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

BP-16 Initial Rate Proposal

Power Risk and Market Price Study

BP-16-E-BPA-04

December 2014

TABLE OF CONTENTS

Page

TABLES

FIGURES

This page intentionally left blank.

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER step	Actual Energy Regulation study
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPA-P	Bonneville Power Administration – Power
BPA-T	Bonneville Power Administration – Transmission
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DOP	Detailed Operating Plan
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

ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GMS	Generation Management Service
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NCP	Non-Coincidental Peak

NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NRFS	New Resource Flattening Service
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OPER step	operational study
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program

RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION

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

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

1.1 Purpose of the Power Risk and Market Price Study

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

1.1.1 BPA's Treasury Payment Probability Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). *See* 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 renamed the "Financial Plan." See http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx.

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

BPA's Treasury payments are an obligation of the Agency. Since 2002, TPP has been independently measured for the Power Services (PS) and Transmission business lines. This Study tests the ability of PS to make its portion of the Treasury payments over the rate period.

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

(1) *Starting PS Reserves (Starting Financial Reserves Available for Risk Attributed to PS).* Financial reserves comprise cash and investment instruments held in the Bonneville Fund, and the deferred borrowing balance. Financial reserves available for risk do not include funds held for others. For example, amounts in the Bonneville Fund that were provided by customers as collateral for credit worthiness are excluded. Deferred borrowing amounts exist when planned borrowing has not yet been completed. When the borrowing is completed, cash in the Bonneville Fund is increased and the deferred borrowing balance is reduced by the same amount, leaving financial reserves unchanged.

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

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

(4) *Within-year Liquidity Need.* The within-year liquidity need is an amount of cash or short-term borrowing capability that must be set aside for meeting within-year liquidity needs (or risks). The PS within-year liquidity need for BP-16 is $320 million. This assumption remains unchanged from BP-14 rates.

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

(6) *Liquidity Borrowing Level.* The liquidity borrowing level is the amount of the Treasury Facility set aside to meet the within-year liquidity need. For this Study, the liquidity borrowing level is $320 million. This leaves $430 million of the $750 million Treasury Facility available for year-to-year liquidity needs (*i.e.*, TPP needs).

(7) *Cost Recovery Adjustment Clause.* The CRAC is an upward adjustment to applicable power and transmission rates. The adjustment is applied to rates charged for service beginning in October following a fiscal year in which PS Accumulated Calibrated Net Revenue (ACNR) falls below the CRAC threshold. The threshold is set at the ACNR equivalent of $0 in financial reserves available for risk attributed to PS. *See* Power Rate Schedules, BP-16-E-BPA-09, GRSP II.C.

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

1.1.2 How Risk and Market Price Results Are Used

The main result from the risk assessment and mitigation process is the TPP calculation. If this number is 95 percent or higher, then the rates and risk mitigation tools meet BPA's TPP standard. The calculations also take into account the thresholds and caps for the CRAC and the DDC. These values are incorporated in the GRSPs 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 2016 or FY 2017.

Forecasts of electricity market prices are used in the Power Rates Study, BP-16-E-BPA-01, for:

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

1.2 Overview of Risk Assessment and Mitigation

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

1.2.1 Risk Mitigation Objectives

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

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

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

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

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

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

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

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

These objectives are not completely independent and may sometimes conflict with each other. Thus, BPA must create a balance among these objectives when developing its overall risk mitigation strategy.

1.2.2 Quantitative and Qualitative Risk Assessment and Mitigation

This Study distinguishes between quantitative and qualitative perspectives of risk. The quantitative risk assessment is a set of quantitative risk simulations that are modeled using a Monte Carlo approach, a statistical technique in which deterministic analysis is performed on a distribution of inputs, resulting in a distribution of outputs suitable for analysis. The output from the quantitative risk assessment is a set of 3,200 possible financial results (net revenues) for each of the two years in the rate period (fiscal years (FY) 2016–2017) and for the year preceding the rate period (FY 2015). The models used in the quantitative risk assessment are described in section 2 of this Study.

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

Some financial risks are unsuitable for quantitative modeling but are significant enough that they need to be accounted for. These risks usually fit into one of two general categories that make them unsuitable for modeling. The first type is risks for which there is no basis for estimating the probabilities of future outcomes; relevant historical data is unavailable and subject matter experts are unable to provide estimates of probabilities. The second type is risks for which modeling may adversely influence the future actions of human beings, including possible impact on legal proceedings.

The qualitative risk assessment and mitigation address these risks. For the most part, the qualitative risk assessment is a logical assessment 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 mitigation measures. The qualitative risk assessment is described in section 4 of this Study.

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

1.2.2.1 Overview of Quantitative Risk Assessment

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

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

1.2.2.2 Overview of Quantitative Risk Mitigation

BPA's primary tool for managing the financial risks it faces is financial reserves. Since the WP-02 rate proceeding, BPA has included in its rate proposals cost recovery adjustment clauses that can adjust power rates between rate proceedings. These clauses add additional risk mitigation to that provided by financial reserves and liquidity. In this rate proceeding, the CRAC, DDC, and _National Marine Fisheries Service, _Federal Columbia River Power System, _Biological Opinion (NFB) Mechanisms will apply to certain power rates as well as certain transmission rates for Ancillary and Control Area Services. When financial reserves available for risk plus the additional revenue earned through the CRAC do not provide sufficient risk mitigation to meet the 95 percent TPP standard, PNRR is added to the revenue requirement. This increases power rates, which generates additional reserves. This Study documents the risk mitigation package included in the BP-16 power rates. See section 1.2.1 above for a discussion of the main policy objectives considered when developing this risk mitigation package.

1.2.2.3 Overview of Qualitative Risk Assessment and Mitigation

Financial uncertainty that is not quantitatively modeled, and any mitigation measures for these risks, are described in section 4 of this Study. There are three primary categories of qualitative risks in this Study: risks associated with FCRPS Biological Opinions; risks associated with Tier 2 rate design; and risks associated with Resource Support Services. Biological Opinion risks are mitigated through the NFB Mechanisms described in this Study and GRSP II.N.

This page intentionally left blank.

2. QUANTITATIVE RISK ASSESSMENT

2.1 Introduction

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

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

PS also faces risks not directly related to the operation of the power system. These non-operating risks are modeled in the Non-Operating Risk Model (NORM). These risks include the potential for CGS, Corps of Engineers (USACE), and U.S. Bureau of Reclamation (USBR) operations and maintenance (O&M) spending to differ from their forecasts. NORM also accounts for variability in interest rate expense. NORM models variability in net revenues, including uncertainty in the length of the CGS refueling outages in FY 2015 and FY 2017.

2.2 Study Models

BPA traditionally models risks using Monte Carlo simulation. Accordingly, AURORAxmp®, RevSim, NORM, and ToolKit each run 3,200 iterations, or games. AURORAxmp® estimates electricity prices, which serve as inputs to numerous other studies, including this Study. RevSim (*see* section 2.2.3.2 below) combines Federal system generation with prices from AURORAxmp®, as well as 4(h)(10)(c) credits and other revenues and expenses, to produce

3,200 values for net revenue. The output of this process is combined with the distribution of output from NORM and provided to ToolKit, which calculates TPP. If TPP is below the 95 percent standard required by BPA's 10-Year Financial Plan, then one of several risk mitigation tools may be adjusted until the standard is met. These options include (1) raising the CRAC threshold, which makes it more likely that the CRAC will trigger; (2) increasing the cap on the annual revenue the CRAC can collect; and/or (3) adding PNRR to the revenue requirement.

2.2.1 @RISK® Computer Software

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

2.2.2 R Statistical Software

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

2.2.3 AURORAxmp®

AURORAxmp® (version 11.5.1001) is used to forecast electricity market prices. For all assumptions other than those explicitly enumerated in section 2.3 of this Study, the model uses data provided by the developer, EPIS Inc. AURORAxmp® uses a linear program to minimize the cost of meeting load in the Western Electricity Coordinating Council (WECC), subject to a number of operating constraints. Given the solution (specifically, an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This approximates the price of electricity by assuming that all resources are centrally dispatched, the equivalent of cost-minimization in production theory, and that the marginal cost of producing electricity approximates the price.

2.2.3.1 Operating Risk Models

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

(a) WECC loads
(b) Natural Gas Price
(c) Regional Hydroelectric Generation
(d) Pacific Northwest (PNW) Hourly Wind Generation
(e) CGS Generation
(f) PNW Hourly Intertie Availability
(g) PS Transmission and Ancillary Services Expenses

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

2.2.3.2 Revenue Simulation Model (RevSim)

RevSim calculates secondary energy revenues, balancing power purchase expenses, system augmentation purchase expenses, and 4(h)(10)(C) credits for use in the Rate Analysis Model (RAM2016). It also simulates PS operating net revenue for use in ToolKit. Inputs to RevSim include the output of certain risk models discussed above (to the extent that they affect generation and loads) and prices from AURORAxmp®. RevSim also uses deterministic monthly load and resource data; revenue and expenses from RAM2016; and non-varying revenues and expenses from the Power Revenue Requirement Study, BP-16-E-BPA-02, and section 2 of the Power Rates Study, BP-16-E-BPA-01.

RevSim uses the monthly risk data generated by the risk models and the monthly electricity prices estimated by AURORAxmp® to compute secondary energy revenues, balancing power purchases expenses, system augmentation expenses, and section 4(h)(10)(C) credits for each of the 3,200 games. The results are used in the revenue forecast and the calculation of power rates in RAM2016. The monthly flat secondary energy values calculated by RevSim for all 3,200 games per fiscal year are inputs to the PS Transmission and Ancillary Services Expense Risk Model, which calculates the average PS transmission and ancillary services expenses included in the Power Revenue Requirement Study, BP-16-E-BPA-02. The transmission and ancillary services expenses calculated by the PS Transmission and Ancillary Services Expense Risk Model for 3,200 games per fiscal year are input into RevSim for use in calculating net revenue risk.

Expenses associated with the purchase of system augmentation are estimated using two approaches, one applying to the calculation of rates in RAM2016 and another determining net revenue provided to the ToolKit model. Each of these approaches is discussed in detail in section 2.6.2 of this Study.

RevSim uses the risk data generated by the various risk models and the monthly electricity market prices estimated by AURORAxmp® to calculate 3,200 annual net revenue outcomes for each fiscal year of the rate period. These are input into ToolKit, which evaluates whether a given risk mitigation package achieves BPA's 95 percent TPP standard for the rate period.

Figure 1 shows the processes and interactions among the models and studies.

2.2.4 Non-Operating Risk Model

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

2.2.4.1 NORM Methodology

NORM follows BPA's traditional approach to modeling risks, which uses Monte Carlo simulation. In this technique, a model runs through a number of games or iterations. In each game, each modeled uncertainty is randomly assigned a value from its 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

New risks for inclusion in NORM are identified based on review of historical results and querying of subject matter experts. If a financial risk has a significant range of financial uncertainty and the risk is suitable for quantitative modeling, it is included in the model. If a risk has a significant range of financial uncertainty, but is not suitable for modeling, it is handled in the qualitative risk analysis and mitigation. *See* section 4 below.

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.

After data is gathered, risks are modeled using Excel® and @RISK®. Risks are generally modeled using continuous or discrete probability distributions, selected to best match the available data on the risk. Serial correlation (correlation over time) and correlation between different risks are included in the modeling when relevant and assessable.

2.3 AURORAxmp® Model Inputs

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

2.3.1 Natural Gas Prices Used in AURORAxmp®

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

2.3.1.1 Methodology for Deriving AURORAxmp® Zone Natural Gas Prices

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

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

Though Henry Hub is the point of reference for natural gas markets, AURORAxmp® uses prices for 11 gas trading hubs in the WECC. The prices at hubs other than Henry are derived using their basis differentials, or the differences in prices between Henry Hub and the hub in question. Basis differentials reflect differences in the regional costs of supplying gas to meet demand after accounting for pipeline constraints and pipeline costs. The 11 western hubs represent three major supply basins that are the source for most of the natural gas delivered in the western United States and 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, which primarily delivers gas to southern California. AECO, the primary trading hub in Alberta, Canada, is the primary benchmark for Canadian gas prices. Kingsgate is the hub that is associated with the demand center in Spokane, Washington. Two eastern Oregon hub locations, Stanfield and Malin, are included because major pipelines intersect at those locations. Pacific Gas and Electric (PG&E)

Citygate represents demand centers in Northern California. Topock, Arizona and Ehrenberg, Arizona represent intermediary locations between the San Juan Basin and demand centers in Southern California. *See* Figure 3. For purposes of the basis differential forecast, the same price is used for both of these hubs, as they are relatively specific to Southern California markets. Finally, Southern California Citygate represents demand centers in Southern California. The forecast of basis differentials is derived from historical price differences between Henry Hub and each of the other 11 trading hubs, along with projections of regional supply and demand.

The final step is to estimate the basis differential between each of the western trading hubs and its associated AURORAxmp® zone. Sumas, AECO, Kingsgate, Stanfield, Malin, and PG&E Citygate are 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 Southern California Citygate are associated with the Nevada, Southern California, Arizona, and New Mexico zones.

2.3.1.2 Recent Natural Gas Market Fundamentals

U.S. natural gas production continues to climb from 56 billion cubic feet per day (bcf/d) in 2009 to an all-time high of more than 70 bcf/d in 2014. *See* Figure 5. The marginal cost of production continues to drop as advances in technology improve the efficiency of production in all phases, including exploration, drilling, and well stimulation. With the addition of new pipeline and processing infrastructure, supply that was previously constrained can now reach the market. Further supply growth has been seen with associated gas resulting from an increase in domestic oil production. As a byproduct of oil production, associated gas has virtually no cost and now accounts for more than 10 percent of domestic natural gas supply.

With the exception of the winter of 2013–2014 and the recovery period that followed that time, the Henry Hub cash price has bounced between $3.08/MMBtu and $4.41/MMBtu over the past two years. *See* Figure 4. The winter of 2013–2014 faced record demand due to cold weather and led to increased prices and a record pace of storage withdrawals. This spike in demand provided an opportunity to test the natural gas market price response to demand growth. Even with Henry Hub reaching as high as $7.92/MMBtu in March of 2014 following supply concerns, production was able to refill storage inventory at a record injection pace (*see* Figure 6) and prices gradually dropped below $4/MMBtu by the middle of July 2014. Storage inventory ended the injection season at 3.611 trillion cubic feet (tcf), only 237 bcf below the five-year average. At this time it is apparent that without robust weather-related demand, supply is outpacing demand, and the abundant supply in the market could lead to a storage inventory as high as 1.900 tcf at the end of withdrawal season.

Upon market recovery, including gas in storage following the winter of 2013–2014, demand growth has been gradual (*see* Figure 7) while still not enough to substantially lift prices. Residential and commercial demand has been fairly flat with periods of increased heating or cooling demand during extreme weather events. Power generation demand for natural gas fluctuates with the price relationship to coal and overall generation demand. Improving economic conditions have created growth in the industrial demand for gas over the past five years. With an outlook indicating robust domestic natural gas supply keeping pace or slightly outpacing demand over the next several years, downward pressure is being placed on the price of natural gas.

2.3.1.3 Henry Hub Forecast

The average of the monthly forecast of Henry Hub prices is $3.86/MMBtu (million British thermal units) during FY 2016 and $4.05/MMBtu during FY 2017. *See* Table 1. Prices in the FY 2016–2017 rate period are expected to remain just under $4.00/MMBtu in FY 2016 and gradually increase along with demand growth in FY 2017. Depending on the makeup of supply from associated gas, dry gas, and wet shale, gas prices should eventually settle out at the long-term marginal cost of production of natural gas barring any major spikes in demand.

Many factors limit the upside risk for natural gas. Pipeline infrastructure and processing capacity continue to come online in the Northeast U.S. to provide relief for constrained supply and allow for an increase in production. A backlog of more than 1,500 wells in the Marcellus Shale formation are awaiting pipeline take-away capacity and are expected to quickly add to supply once the infrastructure is in place. The Utica Shale, located next to the Marcellus, is a promising new play that is expected to rapidly step up production over the next few years. Basins such as the Permian and Anadarko have recently stepped up implementation of the newer drilling technology and are expected to provide strong supply growth. The South-Central Oklahoma Oil Province (SCOOP) and STACK (named for stacked zones) plays of Oklahoma, as well as several other plays currently being explored, are likely to provide additional upside to supply potential. While many rigs have turned to drilling for oil due to higher rates of return, associated gas produced from oil drilling continues to increase and is essentially free. Downward price pressure results as more than 10 percent of domestic natural gas supply is currently sourced from associated gas. At the same time, technically recoverable resource estimates continue to grow and provide the market confidence in the long-term supply of low-cost natural gas.

Advances in technology are contributing greatly to the continued growth in domestic natural gas supply. *See* Figure 5. Technology is allowing for reduced production costs and increased performance. Greater use of multi-pad development with sliding infrastructure has been implemented, along with extended lateral lengths and enhanced lateral spacing. Improved targeting of sweet spots is possible due to computer applications such as three-dimensional geological modeling and petrographic studies. Borehole geophysics also allows for new diagnostic tools as drilling takes place. Once wells are drilled, advances in slickening agents and recycling of fluids used in recovering the natural gas are increasing the success of stimulating wells.

As the price of natural gas remains competitive with other fuels and supply continues to grow, demand growth is expected to follow. Liquefied natural gas (LNG) demand will begin with Sabine Pass coming online in 2016 and Cove Point beginning operation in 2017; however, exports from these facilities will not exceed two bcf/d prior to the end of the FY 2016–2017 time period. Natural gas-fired power generation demand is a wild card over the next few years. Several regulations and policies have been put in place to discourage coal-fired generation, and these changes will likely create demand for additional natural gas-fired generation. With the unknown impact from these regulations on coal-fired generation in addition to the rapid growth of renewables in the market, the impact on natural gas demand is yet to be determined. Industrial demand is looking to natural gas as a fuel source as the economy recovers and new industrial facilities are being constructed. Mainly the industrial demand is increasing in the Gulf and Southeast regions as there is a need for production of ammonia, methanol, and other gas to liquids. Exports to Mexico are another source of demand as Mexico brings on new natural gas-fired generation and increases dependence on a low-cost U.S. natural gas supply. Barring any extreme weather-related demand, residential and commercial demand is expected to remain fairly flat through the FY 2016–2017 time period.

As with any forecast, there is risk involved. Weather-related demand is a factor regardless of whether there is a great deal of, or lack of, such demand. A recent development is a drop in oil price to below $80/barrel. An additional sustained drop in oil price may lead to the shut-in of some oil production, which would directly reduce the production of essentially no-cost associated gas. Additional regulations or policies at the state or federal level could also have an influence on the price of natural gas. The cost of natural gas could be impacted if any new policies or regulations increase production costs and decrease efficiency. Similarly, the transportation cost of natural gas could be impacted if regulations are put in place regarding the reduction of methane emissions, pipeline replacement requirements, or stricter infrastructure permitting. Also, the impacts of approved and proposed EPA emission rules may have a direct effect on natural gas-fired generation demand as coal plants retire or utilities choose to source generation from natural gas. Lastly, there is the potential for LNG-related volatility to enter the market in 2017 from anticipation as the many LNG export facilities set to come online between 2018 and 2020 will be securing new supply needed for facility testing and storage.

Upward pressure on the price of natural gas will likely be minimal due to the abundant supply of gas available at low prices. The rate period natural gas price outlook still appears bound between the $3.50 and $4.50 range. Above $4.50, many more basins would provide attractive rates of return, and the resulting responsiveness of supply should provide relief to the market. Below $3.50, coal-to-gas switching increases and some plays become less profitable, thereby encouraging a supply correction.

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 location of natural gas supply source growth can dramatically change basis relationships as traditional pipeline flows are altered and even reversed. Production levels in both the Rocky Mountains and Western Canada directly impact the relationships among western hubs. Additionally, pipeline transportation availability and cost can impact basis relationships.

The AECO and Kingsgate bases will likely decrease slightly over time with Northeast U.S. production displacing the ability for Western Canadian production to supply Eastern Canada. Canadian production is relatively flat due to the current price environment; however, it will need to gradually increase for Canada to pursue LNG export contracts. The Sumas and Stanfield bases are likely to decrease only modestly over the next few years as they are positioned between supply hubs with decreasing prices and California hubs with sustained strong prices.

The Opal basis is expected to decrease over time as production in the Northeast continues to increase and reduce the amount of Rocky Mountain gas that can economically be delivered eastward. Pipelines such as REX (Rockies Express Pipeline) have given shippers the ability to reverse flow to send Marcellus natural gas east-to-west contrary to the pipeline's original west-to-east design and contracts.

The impact of a lower Opal basis, in addition to a slight decrease in the Kingsgate basis, will lead to a modest decrease in the Malin basis. The PG&E Citygate basis will likely remain at a premium compared to other gas hubs in the country as strong California natural gas demand continues and the anticipated higher cost of transportation on Pacific Gas and Electric's (PG&E) Redwood Path takes effect and steps up over time.

The Southern California hubs of Topock, Ehrenberg, and Southern California Citygate are expected to remain relatively steady. Even with supply growth in the Permian, natural gas exports to Mexico may place a slight upward pressure on Southwest prices in addition to continued California demand for natural gas. The producing San Juan Basin basis is expected to decrease slightly as Permian supply growth continues.

2.3.1.5 Natural Gas Price Risk

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

The natural gas risk model simulates daily natural gas prices, generates a distribution of 875 natural gas price forecasts, and presumes that the gas price forecast represents the median of the resultant distribution. Model parameters are estimated using historical Henry Hub natural gas prices. Once estimated, the parameters serve as the basis for simulated possible future Henry Hub price streams.

The model also constrains the minimum price to $1. Furthermore, because RAM2016 and the TPP calculations use only monthly electricity prices from AURORAxmp®, and the addition of daily natural gas prices does not appreciably affect either the volatility or expected value of monthly electricity prices, the distribution of simulated natural gas prices is aggregated by month prior to being input into AURORAxmp®. The mean, median, and 5th and 95th percentiles of the forecast distribution are reported in Table 2.

2.3.2 Load Forecasts Used in AURORAxmp®

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

2.3.2.1 Load Forecast

AURORAxmp® uses a WECC-wide, long-term load forecast as the base load forecast. Default AURORAxmp® forecasts are used for areas outside the United States. BPA produced a monthly load forecast for each balancing authority in the WECC for the rate period. As AURORAxmp® uses a cut-plane topology (*see* Figure 2) that does not correspond to the WECC balancing authorities, it is necessary to map the balancing authority load forecast onto the AURORAxmp® zones. *See* Power Risk and Market Price Study Documentation (Documentation), BP-16-E-BPA-04A, Table 1. The forecast by balancing authority is in Documentation Table 2.

2.3.2.2 Load Risk Model

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

2.3.2.3 Yearly Load Model

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

The model takes as given the history of annual loads at the balancing authority level, as provided in FERC Form 714 filings from 1993 to 2013 and aggregated into the regions described above. The model estimates the load in each region using a time series econometric model. Once the model is estimated, the parameters of the model are used to generate simulated load growth patterns for each AURORAxmp® zone.

2.3.2.4 Monthly Load Risk

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

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

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

2.3.3 Hourly Load Risk

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

The hourly load model takes as inputs hourly loads for each AURORAxmp® zone from 2002 to 2013. The model groups these hourly load observations by week and month, and each group of week-long hourly load observations constitutes a sample for its respective month. It then normalizes the historical hourly loads by their monthly averages, so the sample space is composed of hourly factors with an average of 1, and then uses a simple bootstrap with replacement to draw sets of week-long, hourly observations from each month. Each draw thus comprises 9,072 hours (54 weeks), with an average of 1. The model repeats this process 50 times, which generates 50 year-long hourly load factor time series. These 50 draws are assigned randomly to the 3,200 AURORAxmp® runs.

2.3.4 Hydroelectric Generation

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

2.3.4.1 PNW Hydro Generation Risk

The PNW hydroelectric generation risk factor reflects uncertainty regarding the timing and volume of streamflows. Given streamflows, HYDSIM computes PNW hydroelectric generation amounts in average monthly values. *See* Power Loads and Resources Study, BP-16-E-BPA-03, § 3.2, for a description of HYDSIM. HYDSIM produces 80 records of PNW monthly hydroelectric generation, each one year long, based on actual water conditions in the region from 1929 through 2008 as applied to the current hydro development and operational constraints. For each of the 3,200 games, the model samples one of the 80 water years for the first year of the rate period (FY 2016) from a discrete uniform probability distribution using R, the software described in section 2.2.1 above. The model then selects the next historical water year for the following year of the rate period, FY 2017 *(e.g.,* if the model uses 1929 for FY 2016, then it selects 1930 for FY 2017). Should the model sample 2008 for fiscal 2016, it uses 1929 for FY 2017. The model repeats this process for each of the 3,200 games and guarantees a uniform distribution over the 80 water years. The resulting 3,200 water year combinations become AURORAxmp® inputs.

2.3.4.2 British Columbia (BC) Hydro Generation Risk

BC hydroelectric generation risk reflects uncertainty in the timing and volume of streamflows and the impacts on monthly hydroelectric generation in British Columbia. The risk model uses historical generation data from 1977 through 2008. The source of this information is Statistics Canada, a publication produced by the Canadian government. Because hydrological patterns, including runoff and hydroelectric generation, in BC are statistically independent of those in the PNW, BPA samples historical water years from BC independently from the PNW water year, as drawn per section 2.3.4.1 above. As with the PNW, water years are drawn in sequence.

2.3.4.3 California Hydro Generation Risk

California hydroelectric generation risk reflects uncertainty with respect to the timing and volume of streamflows and the impacts on monthly hydroelectric generation in California. Historical generation data from 1970–2008 was sourced from the California Energy Commission (CEC), the Federal Power Commission, and the Energy Information Agency (EIA). As with the BC hydro risk model, and for the same reasons, CA water years are drawn independently of PNW water years.

2.3.4.4 Hydro Shaping

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

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

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

2.3.5 Hourly Shape of Wind Generation

AURORAxmp® models wind generation as a must-run resource with a minimum capacity of 70 percent. This assumption implies that, for any given hour, AURORAxmp® dispatches 70 percent of the available capacity independent of economic fundamentals and the remaining 30 percent as needed. The current amount of wind generation operating in the PNW is just over 8,200 MW. The large amount of wind in the PNW (and the rest of the WECC) affects the market price forecast at Mid-C by changing the generating resource used to determine the marginal price. Modeling wind generation on an hourly basis better captures the operational impacts that changes in wind generation can have on the marginal resource compared to using average monthly wind generation values. The hourly granularity for wind generation allows the price forecast to more accurately reflect the economic decision faced by thermal generators. Each hour they must decide whether to operate in a volatile market in which the marginal price can be below the cost of running the thermal generator, but start-up and shut-off constraints could prevent the generator from shutting down.

2.3.5.1 PNW Hourly Wind Generation Risk

The PNW Hourly Wind Generation Risk Model simulates the uncertainty in wind generation output that is derived by averaging the observed output of the BPA wind fleet every five minutes for each hour and converting the data into hourly capacity factors. The source of these data is BPA's external Web site, www.bpa.gov. The data cover the period from 2006 through 2013. The model implements a Markov Chain Monte Carlo (MCMC) sampling algorithm to generate synthetic series of wind generation data. This technique allows the production of statistically valid artificial wind series that preserve the higher-order moments of observed wind time series. Through this process, the model creates 30 time series that include 8,784 hours to create a complete wind year. The model randomly samples these synthetic records and applies them as a forced outage rate against the wind fleet in select AURORAxmp® zones. This approach captures potential variations in annual, monthly, and hourly wind generation.

2.3.5.2 PNW Wind Dispatch Cost

The dispatch cost of wind in the PNW is assigned using data reported during 2012 oversupply events. BPA reported the magnitude of hourly curtailment events during 2012, along with the monthly costs of those events. Using the quantity of wind curtailment along with the cost allows us to infer the cost per aMW of curtailment. BPA imposes a cap of $100 on the displacement cost of wind in an effort to be conservative, and apply that cost curve to wind generators in no particular order.

2.3.6 Thermal Plant Generation

The thermal generation units in AURORAxmp® often drive the marginal unit price, whether the units are natural gas, coal, or nuclear. With the exception of CGS generation, operation of thermal resources in AURORAxmp® is based on the EPIS-supplied database labeled North American DB 2014-02.

2.3.6.1 Columbia Generating Station Generation Risk

The CGS Generation Risk Model simulates monthly variability in the output of CGS such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Power Loads and Resources Study, BP-16-E-BPA-03, § 3.1.3. The simulated results vary from the maximum output of the plant to zero output. The frequency distribution of the simulated CGS output is negatively skewed: the median is higher than the mean. The shape of the frequency distribution reflects the reality that thermal plants such as CGS typically operate at output levels higher than average output levels, but occasional forced outages result in lower monthly average output levels. The output of the model feeds both RevSim (*see* section 2.5 below) and AURORAxmp®, where the results of the model are converted into equivalent forced outage rates and applied to the nameplate capacity of CGS for each of 3,200 games. The simulated frequency distribution for CGS output for October 2015 is shown in Figure 1 of the Documentation.

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

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

First, a consultant was engaged to produce a model capable of quantifying the renewable generation needed to meet each state's RPS goals on an annual basis. This, in combination with existing and planned renewable projects, provides the basis for all renewable resource additions to AURORAxmp®. Second, AURORAxmp® has logic capable of adding and retiring resources based upon economics. In 'capacity expansion' mode, AURORAxmp® generates a catalogue of resource additions and retirements consistent with long-term equilibrium: it (1) identifies any plants whose operating revenue is insufficient to cover their fixed and variable costs of operation and retires them; and (2) selects plants from a candidate list of additions whose operating revenue would cover their fixed and variable costs and adds them to the resource base. Via this process, AURORAxmp® ensures that resources are added when economic circumstances justify. AURORAxmp® adds no new thermal resources to the PNW during the BP-16 rate period. The WECC-wide resource additions are shown in Documentation Figure 2.

2.3.8 Transmission Capacity Availability

In AURORAxmp®, transmission capacity limits the amount of electricity that can be transferred between zones. Figure 2 shows the AURORAxmp® representation of the major transmission interconnections for the West Interconnect topology. The transmission path ratings for the California-Oregon Intertie (AC Intertie or COI), the Direct Current Intertie (DC Intertie), and the BC Intertie are based on historical intertie reports posted on the BPA OASIS Web site from 2003 through 2013. The ratings for the rest of the interconnections are based on the EPIS-supplied database labeled North American DB 2014-02.

2.3.8.1 PNW Hourly Intertie Availability Risk

PNW hourly intertie risk represents uncertainty in the availability of transmission capacity on each of three interties that connect the PNW with other regions in the WECC: AC Intertie, DC Intertie, and BC Intertie. The PNW hourly intertie risk model implements a Markov Chain duration model based on observed data from 2003–2013. The data comprise observed transmission path ratings and the duration of those ratings for both directions on each line.

The model begins with an observed path rating and duration from the historical record. It samples the proximate path rating using a Markov Chain that has been estimated with observed data. Then, it samples a duration for that rating based on observed durations for that specific rating. This process repeats until an 8784 hour record has been constructed. The model generates 200 artificial records. Path ratings are rounded to avoid a Markov Chain that is too sparse to effectively generate synthetic profiles.

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

2.4 Market Price Forecasts Produced By AURORAxmp®

Two electricity price forecasts are created using AURORAxmp®. The market price forecast uses hydro generation data for all 80 water years, and the critical water forecast uses hydro generation for only the critical water year 1937. Table 3 shows the FY 2016 through FY 2017 monthly HLH and LLH prices from the market price forecast.

Table 4 shows the FY 2016 and FY 2017 HLH and LLH prices of the critical water forecast. The mean and median of the market price run are shown in Documentation Figures 3 and 4. The same information for the critical water run is shown in Documentation Figures 5 and 6.

2.5 Inputs to RevSim

As noted earlier, RevSim calculates secondary energy revenues, balancing and augmentation power purchases expenses, and 4(h)(10)(C) credits that are used by RAM2016. It also determines, by simulation, PS operating net revenue risk, used by the ToolKit Model. Inputs to

RevSim include risk data simulated by various risk models (*see* section 2.2.3.1 above) 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-16-E-BPA-03. A summary of these load and resource data in the form of monthly energy for FY 2016–2017 is provided in the Power Loads and Resources Study Documentation, BP-16-FS-BPA-03A, Table 4.1.1.

2.5.1.2 Miscellaneous Revenues

Miscellaneous revenues represent estimated revenues that are not subject to change through BPA's ratesetting process. *See* Power Rates Study, BP-16-E-BPA-01, § 4.2 for a discussion of miscellaneous revenues.

2.5.1.3 Composite, Load Shaping, and Demand Revenue

Composite, Non-Slice, Load Shaping, and Demand revenues are provided by RAM2016. Consistent with the Tiered Rate Methodology (TRM), Composite and Non-Slice revenues do not vary in the RevSim revenue simulation, but Load Shaping and Demand revenues do vary. The Load Shaping billing determinants and Load Shaping rates from RAM2016 are input into RevSim to facilitate the calculation of changes in Load Shaping revenue. Demand billing determinants and rates from RAM2016 are input into RevSim to facilitate the calculation of changes in Demand revenue. *See* Power Rates Study Documentation, BP-16-E-BPA-01A, Table 2.5.5.

2.5.2 Risk Data

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

Operational risks represented as input data to RevSim are Federal hydro generation risk, PS load risk, CGS generation risk, PS wind generation risk, PS transmission and ancillary services expense risk, and electricity price risk. These inputs are reflected in the risk distributions for secondary energy revenues, balancing power purchases 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 uncertain impacts 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 2016–2017, average monthly hydro generation risk is accounted for based on hydro generation estimates from the HYDSIM model for monthly streamflow patterns experienced from October 1928 through September 2008 (also referred to as the 80 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 960 months of the 80 water years. This analysis by HYDSIM is referred to as a continuous study. *See* Power Loads and Resources Study, BP-16-E-BPA-03, § 3, regarding HYDSIM, continuous study, and 80 water years.

For each of the 80 water years, monthly HLH and LLH energy splits for the Federal system hydro generation are developed for each fiscal year of the rate period based on HOSS analyses that incorporate results from HYDSIM hydro regulation studies. 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.

Monthly values for Federal hydro generation for each of the 80 historical water years are provided in Documentation Table 3 for FY 2016 and Table 4 for FY 2017. Monthly values for Federal hydro HLH generation ratios for each of the 80 historical water years are provided in Documentation Table 5 for FY 2016 and Table 6 for FY 2017.

Adjustments are made to the average monthly hydro generation in the 80 water year data to represent efficiency losses associated with standing ready to provide balancing reserve capacity for load and wind variability. *See* Power Loads and Resources Study, BP-16-E-BPA-03, § 3.1.2.1.5.

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 Documentation Tables 7–9 for FY 2016 and Tables 10–12 for FY 2017. These generation data are added to the values presented in Documentation Tables 3–4 to yield the final monthly Federal hydro generation for each of the 80 water years.

The monthly Federal hydro generation data are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on PS secondary energy sales and revenues, balancing power purchases and expenses, and net revenues for 3,200 two-year simulations (FY 2016–2017). The PS secondary energy sales data are input into the PS Transmission and Ancillary Services Expense Risk Model to calculate these expenses for 3,200 two-year simulations. See section 2.5.2.5 below regarding the PS Transmission and Ancillary Services Expense Risk Model.

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

2.5.2.2 BPA Load Risk

The BPA load risk factor represents the impacts that variability in the economy and temperature can have on PS revenues and expenses. Under the TRM, fluctuations in customer loads and revenues are considered as changes in Tier 1 loads, specifically through the Load Shaping and Demand charges. Load fluctuations are also reflected as changes in secondary energy revenues and balancing power purchases 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 load risk model for the WECC. *See* section 2.3.2.2 above for further details regarding the load risk model for the WECC. BPA load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

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

2.5.2.3 CGS Generation Risk

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

2.5.2.4 PS Wind Generation Risk

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

The uncertainty in the amount of energy generated by BPA's portions of these wind projects is simulated in the PNW Hourly Wind Generation Risk Model, which is described in section 2.3.5.1 above. Since the PNW Hourly Wind Generation Risk Model includes the output of wind projects that do not serve BPA loads, the results from this model are scaled such that the average wind generation output is equal to the forecast wind generation in the Power Loads and Resources Study, BP-16-E-BPA-03.

The simulated monthly wind generation results are specified in terms of flat energy. Results shown in Documentation Figure 7 are the monthly flat energy output for all wind projects during FY 2016–2017 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-16-E-BPA-03, § 3.1.3.

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

Results shown in Documentation Tables 13–14 report information from which the value of wind generation during FY 2016–2017 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 represents the uncertainty in PS transmission and ancillary services expenses, relative to the expected values of these expenses included in the power revenue requirement, which are $110.2 million during FY 2016 and $106.7 million during FY 2017. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A**.** This risk is modeled in the PS Transmission and Ancillary Services Expense Risk Model.

The modeling of this risk is based on comparisons between monthly firm PTP Network transmission capacity that PS has under contract, the amount of existing firm contract sales, and the variability in secondary 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 PTP Network transmission capacity that PS has under contract, which must be paid for whether or not it is used. Because PS has more firm PTP Network transmission capacity under contract than it has firm contract sales, the probability distribution for these expenses is asymmetrical. The asymmetry occurs because PS does not incur the costs of purchasing additional transmission capacity until the amount of secondary 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 PTP Network transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions in which PS sells less energy than it has firm PTP Network transmission rights, transmission and ancillary services expenses will remain unchanged.

Results shown in Documentation Figures 8 and 9 indicate how FY 2016–2017 transmission and ancillary service expenses vary depending on the amount of secondary energy sales. In these figures, the PS transmission and ancillary services expenses do not fall below $82.5 million in FY 2016 and $80.1 million in FY 2017, regardless of the amount of secondary energy sales, because PS must pay for the take-or-pay firm transmission capacity it has under contract. Included in these expenses are deterministic costs for the take-or-pay firm transmission capacity the PS has under contract on the Southern Interties (AC and DC).

Results shown in Documentation Figures 10 and 11 reflect the probability distributions for transmission and ancillary service expenses during FY 2016–2017. 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 above, two runs of the AURORAxmp® model are used in this Study. One run uses hydro generation for all 80 water years, referred to as the market price run. The other run uses hydro generation for only the critical water year, 1937, and is referred to as the critical water run. Both produce 3,200 games of monthly HLH and LLH prices for FY 2016–2017.

Prices from the market price run are used by RevSim to develop secondary energy revenues, balancing power purchases expenses, and 4(h)(10)(C) credits for FY 2016–2017. These values are provided to RAM2016 to develop rates for FY 2016–2017.

Prices from the critical water run are used to compute the system augmentation costs provided to RAM2016 for ratesetting purposes and prices from the market price run and critical water run are used to incorporate system augmentation expense risk in the net revenues calculated by RevSim and provided to the ToolKit. See section 2.6.2 below for a description of these processes.

2.6 RevSim Model Outputs

RevSim model outputs are provided to RAM2016, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-16-E-BPA-01, § 4.

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

The 4(h)(10)(C) credit risk is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. The 4(h)(10)(C) credit is the method by which BPA implements section 4(h)(10)(C) of the Northwest Power Act. Section 4(h)(10)(C) allows BPA to allocate its expenditures for system-wide fish and wildlife mitigation activities to various purposes. The credit reimburses BPA for its expenditures allocated to the non-power purposes of the Federal hydro projects. BPA reduces its annual Treasury payment by the amount of the credit. This Study estimates the amount of 4(h)(10)(C) credits available for each of the 80 water years for FY 2016–2017 by summing the costs of the operating impacts on the hydro system (power purchases), direct program expenses, Pisces computer software costs, and capital costs associated with BPA's fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent is the percentage of the FCRPS attributed to non-power purposes).

Operating impact costs are calculated for each of the 80 water years in RevSim for FY 2016–2017 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-16-E-BPA-03, § 3.3. The 4(h)(10)(C) power purchase amounts for FY 2016 and FY 2017 are respectively reported in Tables 2.11.1 and 2.11.2 in the Power Loads and Resources Documentation, BP-16-E-BPA-03A.

The direct program expenses, Pisces computer software costs, and capital costs for FY 2016–2017 do not vary by water volume and timing and are documented in the Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, §§ 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 Table 15 of the Documentation.

Results shown in Documentation Figures 12 and 13 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2016–2017. The average 4(h)(10)(C) credit for the 3,200 games is $95.1 million for FY 2016 and $92.1 million for FY 2017. These values are included in the revenue forecast component of the Power Rates Study, BP-16-E-BPA-01, § 4.

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

2.6.2 System Augmentation Costs

System augmentation costs for FY 2016–2017 are calculated using two different methods, one for the deterministic values provided to RAM2016 and a second for the variable costs included in the net revenues calculated in RevSim and provided to the ToolKit.

For the rate period, the deterministic values provided to RAM2016 are calculated by multiplying the system augmentation amount (aMW) by the average AURORAxmp® price from the critical water run. The source of the system augmentation amounts is the Power Loads and Resource Study, BP-16-E-BPA-03, § 4.2. A summary of this calculation is shown in Documentation Table 16.

The system augmentation costs included in the net revenue provided to the ToolKit represent the uncertainty in the cost of system augmentation purchases not made prior to setting rates. The uncertainty in the cost of system augmentation considers electricity price risk associated with meeting that need. For each game, these variable cost values replace the deterministic values for system augmentation costs provided to RAM2016.

To determine system augmentation cost risk, augmentation needs (aMW) are 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 2017 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 2016, a year without a planned CGS outage, all system augmentation would be classified as Category 1 augmentation need, 50 percent of which is met with purchases at market prices and the remaining 50 percent at prices from the critical water run. For FY 2017, a year with a planned CGS outage, the total system augmentation need is made up of both Category 1 and Category 2 augmentation needs. Fifty percent of the Category 1 augmentation need is met with purchases at prices from the critical water run, and the remaining 50 percent of the Category 1 augmentation need and all the Category 2 augmentation need are met at prices from the market price run.

RevSim calculates the total system augmentation cost risk associated with each of the 3,200 games per fiscal year by summing the system augmentation costs computed by these two approaches. Documentation Table 17 presents sample calculations based on the methodology used to calculate system augmentation cost risk in RevSim for FY 2016–2017.

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

RevSim calculates secondary energy sales and revenues 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 conditions and determines HLH and LLH secondary energy sales and balancing power purchases. Included in this calculation are the additional amounts of secondary energy that result from the forward power purchases of 22 aMW in FY 2016 and 100 aMW in FY 2017 that were acquired to provide SE Idaho Load Service (SILS) once the BPA-PacifiCorp Exchange Agreement terminates. While the SILS loads are included in the loads and the calculation of system augmentation in the Power Loads and Resources Study, BP-16-E-BPA-03, the amounts of these forward power purchases are not included. Once the amounts of the forward power purchases are used to serve the SILS loads, the amounts of secondary energy marketable at Mid-C increase due to the reductions in firm load obligations associated with SILS. *See* Power Loads and Resources Study, BP-16-E-BPA-03, § 3.1.4 regarding the treatment of SILS forward power purchases and Power Loads and Resources Study, BP-16-E-BPA-03A, Tables 1.2.1, 1.2.2, 1.2.3, lines 4-6, and Tables 4.1.1, 4.1.2, 4.1.3, line 6 where the SILS loads are embedded in the total load values.

Transmission losses on BPA's transmission system are incorporated into RevSim by reducing Federal hydro generation, CGS output, and wind generation that BPA has under contract by 2.97 percent. *See* Power Loads and Resources Study, BP-16-FS-BPA-03, § 3.1.5.

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

2.6.4 Median Net Secondary Revenue Computations

Secondary energy revenues and balancing power purchases expenses for FY 2016–2017 are provided to RAM2016. These revenues and expenses are based on the median net secondary revenues (secondary energy revenues less balancing power purchases expenses) from the 3,200 games. The secondary energy sales and balancing power purchases passed to RAM2016, both measured in annual average megawatts, are the arithmetic means of these quantities over the 3,200 games for each fiscal year.

In a data set with an even number of values, the median value is the mean of the two middle values. Because these two middle games have specific qualities *(i.e.,* loads, resources, prices, and monthly shape) that may not be representative of the study as a whole, the mean of more than two middle games was used to smooth out any particular features of individual games. To avoid specific games distorting the results, the mean of 320 games was used. The values for secondary energy sales revenues and balancing power purchases expenses passed to RAM2016 are the arithmetic means of the secondary energy sales revenues and balancing power purchases expenses (calculated and reported separately to RAM2016) for the 320 middle games as measured by net secondary revenue (160 above the median net secondary revenue and 160 below). Documentation Tables 18 and 19 provide summary calculations of the secondary energy sales revenues and balancing power purchase expenses provided to RAM2016 for FY 2016–2017. Documentation Tables 20 and 21 provide monthly values for the secondary energy sales/revenues and total power purchases/expenses provided to RAM2016 for FY 2016–2017. annual secondary energy sales/revenues and total power purchases/expenses for FY 2016–2017 (based on the median approach described above) are reported in Documentation Table 22. The secondary energy revenues are $337.8M for FY 2016 and $377.2M for FY 2017. The total power purchases expenses are $29.6M for FY 2016 and $53.3M for FY 2017.

2.6.5 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2016 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 RAM2016, which in turn depend on the level of PNRR assumed when RAM2016 is run. RevSim simulates intermediate sets of net revenue during this iterative process. The final set of PS net revenue from RevSim is the set that yields a 95 percent TPP without requiring additional PNRR.

Using 3,200 games of net revenue risk data simulated by RevSim and NORM and mathematical descriptions of the CRAC and DDC, the ToolKit produces 3,200 games of cash flow 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 2016–2017 simulated by RevSim using rates with $0 million in PNRR is reported in Table 5. PS net revenue over the rate period averages $2.5 million/year. This amount represents only the operating net revenues calculated in RevSim. It does not reflect additional net revenue adjustments in the ToolKit model due to the output from NORM, interest earned on financial reserves, or impacts of the CRAC and DDC. The average net revenue in Table 5 will differ from the net revenue shown in the Power Revenue Requirement Study, BP-16-E-BPA-02, Table 1, which shows the results of a deterministic forecast that does not account for system augmentation risk and uses median, rather than average, net secondary revenues.

2.7 Inputs to NORM

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

2.7.1 CGS Operations and Maintenance (O&M)

CGS O&M uncertainty is modeled for Base O&M and Nuclear Electric Insurance Limited (NEIL) Insurance Premiums. NORM captures uncertainty around Base O&M and NEIL insurance costs. For Base O&M, NORM distributes the minimum- and maximum-based subject matter expert estimation of deviations from the expected value. The revenue requirement amounts for CGS O&M for FY 2015, FY 2016, and FY 2017 are $331 million, $263 million, and $322 million, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels. For FY 2015, NORM models the maximum O&M expense as 2.5 percent greater than forecast and the minimum as 2.5 percent less than forecast. For FY 2016 and FY 2017, the maximums are 6 percent greater than forecast, and the minimums are 4 percent less than forecast.

For NEIL insurance premiums, risk is modeled around forecast gross premiums and distributions based on the level of earnings on the NEIL fund. Historically, member utilities have received annual distributions based on the level of these earnings; the net premiums they pay are lower as a result. During FY 2015–2017 BPA anticipates that the NEIL Premiums, will be lower than the forecast values of $3.5 million in each year. NEIL premiums are modeled using a Program Evaluation and Review Technique (PERT) distribution. A PERT distribution is a type of beta distribution for which minimum, most likely, and maximum values are specified. For FY 2015, the low, base, and high are set to $2 million, $2.2 million, and $2.5 million respectively. For

FY 2016, the parameters are set to $2 million, $2.5 million, and $3 million. For FY 2017, the parameters are set to $2 million, $2.5 million, and $3.5 million.

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

2.7.2 Corps of Engineers and Bureau of Reclamation O&M

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

(a) Additional costs if a security event occurs or if the security threat level increases
(b) Additional costs if a fish event occurs
(c) Additional extraordinary maintenance
(d) Additional costs due to a catastrophic event
(e) Additional costs due to new system requirements

For additional security costs, NORM assumes for FY 2015 through FY 2017 that there is a 2 percent probability that an event will occur that leads to a requirement for additional security at the Corps and Reclamation facilities. The additional annual cost if an event were to occur is the same for both the Corps and Reclamation at $3 million each.

Additional fish environmental costs are modeled similarly, with a 2 percent probability that an event that requires additional annual expenditures of $2 million each for both the Corps and Reclamation will occur in FY 2015 through FY 2017.

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. For FY 2015 through FY 2017, this risk is modeled with a 2.5 percent probability that an event will occur that leads to an additional $5 million expense. This risk is modeled in the same way for both the Corps and Reclamation.

NORM models the expense cost of a catastrophic, system-wide event. This risk is modeled for FY 2015 through FY 2017 with a $30 million cost and an annual probability of 1 percent. This risk is modeled in the same way for both the Corps and Reclamation.

NORM models the expense cost related to increased compliance or regulatory requirements. This risk is modeled for FY 2015 through FY 2017 with a $5 million cost and an annual probability of 10 percent. This risk is modeled in the same way for both the Corps and Reclamation.

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

2.7.3 Conservation Expense

For this expense item, NORM models uncertainty around Conservation Acquisition and Low-Income and Tribal Weatherization. Conservation acquisition expense is modeled for each year from FY 2015 through FY 2017 using a PERT distribution. Conservation acquisition expense is modeled with a minimum value of 90 percent of the amount in the revenue requirement, a most likely value equal to the amount, and a maximum value of 105 percent of the amount. The amount for FY 2015 for conservation acquisition expense is $14.7 million. The forecasts are $14.6 million and $14.6 million in FY 2016 and FY 2017, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table. The distribution for conservation acquisition is shown in Documentation Figure 16.

Low-income and tribal weatherization expense variability is modeled using a PERT distribution for FY 2015 through FY 2017. These expenses are modeled with a minimum value of 95 percent of the amount in the revenue requirement, a most-likely value equal to the amount, and a maximum value of 105 percent of the amount. The amount for FY 2015 is $5.2 million. The forecasts are $5.3 million and $5.4 million in FY 2016 and FY 2017, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table.

2.7.4 Spokane Settlement

Within the BP-16 rate period, legislation enacting a settlement with the Spokane Tribe, similar to the settlement with the Colville Tribes, could pass. For FY 2016 and FY 2017, the payment to the Spokane Tribe would equal 25 percent of the payments made to the Colville Tribes. This payment amount is calculated from the forecast payments to the Colville Tribes of $21.8 million in FY 2016 and $22.2 million FY 2017. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table.

NORM includes an assumption of a 20 percent probability that the legislation will pass during the rate period, with an equal probability that payments would begin in FY 2016 or FY 2017. The distributions for Spokane Settlement payments are shown in Documentation Figure 17.

2.7.5 Power Services Transmission Acquisition and Ancillary Services

For this cost item, NORM models uncertainty around Third-Party General Transfer Agreement (GTA) Wheeling and Third-Party Transmission and Ancillary Services expenses. NORM models third-party GTA wheeling cost for each year from FY 2015 through FY 2017 with PERT distributions. For FY 2015, the minimum is set to 98 percent of the revenue requirement amount, the most-likely value is set to the revenue requirement amount, and the maximum is set to 101 percent of the revenue requirement amount. For FY 2016, the minimum, most-likely, and maximum are set to 96 percent, 100 percent, and 102 percent of the revenue requirement amounts. For FY 2017, the minimum, most-likely, and maximum are set to 94 percent, 100 percent, and 103 percent of the revenue requirement amounts. The forecast for FY 2015 for third-party GTA wheeling is $6.4 million. The revenue requirement amounts are $61.4 million in FY 2016 and $71.0 million in FY 2017. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table. Figure 18 of the Documentation shows the distribution for third-party GTA wheeling.

The cost of third-party transmission and ancillary services is modeled for FY 2015 through FY 2017 using a PERT distribution with minimum and most likely values set to the revenue requirement amount. For FY 2015, FY 2016, and FY 2017, the maximums are set to 105 percent, 110 percent, and 116 percent of the revenue requirement amount. The amount in the revenue requirement for FY 2015 for third-party transmission and ancillary services is $2.9 million. The amounts in the revenue requirement are $2.4 million for each of FY 2016 and FY 2017. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table.

2.7.6 Power Services Internal Operations Expenses

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

(a) PS System Operations

(b) PS Scheduling

(c) PS Marketing and Business Support

(d) PS allocation of Corporate G&A

PS Internal Operations Expenses are modeled in NORM for FY 2015 through FY 2017. The costs in the PS Internal Operations Expense categories primarily comprise of salaries. Risk in these categories is modeled based on the difference between staffing levels at the start of FY 2015 and the assumed staffing levels in the revenue requirement expense amounts for FY 2015, FY 2016, and FY 2017. Growth in staffing levels from the start of FY 2015 through FY 2017 is modeled in NORM. The difference between the modeled staffing level and the revenue requirement staffing level is multiplied by cost of $108 thousand per employee, to produce a change in PS Internal Operations Expense for each Fiscal Year. The revenue requirement amounts for Power Services Internal Operations Expenses for FY 2015, FY 2016, and FY 2017 are $146.7 million, $146.3 million, and $150.5 million, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table.

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

2.7.7 Fish & Wildlife Expenses

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

2.7.7.1 BPA Direct Program Costs for Fish and Wildlife Expenses

The costs of BPA's Direct Program for fish and wildlife are uncertain, in large part because the actual pace of implementation cannot be known, and there is a chance that program components will not be implemented as planned. This does not reflect any uncertainty in BPA's commitment to the plans; it is merely a realistic understanding that it can take time to start and implement programs, and the expenses of the programs may not be incurred in the fiscal years in which BPA plans for them to be incurred. The uncertainty in fish and wildlife expenses is modeled using PERT distributions. For FY 2015, the minimum expense amount is set to 7.5 percent lower than the forecast amount, the most likely is set to 5 percent less than the forecast amount, and the maximum is set equal to the forecast amount. For FY 2016 and FY 2017, the minimums are set to 5 percent lower than the revenue requirement amount, the most likely values are set to 2.5 percent lower than the revenue requirement amount, and the maximums are set equal to the revenue requirement amounts. The revenue requirement amounts for BPA's Direct Program for fish and wildlife for FY 2015, FY 2016, and FY 2017 are $260.0 million, $267 million, and $274 million, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table. Figure 20 of this Study's Documentation illustrates the distributions for the BPA Direct Program expense.

2.7.7.2 U.S. Fish and Wildlife (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 PERT distribution with a minimum value set to 10 percent less than the forecast value, a most likely of 5 percent less than the forecast value, and a maximum equal to the forecast value. The revenue requirement amounts for USF&W Service Lower Snake River Hatcheries for FY 2015, FY 2016, and FY 2017 are $31.7 million, $32.3 million, and $32.9 million, respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table. Figure 21 of the Documentation shows the distributions for risk over the Lower Snake River Hatcheries expense.

2.7.7.3 Bureau of Reclamation Leavenworth Complex O&M Expenses

NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using a discrete risk model, with a 1 percent probability of incurring an additional $1 million expense in each year. The revenue requirement amounts for Bureau of Reclamation Leavenworth Complex O&M for FY 2015, FY 2016, and FY 2017 are included in the Bureau's O&M budget, which is discussed in section 2.7.2 above. Documentation Figure 22 shows the distributions for Leavenworth Complex O&M expense.

2.7.7.4 Corps of Engineers Fish Passage Facilities Expenses

NORM models uncertainty of the cost of the fish passage facilities for the Corps using a discrete risk model, with a 1 percent probability of incurring an additional $1 million expense in each year. The revenue requirement amounts for Corps of Engineers Fish Passage Facilities Expenses for FY 2015, FY 2016, and FY 2017 are included in the Corps' O&M budget, which is discussed in section 2.7.2 above. Documentation Figure 23 shows the distributions for Fish Passage Facilities expense.

2.7.8 Interest Expense Risk

NORM models the impact of interest rate uncertainty associated with new debt issuances during the forecast period and the resulting interest expense impact. For FY 2015 through FY 2017, the amount of planned new borrowing is $565 million, $792 million, and $795 million respectively. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 7A. The planned borrowings and official forecast interest rates (Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, § 6) are used to calculate expected interest expense on long-term debt and appropriations for the revenue requirement. This analysis assesses the potential difference in interest expense on long-term debt and appropriations from the amount rates are set to recover in the revenue requirement.

In each Fiscal Year, planned new borrowings occur on a monthly basis for different amounts each month, with different term lengths. *See* Power Revenue Requirement Study Documentation, BP-16-E-BPA-02A, Table 7A. NORM models uncertainty in the interest rate BPA will eventually get when these borrowings occur. The analysis does not model uncertainty in the amount borrowed, term length of the borrowing, or timing of the borrowing.

NORM uses a historical database of interest rates as the basis to forecast future uncertainty in interest rates. The database was generated from twenty years of historical daily data from 1994 to 2014 that includes each interest rate term (for example one year, two year, …thirty year). This historical data is captured for U.S. Agency interest rates, which are the rates BPA borrows at for Federal borrowings, and are also used for modeling uncertainty in the rates for Appropriations paid by BPA. The data source for these rates is Bloomberg Curve CO843. Historical data is also captured for taxable and tax-exempt interest rate indexes for AA-rated utilities. These are used as proxy rates for third-party financing related to Energy Northwest new capital and refinancing of existing Energy Northwest Debt. The data sources for these taxable and tax-exempt rates are Bloomberg Curve 903M and Bloomberg Curve 520M, respectively.

To model the interest expense uncertainty in NORM, for each game, a starting date from the historical data set is selected and, for that date, the interest rate for each term length on the yield curve is captured. Then, the interest rates are captured for each term length on the yield curve 30 days later. This process is repeated for three years and one month following the starting date, so that 37 interest rate data points for each term length are captured. This process is performed for Agency interest rates, AA Utility Taxable rates, and AA Utility Tax-Exempt interest rates.

BPA measures the monthly returns by taking the log return, also known as geometric return, which is the natural logarithm of the interest rate from one month less the natural logarithm of the interest rate of the prior month. This is very similar to taking the percentage change, known as the simple return. The log return approach is preferred because it is more accurate calculating small returns, which are more common when the time difference between returns is shorter (for example when the time difference is monthly, as in this analysis, versus annually). Also, the log returns possess the convenient mathematical property that they are additive through time whereas simple returns are not. Monthly returns are calculated for each interest rate product (Agency and AA Taxable), for each term length of that product, and for each thirty day period for a full three years from the sample starting date. BPA uses the 3200 calculated monthly returns to create a 3-year projections of interest rate, for each term length, and for each interest rate product, all of which start from BPA's official starting interest rates in FY 2015. For example, assume the sample starting date for game 1 is June 5, 2001. The interest rate for the Agency product, with a 10- year term, in the first month of the 36 month projection is equal to the FY 2015 Agency 10-year interest rate from the official forecast (3.54 percent, *id.*) multiplied by the calculated return from June 5, 2001, to July 5, 2001 (June 5, 2001 10-year Agency interest rate = 6.02 percent, July 5, 2001 10-year Agency interest rate = 6.19 percent, the log return equals 1.2094 percent (log(6.19) less log (6.02)). Taking the exponent of the log return yields (1.012168), the appropriate factor to multiply 3.54 percent to get a one month projection (3.583 percent) of the 10-year Agency interest rate for game 1. To generate the month 2 projection of the 10-year Agency interest rate for game 1, BPA takes the calculated rate from month 1, 3.583 percent, and multiplies it by the sampled return from August 5, 2001, to July 5, 2001. For the full projection, repeat the process for all 36 months, for each term length on the yield curve, and for each interest rate product. In the second game, a new sample starting date is selected from the 20-year dataset, and the process is repeated, but representative of a different 3-year historical window within the dataset.

Using this methodology, 3,200 games are run, generating interest rate projections of each term length for each interest rate product. Once all 3200 projections are generated, they are adjusted so that the average interest rate for all 3200 runs aligns with the expected interest rate in BPA's official 2017 interest rate forecast. Thus, this analysis captures the possible uncertainty around the expected interest expense in the revenue requirement and does not assess the expected value itself. The generated interest rates are then combined with the corresponding timing and term length of anticipated monthly borrowings in the repayment study to generate 3,200 projections of interest expense and appropriations expense. The difference between the deterministic forecast and the gamed amount is calculated for each issuance. The distribution of variation in Federal debt service expense, non-Federal debt service expense, and appropriations expense is shown in Documentation Figure 24.

2.7.9 CGS Refueling Outage Risk

In the spring of 2015 and the spring of 2017, Energy Northwest plans to take CGS out of service for refueling and maintenance. There is uncertainty in the duration of these outages and thus uncertainty in the amount of replacement power BPA must purchase from the market or the amount of secondary energy available to be sold in the market.

CGS outage duration risk is modeled as deviations from expected net revenue due to variability in the duration of the planned maintenance outages in FY 2015 and FY 2017. Increases or decreases in downtime of the CGS plant result in changes in megawatthours generated, which results in decreased or increased net revenue for Power Services in FY 2015 and FY 2017. This revenue variability is a function of plant outage duration, monthly flat AURORAxmp® market prices, and monthly flat CGS energy amounts from RevSim.

The outage duration for FY 2015 was modeled with a minimum of 42 days, a maximum of 75 days, and a median of 54 days. For FY 2017, the minimum is 40 days, the maximum is 75 days, and the median is 54 days. The probability distribution of the outage durations is shown in Documentation Figure 25.

To calculate the impact of the outages on net revenue, 3,200 outage durations are simulated. The difference between the simulated duration from NORM and the deterministic duration assumed in RevSim is used to determine the number of additional days the plant is in or out of service in each month. These additional days in or out of service are then applied to the gamed CGS energy amounts from RevSim to calculate monthly megawatthour deviations. Monthly, flat AURORAxmp® prices (§ 2.4) are then multiplied by the gamed generation deviations and adjusted for Slice, resulting in a PS net revenue deviation. The distributions of revenue changes for FY 2015 and FY 2017 are shown in Documentation Figure 26.

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

In FY 2016 and FY 2017, Transmission Services (TVS) will provide VERBS to wind and other variable resource generators in BPA's balancing authority area. TS will charge generators for VERBS based on the installed capacity of the variable energy resources. TS will obtain from PS up to 400 MW of *inc* balancing reserve capacity during the "spring" (April through July) and 900 MW of *inc* balancing reserve capacity during the remainder of the year. TS will obtain from PS up to 900 MW of *dec* balancing reserve capacity across the entire year. TS will pay PS for the balancing reserve capacity through the cost allocation set in the Generation Inputs Settlement. *See* Fisher and Fredrickson, BP-16-E-BPA-12, Appendix A, Attachment 3.

TS will attempt to obtain up to an additional 500 MW of *inc* balancing reserve during the spring. TS will first attempt to obtain this service from PS before attempting to obtain the service from the market. The revenue forecast includes the assumption that TS will purchase an additional 150 MW of *inc* balancing reserve from PS during the spring. NORM models the uncertainty in the amount of *inc* balancing reserve that TS will obtain from PS for the spring. The uncertainty in the amount supplied is modeled using a PERT distribution, with the most likely set at the 550 MW forecast, the high set at 900 MW at the 5th percentile, and the low set at 400 MW at the 100th percentile.

The net revenue impact of an increase (decrease) in *inc* balancing reserve sales consists of an increase (decrease) in inter-business unit revenue, partially offset by a decrease (increase) in net secondary energy revenue due to de-optimization of the hydro system. The impact on net secondary revenue was calculated to be 22 percent of the sales amount In the settlement.

In each of the 3200 games in NORM, an amount of spring *inc* balancing reserves is drawn. A net revenue impact is calculated by applying the selling price of 29 cents per kilowatt per day (*see* Fisher and Fredrickson, BP-16-E-BPA-12, Appendix A, Attachment 1) to the difference between the amount drawn and the deterministic forecast, then multiplying that value by 78 percent (one minus the 22 percent secondary revenue impact percentage). The distributions of net revenue changes for FY 2016 and FY 2017 are shown in Documentation Figure 27.

2.7.11 Lower Snake Spill Risk

In each of the 3200 games in NORM, the Net Revenue effect of Lower Snake River spill uncertainty is modeled. The Power Loads and Resources Study assumes that in certain poor FY 2017 water conditions, fish would be barged past Lower Snake River dams. This assumption results in lower spill requirements in eight of the 80 water years.

NORM models the effect on Net Revenue if barging does not occur and the Snake River dams continue to spill in those eight water years. To calculate this, NORM first takes the difference between monthly aMW generation under the barging assumption and the continued spill assumption for each of the 80 water years. *See* Documentation Table 23. These generation differences are then aligned with the 3,200 games of monthly prices from AURORAxmp® (*see* section 2.4) based on the water year for the AURORAxmp® price games. The 3,200 games of monthly generation differences, multiplied by the monthly prices, multiplied by the number of hours in each month, multiplied by the non-slice percentage, produces 3,200 games of FY 2017 revenue deviations in NORM. The distribution of net revenue changes for FY 2017 is shown in Documentation Figure 28.

2.7.12 The Net Revenue-to-Cash (NRTC) Adjustment

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

The NRTC Adjustment is modeled probabilistically in NORM. NORM uses the deterministic NRTC Table, Table 6, as its starting point and includes 3,200 gamed adjustments for the Slice True-Up, based on the calculated deviations in those revenue and expense items in NORM that are subject to the True-Up.

2.8 NORM Results

The output of NORM is an Excel® file containing (1) the aggregate total net revenue deltas for all of the individual risks that are modeled, and (2) the associated NRTC adjustments for each game for FY 2015, FY 2016, and FY 2017. Each run has 3,200 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in Documentation Figure 29.

This page intentionally left blank.

3. QUANTITATIVE RISK MITIGATION

3.1 Introduction

The preceding sections of this Study describe the risks that are modeled explicitly, with the output of NORM and RevSim quantitatively portraying the financial uncertainty faced by PS in each fiscal year. This section describes the tools used to mitigate these risks—PS Reserves, the Treasury Facility, PNRR, the CRAC, and the DDC—and how BPA evaluates the adequacy of this mitigation. Section 4 describes the risks that BPA has analyzed qualitatively, that is, logically rather than through modeling, and the measures for treating them.

The risk that is the primary subject of this Study is the possibility that BPA might not have sufficient cash on September 30, the last day of a fiscal year, to fully meet its obligation to the Treasury for that fiscal year. BPA's TPP standard, described in section 1.1.1 above, 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.

TPP is modeled in ToolKit using a Monte Carlo approach in which 3,200 separate iterations (or games) of financial results are generated. Each game covers three years: FY 2015 and the two years in the BP-16 rate period, FY 2016 and FY 2017. FY 2015 is simulated to reflect the uncertainty of the starting FY 2016 balance of PS reserves available for risk. In each game, a test is performed to see if BPA has sufficient reserves available for risk to make its Treasury payment during each year of the rate period. The TPP is the percentage of those 3,200 games in which BPA makes its Treasury payment on time and in full in both years. The ToolKit is further described in section 3.3 below.

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

3.2 Risk Mitigation Tools

3.2.1 Liquidity

Cash and cash equivalents provide liquidity. For this rate proceeding, BPA has two sources of liquidity: (1) Financial Reserves Available for Risk Attributed to PS (PS Reserves) and (2) the Treasury Facility. These liquidity sources mitigate financial risk by serving as a temporary source of cash for meeting financial obligations during years in which net revenue and the corresponding cash flow are lower than anticipated. In years of above-expected net revenue and cash flow, financial reserves will be replenished so they will be available in later years.

3.2.1.1 PS Reserves

PS Reserves are the fundamental protection against the financial impacts of the uncertainty BPA faces in its financial reserves. For power ratesetting purposes, it is the Financial Reserves Available for Risk attributed to the generation function (PS reserves) that is considered when measuring TPP. Financial reserves available to the generation function include cash and investments ("Treasury Specials") held by BPA in the Bonneville Fund at the Treasury plus any deferred borrowing. Deferred borrowing refers to amounts of capital expenditures 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.

PS Reserves are not held in a PS-specific account. BPA has only one account, the Bonneville Fund, in which it maintains financial reserves. Staff in the Chief Financial Officer's (CFO's) organization "attribute" part of the BPA Fund balance to the generation function and part to the transmission function. Reserves attributed to Power do not belong to Power Services; they belong to BPA.

As $333 million of PS reserves are considered not to be available for risk, that amount is not included in the starting financial reserves or any other part of the TPP calculation. These "Reserves Not For Risk" are made up of five categories. First, PS reserves exclude $75 million in funds BPA has received for previously unpaid receivables for sales into the California ISO and California PX markets during the energy crisis of 2000–2001. There remains a risk that BPA may be obligated to refund some amount for BPA's sales into these markets during the energy crisis as a result of ongoing litigation. Second, $31 million of funds collected from customers under contracts that obligate BPA to perform energy efficiency-related upgrades to the customers' facilities are excluded. Third, $205 million in customer Prepay funds, which are set aside for specific categories of Power capital projects, are excluded. Fourth, $15 million in customer deposits for credit worthiness are excluded. These deposits are held in the BPA fund as collateral for open trades. Fifth, $6 million for deposits received from third parties for cost-sharing of fish and wildlife projects are 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.

The Treasury Facility is an Agency liquidity tool, managed by Corporate Finance. For actual use, the Treasury Facility is not allocated or earmarked for specific business lines or purposes. For the purpose of modeling risk for the BP-16 rate period, all $750 million of the Treasury Facility is modeled to be available for PS risk. This allocation is made for TPP modeling purposes only.

3.2.1.3 Within-Year Liquidity Need

BPA needs to maintain access to short-term liquidity for responding to within-year needs, such as uncertainty due to the unpredictable timing of cash receipts or cash payments, or known timing mismatches. An illustrative timing mismatch is the large Energy Northwest bond payment due in the spring. PF rates are set to recover the entire amount of this payment, but by spring BPA will have received only about half of the PF revenue that will fully recover this cost by the end of the fiscal year. A within-year liquidity need of $320 million for PS was determined in the BP-14 rate proceeding. This assumption remains unchanged for BP-16.

3.2.1.4 Liquidity Reserves Level

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

3.2.1.5 Liquidity Borrowing Level

For this Study, $320 million of the short-term borrowing capability provided by the Treasury Facility is considered to be available only for within-year liquidity needs, fully meeting the need for short-term liquidity. Thus, $430 million of the $750 million Treasury Facility is considered to be available for year-to-year liquidity for TPP.

3.2.1.6 Net Reserves

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

3.2.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted during rate development using current projections of PS Reserves and other sources of liquidity. If the TPP is below the 95 percent two-year standard established in BPA's Financial Plan, then the projected reserves, along with whatever other risk mitigation is considered in the risk study, are not sufficient to reach the TPP standard. This is typically corrected by adding PNRR to the revenue requirement as a cost needing to be recovered by rates. This addition has the effect of increasing rates, which will increase net cash flow, which will increase the available PS Reserves and therefore increase TPP. No PNRR is needed to meet the TPP standard for the proposed rates; PNRR is $0 for both FY 2016 and FY 2017.

PNRR is calculated in the ToolKit, described in section 3.3 below. If the ToolKit calculates TPP below 95 percent, PNRR can be iteratively added to the model in one or both years of the rate period (typically, PNRR is evenly added to both years). PNRR is added in $1 million increments until a 95 percent TPP is achieved. The calculated PNRR amounts are then provided to the Power Revenue Requirement Study, BP-16-E-BPA-02, which calculates a new Revenue Requirement. This adjusted Revenue Requirement is then iterated through the rate models and tested again in ToolKit. If ToolKit reports TPP below 95 percent or TPP above 95 percent by more than the equivalent of $1 million in PNRR, PNRR adjustments are calculated again and reiterated through the rate models.

3.2.3 The Cost Recovery Adjustment Clause (CRAC)

In most power rates in effect since 1993, BPA has employed CRACs or Interim Rate Adjustments (IRAs) as upward rate adjustment mechanisms that can respond to the financial circumstances BPA experiences before the next opportunity to adjust rates in a rate proceeding. The CRAC explained here could increase rates for FY 2016 based on financial results for FY 2015. It also could increase rates for FY 2017 based on the accumulation of financial results for FY 2015 and FY 2016 (taking into account any CRAC applying to FY 2016 rates). The rates subject to the CRAC (and eligible for the DDC, section 3.2.5 below) are the Non-Slice Customer rate, the PF Melded rate, the IP rate, the NR rate, and the Reserves-based Ancillary and Control Area Services rates, which are levied by Transmission Services. *See* Power Rate Schedules, BP-16-E-BPA-09, GRSP II.C; Transmission Rate Schedules, BP-16-E-BPA-10, GRSP II.G.

3.2.3.1 Calibrated Net Revenue (CNR)

CNR is Power Services' NR adjusted for certain debt management and contract-related transactions that affect the relationship between accruals and cash. The method for calculating CNR is described in GRSP II.C. Examples of the application of this method, including actions that change Federal depreciation, debt transactions that affect NR but not cash, and cash contract settlements, are described in the Documentation, Example 1.

3.2.3.2 Description of the CRAC

The CRAC for FY 2016 and FY 2017 is an annual upward adjustment in various power and transmission rates. The threshold for triggering the CRAC is an amount of Power Services' CNR accumulated since the end of FY 2014.

The Accumulated Calibrated Net Revenue (ACNR) threshold values are set equivalent to $0 in PS net reserves. The ACNR threshold for each year is calculated by taking the difference between average ACNR and average Net Reserves across all 3200 games in the ToolKit, and adding that difference to the target CRAC threshold in terms of reserves.

As an example, assume that a given FY's CRAC threshold in terms of reserves is supposed to be $0. If the average ACNR at the start of that FY is $200 million and the average Net Reserves at the start of that FY is $50 million, then the CRAC threshold in terms of ACNR for that year is $150 million ($0 + $200 – $50 = $150 million).

The CRAC will recover 100 percent of the first $100 million that ACNR is below the threshold. Any amount beyond $100 million will be collected at 50 percent, up to the CRAC annual limit on total collection, or cap, of $300 million. For example, at an equivalent of negative $100 million in reserves at the end of the fiscal year, $100 million will be collected in the next year. At the equivalent of negative $150 million, $125 million will be collected ($100 million plus one-half of the next $50 million). The CRAC will be implemented only if the amount of the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2016 rates will be made in July 2015; the corresponding calculations for possible adjustments to FY 2017 rates will be made in September 2016. A forecast of the year-end Power Services ACNR will be made based on the results of the Third Quarter Review and then compared to the thresholds for the CRAC and the DDC. See section 3.2.5 below. If the ACNR 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 7.

3.2.3.3 Administrator's Discretion to Reduce the CRAC

BPA's CRAC methodology includes a process that allows BPA to look ahead to the remaining fiscal year(s) of the rate period and determine whether the calculated CRAC amount could be reduced without causing the PS TPP to fall short of BPA's TPP standard. The ability to apply discretion in the CRAC adjustment is tempered by the requirement to maintain the TPP standard for the remainder of the rate period and the requirement to restore liquidity tools, such as the Treasury Facility, if 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 2016 may be reduced from the calculated amount as long as the two-year TPP for FY 2016–2017 remains at or above 95 percent. BPA may adjust the parameters *(i.e.*, the Cap and Threshold) for the CRAC applicable to FY 2017 to maintain the FY 2016–2017 TPP. A CRAC that is calculated for FY 2017 may be reduced from the calculated amount as long as the one-year TPP for FY 2017 would still be at or above 97.5 percent. These reductions may not be made if they would reduce the generation of incremental revenue intended to allow repayment of any borrowing under the Treasury Facility. Because the CRAC thresholds have been set at the lowest level that allows for beginning prompt replenishment of liquidity tools if 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 2016 or FY 2017.

3.2.4 The NFB Adjustment

NFB (NMFS [National Marine Fisheries Service] FCRPS [Federal Columbia River Power System] BiOp [Biological Opinion]) risks arise from litigation over the FCRPS BiOp. NFB risks and mitigation are addressed through qualitative risk assessment and mitigation. *See* section 4.2 below.

3.2.5 Dividend Distribution Clause (DDC)

One of BPA's financial policy objectives is to ensure that reserves do not accumulate to excessive levels. *See* section 1.2.1 above. The DDC is triggered if Power Services' ACNR is above a threshold (instead of below, as with the CRAC), and provides a downward adjustment to the same power and transmission rates that are subject to the CRAC. In the same way that a CRAC passes costs of bad financial outcomes to BPA's customers, a DDC passes benefits of 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 8.

3.3 Overview of the ToolKit

The ToolKit is an Excel® 2003 spreadsheet that is used to evaluate the ability of PS to meet BPA's TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. The ToolKit contains several parameters *(e.g.,* Starting Reserves and CRAC and DDC settings) defined within the ToolKit file itself. The ToolKit reads in data from two external files, one each from RevSim and NORM. Most of the modeling of risks are performed by the Operating Risk Models and NORM, as described in sections 2 and 3 of this Study. Most of the logic for simulating the financial results in the years included in a ToolKit analysis is in VBA code (Microsoft's *V*isual *B*asic for *A*pplications).

The ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves and liquidity attributable to Power Services, and thus on TPP. It registers a deferral of a Treasury payment when reserves and all sources of liquidity are exhausted in any given year. The ToolKit is run for 3,200 games or iterations. TPP is calculated by dividing the number of games where a deferral did not occur in either year of the rate period by 3,200. The ToolKit calculates the TPP and other risk statistics and reports results. The ToolKit also allows analysts to calculate how much PNRR is needed in rates, if any, to meet the TPP standard. The "Main" page of the ToolKit is shown in Documentation Figure 30.

3.4 ToolKit Inputs and Assumptions

3.4.1 RevSim Results

The ToolKit reads in risk distributions generated by RevSim that are created for the current year, FY 2015, and the rate period, FY 2016–2017. TPP is measured for only the two-year rate period, but the starting Reserves Available for Risk for FY 2016 depend on events yet to unfold in FY 2015; these runs reflect that FY 2015 uncertainty. See section 2 of this Study for more detail on Operating Risk Models.

3.4.2 Non-Operating Risk Model

The ToolKit reads in NORM distributions that are created for FY 2015–2017, which reflect the uncertainty around non-operating expenses. See section 2 of this Study for more detail on NORM.

3.4.3 Treatment of Treasury Deferrals

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

3.4.4 Starting PS Reserves

The FY 2015 starting PS reserves have a known value of $273.1 million based upon the FY 2014 Fourth Quarter Review. Each of the 3,200 games starts with this value. See section 3.2.1.1 above for a description of PS Reserves.

3.4.5 Starting ACNR

The FY 2015 starting ACNR value of $0 million is known from the definition of ANCR as being accumulated PS net revenue since the end of FY 2014. Each of the 3,200 games starts with this value.

3.4.6 PS Liquidity Reserves Level

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

3.4.7 Treasury Facility

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

3.4.8 Interest Rate Earned on Reserves

Interest earned on the both the cash component and the Treasury Specials component of PS Reserves is 1.1 percent in FY 2015, 1.6 percent in FY 2016, and 2.8 percent in FY 2017. Interest paid on use of the Treasury Facility is 0.67 percent, 2.29 percent, and 3.77 percent for those three fiscal years.

3.4.9 Interest Credit Assumed in Net Revenue

An important feature of the ToolKit is the ability to calculate interest earned on PS reserves separately for each game. The net revenue games the ToolKit reads in from RevSim include deterministic assumptions of interest earned on reserves for each fiscal year; that is, the interest earned does not vary from game to game. To capture the risk impacts of variability in interest credit induced by variability in the level of reserves, in the TPP calculations the values embedded in the RevSim results for interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The interest credit assumptions embedded in RevSim results that are backed out are $6.6 million for FY 2015, $9.1 million for FY 2016, and $16.6 million for FY 2017.

3.4.10 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the non-linear shape of PS Reserves throughout a fiscal year as well as the interest earned on reserves attributed to PS that are not available for risk and not modeled in the ToolKit. 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. Additionally, the ToolKit does not model Reserves Not For Risk (*see* section 3.2.1.1, above), nor the interest earned from these. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year along with the interest earned on reserves attributed to PS that are not available for risk. The cash timing adjustments for this Study are $3.7 million for FY 2015, $4.7 million for FY 2016, and $8.2 million for FY 2017.

3.4.11 Cash Lag for PNRR

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

3.5 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 9.

3.5.1 TPP

The two-year TPP is 99.91 percent. In 3,200 games, there are no deferrals for FY 2015 or FY 2016. There are 3 deferrals for FY 2017, with the expected value of the amount deferred equal to $0.016 million. The mean size of deferrals when they occur is $17.1 million.

3.5.2 Ending PS Reserves

Known starting PS Reserves for FY 2015 are $273.1 million. The expected values of ending net reserves are $378 million for FY 2015, $411 million for FY 2016, and $367 million for FY 2017. Over 3,200 games, the range of ending FY 2017 net reserves is from negative $430 million to $1,302 million. The rate adjustment mechanisms would produce a CRAC of $265 million or a DDC of $552 million in these extreme cases if the FY 2018 rates include mechanisms comparable to those included in the FY 2016–2017 rates. The 50 percent confidence interval for ending net reserves for FY 2017 is $121 million to $610 million. ToolKit summary statistics for reserves and liquidity are in Documentation Figure 31 and Table 24.

3.5.3 CRAC and DDC

The CRAC triggers in 86 of the 3,200 games (3 percent of the time) for FY 2016, yielding an expected value of $0.95 million in CRAC revenue in that year. The average size of the CRAC when it occurs is $35.5 million. For FY 2017, the CRAC triggers 128 times (4 percent), yielding an expected value of $3.0 million of CRAC revenue in that year, with an average CRAC size of $75.1 million when the CRAC does occur.

The DDC triggers in 15 of the 3,200 games (0.5 percent of the time) for FY 2016, yielding an expected value of $0.13 million in distributions in that year. The average size of the distributions when the DDC does trigger is $28.1 million. For FY 2017, the DDC triggers 256 times (8 percent), yielding an expected value of $8.4 million in distributions in that year, with an average distribution size of $105.2 million when the DDC does trigger.

The thresholds and caps for the CRAC and DDC applicable to rates for FY 2016 and FY 2017 are shown in Tables 7 and Table 8.

This page intentionally left blank.

4. QUALITATIVE RISK ASSESSMENT AND MITIGATION

4.1 Introduction

The qualitative risk assessment described here is a logical analysis of the potential impacts of risks that have been identified (but not included in the quantitative risk assessment), given the risk mitigation measures that have been created, which are 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 BPA can cover its fish and wildlife program costs is an important objective. Because of pending and possible litigation over BPA's FCRPS fish and wildlife obligations, it is impossible to determine now with certainty the approach to fish recovery and the associated costs that BPA will be required to implement during the rate period, FY 2016–2017.

The possibilities for FY 2016–2017 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 FCRPS BiOps 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 provided in Power Rate Schedules, BP-16-E-BPA-09, GRSP II.N.

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

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by NMFS (also known as NOAA Fisheries Service) or the U.S. Fish and Wildlife 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, 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, Litigation.
(5) Actions or measures ultimately required under the 2014 Supplemental FCRPS BiOp that differ from the 2014 Supplemental FCRPS BiOp implementation forecast in the rate case.

The fish and wildlife operation or fish and wildlife program (or both) that BPA implements in a fiscal year (for example, FY 2015) may not be the same as that assumed in the rate proposal.

The "as modified" term used in the description of the NFB mechanisms means that BPA will first adjust for changes in operations due to non-trigger event reasons, as well as changes in operations due to prior NFB events to determine the baseline for calculating the financial effects of an NFB event.

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 BiOps and litigation over BiOps (as specified above).

4.2.1 The NFB Adjustment

The NFB Adjustment adjusts the CRAC for any year in the rate period if one or more NFB Trigger Events with financial effects occurred in the previous year (unless one or more Emergency NFB Surcharges in the previous year completely collected additional revenue equal to the financial effects). The adjustment allows the CRAC to collect more revenue under specific conditions. The NFB Adjustment could modify the CRAC Cap applicable to rates for FY 2016 or FY 2017. While the NFB Adjustment increases the revenue the CRAC can collect, it does not necessarily result in higher revenue collected. If the NFB Adjustment triggers but Power Services' ACNR is above the CRAC threshold specified in the GRSPs, there will be no adjustment to rates, because the CRAC will not trigger. It is possible to have a trigger event which does not reduce Net Revenue; these events do not trigger NFB Adjustments or Emergency NFB Surcharges.

4.2.2 The Emergency NFB Surcharge

The Emergency NFB Surcharge results in nearly immediate increases in net revenue for PS if (a) an NFB Trigger Event occurs, and (b) BPA is in a "Cash Crunch" and cannot prudently wait until the next year to collect incremental net revenue. A Cash Crunch is defined to exist when BPA calculates that the within-year Agency TPP (*i.e.*, including both TS and PS) is below 80 percent. The surcharge increases net revenue by making an upward adjustment to power and transmission rates as specified in Power Rate Schedules, BP-16-E-BPA-09, GRSP II.N.

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 2016 if the events required to impose the surcharge occur in that fiscal year, or in FY 2017 if the requisite events occur in that year.

4.2.3 Multiple NFB Trigger Events

There can be multiple NFB Trigger Events in one year. If BPA is not in a Cash Crunch in such a year, then there will be only one final analysis near the end of the year that calculates the NFB Adjustment to the cap on the CRAC applicable to the next fiscal year. If BPA is in a Cash Crunch in such a year, there may be more than one Emergency NFB Surcharge calculated and applied during that year. For example, there could be more than one court order in FY 2016 that increases the financial impacts of operations in FY 2016. 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 2016. If BPA were not in a Cash Crunch in FY 2016, all of these triggering events would be included in the calculation of the single NFB Adjustment that would increase the cap on the CRAC applicable to FY 2017.

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 most recent final rate proposal (as modified prior by previously responded-to NFB Events), it is possible for a Trigger Event to affect operations for more than one year of the rate period. For example, a decision in FY 2015 may affect operations in both FY 2015 and FY 2016. The analysis of the total financial impact during FY 2015 for adjusting the cap on the CRAC applying to FY 2016 would be separate from the analysis of the total financial impact during FY 2016 for adjusting the cap on the CRAC applying to FY 2017 (or for implementing an Emergency NFB Surcharge during FY 2016). Increases in the financial impacts during FY 2017 are not covered by the NFB Adjustment, because incorporating those increases through an NFB Adjustment would require a CRAC during FY 2016, and the rates for FY 2016 are not covered by this Study. However, financial impacts during FY 2017 are covered by the Emergency NFB Surcharge provisions applicable to FY 2017.

4.3 Risks Associated with Tier 2 Rate Design

4.3.1 Introduction

For the FY 2016–2017 rate period, there are four Tier 2 rate alternatives: the Tier 2 Short-Term, Tier 2 Load Growth, Tier 2 VR1-2014, and Tier 2 VR1-2016 rates. *See* Power Rates Study, BP-16-E-BPA-01, § 3.1.7. BPA has made all of the necessary 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). *Id.*, § 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 2016–2017 rate period. *See* section 1.2.1 above.

4.3.2 Identification and Analysis of Risks

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

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

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

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

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

(e) A customer's Above-RHWM load is lower than its take-or-pay VR1-2016 rate amounts.

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

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

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

If there is a disruption in the delivery from Mid-C to the BPA point of delivery due to a transmission event, BPA will supply replacement power and pass through the cost of the replacement power to the Tier 2 purchasers by means of a Transmission Curtailment

Management Service (TCMS) calculation. The Power Rates Study, BP-16-E-BPA-01, § 3.1.9.1, explains how the TCMS calculation is performed for service at Tier 2 rates. BPA will base the TCMS cost on the amount of megawatthours that was curtailed and the Powerdex (or its replacement) Mid-C hourly index for the hour the event occurred. Based upon BPA's past experiences, it is not anticipated that such disruptions would affect a substantial number of hours in a year. The market index is a fair, unbiased estimate of the cost of replacement power; therefore, there is no reason to believe that if such events occur in a fiscal year BPA would incur a net cost.

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

Each customer provided BPA an election regarding its intention to meet none, some, or all of its Above-RHWM load with Tier 2-priced power from BPA. Elections were made by September 30, 2011, for FY 2016 and FY 2017. Using the Above-RHWM loads that were computed in the RHWM process, which concluded in October 2014, and the customers' elections, BPA has determined each customer's Above-RHWM load served at a Tier 2 rate for the BP-16 rate period. As noted in section 4.3.2.1 above, BPA has made contractual commitments to purchase power sufficient to supply the necessary quantity of power at Tier 2 rates.

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

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

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

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

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

4.3.2.5 Risk: A Customer's Above-RHWM Load is Lower than its Take-or-Pay Tier 2 Amounts

When customers subscribed to the Tier 2 VR1-2014 and Tier 2 VR1-2016 rates, they requested specific amounts of load to be served at these rates on a take-or-pay basis for the term of the rate alternative's application. Customers were eligible for amounts that were capped at levels based on BPA load forecasts completed the previous spring. Once customers requested an amount, however, and BPA was successful purchasing that amount, then the customers became contractually committed to that purchase amount. Some customers elected, in accordance with section 10 of the CHWM contract, to have BPA remarket amounts of their purchases that are in excess of their Above-RHWM load. These customers will continue to pay the full cost of the purchases they elected. BPA will allocate some of this power to the Tier 2 Short-Term cost pool at a market price. The remainder will be purchased to meet a portion of BPA's Tier 1 augmentation need at the forecast Tier 1 augmentation prices. Because BPA is selling the excess power at fixed prices to Short-Term customers and at fixed prices for Augmentation needs, the revenues that will be received from Short-Term customers will equal the remarketing credits paid to Tier 2 customers, and there is no risk to BPA.

4.4 Risks Associated with Resource Support Services Rate Design

4.4.1 Introduction

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

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-16-E-BPA-01A, Table 3.21.

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" its operational decisions. 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 $4 million annually. *See* Power Rates Study, BP-16-E-BPA-01, § 3.1.15.1. The magnitude of the risk of miscalculation of these RSS costs is not large enough to affect TPP calculations.

4.5 Qualitative Risk Assessment Results

4.5.1 Biological Opinion Risks

The financial risks deriving from possible changes to Biological Opinions are adequately mitigated by the NFB mechanisms. *See* section 4.2 above and Power Rate Schedules, BP-16-E-BPA-09, GRSP II.N.

4.5.2 Risks Associated with Tier 2 Rate Design

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

4.5.3 Risks Associated with Resource Support Services Rate Design

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

This page intentionally left blank.

TABLES AND FIGURES

This page intentionally left blank

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

	FY 2016	FY 2017
Henry Hub	$3.86	$4.05
AECO	-0.40	-0.42
Kingsgate	-0.16	-0.16
Malin	-0.03	-0.04
Opal	-0.13	-0.15
PG&E	0.31	0.32
Topock/Ehrenberg	0.12	0.13
Socal Citygate	0.24	0.26
San Juan	-0.16	-0.17
Stanfield	-0.10	-0.11
Sumas	-0.09	-0.10

Table 2: Natural Gas Price Risk Model Percentiles (Nominal Henry Hub)

FY16	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
95th	5.12	5.27	5.62	5.88	6.02	5.84	5.67	5.43	5.36	5.49	5.58	5.62
50th	3.70	3.77	3.93	4.16	4.12	3.91	3.77	3.71	3.70	3.81	3.82	3.86
5th	2.75	2.75	2.90	3.00	2.94	2.82	2.69	2.66	2.65	2.74	2.77	2.80

FY17	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
95th	5.44	5.55	5.89	6.34	6.56	6.61	6.21	5.98	6.04	6.05	6.02	5.92
50th	3.84	3.90	4.08	4.21	4.20	4.12	3.96	3.89	3.97	4.07	4.05	4.02
5th	2.84	2.89	2.98	3.03	3.10	2.99	2.74	2.73	2.77	2.89	2.87	2.82

Table 3: Average Market Price from the Market Price Run for FY16/FY17

FY16	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	30.80	32.68	34.44	34.13	33.38	27.80	26.17	22.42	21.81	29.28	32.80	34.38
LLH	26.77	28.24	29.28	27.49	27.96	23.86	22.55	14.62	7.88	22.50	27.16	28.43

FY17	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	32.38	34.10	36.17	36.50	36.80	29.62	28.00	25.08	25.62	32.18	35.28	36.10
LLH	27.94	29.50	30.98	31.08	30.60	25.48	24.39	17.24	13.32	24.59	28.72	29.62

Table 4: Average Market Price from AURORAxmp® Critical Water Run for FY16/FY17

FY16	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	32.33	35.10	37.25	42.21	41.63	32.01	31.32	25.26	26.93	34.77	34.34	35.47
LLH	27.57	30.10	31.96	35.59	34.26	28.31	27.19	22.83	23.51	28.14	27.66	28.75

FY17	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	33.94	36.68	38.93	44.24	47.31	34.69	32.81	27.48	29.80	37.99	36.65	37.17
LLH	28.74	31.40	33.07	37.66	37.79	30.48	28.77	23.97	26.05	30.70	29.28	29.88

Table 5: RevSim Net Revenue Statistics (With PNRR of $0 million)

	A	B	C
1		FY16	FY17
2	Average	$ 50,846	$ (45,772)
3	Median	$ 48,336	$ (45,423)
4	Standard Deviation	$ 170,537	$ 189,448
5			
6	1%	$ (246,175)	$ (379,412)
7	2.50%	$ (235,678)	$ (364,223)
8	5%	$ (225,252)	$ (353,031)
9	10%	$ (189,836)	$ (318,704)
10	15%	$ (146,032)	$ (261,413)
11	20%	$ (109,832)	$ (221,143)
12	25%	$ (83,724)	$ (194,209)
13	30%	$ (56,453)	$ (168,152)
14	35%	$ (25,278)	$ (132,163)
15	40%	$ 4,128	$ (97,278)
16	45%	$ 26,849	$ (71,701)
17	50%	$ 48,336	$ (45,423)
18	55%	$ 72,206	$ (18,386)
19	60%	$ 99,329	$ 8,370
20	65%	$ 124,317	$ 38,901
21	70%	$ 147,076	$ 65,279
22	75%	$ 176,790	$ 94,331
23	80%	$ 206,274	$ 122,929
24	85%	$ 241,635	$ 159,135
25	90%	$ 278,674	$ 201,592
26	95%	$ 328,369	$ 262,832
27	97.50%	$ 375,043	$ 315,095
28	99%	$ 426,556	$ 389,565

Table 6: Risk Modeling Net Revenue To Cash Adjustments (in $Thousands)

A	B	C	D	E
		FY 2015	FY 2016	FY 2017
1	Depreciation/Capitalization	182,766	166,609	181,212
2	FY14 Libby/NTSA	16,867	-	-
3	Other Misc Adjustments	(4,295)	-	-
4	Debt Principal Repayment	(410,163)	(166,610)	(181,212)
5	FY14 Slice Payment	(40,826)	-	-
6	FY15 Slice Accrual	26,755	(26,755)	-
7	NORM Slice True Up Lagging out of this year	**4,077**	**2,934**	**810**
8	NORM Slice True Up Lagging in from previous year	**-**	**(4,077)**	**(2,934)**
9	**Net Revenue to Cash Adjustment**	(224,819)	(27,899)	(2,124)

Table 7: CRAC Annual Thresholds and Caps
[Dollars in millions]

A **ACNR Calculated at End of Fiscal Year**	B **CRAC Applied to Fiscal Year**	C **CRAC Threshold as Measured in ACNR**	D **Approx. Threshold as Measured in PS Reserves**	E **Maximum CRAC Recovery Amount (CRAC Cap)***
2015	2016	-$48.3	$0	$300
2016	2017	-$20.2	$0	$300

* The CRAC Cap may be modified by NFB Adjustments

Table 8: DDC Thresholds and Caps
[Dollars in millions]

A **ACNR Calculated at End of Fiscal Year**	B **DDC Applied to Fiscal Year**	C **DDC Threshold as Measured in ACNR**	D **Approx. Threshold as Measured in PS Reserves**	E **Maximum DDC Distribution Amount (DDC Cap)**
2015	2016	$701.7	$750	$1,000
2016	2017	$729.8	$750	$1,000

Table 9: ToolKit Summary Statistics

	[Dollars in Millions]			
	A	**B**	**C**	**D**
1	Two-Year TPP		99.91%	
		FY 2015	**FY 2016**	**FY 2017**
2	PNRR	-	$0.0	$0.0
3	CRAC Frequency	0%	3%	4%
4	Expected Value CRAC Revenue	$0.0	$1.0	$3.0
5	DDC Frequency	0%	0.5%	8%
6	Expected Value DDC Payout	$0.0	$0.1	$8.4
7	Treasury Deferral Frequency	0.0%	0.0%	0.1%
8	Expected Value Treasury Deferral	$0.0	$0.0	$0.016
9	Exp. Value End-of-Year Net Reserves	$377.6	$410.6	$367.0
10	Net Reserves, 5th percentile	$107.1	$15.4	($181.0)
11	Net Reserves, 25th percentile	$264.6	$243.9	$121.2
12	Net Reserves, 50th percentile	$382.2	$409.2	$380.1
13	Net Reserves, 75th percentile	$500.3	$582.2	$610.0
14	Net Reserves, 95th percentile	$635.4	$806.5	$887.9

Figure 1: Risk Assessment Information Flow

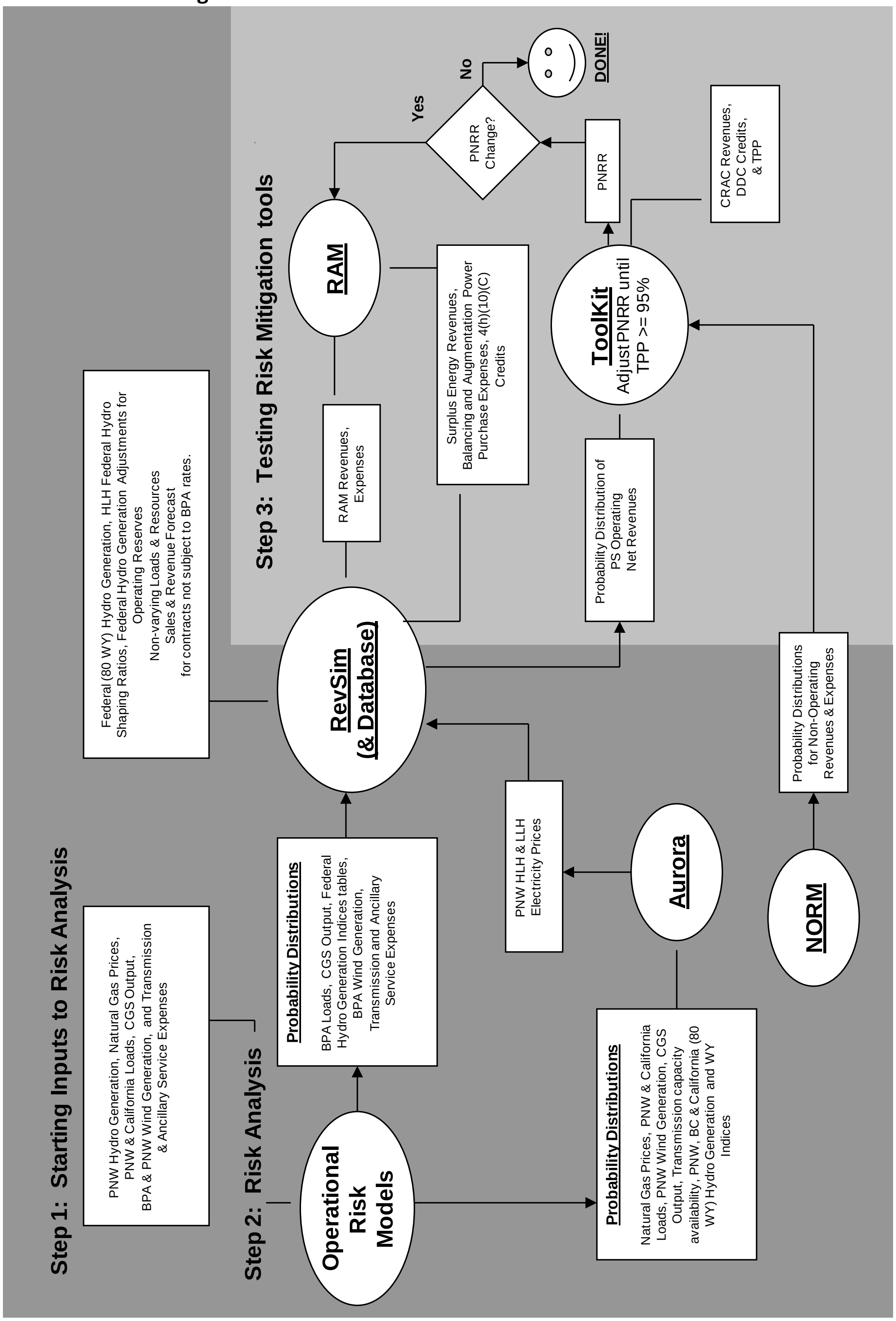


Figure 2: AURORAxmp® Zonal Topology

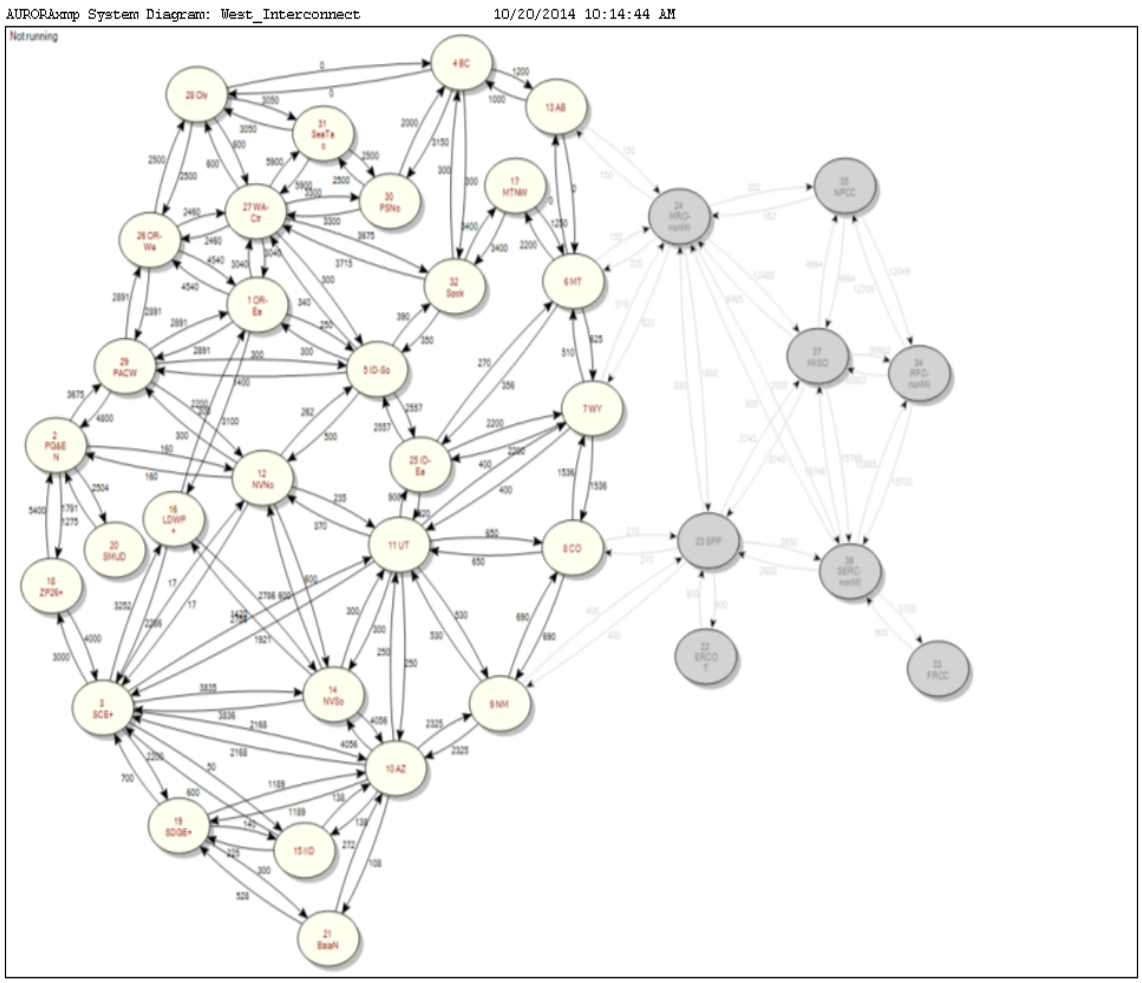


Figure 3: Basis Locations

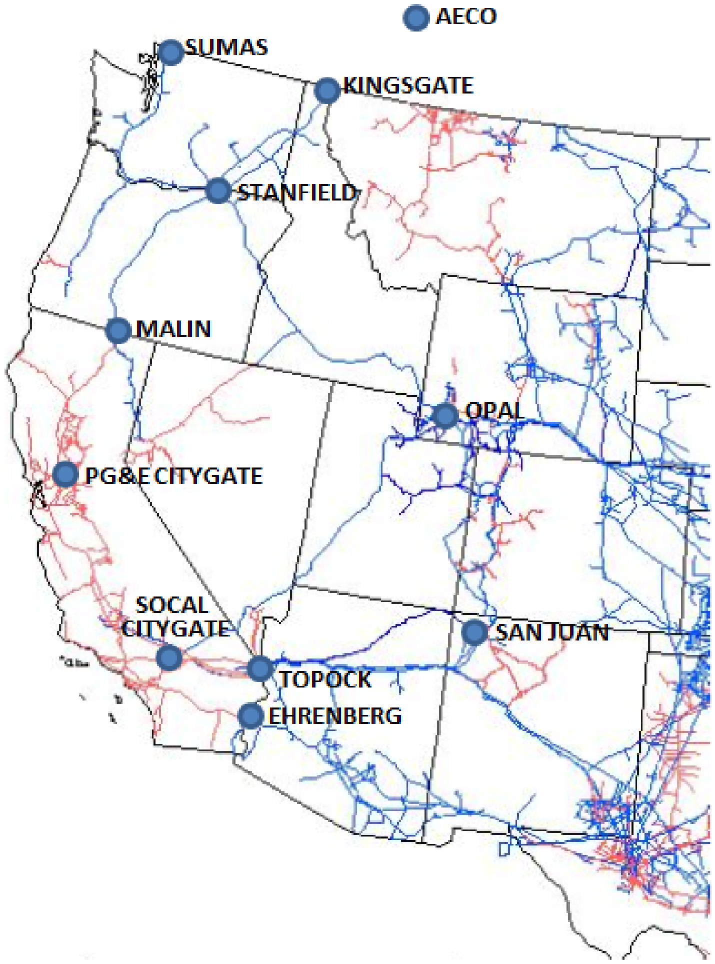


Figure 4: January 2013 through October 2014 Henry Hub Gas prices

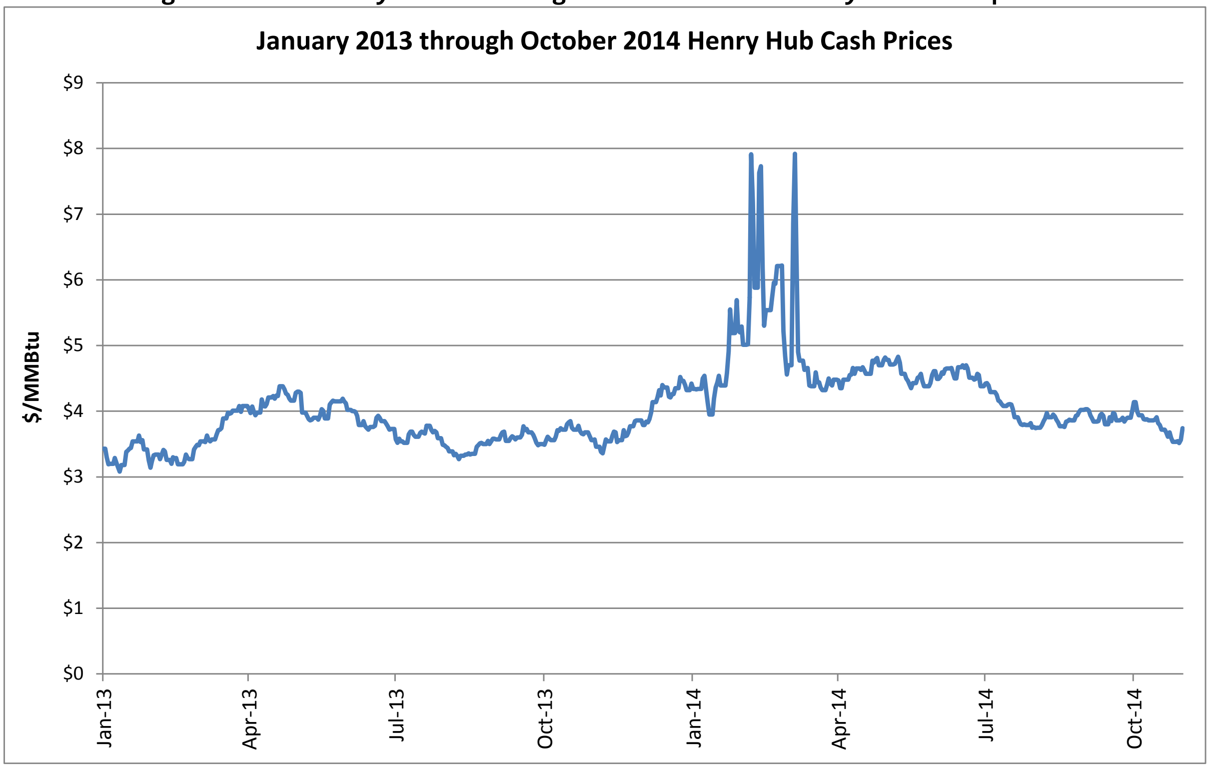
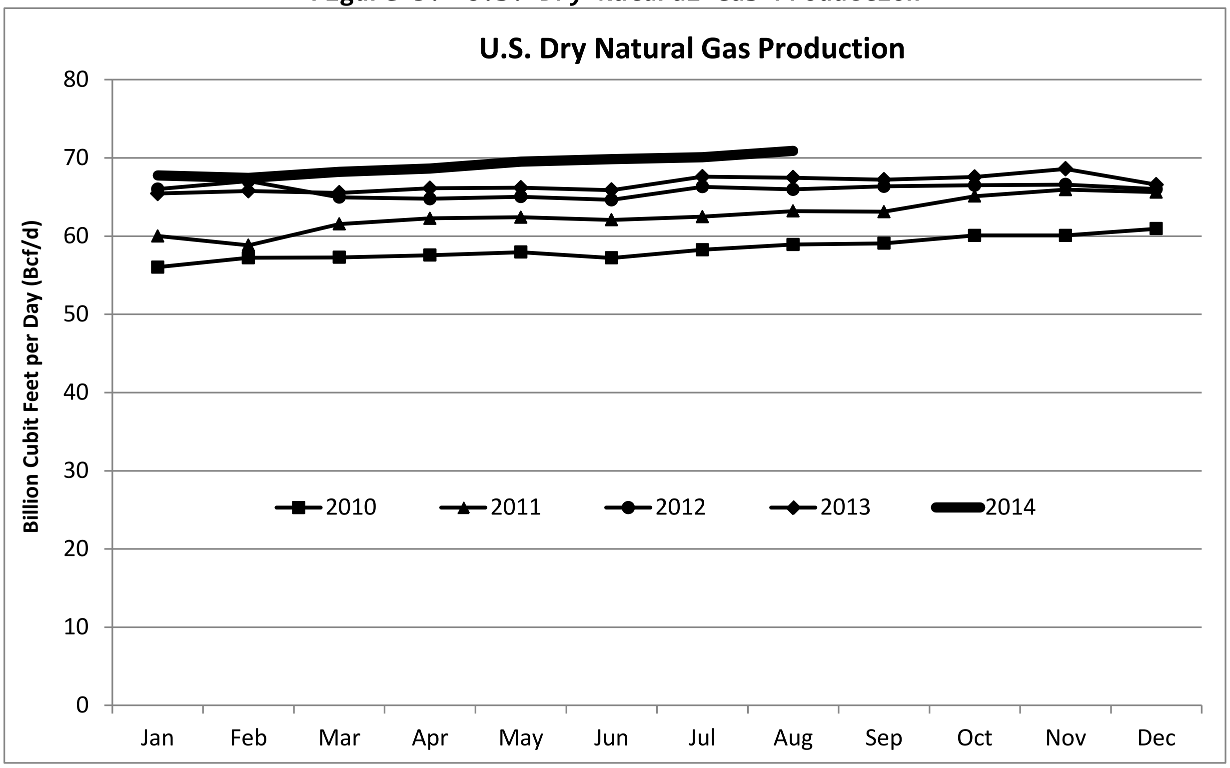
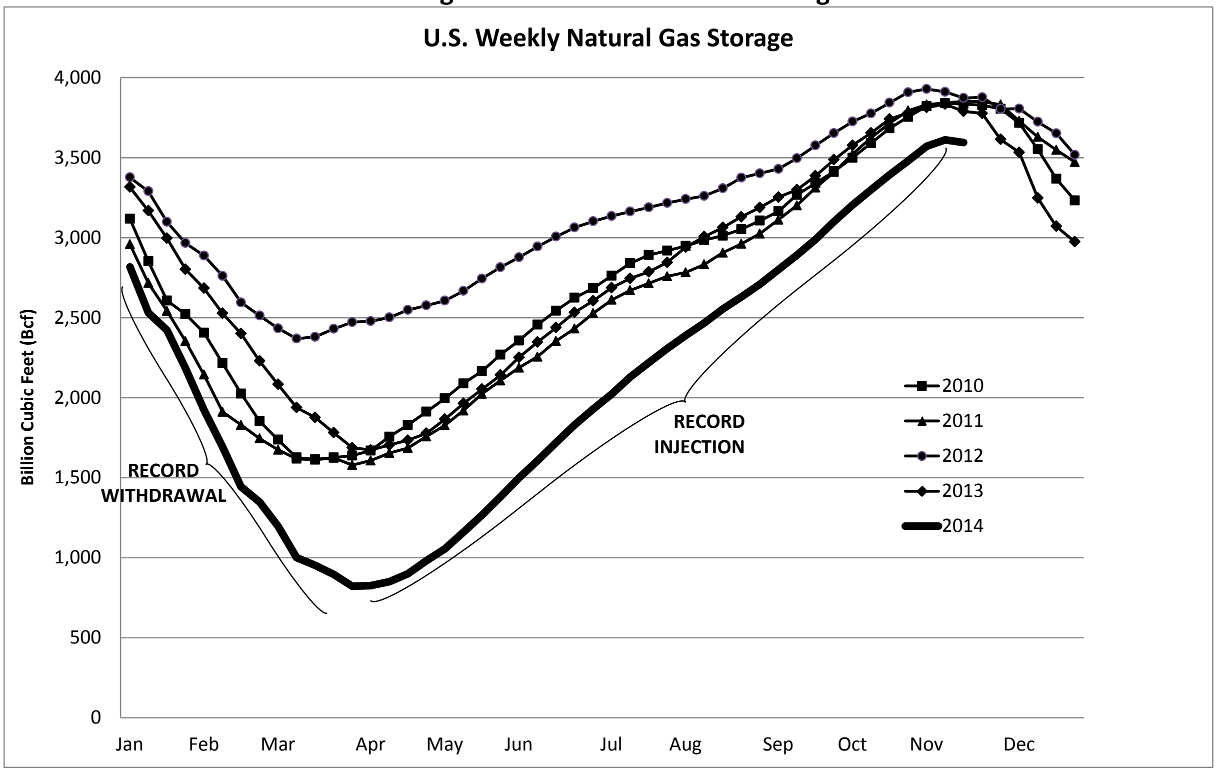


Figure 5: U.S. Dry Natural Gas Production



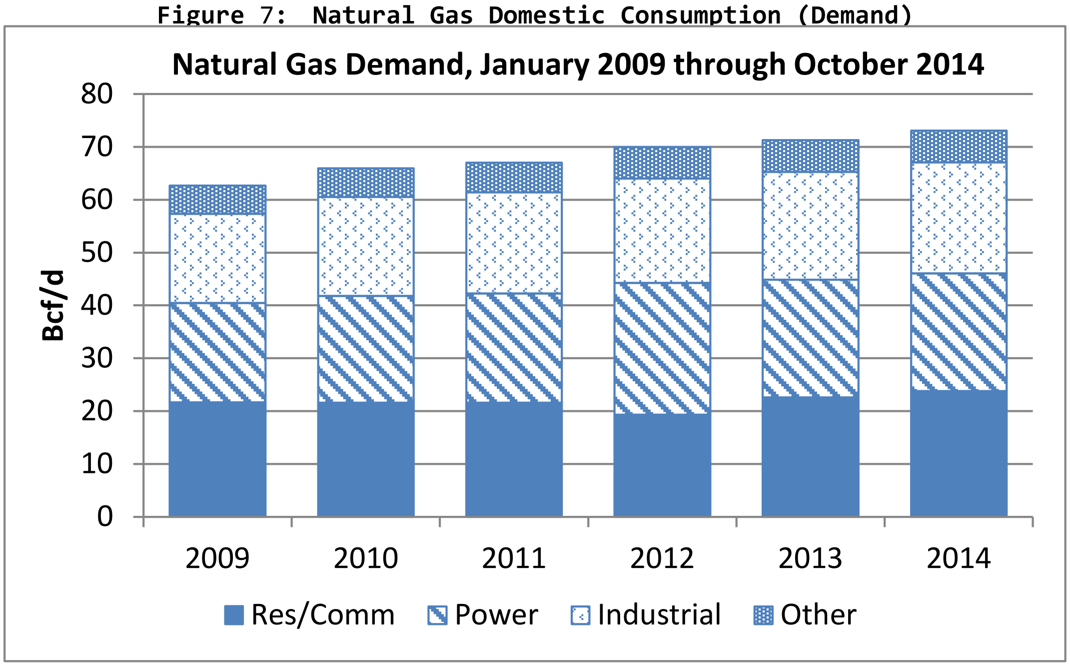
Source: U.S. Energy Information Administration

Figure 6: Natural Gas Storage



Source: U.S. Energy Information Administration

Figure 7: Natural Gas Domestic Consumption (Demand)



Source: U.S. Energy Information Administration

This page intentionally left blank.

BONNEVILLE POWER ADMINISTRATION
DOE/BP-4612 • December 2014