revenue Requirement is $0; the minimum value (largest negative deviation) is $500,000 lower than most likely; and the maximum value is $500,000 above most likely. 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 2011, FY 2012, and FY 2013 are included in the Bureau's O&M budget, which is discussed in section 2.7.2 of this Study. Figure 28 of the Documentation shows the distributions for Leavenworth Complex O&M expense.

2.7.8.4 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 2011 through FY 2013. The most likely value for the deviation from the Revenue Requirement is $0; the minimum value for cost (*i.e.*, the largest negative deviation) 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 2011, FY 2012, and FY 2013 are included in the Corps's O&M budget, which is discussed in section 2.7.2 of this Study. Figure 29 of the Documentation shows the distributions for Fish Passage Facilities expense.

2.7.9 2008 FCRPS Biological Opinion (BiOp) Secondary Sales Risk

The 2008 FCRPS BiOp is incorporated into the hydro studies. Power Loads and Resources Study, BP-12-FS-BPA-03, section 3.1.2.1. This BiOp includes performance standards. If the performance standards are not met, it may be necessary to make changes to the operational regime that would reduce operational flexibility for power generation, resulting in decreased net secondary revenue. Conversely, it may be possible to relax the operational regime as a result of exceeding the performance standards, increasing operational flexibility and thus resulting in increased net secondary revenue. This risk continues as long as the current 2008 BiOp remains in effect (the separate risk of changes to FCRPS operations or expenses arising from litigation over either the 2004 or the 2008 FCRPS BiOp is treated with the two NFB mechanisms, described in section 4). A PERT distribution of this risk is created and used for each of the two fiscal years in the rate period and for FY 2011. For all three years, the most likely value is $0 change, the minimum value (largest negative impact on revenue) is a negative $40 million, and the maximum value is positive $5 million. This results in an expected value net revenue impact on net revenue of a negative $5.8 million for all of the years. Figure 30 of the Documentation shows the distributions for BiOp Secondary Sales Risk.

2.7.10 Capital Expenditure Risk

For this Study, capital expenditure uncertainty is generally not modeled in NORM. New capital expenditures are generally financed by matching amounts of new debt. Thus, variability in cash disbursement for capital projects is offset by the corresponding variability in cash inflow from borrowing. The remaining risk is variability in interest expense due to the variability in total debt, which is distributed over several years (the precise duration depends on the type of financing). A small fraction of the expenses related to capital expenditures is therefore distributed to net revenue for FY 2011-2013 for the calculation of TPP. Current evaluation and past modeling show that the effect of capital expenditures uncertainty on TPP will be minimal in the FY 2012–2013 rate period.

The one capital risk that is modeled in NORM is associated with CGS capital expenditures. The modeling of CGS capital addition uncertainty is based on historical variability, with added uncertainty around the costs of the condenser replacement. This capital uncertainty affects

Energy Northwest (EN) debt service for the calculation of TPP. Figure 31 of the Documentation shows the distribution of the CGS debt service effect due to variation in interest rates and capital expenditures.

2.7.11 Interest Rate and Inflation Risk

Inflation risk is currently not modeled in NORM. Current evaluation and past modeling indicate that the effect on TPP of financial risk due to uncertainty over inflation during FY 2011–2013 is minimal.

The impact of interest rate risk on non-Federal debt issuance is not modeled in NORM. There is no forecast variability for BPA's non-Federal debt during the rate case period as there are no planned issuances of debt that have not already been completed.

The impact of interest rate risk on Federal debt issuance is also modeled in NORM. The risk of interest rate fluctuation is modeled based on forecast refinancings of existing debt and issuance of new Federal debt. Interest rate fluctuation is modeled based on potential interest rates for refinanced debt and newly issued Federal debt based on planned debt refinancing and issuance schedules. The difference in interest payments from the deterministic forecast is calculated for every game run by NORM. The distribution of variation in the Federal interest from the deterministic forecast is shown in Documentation Figure 32.

The impact of interest rate risk on FY 2011–2013 Federal appropriations is modeled in NORM. The risk of varying total interest expense for FY 2011–2013 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 2011, FY 2012, and FY 2013 are $215.9 million, $221.9 million, and $222.7 million, respectively. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, Table 3B. Distributions for Federal appropriations expense are shown in Documentation Figure 33.

2.7.12 CGS Main Condenser Replacement Risk

Energy Northwest is currently in the process of replacing the main condenser at CGS. This project began on April 6, 2011, concurrent with the already-scheduled CGS refueling outage. CGS will not be producing power until this project is completed. The financial risk considered here arises from uncertainty in the outage duration 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 outage in FY 2011. 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 2011. This revenue variability is a function of plant outage duration, monthly flat AURORAxmp market prices, monthly flat CGS energy amounts from RevSim, and NEIL reimbursements for lost generation.

The outage duration is modeled with a minimum of 98 days and a mean value of 116 days. These values reflect an updated forecast of when the condenser replacement will be completed. The model includes a very small probability (less than 0.1 percent) that the outage will extend beyond the end of the BP-12 rate period. The probability distribution of the outage duration is shown in Documentation Figure 34.

To calculate the impact of the outage on net revenue, 3,500 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 from June 2011 through the end of FY 2013. These additional days in or out of service are then compared to the gamed CGS energy amounts from RevSim, and the difference between the CGS megawatthour deviation from NORM and the CGS megawatthour deviation from RiskMod is calculated for each month. 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, resulting in a net revenue deviation.

BPA's NEIL I Accidental Outage Insurance Policy pays $3.5 million per week, after a 12-week deductible period, if CGS is out of service due to accidental property damage. In the event that accidental damage occurs while CGS is down for a planned outage, the 12-week deductible period applies after the end of the planned outage period. The probability that an extended outage (that is, beyond 70 days) was due to an event covered by NEIL I insurance was assumed to be 50 percent. For each outage game, revenue from NEIL I insurance, if any, is calculated in each month based on the above parameters and added to the calculated net revenue deviation due to changes in energy production. This addition partially offsets the reduction in net revenue caused by the deviation in outage duration. The distribution of revenue changes for each fiscal year is shown in Documentation Figure 35.

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

In FY 2011–2013, TS will provide VERBS, formerly known as Wind Balancing Service, to wind and other variable resource generators in the BPA Balancing Authority Area. Generation Inputs Study, BP-12-FS-BPA-05, section 10.5. TS will charge generators for the VERBS services they receive. TS will obtain from PS the generation inputs needed to support these services and will pay PS for these generation inputs.

VERBS comprise three components: regulation, following, and imbalance, with separate rates applying to each. Generation Inputs Study, BP-12-FS-BPA-05, section 10.5.4. The costs of supplying these services can be characterized as having two components: embedded costs and variable costs.

The quantity of wind generation in BPA's Balancing Authority Area during the FY 2012–2013 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 costs. PS will 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. 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. 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 costs, however, is subject to risk, 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 embedded-cost portion 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 embedded-cost portion of the TS revenue increase.

Installed wind capacity is modeled using estimates of low, most likely, and high quantities for FY 2011–2013, 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 impacts 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 3,500 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 Services for Wind Generators revenue are shown in Documentation Figure 36.

2.7.14 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 cash payments to the Treasury. While cashflow 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 cashflow result, the impact of depreciation must be removed and the impact of cash principal payments must be added. The 3,500 ATC adjustments calculated in NORM make the changes needed to translate these accrual results (net revenue results) into the equivalent cashflows 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 13, as its starting point but includes 3,500 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 expense deltas for all of the individual risks that are modeled, and (2) the associated ATC adjustments for each game. Each run has 3,500 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in Documentation Figure 37.

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 RiskMod 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, but is not 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 case, 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 Tools

Liquidity tools comprise cash and cash equivalents. These include:

(a) Reserves Available for Risk attributed to PS;

(b) The Treasury Facility (previously referred to as the "Treasury Note"); and

(c) Reserves attributed to TS made temporarily available for PS risk mitigation (no reserves attributed to TS are relied upon for PS risk mitigation in setting power rates for FY 2012–2013).

These liquidity tools mitigate financial risk by serving as a temporary source of cash for meeting financial obligations during years in which net revenue and the corresponding cashflows are lower than anticipated. In years of above-expected net revenue and cashflow, financial reserves will be replenished so they will be available in later years.

3.2.1.1 Reserves Available for Risk

Reserves Available for Risk is 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 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.

Some financial reserves attributed to PS are not considered to be available for risk and thus are not included in the starting financial reserves or any other part of the TPP calculation. In this Study, financial Reserves Available for Risk attributed to PS exclude financial reserves that accumulated due to the suspension of payment of 2000 REP Settlement benefits in FY 2007. This exclusion comprises $81.61 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). Funds collected from customers under contracts that obligate BPA to perform energy efficiency-related upgrades to the customers' facilities are also 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. A total of $300 million of the Treasury Facility is considered available for within-year liquidity needs (as described in section 1.1.1), and $450 million is to be available for PS TPP support, augmenting the liquidity provided by financial reserves.

3.2.1.3 Reserves Attributed to TS

In order to reduce the impact of risk mitigation on power rates, PS could rely for risk mitigation upon a portion of reserves attributed to TS, beyond the amount needed for Transmission risk mitigation and other Transmission purposes. PS does not need to rely on these additional reserves to meet the 95 percent TPP standard in FY 2012–2013. Consequently, no reserves attributed to TS are relied upon for PS risk mitigation in setting FY 2012–2013 power rates.

3.2.1.4 Net Reserves

The concept of "Net Reserves" is also used in this Study. Net Reserves simplifies the discussion of the above sources of liquidity by combining the three discrete sources into a single measure.

Net Reserves is the amount of reserves attributed to PS above zero, less any quantity of TS reserves consumed, less any balance on the Treasury Facility. In each individual Monte Carlo game in the ToolKit, reserves will be equal to net reserves. This is because the ToolKit models a positive outstanding balance on the Treasury Facility if and only if the balance of reserves attributed to PS is negative. 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* the expected value of the outstanding balance on the Treasury Facility to be above zero.

3.2.2 Liquidity Reserve Level

During the development of the WP-10 power rates, BPA investigated its need for within-year liquidity and concluded that $300 million was adequate to meet the part of BPA's need for within-year liquidity that was related to PS. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, at 54. Part of the Treasury Facility, $300 million, is considered to be available for within-year liquidity needs. Therefore, no PS reserves are set aside to provide liquidity *(i.e.,* PS liquidity reserves equal $0).

3.2.3 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted in rate proceedings using current projections of PS financial 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 analysis, 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 cashflow, which will increase the available PS financial reserves and therefore increase TPP. No PNRR is needed to meet the TPP standard; PNRR is $0 for both FY 2012 and FY 2013.

3.2.4 The Cost Recovery Adjustment Clause

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 risks BPA faces between rate cases. The CRAC explained here could increase rates for FY 2012 based on financial results for FY 2011. It also could increase rates for FY 2013 based on the accumulation of financial results for FY 2011 and FY 2012 (taking into account any CRAC applying to FY 2012 rates).

3.2.4.1 Description of the CRAC

The CRAC for FY 2012 and FY 2013 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 2010. 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. The CRAC will be implemented only if the amount of the CRAC is greater than or equal to $5 million.

Calculations for the CRAC (and for the NFB Adjustment or DDC; see below) that could apply to FY 2012 rates will be made in July 2011; the corresponding calculations for possible adjustments to FY 2013 rates will be made in September 2012. 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. 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 14: CRAC Annual Thresholds and Caps.

3.2.4.2 Administrator's Discretion to Adjust 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 any or all of the CRAC is needed to help BPA maintain its financial standing. The ability to apply discretion in the CRAC adjustment is tempered by the requirement to maintain the TPP standard for the remainder of the rate period 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 2012 may be reduced from the calculated amount as long as the two-year TPP for FY 2012–2013 remains at or above 95 percent. BPA may adjust the parameters *(i.e.*, the Cap and Threshold) for the CRAC applicable to FY 2013 to maintain the FY 2012–2013 TPP. A CRAC that is calculated for FY 2013 may be reduced from the calculated amount as long as the one-year TPP for FY 2013 would still be at or above 97.5 percent. These reductions may not be made if they would reduce the restoration of reserves attributed to TS or 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 2012 or FY 2013.

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. 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 15: DDC Thresholds and Caps.

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 RiskMod and NORM. Most of the modeling of risks is performed by RiskMod and NORM, as described in sections 2 and 3 of this Study. Most of the logic for simulating the financial results in the years included in a ToolKit analysis is in VBA code (Microsoft's *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 3,500 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 3,500. 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.

3.4 ToolKit Inputs and Assumptions

3.4.1 Risk Analysis Model

The ToolKit reads in RiskMod distributions that are created for the current year, FY 2011, and the rate period, FY 2012–2013. TPP is measured for only the two-year rate period, but the starting Reserves Available for Risk for FY 2012 depend on events yet to unfold in FY 2011; these runs reflect that FY 2011 uncertainty. See section 2 of this Study for more detail on RiskMod.

3.4.2 Non-Operating Risk Model

The ToolKit reads in NORM distributions that are created for FY 2011–2013 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 Available for Risk

The FY 2011 starting PS reserves have a known value of $233 million based upon the FY 2010 Fourth Quarter Review. Each of the 3,500 games starts with this value. See section 3.2.1.1 for a description of PS Reserves Available for Risk.

3.4.5 Starting ANR

The FY 2011 starting ANR value of $0 million is known from the definition of ANR as being accumulated PS net revenue since the end of FY 2010. Each of the 3,500 games starts with this value.

3.4.6 PS Liquidity Reserves

The amount of PS Liquidity Reserves, which are reserves that need to be kept available for within-year cashflow variation, is set to $0 in the model due to the availability of short-term borrowing under the Treasury Facility, which is sufficient to meet the within-year liquidity needs for PS. Section 3.2.2.

3.4.7 TS Reserves Allocation

This Study does not rely on reserves attributed to TS for PS TPP purposes in setting power rates for this rate period.

3.4.8 Treasury Facility

This Study relies on all $750 million of BPA's Treasury Facility. A total of $450 million is used explicitly in the ToolKit Treasury Facility input, and $300 million of the Treasury Facility is reserved for within-year liquidity needs that are not explicitly modeled in ToolKit.

3.4.9 Interest Rate Earned on Reserves

Interest earned on PS reserves is 2.24 percent in FY 2011, 3.60 percent in FY 2012, and 4.77 percent in FY 2013. Interest paid on use of the Treasury Facility is 0.96 percent, 2.52 percent, and 3.82 percent for the same fiscal years.

3.4.10 Interest Credit Assumed in the 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 RiskMod 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 RiskMod 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 RiskMod results that are backed out are $13.60 million for FY 2011, $12.48 million for FY 2012, and $16.65 million for FY 2013.

3.4.11 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the typical 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 $4.8 million for FY 2011, $7.4 million for FY 2012, and $7.4 million for FY 2013.

3.4.12 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 RiskMod runs, the ToolKit calculates the same kind of lag for PNRR that is embedded in the RiskMod output file the ToolKit reads. Because this Study does not require PNRR, there are no cash adjustments for PNRR.

3.4.13 Other Cash Adjustments

There are no adjustments of this type in this Study.

3.5 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 16.

3.5.1 TPP

The two-year TPP is 97.11 percent. In 3500 games, there are no deferrals for FY 2011 or FY 2012. There are 101 deferrals for FY 2013, with the expected value of the amount deferred equal to $1.68 million.

3.5.2 Ending PS Reserves

Known starting PS reserves for FY 2011 are $233 million. The expected values of ending net reserves are $189 million for FY 2011, $212 million for FY 2012, and $242 million for FY 2013. Over 3,500 games, the range of ending FY 2013 net reserves is from negative $450 million to $2,171 million. The rate adjustment mechanisms would produce a CRAC of $300 million or a

DDC of $1,000 million in these extreme cases if the BP-14 rate proposal includes mechanisms comparable to those included in the FY 2012–2013 rates. The 50-percent confidence interval for ending net reserves for FY 2013 is negative $91 million to $506 million.

3.5.3 CRAC and DDC

The CRAC does not trigger in any of the 3500 games for FY 2012. For FY 2013, the CRAC triggers 827 times (24 percent), yielding an average of $96 million per triggering and an expected value of $23 million.

The DDC does not trigger in any of the 3500 games for FY 2012. In FY 2013, the DDC triggers 132 times (4 percent), yielding an average of $170 million per triggering and an expected value of $6.4 million of dividend distributions.

4. QUALITATIVE RISK ANALYSIS AND MITIGATION

4.1 Introduction

The qualitative risk analysis described here is a logical analysis of the potential impacts of risks that have been identified (but not included in the quantitative risk analysis), 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 2012–2013.

The possibilities for FY 2012–2013 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.K, BP-12-A-02B.

These NFB Mechanisms will take effect should certain events, called trigger events, occur. An NFB Trigger Event is one of the following five kinds of 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; and

(5) Actions or measures required under the Adaptive Management Implementation Plan associated with the FCRPS BiOp that reduce BPA's forecast net revenue.

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 results in an upward adjustment to the CRAC Cap for any year in the rate period if one or more NFB Trigger Events with financial effects has 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 NFB Adjustment could modify the CRAC Cap applicable to rates for FY 2012 or FY 2013.

While the NFB Adjustment increases the cap on the amount the CRAC can collect, it does not necessarily increase the amount of revenue collected. If the NFB Adjustment triggers but Power Services ANR is above the threshold specified in the GRSPs, BP-12-A-02B, there will be no adjustment to rates, because the CRAC will not trigger. If the NFB Adjustment triggers and Power Services ANR is below the threshold, but not by more than the original CRAC cap of $300 million, the CRAC will trigger for an amount that is below the original cap. In the two cases just described, the NFB Adjustment will not change rates. On the other hand, if Power Services ANR is more than $300 million below the threshold, the NFB Adjustment will allow BPA to recover more than the original $300 million cap.

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 specified power and transmission rates.

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 2012 if the events required to impose the surcharge occur in that fiscal year or in FY 2013 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 per 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 2012 that increases the financial impacts of operations in FY 2012. 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 2012. If BPA were not in a Cash Crunch in FY 2012, both 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 2013.

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 to a Trigger Event), 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 2011 may affect operations in both FY 2011 and FY 2012. The analysis of the total financial impact during FY 2011 for adjusting the cap on the CRAC applying to FY 2012 would be separate from the analysis of the total financial impact during FY 2012 for adjusting the cap on the CRAC applying to FY 2013 (or for implementing an Emergency NFB Surcharge during FY 2012). Increases in the financial impacts during FY 2013 are not covered by the NFB Adjustment because incorporating those increases through an NFB Adjustment would require a CRAC during FY 2014, and the rates for FY 2014 are not covered by this Study. However, financial impacts during FY 2013 are covered by the Emergency NFB Surcharge provisions applicable to FY 2013.

4.3 Risks Associated with Tier 2 Rate Design

4.3.1 Introduction

For the FY 2012–2013 rate period, BPA is establishing two Tier 2 rate alternatives, the Tier 2 Short-Term rate and the Tier 2 Load Growth Rate. Power Rates Study, BP-12-FS-BPA-01, section 3.1.9. BPA has made power purchases to meet its load obligations at the Tier 2 rate for the rate period. BPA purchased three flat annual blocks of power from the market for delivery to BPA at the Mid-Columbia delivery point (Mid-C). Power Rate Study, BP-12-FS-BPA-01, section 3.1.7.3. 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 2012–2013 rate period. See section 1.2.1.

4.3.2 Identification and Analysis of Risks

The qualitative analysis 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; and

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

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 already executed standard Western Systems Power Pool (WSPP) contracts for purchases made to meet all of its load obligations under Tier 2 rates for the rate period. Under the WSPP 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-12-FS-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 Customer's Above-RHWM Load is Lower than the Amount Forecast

In May 2009, BPA made a forecast of each customer's Above-RHWM load. On the basis of that forecast and each customer's intention to meet none, some, or all of its Above-RHWM load with non-BPA power, each customer made an election in November 2009 to purchase a specific quantity of power at Tier 2 rates (that quantity could be zero). BPA made contractual commitments to purchase power sufficient to supply that quantity of power at Tier 2 rates. If the customer's actual load is lower than the BPA forecast, the terms of the customer's Contract High Water Mark (CHWM) contract nevertheless 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 frees up some of the power BPA has contracted for, and BPA will remarket this power. BPA returns 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 is effectively crediting 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 Customer's Above-RHWM 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 will obtain additional power from the market and will 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.

4.4 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-12-FS-BPA-01A, Table 3.23.

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-12-FS-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 Analysis Results

4.5.1 Biological Opinion Risks

The financial risks deriving from possible changes to Biological Opinions are adequately mitigated by the NFB mechanisms.

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 impact 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 rate case.

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

	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
Henry Hub	$4.22	$4.67	$4.96	$5.12	$5.38	$5.62
AECO	-0.45	-0.46	-0.51	-0.57	-0.63	-0.71
Kingsgate	-0.32	-0.31	-0.33	-0.41	-0.47	-0.58
Malin	-0.20	-0.17	-0.19	-0.21	-0.25	-0.28
Opal	-0.27	-0.27	-0.29	-0.33	-0.46	-0.63
PG&E	0.07	0.14	0.14	0.13	0.13	0.13
Topock/Socal/Ehrenberg	0.00	0.05	0.07	0.07	0.07	0.07
San Juan	-0.22	-0.20	-0.19	-0.19	-0.20	-0.20
Stanfield	-0.28	-0.27	-0.29	-0.31	-0.34	-0.37
Sumas	-0.25	-0.28	-0.31	-0.34	-0.38	-0.42

Table 2: Average Market Price from the Market Price Run for FY12

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12
HLH	**$34.79**	**$36.42**	**$39.02**	**$37.18**	**$37.62**	**$36.29**	**$35.09**	**$33.04**	**$34.13**	**$40.58**	**$42.21**	**$40.78**
LLH	**$28.39**	**$29.87**	**$31.79**	**$29.51**	**$30.63**	**$29.69**	**$28.10**	**$22.44**	**$21.95**	**$29.00**	**$30.67**	**$31.55**
Flat	**$31.97**	**$33.50**	**$35.83**	**$33.63**	**$34.65**	**$33.53**	**$31.99**	**$28.37**	**$28.99**	**$35.22**	**$37.37**	**$36.47**

Table 3: Average Market Price from the Market Price Run for FY13

	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13
HLH	**$40.93**	**$40.31**	**$43.17**	**$42.87**	**$44.24**	**$42.85**	**$39.96**	**$37.08**	**$37.81**	**$43.57**	**$46.49**	**$46.13**
LLH	**$34.00**	**$32.94**	**$35.00**	**$33.89**	**$35.70**	**$34.98**	**$32.71**	**$26.36**	**$24.08**	**$30.83**	**$33.62**	**$35.64**
Flat	**$38.03**	**$37.03**	**$39.39**	**$38.91**	**$40.58**	**$39.39**	**$36.90**	**$32.35**	**$31.71**	**$37.95**	**$41.09**	**$41.23**

Table 4: Average Market Price from the Market Price Run for 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	**$45.04**	**$43.40**	**$46.58**	**$46.53**	**$48.36**	**$45.16**	**$40.84**	**$37.77**	**$37.52**	**$44.94**	**$49.74**	**$48.66**
LLH	**$37.16**	**$35.33**	**$37.40**	**$36.73**	**$38.94**	**$36.82**	**$32.09**	**$24.23**	**$22.19**	**$31.10**	**$35.35**	**$37.72**
Flat	**$41.74**	**$39.81**	**$42.33**	**$42.21**	**$44.32**	**$41.49**	**$37.15**	**$31.80**	**$30.71**	**$38.84**	**$43.40**	**$43.80**

Table 5: Average Market Price from the Market Price Run for 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	**$49.79**	**$48.29**	**$50.74**	**$49.21**	**$49.93**	**$47.51**	**$42.53**	**$39.52**	**$40.07**	**$48.00**	**$52.29**	**$50.74**
LLH	**$41.03**	**$39.67**	**$40.74**	**$38.40**	**$39.90**	**$38.51**	**$33.00**	**$24.86**	**$23.94**	**$32.25**	**$36.26**	**$38.55**
Flat	**$46.12**	**$44.26**	**$46.34**	**$44.45**	**$45.63**	**$43.55**	**$38.51**	**$32.74**	**$33.26**	**$41.06**	**$45.22**	**$45.33**

Table 6: Average Market Price from the Market Price Run for FY16

	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
HLH	**$51.13**	**$49.66**	**$51.32**	**$50.85**	**$52.48**	**$49.11**	**$44.28**	**$40.49**	**$38.94**	**$47.98**	**$51.78**	**$51.40**
LLH	**$41.76**	**$40.32**	**$41.33**	**$39.42**	**$42.14**	**$39.53**	**$35.00**	**$26.68**	**$22.56**	**$32.11**	**$35.80**	**$38.53**
Flat	**$47.20**	**$45.30**	**$46.91**	**$45.57**	**$48.08**	**$45.10**	**$40.36**	**$34.10**	**$32.02**	**$40.64**	**$45.08**	**$45.68**

Table 7: Average Market Price from the Market Price Run for FY17

	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
HLH	**$52.18**	**$51.21**	**$53.19**	**$52.04**	**$53.24**	**$50.90**	**$45.18**	**$42.57**	**$42.98**	**$51.62**	**$54.89**	**$53.27**
LLH	**$41.87**	**$41.02**	**$42.82**	**$40.27**	**$42.78**	**$40.76**	**$34.20**	**$26.35**	**$25.36**	**$34.07**	**$37.31**	**$39.46**
Flat	**$47.63**	**$46.68**	**$48.62**	**$46.60**	**$48.76**	**$46.65**	**$40.30**	**$35.42**	**$35.54**	**$43.50**	**$47.52**	**$47.13**

Table 8: Average Market Price from AURORAxmp Critical Water Run for FY12

	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12
HLH	$36.18	$38.15	$39.45	$47.47	$47.69	$45.20	$41.73	$36.37	$37.81	$42.25	$44.09	$41.04
LLH	$29.64	$31.36	$33.41	$36.83	$38.22	$36.36	$35.00	$28.92	$28.70	$32.92	$33.41	$32.51
Flat	$33.30	$35.13	$36.79	$42.55	$43.66	$41.50	$38.74	$33.08	$33.96	$37.94	$39.61	$37.06

Table 9: Average Market Price from AURORAxmp Critical Water Run for FY13

	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13
HLH	$42.42	$42.38	$44.16	$53.92	$55.55	$52.86	$48.90	$40.08	$42.23	$45.43	$48.72	$46.59
LLH	$35.54	$35.07	$37.12	$42.92	$44.55	$42.86	$40.28	$33.06	$31.02	$35.11	$36.58	$36.94
Flat	$39.53	$39.13	$40.91	$49.07	$50.84	$48.46	$45.26	$36.98	$37.24	$40.88	$43.63	$42.09

Table 10: Average Market Price by Fiscal Year from AURORAxmp Market Price Run

	FY12	FY13	FY14	FY15	FY16	FY17
HLH	$37.26	$42.12	$44.54	$47.39	$48.28	$50.27
LLH	$28.63	$32.48	$33.76	$35.59	$36.27	$37.19
Flat	$33.46	$37.88	$39.80	$42.20	$43.00	$44.53

Table 11: Average Market Price by Fiscal Year from AURORAxmp Critical Water Run

	FY12	FY13
HLH	$41.45	$46.94
LLH	$33.11	$37.59
Flat	$37.78	$42.83

Table 12: RiskMod Net Revenue Statistics (With PNRR of $0 million)

	A	B	C
1		FY12	FY13
2		(Dollars in Thousands)	(Dollars in Thousands)
3	**Average**	$ 71,546	$ 28,108
4	**Median**	$ 52,139	$ 7,361
5	**Standard Deviation**	$ 264,956	$ 292,799
6			
7	**1%**	$ (365,260)	$ (441,383)
8	**2.50%**	$ (328,831)	$ (412,880)
9	**5%**	$ (299,918)	$ (378,976)
10	**10%**	$ (268,950)	$ (342,993)
11	**15%**	$ (214,528)	$ (283,931)
12	**20%**	$ (167,747)	$ (241,287)
13	**25%**	$ (123,605)	$ (190,036)
14	**30%**	$ (84,866)	$ (145,988)
15	**35%**	$ (48,283)	$ (103,312)
16	**40%**	$ (15,339)	$ (67,366)
17	**45%**	$ 14,231	$ (30,741)
18	**50%**	$ 52,139	$ 7,361
19	**55%**	$ 83,441	$ 41,565
20	**60%**	$ 115,095	$ 73,279
21	**65%**	$ 153,683	$ 113,136
22	**70%**	$ 191,017	$ 154,280
23	**75%**	$ 229,458	$ 197,892
24	**80%**	$ 277,263	$ 250,152
25	**85%**	$ 340,204	$ 322,097
26	**90%**	$ 416,382	$ 409,480
27	**95%**	$ 534,294	$ 537,299
28	**97.50%**	$ 648,287	$ 666,430
29	**99%**	$ 810,958	$ 904,528

Table 13: Risk Modeling Accrual To Cash Adjustments (in $Millions)

A	B	C	D	E	F
			FY 2011	FY 2012	FY 2013
1	Depreciation/Amortization		$200.165	$203.198	$214.327
2	Interest Adjustments		($45.937)	($45.937)	($45.937)
3	ENW Direct Pay Prepaid Expense		$7.771	($10.687)	$5.835
4	All Other (see lines 14 thru 21 below)		($47.420)	$1.548	($3.394)
5	**Sub Total Lines 1 - 4**		$114.579	$148.123	$170.831
6	Add: EN Debt Service Before Refinancing /1		$0.000	$0.000	$0.000
	Add: @Risk Debt Service Adjustment		$0.000	$0.000	$0.000
7	Adjust for Current Estimated ENW Debt Service (PBL only)		$0.000	$0.000	$0.000
8	Less: Planned Advanced Amortization of Federal Debt		$0.000	$0.000	$0.000
9	**Sub Total Lines 6 - 8**		$0.000	$0.000	$0.000
10	Less: Scheduled Federal Debt Amortization		($162.163)	($194.182)	($181.622)
11	Less: Revenue/Reserve financing		$0.000	$0.000	$0.000
12	**Sub Total Lines 10 - 11**		($162.163)	($194.182)	($181.622)
13	**Accrual to Cash Adjustment (Lines 5 + 9 + 12)**		**($47.584)**	**($46.059)**	**($10.791)**
14	**All Other**				
15	Net Slice True up lag into (out of) current year		($38.567)	$5.506	($0.087)
	Slice Adjustment Cash Lagging out of this year		**($4.942)**	**$0.000**	**$0.000**
	Slice Adjustment Cash Lagging from previous year		**($34.238)**	**$4.942**	**$0.000**
	NORM Slice True Up Lagging out of this year		**$0.613**	**$1.177**	**$1.090**
	NORM Slice True Up Lagging in from previous year		**$0.000**	**($0.613)**	**($1.177)**
16	NB Revenue and other cash lags		$0.000	$0.000	$0.000
17	Terminated contracts & Settlements		($3.379)	($3.079)	($3.079)
18	Energy Efficiency Projects		$0.000	$0.000	$0.000
19	Inter Company Revenue Net of Expense		$0.000	$0.000	$0.000
20	Other Miscellaneous		($4.861)	($0.315)	($0.315)
21	**TOTAL All Other**		**($46.807)**	**$2.112**	**($3.480)**

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 14: CRAC Annual Thresholds and Caps
[Dollars in Millions]

A **ANR Calculated at End of Fiscal Year**	B **CRAC Applied to Fiscal Year**	C **CRAC Threshold as Measured in ANR**	D **Approx. Threshold as Measured in PS Reserves**	E **Maximum CRAC Recovery Amount (CRAC Cap)***
2011	2012	-$187.6	$0	$300
2012	2013	-$143.4	$0	$300

* The CRAC Cap may be modified by NFB Adjustments

Table 15: DDC Thresholds and Caps
[Dollars in Millions]

A **ANR Calculated at End of Fiscal Year**	B **DDC Applied to Fiscal Year**	C **DDC Threshold as Measured in ANR**	D **Approx. Threshold as Measured in PS Reserves**	E **Maximum DDC Recovery Amount (DDC Cap)**
2011	2012	$562.4	$750	$1,000
2012	2013	$606.6	$750	$1,000

Table 16: ToolKit Summary Statistics

[Dollars in Millions]			
Two Year TPP	97.11%		
	FY 2011	**FY 2012**	**FY 2013**
PNRR	-	$0.0	$0.0
CRAC Frequency	0%	0%	24%
Expected Value CRAC Revenue	$0.0	$0.0	$22.6
DDC Frequency	0%	0%	4%
Expected Value DDC Payout	$0.0	$0.0	$6.4
Treasury Deferral Frequency	0.0%	0.0%	2.9%
Expected Value Treasury Deferral	$0.0	$0.0	$1.7
Average End-of-Year Net Reserves	$189.3	$212.2	$242.3
Net Reserves, 5th percentile	$115.6	($181.5)	($401.1)
Net Reserves, 25th percentile	$159.3	$10.5	($91.4)
Net Reserves, 50th percentile	$189.6	$193.0	$208.6
Net Reserves, 75th percentile	$217.6	$372.2	$505.6
Net Reserves, 95th percentile	$267.8	$698.7	$1,015.5

Figure 1: Risk Analysis Information Flow

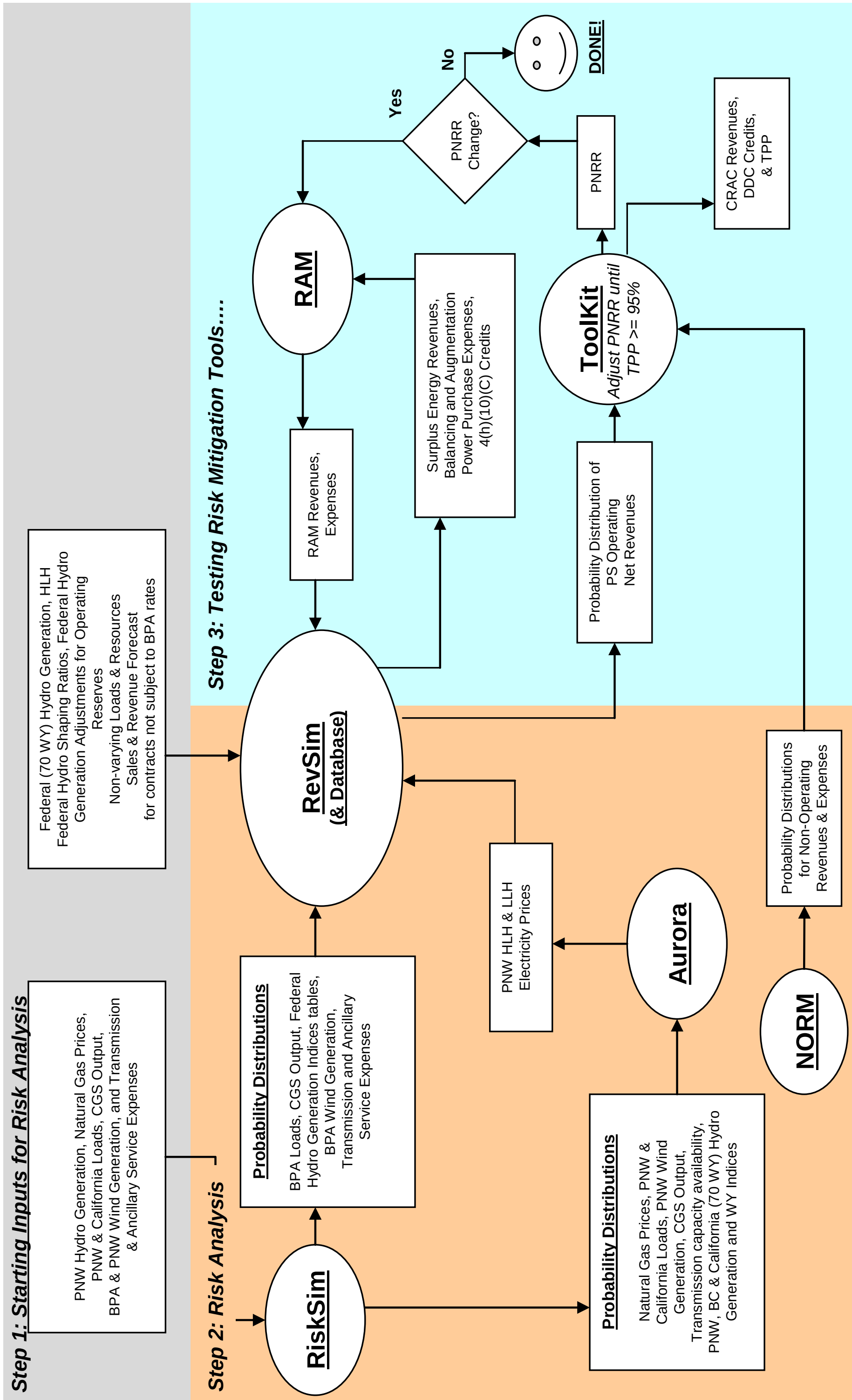


Figure 2: AURORAxmp Zonal Topology

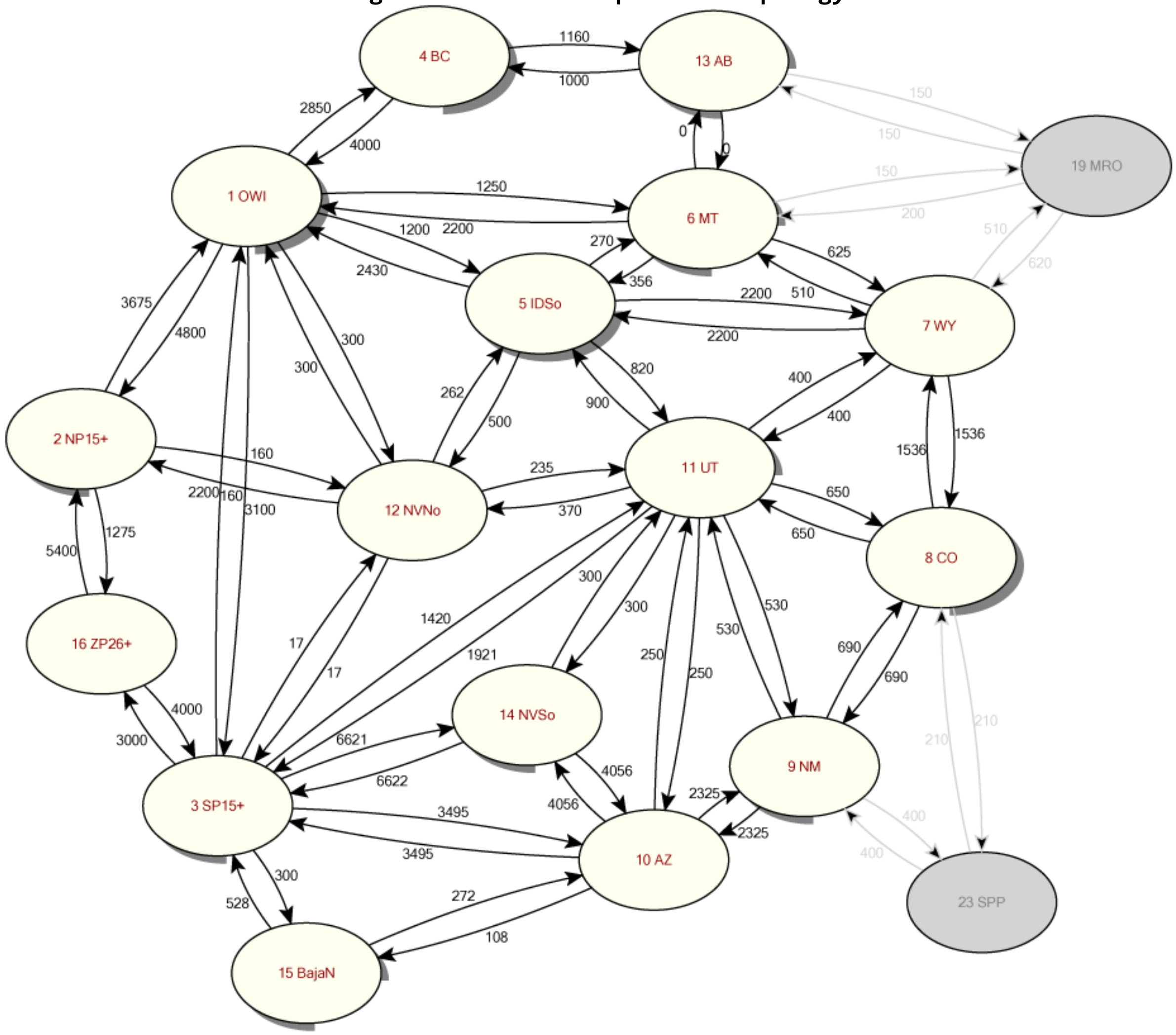


Figure 3: Basis Locations

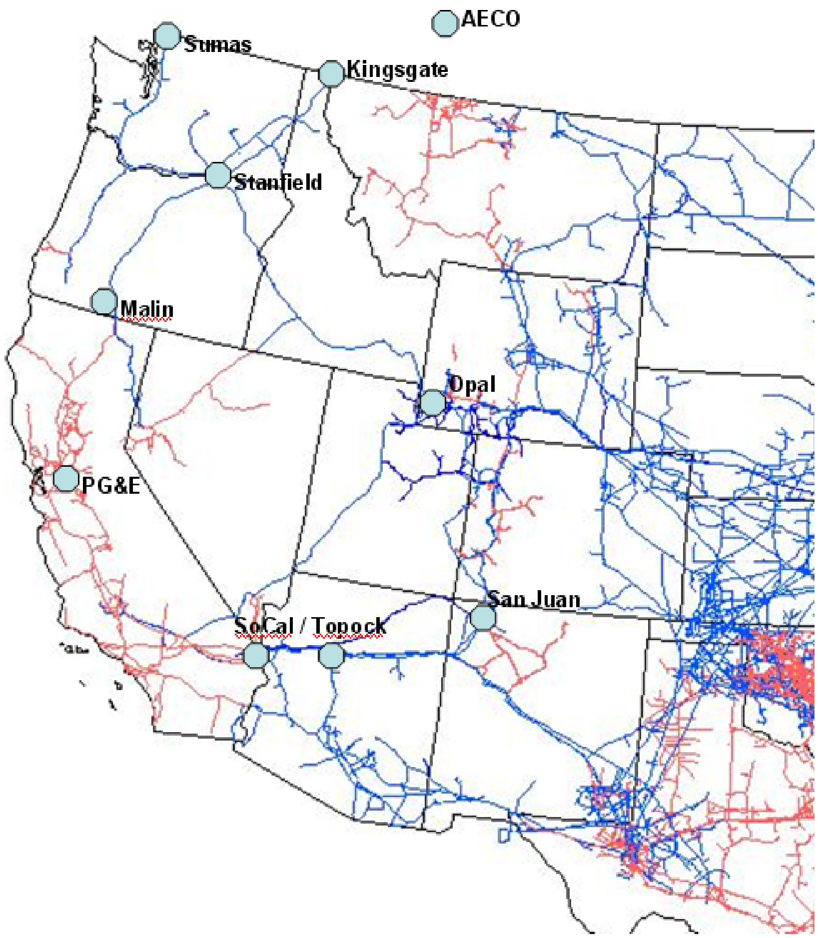


Figure 4: Lower 48 Natural Gas Production

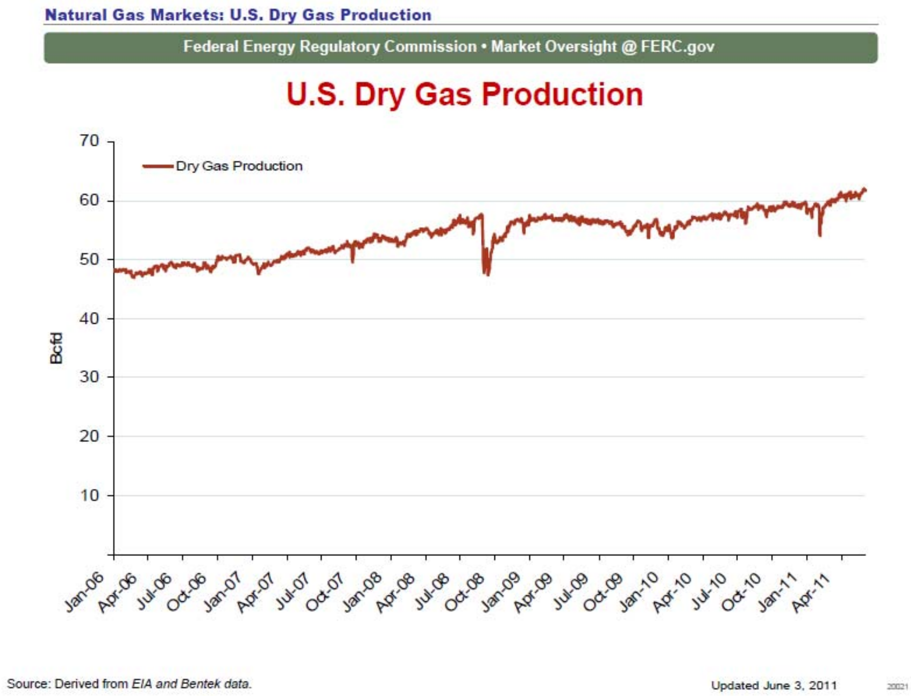


Figure 5: Natural gas storage

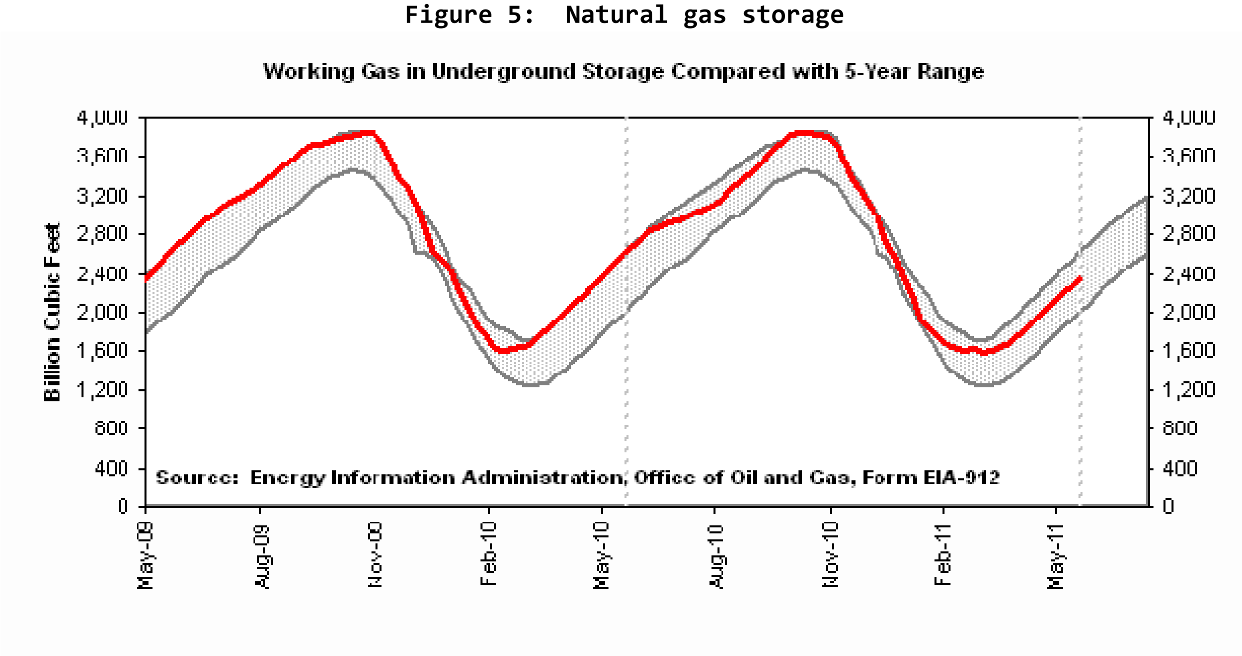


Figure 6: Natural Gas Domestic Consumption (Demand)

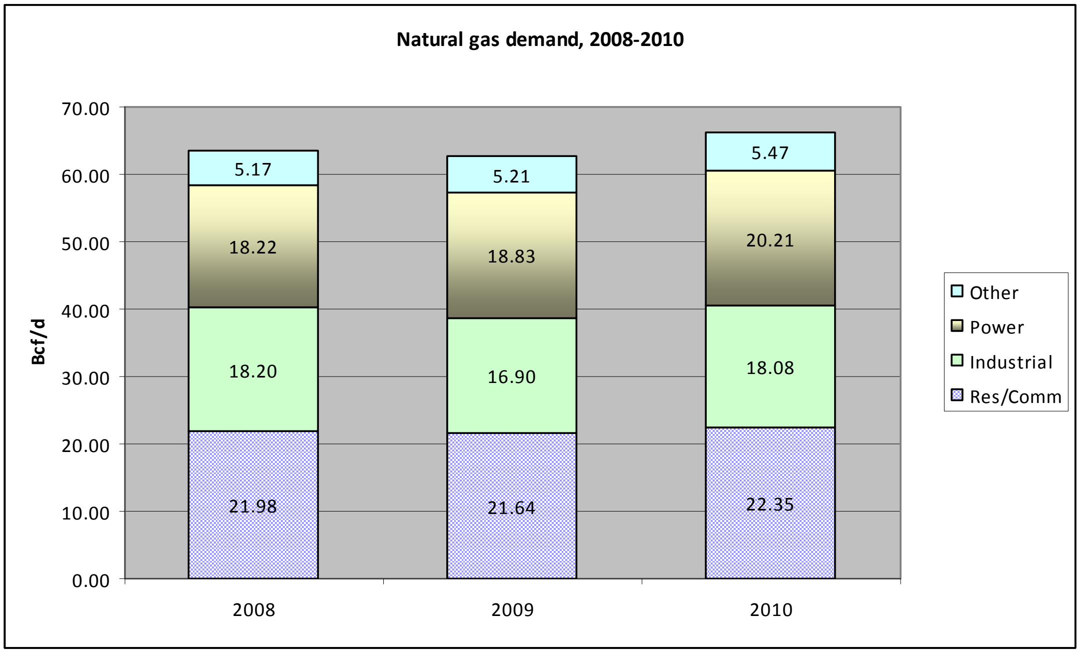
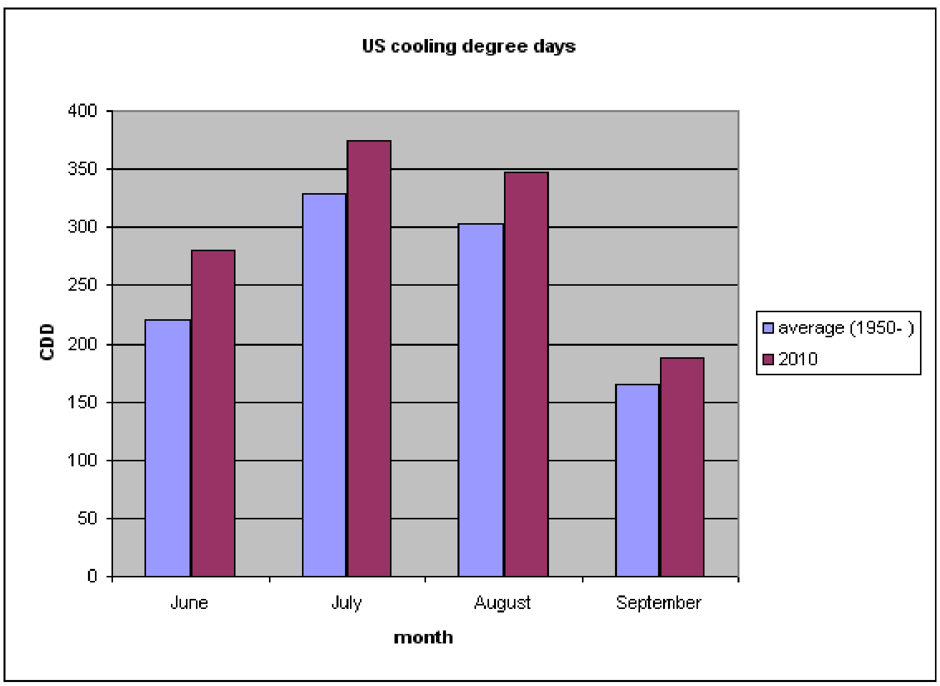
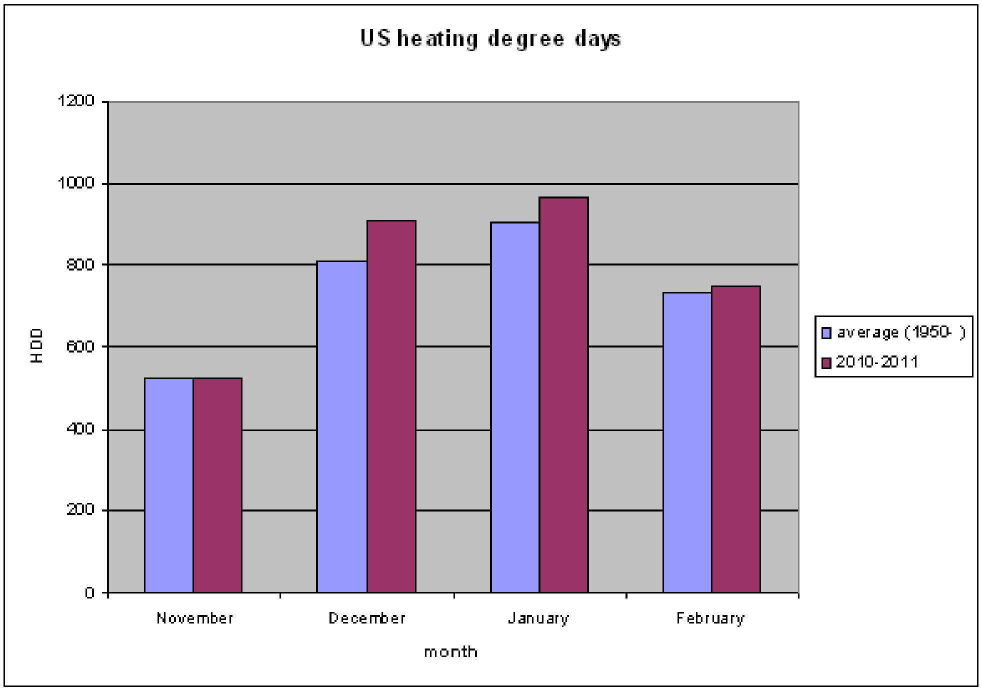


Figure 7: U.S. Cooling and Heating Degree Days



source: National Climatic Data Center (NCDC) Divisional/Regional Data



source: National Climatic Data Center (NCDC) Divisional/Regional Data

Figure 8: Ruby Pipeline Map

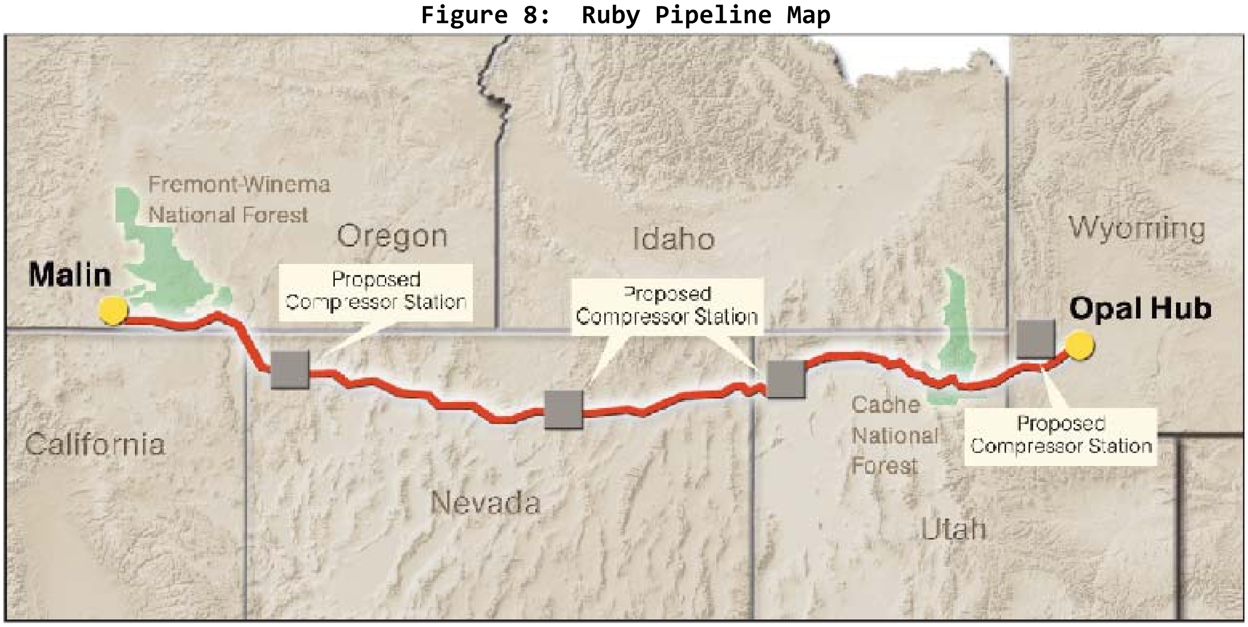
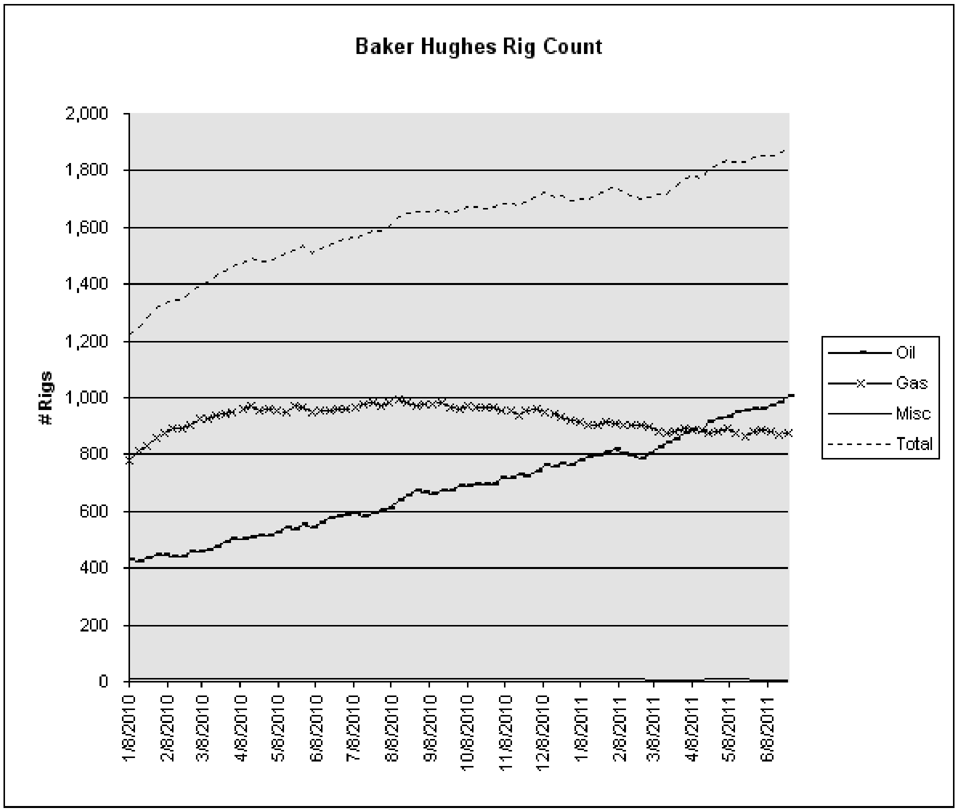
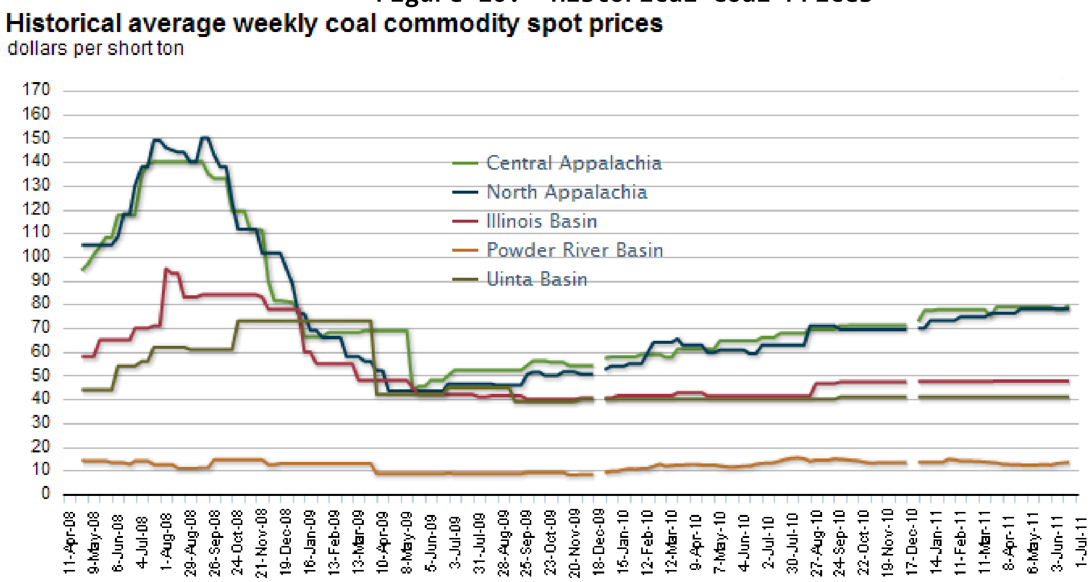


Figure 9: Rig Count



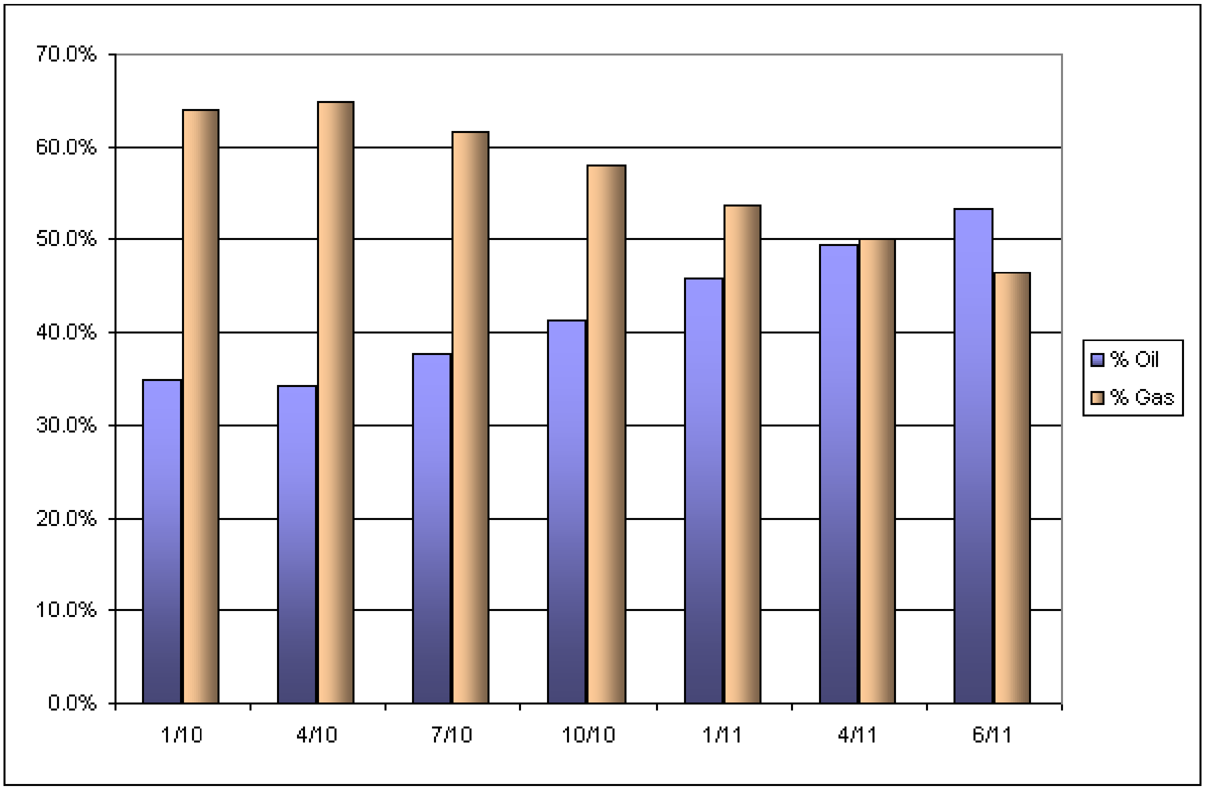
source: Baker Hughes

Figure 10: Historical Coal Prices



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

Figure 11: Oil vs. Gas Share of Rigs



source: Baker Hughes

Figure 12: Natural Gas Risk Model Equation

Let $H_{t,i}$ be the simulated natural gas price at Henry Hub for time t for game i. Take t to be in monthly time step increments for a forecast horizon. Let F_t be the forecast Henry Hub price for time t. Let σ_k be the volatility for month k. Let δ_y be reversion factor for year y. Let $X(i)\sim N(0,1)$. Let η be the minimum price. Then the initial simulated natural gas price for game i at time t is given by:

$$H_{t,i}=\max\left(H_{t-1,i}\exp\left\{\left[X(i)+\delta_y*\left(1-\frac{\ln(H_{t-1})}{\ln(F_{t-1})}\right)\right]*\sigma_k\right\}+\left(F_t-F_{t-1}\right),\eta\right)\quad(1)$$

After calculating these values for all the simulated games, then take γ_t to be the median of the simulated values for time t. Then the final simulated natural gas price for time t is:

$$H_{t,i} + \left(F_t - \gamma_t\right) \quad (2)$$

Figure 13: Load Model Equation

Let $L_{y,i}$ be the simulated load for year *y* and game *i*. Take F_y to be the forecasted load for year *y*. Take G_y to be the forecasted load growth for year *y*. Let $X(y)\sim N(0,1)$. Let δ_y be a reversion factor for year *y*. Take σ to be the standard deviation of annual load growth. Then the annual simulated load due to load growth is given by:

$$L_{y,i} = F_y + \left[L_{y-1,i} * \left(1 + G_y + X(y) * \sigma\right) - F_y\right] * \left(1 - \delta_y * \frac{F_{y-1}}{L_{y-1,i}}\right) \quad (3)$$

Now take $Y(t)\sim N(0,1)$. Take *t* to be in monthly time step increments for a forecast horizon. Let ν_k be a load shaping factor for month *k*. Let τ_k be an additional monthly standard deviation factor for month *k*. Then the unadjusted monthly simulated load after accounting for load variability due to weather, $M_{t,i}$, is given by

$$M_{t,i} = L_{y,i} * \left(\nu_k + Y(t) * \tau_k\right) \quad (4)$$

After calculating these values for all the simulated games, take μ_t to be the mean of the simulated values for time *t*. Then the final simulated load for time *t* is:

$$M_{t,i} + \left(F_y * \nu_k - \mu_t\right) \quad (5)$$

Figure 14: CGS Model Equation

Let $N_{t,i}$ be the simulated CGS generation for time *t* and game *i*. Take *t* to be in monthly time step increments for a forecast horizon. Take δ_t to be a outage/refueling factor representing the percentage of days CGS is expected to operate. Take τ to be the peak generation of CGS. Take

η to be a calibration factor that calibrates the average of monthly simulated values to the forecast values. Take $X(i) \sim Uniform(0,1)$. Then the simulated CGS output is given by

$$N_{t,i} = \delta_t * \left(\eta * \tau * X(i)\right) / \left(1 + \left(\eta - 1\right) * X(i)\right) \qquad (6)$$

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