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-22 Rate Proceeding

Final Proposal

Power and Transmission Risk Study

BP-22-FS-BPA-05

July 2021

POWER AND TRANSMISSION RISK STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also “NPCC”)
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service

DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	Environmental Impact Statement
ELMP	Extended Locational Marginal Pricing
EN	Energy Northwest, Inc.
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
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental

IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
KSI	key strategic initiative
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service

NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	Point of Receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge

RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
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	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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1. INTRODUCTION

The objectives of the Power and Transmission Risk Study (Study) are to identify, model, and analyze the impacts that key risks and risk mitigation tools have on BPA's net revenue (total revenue less total expenses) and cash flow. The Study ensures that power and transmission 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: (1) a risk assessment step, in which the distributions (or profiles) of operating and non-operating risks are defined; and (2) a risk mitigation step, in which risk mitigation tools are assessed with respect to their ability to recover costs given the uncertainties assessed in step 1. The risk assessment estimates two elements: 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 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 and Transmission Risk Study

The Power and Transmission Risk Study demonstrates that BPA's proposed rates and risk mitigation tools together meet BPA's standard for financial risk tolerance: the TPP standard. This Study includes quantitative and qualitative analyses of risks to net revenue and tools for mitigating those risks. It also establishes the adequacy of those tools for meeting BPA's TPP standard.

In addition to mitigating the risk that financial reserves and other liquidity may be insufficient to repay the U.S. Treasury (Treasury), this Study also describes the implementation of BPA's Financial Reserves Policy (FRP), which was established in the Administrator's Record of Decision for BP-18 and refined in September 2018. *See* Appendix A, Financial Reserves Policy; *see also* Administrator's Final Record of Decision, BP-18-A-04, Appendix A; Administrator's Record of Decision, Financial Reserves Policy Phase-In Implementation (Sept. 2018) (*available at* https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx). The FRP was established to maintain BPA's financial health. It establishes financial reserves' target ranges for the business lines and agency, as well as rate actions to be taken when financial reserves are outside those target ranges.

2. FINANCIAL RISK POLICIES AND OBJECTIVES

2.1 Risk Mitigation Policy Objectives

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

- Create a rate design and risk mitigation package that meets BPA financial standards, particularly achieving the TPP Standard.
- 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 Federal Columbia River Power System (FCRPS) and Federal Columbia River Transmission System (FCRTS).
- Implement BPA's FRP to maintain prudent financial reserves levels and support BPA's financial objectives.
- Include in the risk mitigation package only those elements that can be relied upon.
- Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, for Power rates, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation.
- 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.

2.2 How Risk 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 calculation takes into account the thresholds and caps for the risk adjustment mechanisms, that is, the Cost Recovery Adjustment Clause (CRAC), the Reserves Distribution Clause (RDC), and the FRP Surcharge. These thresholds and caps are incorporated in the Power and Transmission General Rate Schedule Provisions (GRSPs) and will be used in later calculations outside the ratemaking process to determine whether a CRAC, RDC, or FRP Surcharge will be applied to certain power and transmission rates for FY 2022 or FY 2023. *See* Power Rate Schedules and GRSPs, BP-22-FS-BPA-10 (Power GRSPs); Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-FS-BPA-11 (Transmission GRSPs).

2.3 Financial Reserves and Liquidity

This Study evaluates the availability of financial reserves to meet BPA's obligations over the rate period when taking into account rates and risk mitigation tools. When this Study uses the term "financial reserves," it is referring to a specific subset of total financial reserves, known as "financial reserves available for risk," which consist of cash and investments held in the Bonneville Fund, *plus* any deferred borrowing, *less* any financial reserves not available for risk, *less* any outstanding balance on the Treasury Facility. These components are discussed below.

- Deferred borrowing consists of amounts of capital expenditures BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts can be converted to cash at any time by completing the borrowing.
- Reserves not available for risk consist of funds held for specific purposes, such as deposits from customers and other entities.
- The Treasury Facility is an agreement between BPA and the Treasury that makes a $750 million short-term note available to BPA for up to two years to pay expenses.

BPA has concluded that this note can be prudently relied upon as a source of liquidity. The Treasury Facility allows BPA to borrow to meet cash needs. Because of this, financial reserves could fall to a negative level, and BPA could still meet its cash obligations. Borrowing from the Treasury Facility generates cash, but also results in an outstanding balance against the Treasury Facility. When borrowing occurs, the effect on financial reserves is neutral; financial reserves are augmented by the cash but reduced by the outstanding balance. As the cash is expended, however, this relationship allows financial reserves to go negative.

This Study also differentiates between financial reserves attributable to Power Services (PS reserves) and financial reserves attributable to Transmission Services (TS reserves). Financial reserves are not held in Power Services- or Transmission Services-specific accounts. BPA has only one account, the Bonneville Fund, in which it maintains financial reserves. Staff in the BPA Chief Financial Officer's organization "attribute" part of the Bonneville Fund balance to the power generation function and part to the transmission function. These funds do not belong to Power Services or Transmission Services; they belong to BPA.

2.4 BPA's Treasury Payment Probability (TPP) Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the 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 multi-year rate period rather than the probability for a single year. The TPP standard remains in effect in the most recent release of the Financial Plan, dated February 2018. *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 separately measured for Power Services and Transmission Services. This Study tests the ability of Power Services and Transmission Services to make their portions of the Treasury payments over the rate period.

The following items (explained in more detail in Chapter 4 below) are included in the calculation of TPP:

- *Starting Financial Reserves.* The amount of PS reserves and TS reserves at the start of FY 2021.
- *Planned Net Revenues for Risk (PNRR).* PNRR is the final component of the revenue requirement that may be added to annual expenses. PNRR may be added when the risk mitigation provided by starting financial reserves and other risk mitigation tools is insufficient to meet the TPP standard. PNRR may also be added to meet the needs of the FRP or for settlement purposes.
- *BPA's Treasury Facility.* BPA's Treasury Facility is relied on as a source of borrowing to meet liquidity needs (Borrowing Liquidity). The full $750 million in the Treasury

Facility is considered to be available for the liquidity needs associated with Power Services.

- *Agency Liquidity in Excess of TPP (Agency Liquidity).* BPA assumes that any liquidity above the level required to meet a business line's 95 percent TPP standard can be made available to meet the remaining Treasury payment obligations of the agency. The other business line may rely on this liquidity as a source of Borrowing Liquidity, for purposes of the TPP test, up to the amount needed to demonstrate achievement of the TPP standard. Use of Agency Liquidity does not affect the attribution of financial reserves or interest earnings for either business line.
- *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 within-year liquidity need is $320 million for Power Services and $100 million for Transmission Services. The methodologies for calculating these amounts and the resulting amounts remain unchanged from BP-20 rates. The within-year liquidity need is first applied as a reduction to Borrowing Liquidity. If Borrowing Liquidity is insufficient to cover the within-year liquidity need, the remainder of the need is applied as a reduction to financial reserves available to meet the TPP standard.
- *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 December following a fiscal year in which Power Services or Transmission Services Reserves For Risk fall below the Power or Transmission CRAC threshold. The Power Services threshold is set at $0 in Power Services Reserves For Risk in accordance with the FRP. Power GRSP II.O. The Transmission Services threshold is set at $0 in Transmission Services Reserves For Risk in accordance with the FRP. Transmission GRSP II.G.

- *Reserves Distribution Clause.* The RDC allows the Administrator to repurpose financial reserves (that are above the level necessary for TPP and the FRP) as debt reduction, incremental capital investment, rate reduction through a Dividend Distribution (DD), distribution to customers, or any other business-line-specific purpose determined by the Administrator. A DD is a downward adjustment to the applicable power or transmission rates. The adjustment is applied to rates charged for service beginning in December following a fiscal year in which Power Services or Transmission Services Reserves For Risk are above the RDC threshold. A financial reserves distribution may be made if (1) financial reserves attributed to a business line exceed the RDC threshold for that business line, and (2) BPA financial reserves exceed the BPA RDC threshold. Power GRSP II.P; Transmission GRSP II.H.
- *FRP Surcharge.* The FRP Surcharge is an upward adjustment to applicable power and transmission rates. The adjustment is applied to rates charged for service beginning in December following a fiscal year in which Power Services or Transmission Services Reserves For Risk falls below the business line lower threshold. The Power Services lower threshold is set at $302 million in Power Services Reserves For Risk, in accordance with the FRP. The Transmission Services lower threshold is set at $102 million in Transmission Services Reserves For Risk, in accordance with the FRP.
- *Revenue Financed Capital.* Transmission rates include $40 million per year in revenue financed capital projects. Transmission Revenue Requirement Study Documentation, BP-22-FS-BPA-09A, §2.2.3. Power rates include $40 million per year in revenue financed capital projects. Power Revenue Requirement Study, BP-22-FS-BPA-02, §2.2.4. This study assumes that these revenue financed projects will be borrowed against to offset or reduce an FRP Surcharge or CRAC.

2.5 BPA's Financial Reserves Policy (FRP)

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A, Financial Reserves Policy. The FRP describes the actions BPA may take in response to financial reserves levels that either fall below a lower threshold or exceed an upper threshold. Relevant to this Study, the FRP is implemented through the CRAC, RDC, and FRP Surcharge rate mechanisms for Power Services and Transmission Services. This is described further in Sections 4.2 and 5.2.

The FRP was adopted in the BP-18 rate proceeding. Administrator's Final Record of Decision, BP-18-A-04, Appendix A. In 2018, BPA refined the FRP to specify the rate actions that would be taken when financial reserves attributable to a business line are below its lower threshold. Administrator's Record of Decision, Financial Reserves Policy Phase-In Implementation (Sept. 2018) (*available at* https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx. The policy is shown in Appendix A of this Study.

2.6 Quantitative vs. Qualitative Risk Assessment and Mitigation

This Study distinguishes between quantitative and qualitative perspectives of risk. The quantitative risk assessment is a set of 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 and financial reserves) for each of the two years in the rate period (FY 2022-2023) and for the year preceding the rate period (FY 2021). The models used in the quantitative risk assessment are described in Chapter 3. Quantitative risk modeling for Power is described in Section 4.1 and for Transmission in Section 5.1.

BPA's primary tool for risk mitigation is financial reserves. BPA also uses the CRACs and FRP Surcharges for Power and Transmission to manage financial risk. The CRACs and FRP Surcharges add additional risk mitigation to that provided by financial reserves and liquidity. When financial reserves, plus the additional revenue earned through a business line's CRAC and FRP Surcharge, plus Agency Liquidity, do not provide sufficient risk mitigation to meet the 95 percent TPP standard, PNRR is added to the revenue requirement. This increases rates, which generates additional financial reserves, which increases TPP. The models used in the quantitative risk mitigation are described in Section 3. Modeling of quantitative risk mitigation is described in Section 4.2 for Power Services and Section 5.2 for Transmission Services.

Some financial risks are unsuitable for quantitative modeling but are significant enough that they need to be accounted for. These qualitative risks usually fit into one of two general categories that make them unsuitable for quantitative 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.

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. Qualitative Power risks and associated mitigation are described in Section 4.3. There have been no qualitative risks identified for Transmission rates.

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3. TOOLS AND SIMULATORS USED IN QUANTITATIVE RISK MODELING

This section provides an overview of BPA's general approach to quantitative risk assessment and mitigation. More detailed descriptions of how this approach is implemented for Power and Transmission rates are provided below in Sections 4 and 5.

The approach BPA takes to quantify risks and assess whether BPA's proposed risk mitigation packages for Power Services and Transmission Services rates are sufficient is based on Monte Carlo simulation. In this technique, risks and the relationships between risks are defined using probabilistic models. A large number of games, or iterations, are run. In each game, a random value is drawn for each probabilistic model and the results are recorded. The entire set of gamed results is examined to verify that BPA's risk mitigation objectives have been achieved.

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. *See* §§ 2.4, 3.1.5.

3.1 Modeling Process to Calculate TPP

3.1.1 Study Models

BPA traditionally models risks using Monte Carlo simulation. Accordingly, models including Aurora®, the Revenue Simulation Model (RevSim), the Non-Operating Risk Models (P-NORM and T-NORM, explained in Section 3.1.3 below), and ToolKit each run 3,200 iterations, or games. Aurora estimates electricity prices, which serve as inputs to numerous other studies, including the Power portions of this Study. RevSim (see Section 3.1.2.1 below) combines deterministic load, resource, revenue, and expense values with the uncertainty in spot market electricity prices, loads and resources, Power Services transmission and ancillary services expenses, and Northwest Power Act Section 4(h)(10)(C) credits to produce 3,200 values for Power Services annual net revenue for each year of the BP-20 rate period, FY 2022 and FY 2023. The output of this process is combined with the distribution of output from P-NORM and provided to the ToolKit to calculate Power Services TPP. Similarly, Transmission Services revenue uncertainty is modeled for the Transmission Services Sales and Revenue Forecasts. *See* Transmission Rates Study and Documentation, BP-22-FS-BPA-08, § 2, Table 4, Table 5, and Table 12. The Transmission revenue uncertainty is combined with the distribution of output from T-NORM and provided to ToolKit to calculate Transmission Services TPP.

3.1.2 Revenue Simulation Models

3.1.2.1 Power – RevSim

RevSim calculates secondary energy revenues, balancing power purchase expenses, system augmentation purchase expenses, and extraregional sales revenue. Two financial operating risks are modeled externally and input to RevSim: 4(h)(10)(C) credits and Power Services transmission and ancillary services expenses. The results from RevSim and these two financial operating risks are provided for input into the Rate Analysis Model (RAM2022). RevSim also simulates Power Services operating net revenue for use in ToolKit. Inputs to RevSim include the output of certain risk models discussed in the Power Market Price Study and Documentation (to the extent that they affect generation and loads) and prices from Aurora. *See* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.3. RevSim also uses deterministic monthly load and resource data; rates from RAM2022; and non-varying revenues and expenses from Section 9 of the Power Rates Study, BP-22-FS-BPA-01.

3.1.2.1.1 Operating Risk Models

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

- Western Electricity Coordinating Council (WECC) loads
- Natural gas price
- Regional hydroelectric generation
- Pacific Northwest (PNW) hourly wind generation
- Columbia Generating Station (CGS) generation
- PNW hourly intertie availability

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 Aurora. Where applicable, the results for that game also serve as input to RevSim. The prices from Aurora, combined with the deterministic and variable values used in RevSim, constitute one net revenue game. Not every risk model will generate 3,200 games, and where necessary, a bootstrap approach (*i.e.,* resampling with replacement) is used to produce a full distribution of 3,200 games. Each of the 3,200 games in the joint distribution is uniquely identified, which allows for coordination between Aurora prices and RevSim inventory levels.

If BPA forecasts system augmentation purchases, their cost is estimated in RevSim using variable electricity prices calculated under 1937 "critical water" conditions. These results are used by RAM2022 when calculating rates and calculating net revenues provided for input into the ToolKit model. *See* § 3.1.5.

The monthly flat electricity prices calculated by Aurora under 80 water year conditions for all 3,200 games for each fiscal year are inputs into the risk model that calculates the average 4(h)(10)(C) credits included in the Power Revenue Requirement Study, BP-22-FS-BPA-02. The 4(h)(10)(C) credits calculated by this risk model for 3,200 games for each fiscal year are input into RevSim for use in calculating net revenue risk.

The monthly flat secondary energy values calculated by RevSim for all 3,200 games for each fiscal year are inputs into the Power Services Transmission and Ancillary Services Expense Risk Model, which calculates the average Power Services transmission and ancillary services expenses included in the Power Revenue Requirement Study, BP-22-FS-BPA-02. The transmission and ancillary services expenses, calculated for 3,200 games for each fiscal year, are input into RevSim for use in calculating net revenue risk.

3.1.2.2 Transmission – RevRAM

Transmission revenue is a key input to the income statement and to T-NORM. The Transmission Revenue Risk Assessment Model (RevRAM) models the revenue uncertainty in BPA's transmission products and services. RevRAM uses Microsoft Excel®-based models with the add-in risk simulation computer package @RISK®, a product of Palisade Corporation of Ithaca, New York, to generate 3,200 games with Monte Carlo simulation. Transmission products and services that are modeled for revenue uncertainty include:

- Network Integration (NT) Load Service, which has risk based on load variability.
- Long-Term Point-to-Point (PTP) Service on the Network and Southern Intertie (PTP LT and IS LT), which has risk based on probability of customers taking the contractual service and incorporates the risk of Legacy Products (Formula Power Transmission) conversion.

- Short-Term PTP Service on the Network and Intertie (PTP ST and IS ST), which has risk based on variability of market conditions that include hydro and prices.
- Scheduling, System Control and Dispatch (SCD), which has variability dependent on sales of Network and Intertie transmission service.
- Other revenues, including Delivery, Fiber and Personal Communications Services (PCS) Wireless, and other miscellaneous revenues, which have differing inputs but are modeled using historical variability.

The transmission products and services that are modeled for revenue uncertainty are individually modeled in Excel. A separate spreadsheet tab in RevRAM adds all individual revenue products to generate the total Transmission revenue forecast (excluding reimbursable revenues).

3.1.3 Non-Operating Risk Models

A Non-Operating Risk Model (NORM) is an analytical risk tool that quantifies the impacts of risks that are not modeled in the revenue simulation models (Section 3.1.2). Two NORMs are used in BP-22: P-NORM, which contains models of non-operating risks for Power Services; and T-NORM, which contains models of non-operating risks for Transmission Services. The NORMs follow BPA's traditional approach to modeling risks, which uses Monte Carlo simulation. In this technique, a model runs through a number of games (also known as 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.

New risks for inclusion in P-NORM or T-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 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 evaluated in the qualitative risk analysis. *See* § 4.3.

The probability distributions used by NORM were developed using historical financial data and subject matter expert interviews. 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.

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.

3.1.3.1 Power – P-NORM

P-NORM models Power Services risks that are not incorporated into RevSim, such as risks around corporate costs covered by power rates and debt service-related risks. P-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 – P-NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the Power Services revenue requirement. P-NORM models the accrual impacts of the included risks, as well as Net-Revenue-to-Cash (NRTC, explained in Section 3.1.4 below) adjustments, which translate the net revenue impacts into cash flow impacts. P-NORM supplies 3,200 games (or iterations) of net revenue and cash flow impacts of the risks that it models. The outputs from P-NORM, along with the outputs from RevSim, are passed to the ToolKit model to assess Power TPP.

3.1.3.2 Transmission – T-NORM

Similar to P-NORM, T-NORM models Transmission Services risks that are not incorporated into RevRAM, as well as some changes in revenue and some changes in cash flow. T-NORM models the accrual impacts of the included risks, as well as NRTC adjustments, which translate the net revenue impacts into cash flow impacts. T-NORM supplies 3,200 games (or iterations) of net revenue and cash flow impacts of the risks that it models. The outputs from T-NORM, along with the outputs from RevRAM, are passed to the ToolKit model to assess Transmission Services TPP.

3.1.4 Net-Revenue-to-Cash (NRTC) Adjustments

One of the inputs to the ToolKit (through P-NORM and T-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.

P-NORM and T-NORM each calculate 3,200 NRTC adjustments to make the necessary changes to convert accrual results (net revenue results) into the equivalent cash flows so the ToolKit can calculate financial reserves values in each game and thus calculate TPP.

The NRTC Adjustment is modeled probabilistically in P-NORM and T-NORM using a table of adjustments as its starting point and includes 3,200 gamed adjustments based on deviations in revenue and expense items. *See* §§ 4.1.3, 5.1.3.

3.1.4.1 @RISK Computer Software

P-NORM and T-NORM are maintained in Excel using @RISK, which 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.

3.1.5 Overview of the ToolKit

The ToolKit is a model that is used to evaluate the ability of Power Services and Transmission Services to meet BPA's TPP standard given the net revenue and financial reserve variability embodied in the distributions of operating and non-operating risks. The ToolKit is modeled in Microsoft Excel.

The ToolKit contains several parameters (*e.g.,* Starting Financial Reserves and CRAC and RDC settings) defined within the ToolKit file itself. The ToolKit reads in data from three external files. For Power, ToolKit reads in a file from RevSim and a file from P-NORM. For Transmission, ToolKit reads in a file from from T-NORM, which includes the RevRAM data. Most of the modeling of risks is performed by the input risk models, as described in Sections 4 and 5.

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 financial reserves and liquidity attributable to each business line, and thus on TPP. The ToolKit registers a Treasury payment deferral when financial reserves and all sources of liquidity for a business line 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 for each business line and reports results. The ToolKit also allows analysts to calculate how much PNRR is needed in rates, if any, to meet the TPP standard.

If TPP is below the 95 percent standard required by BPA's Financial Plan, then one or more risk mitigation tools may be adjusted in the ToolKit until the standard is met. These options include (1) adding PNRR to the revenue requirement; (2) raising the CRAC and FRP Surcharge thresholds, which makes them more likely to trigger; and (3) increasing the cap on the annual revenue the CRAC can collect.

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4. POWER RISK

4.1 Power Quantitative Risk Assessment

This section describes the uncertainties pertaining to Power Services finances in the context of setting power rates. Section 4.2 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 Power Services net revenue, largely a product of uncertainty in both Federal hydro generation and market prices, is substantial. BPA also considers uncertainty in (1) customer load; (2) CGS output; (3) wind generation; (4) system augmentation costs; (5) Power Services transmission and ancillary services expenses; and (6) Northwest Power Act Section 4(h)(10)(C) credits. The effects of these risk factors on Power Services net revenue are quantified in this Study.

Power Services also faces risks not directly related to the operation of the power system. These non-operating risks are modeled in P-NORM. These risks include the potential for CGS, Corps of Engineers (Corps), and U.S. Bureau of Reclamation (Reclamation) operations and maintenance (O&M) spending to differ from their forecasts. P-NORM also accounts for variability in interest rate expense. P-NORM models variability in net revenues, including uncertainty in the length of the CGS refueling outages in FY 2021 and FY 2023.

4.1.1 RevSim

As described in Section 3.1.2, RevSim calculates secondary energy revenues, balancing power purchase expenses, system augmentation purchase expenses, and extraregional sales revenue. Two financial operating risks are modeled externally and input into RevSim:

4(h)(10)(C) credits and Power Services transmission and ancillary services expenses. The results from RevSim and these two financial operating risks are provided for input into RAM2022. RevSim also determines, by simulation, Power Services operating net revenue risk for use in the ToolKit model. *See* § 3.1.5.

4.1.1.1 Inputs to RevSim

Inputs to RevSim include risk data simulated by various risk models and market prices calculated by Aurora. *See* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.1. Other inputs include deterministic monthly data from other rate development studies. Deterministic data are data provided as single forecast values, as opposed to data presented as a distribution of many values.

4.1.1.1.1 Section not used

4.1.1.1.2 Loads and Resources

Monthly heavy load hour (HLH) and light load hour (LLH) load and resource data are provided by the Power Loads and Resources Study, BP-22-FS-BPA-03. A summary of these load and resource data in the form of monthly surplus/deficit energy for FY 2022–2023 is provided in the Power Loads and Resources Study Documentation, BP-22-FS-BPA-03A, Table 10.1.1.

4.1.1.1.3 Miscellaneous Revenues

Miscellaneous revenues represent estimated revenues that are not subject to change through BPA's ratemaking process. *See* Power Rates Study, BP-22-FS-BPA-01,§ 9.2, for a discussion of miscellaneous revenues.

4.1.1.1.4 Composite, Non-Slice, Load Shaping, and Demand Revenues

Composite, Non-Slice, Load Shaping, and Demand revenues are provided by RAM2022. 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 RAM2022 are input into RevSim to facilitate the calculation of changes in Load Shaping revenue. Demand Billing Determinants and rates from RAM2022 are input into RevSim to facilitate the calculation of changes in Demand revenue. *See* Power Rates Study Documentation, BP-22-FS-BPA-01A, Table 3.1.5.

4.1.1.1.5 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 the non-operational uncertainty considered in P-NORM. Uncertainty in the deterministic data is represented by risk data; *i.e.,* a distribution of many values.

Input data to RevSim for operational uncertainty include Federal hydro generation risk, Power Services load risk, CGS generation risk, Power Services wind generation risk, Power Services transmission and ancillary services expense risk, 4(h)(10)(C) credit risk, and electricity price risk. The load, resource, and price risk inputs are reflected in the risk distributions for secondary energy revenues, balancing power purchases expenses, system augmentation expenses, and extraregional sales revenues. These risks, along with the 4(h)(10)(C) credit risk and Power Services transmission and ancillary services expense risk, are reflected in the Power Services operating net revenues calculated by RevSim and provided for input into ToolKit.

4.1.1.1.5.1. Federal Hydro Generation Risk

The Federal hydro generation risk factor reflects the uncertain impacts that streamflow timing and volume 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 BPA standing ready to provide balancing reserve capacity, which is discussed below.

For FY 2022–2023, 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. *See* Power Loads and Resources Study, BP-22-FS-BPA-03, § 3.1.2.1.2.

For each of the 80 water years, monthly HLH and LLH energy splits for the Federal system's hydro generation are developed for each fiscal year of the rate period based on analyses by the Hourly Operating and Scheduling Simulator (HOSS) Model, which incorporates results from HYDSIM hydro regulation studies. *See id.* § 3.1.2.1.4. 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 the Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, and are reported in terms of HLH, LLH, and flat energy in Tables 1, 3, and 3a for FY 2022 and Tables 2, 4, and 4a for FY 2023.

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. A significant factor in these adjustments is the shift of hydro generation from HLH to LLH. The generation adjustments are reported in terms of HLH, LLH, and flat energy adjustments in the Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Tables 5-7 for FY 2022 and Tables 8-10 for FY 2023 These generation data are added to the values presented in Tables 1-2 to yield the final monthly Federal hydro generation for each of the 80 water years.

The monthly Federal hydro generation data are input into RevSim to quantify the impact that Federal hydro generation variability has on Power Services secondary energy sales and revenues, balancing power purchases and expenses, and net revenues for 3,200 two-year simulations (FY 2022-2023). The Power Services secondary energy sales data are input into the Power Services Transmission and Ancillary Services Expense Risk Model to calculate these expenses for 3,200 two-year simulations. See Section 4.1.1.1.5.5 below regarding the Power Services Transmission and Ancillary Services Expense Risk Model.

The water year sequences developed for each game for Federal hydro generation are also used for PNW hydro generation, resulting in a consistent set of Federal and PNW hydro generation being used for each game in Aurora and RevSim. See Power Market Price Study and Documentation, BP-22-FS-BPA-04, Section 2.3.3.1, regarding the development of water year sequences for PNW hydro generation. The spill operations detailed in the Power Loads and Resources Study, BP-22-FS-BPA-03, Section 3.1.2.1, are also incorporated.

4.1.1.1.5.2. BPA Load Risk

The BPA load risk factor represents the impacts that variability in the economy and temperature can have on Power Services 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 purchase expenses. The level of regional economic activity affects the annual amount of load placed on BPA. Weather and climate conditions cause real-time and 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 WECC. *See* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.3.2.1. 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 Aurora, only the PNW component of the load risk is applied to BPA loads for the revenue simulation.

4.1.1.1.5.3. CGS Generation Risk

The CGS generation risk factor reflects the impact that variability in the output of CGS has on the amount of Power Services secondary energy sales and balancing power purchases estimated by RevSim. The source of the CGS generation risk data input into RevSim is Aurora, which simulates these data when calculating electricity prices. See *id.* at Section 2.3.6.3 regarding the methodology used in quantifying CGS generation risk.

4.1.1.1.5.4. Power Services Wind Generation Risk

The Power Services 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, and Stateline 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 the Power Market Price Study and Documentation, BP-22-FS-BPA-04, Section 2.3.4.1. 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-22-FS-BPA-03, Section 3.1.3.

The simulated monthly wind generation results are specified in terms of flat energy. Results shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 1, are the monthly flat energy output for all wind projects during FY 2022-2023 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 Other Federal Generation in the Power Loads and Resources Study, BP-22-FS-BPA-03, Section 3.1.3.

The uncertainty in the value of the wind generation output is calculated in RevSim based on the differences between (1) the monthly weighted average purchase prices for all the output contracts between wind generators and BPA and (2) 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 output 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 Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Tables 11-12, report information from which the value of wind generation during FY 2022-2023 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, 5^{th}, 50^{th}, and 95^{th} percentile electricity prices estimated by Aurora are provided, with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

4.1.1.1.5.5. Power Services Transmission and Ancillary Services Expense Risk

The Power Services transmission and ancillary services expense risk factor represents the uncertainty in Power Services transmission and ancillary services expenses relative to the expected values of these expenses included in the power revenue requirement. Those expected values are $111.4 million during FY 2022 and $108.0 million during FY 2023. *See* Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Table 3A, line 104. This risk is modeled in the Power Services Transmission and Ancillary Services Expense Risk Model.

The modeling of this risk is based on comparisons between monthly firm PTP Network transmission capacity that Power Services 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 Power Services has under contract. Because Power Services has more firm PTP Network transmission capacity under contract than it has firm contract sales, the probability distribution for these expenses is asymmetrical. This asymmetry occurs because Power Services 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.

Transmission and ancillary services expenses will increase under conditions in which Power Services sells more energy than it has firm PTP Network transmission rights. Alternatively, transmission and ancillary services expenses will remain unchanged under conditions in which Power Services sells less energy than it has firm PTP Network transmission rights.

Results shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figures 2 and 3, indicate how FY 2022–2023 transmission and ancillary service expenses vary depending on the amount of secondary energy sales. In these figures, the Power Services transmission and ancillary services expenses do not fall below $79.3 million in FY 2022 and $79.7 million in FY 2023, regardless of the amount of secondary energy sales. This result is because Power Services 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 that Power Services has under contract on the Southern (alternating current (AC) and direct current (DC)) Interties.

Results shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figures 4 and 5, reflect the probability distributions for transmission and ancillary service expenses during FY 2022-2023. These figures indicate how often transmission and ancillary service expenses fall within various expense ranges.

4.1.1.1.5.6. 4(h)(10)(C) Credits

The 4(h)(10)(C) credit risk results are quantified in an external risk model and input into RevSim. These results reflect the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the Treasury. Section 4(h)(10)(C) of the Northwest Power Act allows BPA to allocate its expenditures for systemwide fish and wildlife mitigation activities to various purposes. 16 U.S.C. § 839b(h)(10)(C). The credit reimburses BPA for its expenditures allocated to the non-power purposes of the Federal hydro projects, and BPA reduces its annual Treasury payment by the amount of the credit. The 4(h)(10)(C) credit risk analysis performed in this Study estimates the amount of 4(h)(10)(C) credits available for each of the 80 water years for FY 2022–2023 by first summing the costs of the operating impacts on the hydro system (*e.g.*, power purchase expenses), direct program expenses, and capital costs associated with BPA's fish and wildlife mitigation measures. The resulting total cost is multiplied by 0.223 (22.3 percent is the percentage of the FCRPS attributed to non-power purposes) to yield the amount of 4(h)(10)(C) credits available for each of the 80 water years.

Operating impact costs are calculated for each of the 80 water years for FY 2022-2023 by multiplying spot market electricity prices from Aurora by the amount of power purchases (in average megawatts (aMW)) qualifying for 4(h)(10)(C) credits. The amount of power purchases qualifying for 4(h)(10)(C) credits is derived outside of RevSim and is used 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-22-FS-BPA-03, Section 3.3. The Power Loads and Resources Study Documentation, BP-22-FS-BPA-03A, shows the 4(h)(10)(C) credit power purchase amount for FY 2022 in Table 6.1.1 and for FY 2023 in Table 6.1.2.

The direct program expenses and capital costs for FY 2022-2023 do not vary by water volume or flow timing and are documented in the Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Sections 3 and 4. A summary of the costs included in the 4(h)(10)(C) calculation and the resulting credit for each fiscal year are shown in Table 13 of this Study's documentation, Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A.

Results shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figures 6 and 7 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2022-2023. The average 4(h)(10)(C) credit for the 3,200 games rounds to $94.2 million for both FY 2022 and FY 2023. These values are included in the revenue forecast described in Section 9.4.1 of the Power Rates Study, BP-22-FS-BPA-01. The 4(h)(10)(C) credit for each of the 3,200 games is included in the net revenue provided to the ToolKit.

4.1.1.1.5.7. Electricity Price Risk (Market Price and Critical Water Aurora Runs)

Results from two runs of the Aurora model are typically used in this Study. One run, which uses hydro generation for all 80 water years, is referred to as the "market price run." The other run, which uses hydro generation for only the critical water year, 1937, is referred to as the "critical water run." *See also* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4. Both runs produce 3,200 games of monthly HLH and LLH prices for FY 2022-2023. Figures 4 and 5 of the Power Market Price Study and Documentation provides a summary of the average monthly HLH and LLH prices for each of these Aurora runs.

Prices from the market price run are used by RevSim to develop secondary energy revenues and balancing power purchase expenses for FY 2022–2023. They are also used to compute 4(h)(10)(C) credits that are computed external to, but input into, RevSim. These values are provided to RAM2022 to develop rates for FY 2022–2023. Prices from the market price run are also used to incorporate risk in the operating net revenues calculated by RevSim and provided to the ToolKit. See Sections 4.1.1.2.1 through 4.1.1.2.4, below for a description of this process.

If augmentation purchases are forecast, prices from the critical water run are used to compute the system augmentation costs provided to RAM2022 for ratemaking purposes. Prices from the critical water run are also used to incorporate system augmentation expense risk in the operating net revenues calculated by RevSim and provided to the ToolKit. See Section 4.1.1.2.1 below for a description of this process.

4.1.1.2 RevSim Model Outputs

RevSim model outputs are provided to RAM2022, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-22-FS-BPA-01, Section 9.

4.1.1.2.1 System Augmentation Costs and Firm Surplus Energy Revenues

For this rate period, there is no system augmentation – the system is firm surplus. However, if there were a need to augment the system, deterministic values for system augmentation costs would be provided for input into RAM2022 by multiplying the system augmentation amount (aMW) by the average Aurora price from the critical water run. The source of the system augmentation amounts is the Power Loads and Resources Study, BP-22-FS-BPA-03, Section 4.2. A summary of the system augmentation costs calculation in this Study is shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Table 14.

The deterministic values for firm surplus energy revenues provided to RAM2022 are calculated by multiplying the firm surplus energy amount (aMW) by the Firm Surplus Sales price, as detailed in the Power Rates Study, BP-22-FS-BPA-01, Section 3.2.2.6. This value uses forward market prices to establish the value of remarketed non-Federal energy, and establishes the Tier 2 short-term rate.

The computation of firm surplus includes the additional inventory that results from the forward power purchases of 34 aMW in FY 2022 and FY 2023, which were acquired to provide Southeast Idaho Load Service (SILS). As well as forward power purchases, the calculation of firm surplus also accounts for any forward power sales BPA had executed at the time of calculating rates. The source of the firm surplus energy amounts is the Power Loads and Resources Study, BP-22-FS-BPA-03, Section 4.3. The inclusion of the firm surplus energy revenues in RAM2022 reduces the total amount of surplus energy (aMW) such that loads and resources are in balance on a firm energy basis. Thus, the net secondary energy revenue analysis in RevSim reflects only secondary energy values. See Power Loads and Resources Study, BP-22-FS-BPA-03, Section 3.1.5, regarding the treatment of SILS forward power purchases, and Power Loads and Resources Study Documentation, BP-22-FS-BPA-03A, Tables 9.1.1, 9.1.2, and 9.1.3, where the SILS loads are embedded in the total load values. The firm surplus energy revenues calculation is shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Table 15.

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

RevSim calculates secondary energy sales and revenues under various load, resource, and market price conditions. 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.

Losses on BPA's transmission system, which reduce the amount of resource output that can be delivered to load or sold as surplus, are incorporated into RevSim by reducing generation in the summer (June through August) by 3.38 percent and reducing generation for the rest of the year by 3.02 percent. *See* Power Loads and Resources Study, BP-22-FS-BPA-03, § 3.1.7. This is applied to the Federal hydro generation, CGS output, and wind generation that BPA has under contract. Additional incremental loss percentages (more than the amounts described above) are applied to the Green Springs, Lost Creek, and Cowlitz Falls independent hydro projects. These losses are 4.45 percent for Green Springs, 4.45 percent for Lost Creek, and 0.5 percent for Cowlitz Falls.

Electricity prices estimated by Aurora 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 purchase expenses. These HLH and LLH revenues and expenses are then combined with other revenues and expenses to calculate Power Services operating net revenues.

4.1.1.2.3 Valuing Extra-regional Marketing in RevSim

Given that BPA has access to extra-regional markets (*e.g.*, California-Oregon Border (COB), Nevada-Oregon Border (NOB), and other points of delivery contiguous to the California Independent System Operator (CAISO)), BPA can reasonably expect to participate in these markets and receive a premium, where such a premium exists, for corresponding sales. Extra-regional sales include CAISO transactions as well as bilateral transactions at COB and NOB, where BPA realizes a premium for COB and NOB sales on the presumption that such energy will be remarketed into California. RevSim allocates surplus energy sales between Mid-C, COB, and NOB such that it maximizes surplus energy revenues. This allocation takes into consideration the relative price spreads between COB, NOB, and Mid-C; the amount of available transmission capacity on the Southern Interties; the amount of excess available firm transmission capacity on the Southern Interties that Power Services has under contract; and the cost of transmission losses for sales over the interties. The source of the available excess transmission capacity and the price spreads is Aurora. *See* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.3.

The excess available firm transmission capacities that Power Services has under contract on the Southern Interties are represented by deterministic data that are input into RevSim. Results from the WECC-wide dispatch process in Aurora provide a distribution of modeled transmission capacity constraints. Therefore, for a given game, RevSim is able to determine whether all or only a portion of Power Services excess firm transmission capacity on the Southern Interties is available for export sales.

BPA recognizes that extra-regional sales incur incremental transaction costs that are not observed at Mid-C. As noted above, additional transmission losses are assessed to each unit of energy RevSim markets to California to account for losses associated with moving energy to COB or NOB over the interties. Additionally, to account for costs associated with sales to CAISO, RevSim applies a per megawatthour (MWh) reduction to the modeled value of a portion of the modeled extra-regional sales, where this decrement represents the sum of the CAISO Grid Management Charges (GMC) and carbon allowance purchase costs BPA will incur in association with these sales.

The portion of sales assumed to be made to CAISO was determined by looking at BPA's historical transactions in the Federal Energy Regulatory Commission's (FERC's) Electronic Quarterly Reporting (EQR) data, from years 2015–2019. For the BP-22 rate period, BPA assumes 30 percent of its sales to California will be made to CAISO – in line with the average over the past five years of EQR data.

Any sale into CAISO is assessed a GMC on a per MWh basis, and this charge is the vehicle through which CAISO recovers its administrative and capital costs from the entities that utilize CAISO's service. This charge is a published rate, and as of June 1, 2021, the rate was about $0.35/MWh. There is also a Bid Segment Fee and a SCID monthly fee, both of which are relatively minor. Considering these three fees together, BPA included a $0.40/MWh GMC fee on all modeled sales assumed to be made to CAISO.

Finally, BPA must pay for carbon allowances when selling to CAISO. The forecast cost of carbon allowance purchases is based off a forecast of carbon allowance pricing and a forecast of BPA's system's average carbon content. BPA's Asset Controller Supplier emission factor averaged 0.018 Megatons of CO_2 equivalent per MWh (MT CO_{2e}/MWh) from the years 2013 to 2021. This value is used as the forecast for FY 2022 and FY 2023. This emission factor forecast combines with BPA's carbon allowance price forcast of \$19.8/MT CO_{2e} in FY 2022 and \$21.3/MT CO_{2e} in FY 2023 to yield an estimated carbon compliance cost for BPA of \$0.35/MWH in FY 2022 and \$0.38/MWh in FY 2023.

Talks with BPA's marketing subject matter experts led to an assumption in RevSim that costs will total to \$0.70/MWh. This is slightly different from a simple sum of the above charges because the most recent information available points to a potentially lower carbon compliance price forecast and lower GMCs than implied by the current forecasts.

Taking everything together, BPA assumes that 30 percent of its modeled extraregional sales will be made to CAISO. These sales are assessed an incremental cost of \$0.70/MWh to account for the GMC fee and carbon allowances. Modeling extra-regional sales adds \$25.3 million in FY 2022 and \$28.2 million in FY 2023 to the net secondary energy revenue credits, as compared to modeling sales being made only at Mid-C.

BPA continues to prepare for a potential decision to join the Western Energy Imbalance Market (EIM). An incremental credit of \$3.4 million was included within BPA's Secondary Revenue Credit, which is equal to the ongoing costs BPA expects to incur related to potential EIM participation.

4.1.1.2.4 Modeling Capacity Sales in RevSim

In BP-22, RevSim will continue to account for the impacts of capacity sales made by BPA. This will be done in a manner consistent with that of BP-20, where capacity that BPA has sold is held in reserve to provide to the counterparties, should they call for it. In compensation for this, BPA receives monthly capacity fees.

These capacity agreements impact RevSim in the calculation of extra-regional sales and in the committed sales revenue category. For any given period, when RevSim checks whether there is surplus energy available to market at COB or NOB, the first set of megawatts are held exempt from consideration – it is effectively on reserve, held in case a counterparty calls for it. RevSim subsequently sells this holdout at Mid-C, which adequately models either BPA providing the energy to a counterparty and said counterparty compensating BPA at Mid-C prices, or BPA holding the energy when a counterparty does not call for it and then BPA marketing the megawatts itself at Mid-C. The capacity payment BPA receives is included in the committed sales revenue category.

A recent capacity sale made by BPA stipulates that BPA will be compensated for the energy value of any capacity called by the counterparty at the contemporaneous price of energy at Mid-C, plus a premium. To forecast a value BPA might expect to receive from the premium portion of the contract, BPA would have to estimate how often, and when, the counterparty would call the option for capacity. Given the unique terms of the sale and a lack of recent historical experience with this type of a sale, which could inform an expectation of when the counterparty may exercise its option, BPA is not forecasting, in BP-22, the premium on the energy component that it may receive from this sale.

4.1.1.2.5 Mean Net Secondary Revenue Computations

Secondary energy revenues and balancing power purchases expenses for FY 2022-2023 are provided to RAM2022. These revenues and expenses are based on the arithmetic mean 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 RAM2022, both measured in annual average megawatts, are also the arithmetic means of these quantities over the 3,200 games for each fiscal year.

In the Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Tables 18 and 19 provide monthly values for the secondary energy sales/revenues and total power purchases/expenses provided to RAM2022 for FY 2022-2023. The total power purchases expenses are $43.3 million for FY 2022 and $38.1 million for FY 2023. The secondary energy revenues are $414.9 million for FY 2022 and $393.5 million for FY 2023. Annual secondary energy sales/revenues and total power purchases/expenses for FY 2022-2023 are reported together in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Table 20.

4.1.1.2.6 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2022 to calculate PNRR and, ultimately, rates that provide BPA with at least a 95 percent TPP for the two-year rate period. The Power Services net revenue simulated in each RevSim run depends on the revenue components developed by RAM2022, which in turn depend on the level of PNRR assumed when RAM2022 is run. RevSim simulates intermediate sets of net revenue during this iterative process. The final set of Power Services net revenue from RevSim is the lowest set that yields at least a 95 percent TPP.

Using 3,200 games of net revenue risk data simulated by RevSim and P-NORM and mathematical descriptions of the CRAC and RDC, the ToolKit produces 3,200 games of cash flow and annual ending financial reserves levels. The ToolKit calculates TPP from these games, and then analysts change the amounts of PNRR to achieve TPP targets. For BP-22, no PNRR was needed to meet the TPP target. However, PNRR has been added to the power revenue requirement as described in the Settlement Agreement for Rates for Fiscal Years 2022-23, BP 22-A-02, Appendix A.

A statistical summary of the annual net revenue for FY 2022-2023 simulated by RevSim using proposed rates is reported in Table 1. Power Services net revenue over the rate period averages $117.0 million per year. This amount represents only the operating net revenues calculated in RevSim. It does not reflect additional net revenue adjustments in the ToolKit model caused by the output from P-NORM, interest earned on financial reserves, or impacts of the CRAC, FRP Surcharge, and RDC.

4.1.2 P-NORM

4.1.2.1 Inputs to P-NORM

To obtain the data used to develop the probability distributions used by P-NORM, BPA analyzed historical data and consulted with subject matter experts for their assessment of the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. Table 2 shows the 5^{th} percentile, mean, and 95^{th} percentile results from each of the risk models described below, along with the deterministic amount that is assumed in the revenue requirement for that risk. *See* Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Table 3A.

4.1.2.1.1 CGS Operations and Maintenance (O&M)

CGS O&M uncertainty is modeled for Base O&M and Nuclear Electric Insurance Limited (NEIL) insurance premiums. P-NORM captures uncertainty around Base O&M and NEIL insurance costs. For Base O&M, P-NORM distributes the minimum- and maximum-based subject matter expert estimation of deviations from the expected value. For FY 2021, P-NORM models no variation in CGS O&M. For FY 2022 and FY 2023, 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, and the net premiums they pay are lower as a result. 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 2021, FY 2022, and FY 2023, the most likely is set to the base NEIL premium amount, the maximum is set 5 percent higher than the most likely and the minimum is set to 5 percent lower. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.2 U.S. Army Corps of Engineers and Bureau of Reclamation O&M

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

- Additional costs if a security event occurs or if the security threat level increases;
- Additional costs if a fish event occurs;
- Additional extraordinary hydro system maintenance;
- Additional costs due to a catastrophic event; and
- Additional costs due to new system requirements.

For additional security costs, P-NORM assumes for FY 2021 that there is a 1 percent probability and for FY 2022 and FY 2023 that there is a 2 percent probability that an event will occur in any given year that leads to a requirement for additional security at Corps or 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 for FY 2021, FY 2022, and FY 2023, with a respective 1 percent, 2 percent, and 2 percent probability that an event that requires additional annual expenditures of $2 million each for either the Corps or Reclamation will occur in FY 2021 through FY 2023.

For additional extraordinary hydro system maintenance needs, P-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 2021, FY 2022, and FY 2023, this risk is modeled with a respective 2.5 percent, 2.5 percent, and 2.5 percent probability that an event will occur in any given year that leads to an additional $5 million expense. This risk is modeled in the same way for both the Corps and Reclamation.

P-NORM models the expense cost of a catastrophic, systemwide event. This risk is modeled for FY 2021, FY 2022, and FY 2023 with a respective 1 percent, 1 percent, and 1 percent probability of an event occurring in any given year resulting in a $30 million expense. This risk is modeled in the same way for both the Corps and Reclamation.

P-NORM models the expense cost related to increased compliance or regulatory requirements. This risk is modeled for FY 2021, FY 2022, and FY 2023 with a respective 10 percent, 10 percent, and 10 percent probability of a $5 million expense in any given year. This risk is modeled in the same way for both the Corps and Reclamation. See Table 2 for the expected, 5^{th} percentile, and 95^{th} percentile values for these risks.

4.1.2.1.3 Conservation Expense

For this expense item, P-NORM models uncertainty around Conservation Acquisition and Low-Income and Tribal Weatherization. Conservation Acquisition expense is modeled for each year from FY 2021 through FY 2023 using a PERT distribution. For FY 2021, FY 2022, and FY 2023, 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. *See* Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Table 3A.

Low-Income and Tribal Weatherization expense variability is modeled using a PERT distribution for FY 2021 through FY 2023. For FY 2021, FY 2022, and FY 2023, 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. *Id*. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.4 Power Services Transmission Acquisition and Ancillary Services

For this cost item, P-NORM models uncertainty around expenses for Third-Party Transfer Service Wheeling and Third-Party Transmission and Ancillary Services.

P-NORM models Third-Party Transfer Service Wheeling cost for each year from FY 2021 through FY 2023 with PERT distributions. For FY 2021 and FY 2022, the minimum, most likely, and maximum are set to 96 percent, 100 percent, and 102 percent of the revenue requirement amounts. For FY 2023, the minimum, most likely, and maximum are set to 96 percent, 100 percent, and 103 percent of the revenue requirement amounts.

The cost of Third-Party Transmission and Ancillary Services is modeled for FY 2021 through FY 2023 using a PERT distribution with minimum and most likely values set to the revenue requirement amount. For FY 2021, FY 2022, and FY 2023, the maximums are set to 102.5 percent, 110 percent, and 116 percent of the revenue requirement amount. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.5 Fish and Wildlife Expenses

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

4.1.2.1.5.1. BPA Direct Program Costs for Fish and Wildlife Expenses

The costs of BPA's fish and wildlife program are uncertain, in large part because the actual pace of implementation cannot be known ahead of time 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; instead, it reflects the reality that it can take time to plan 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 2021, FY 2022, and FY 2023, 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. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.5.2. U.S. Fish and Wildlife Service (USFWS) Lower Snake River Hatcheries Expenses

For FY 2021, FY 2022 and FY 2023, USFWS Lower Snake River Hatcheries Expense uncertainty is modeled as a PERT distribution with a minimum value set to 10 percent less than the forecast value, a most likely value 5 percent less than the forecast value, and a maximum equal to the forecast value. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.5.3. Bureau of Reclamation Leavenworth Complex O&M Expenses

P-NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using a discrete risk model. A discrete risk is defined using a set of specified values, with probabilities assigned to each value. In a discrete distribution, only the specified values can be drawn, as opposed to a continuous distribution, in which the set of possible values is not specified and any value between the minimum and maximum can be drawn. Leavenworth Complex O&M risk is modeled with a 1 percent probability of incurring an additional $1 million expense in each year. The revenue requirement amounts for Reclamation's Leavenworth Complex O&M for FY 2021, FY 2022, and FY 2023 are included in Reclamation's O&M budget, which is discussed in Section 4.1.2.1.2 above. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.5.4. Corps of Engineers Fish Passage Facilities Expenses

P-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 Fish Passage Facilities Expenses for FY 2021, FY 2022, and FY 2023 are included in the Corps' O&M budget, which is discussed in Section 4.1.2.1.2 above. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.6 Interest Expense and Earnings

P-NORM captures the impact of interest rates, capital uncertainty, and Power Services reserves levels on interest expense and earnings. Interest expense risk is modeled for FY 2021, FY 2022, and FY 2023 using a normal distribution with the expected values set at the revenue requirement amount and the standard deviations set at $1.7 million for FY 2021, $2.2 million for FY 2022, and $3.8 million for FY 2023. P-NORM models interest earnings risk for FY 2021, FY 2022, and FY 2023 using a uniform distribution with the maximum set at the revenue requirement amount and the minimum set at $0. See Table 2 for the expected, 5th percentile, and 95th percentile values for these risks.

4.1.2.1.7 CGS Refueling Outage Risk

In the spring of 2021, Energy Northwest will take CGS out of service for refueling and maintenance. The same will occur in the spring of 2023. There is uncertainty in the duration of these outages and thus uncertainty in the amount of replacement power BPA must purchase from the market, the amount of secondary energy available to be sold in the market, and the price of secondary energy at the time of any particular purchase or sale.

CGS outage duration risk is modeled as deviations from expected net revenue due to variability in the duration of the planned maintenance outages. Increases or decreases in downtime of the CGS plant result in changes in megawatthours generated, which result in decreased or increased net revenue for Power Services in FY 2021 and FY 2023. This revenue variability is a function of plant outage duration, monthly flat Aurora market prices, and monthly flat CGS energy amounts from RevSim. The outage duration for

FY 2021 and FY 2023 was modeled with a minimum of 36 days, a maximum of 61 days, and a median of 40 days.

To calculate the impact of the outages on net revenue, 3,200 outage durations are simulated. The difference between the simulated duration from P-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 Aurora prices (*see* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4) are then multiplied by the gamed generation deviations, resulting in a net revenue deviation. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.2 P-NORM Results

The output of P-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 Net-Revenue-to-Cash adjustments for each game for FY 2021, FY 2022, and FY 2023. 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 Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 8.

4.1.3 Net-Revenue-to-Cash Adjustment

P-NORM calculates 3,200 NRTC adjustments to make the necessary changes to convert RevSim and P-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate financial reserves values in each game and thus calculate TPP. *See* § 3.1.4 (NRTC Adjustments).

The NRTC Adjustment is modeled probabilistically in P-NORM. P-NORM uses the deterministic NRTC Table as its starting point and includes 3,200 gamed adjustments for the Slice True-Up (*see* Power Rates Study, BP-22-FS-BPA-01, Section 7; Power GRSP II.R.), based on the calculated deviations in those revenue and expense items in P-NORM that are subject to the true-up. The NRTC table is shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Table 21.

4.2 Power Quantitative Risk Mitigation

The preceding sections of this section describe the Power risks that are modeled explicitly, with the output of P-NORM and RevSim quantitatively portraying the financial uncertainty faced by Power Services in each fiscal year. This section describes the tools used to mitigate these risks – Power Services reserves, the Treasury Facility, Agency Liquidity, PNRR, the CRAC, the FRP Surcharge, and the RDC – and how BPA evaluates the adequacy of this mitigation.

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 2.4 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a 5 percent probability of any deferrals of BPA's Treasury payment in a two-year rate period). TPP and the ability of the rates to meet the TPP standard are measured in the ToolKit by applying the risk mitigation tools described in this section to the modeled financial risks described in the previous sections.

A second risk addressed in this Study is within-year liquidity risk, i.e., 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 financial reserves for within-year liquidity (liquidity reserves) has been defined.

4.2.1 Thresholds for CRAC, RDC, and FRP Surcharge

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A, Financial Reserves Policy. The lower and upper thresholds are used to determine when rate actions will be taken to increase or decrease financial reserves. These rate actions are implemented through the FRP Surcharge and the RDC. The FRP also establishes a $0 threshold for each business line, below which an additional rate action must be taken. This rate action is implemented through the CRAC.

The Power CRAC thresholds are shown in Table 5. The Power RDC thresholds are shown in Table 6. The Agency RDC thresholds are shown in Table 7. The Power FRP Surcharge thresholds are shown in Table 8.

4.2.1.1 Power Services Lower Financial Reserves Threshold

The Lower Financial Reserves Threshold for Power is the greater of 60 days cash or what is necessary to meet the TPP Standard. For this Rate Case, no additional financial reserves are needed to meet the TPP Standard, so the threshold is set at 60 days cash. The calculations of Power operating expenses and translations into days cash dollar amounts are shown in Table 3.

4.2.1.2 Power Services Upper Financial Reserves Threshold

The Upper Financial Reserves Threshold for Power is the Lower Financial Reserves Threshold plus 60 days cash. The calculations of Power operating expenses and translations into days cash dollar amounts are shown in Table 3.

4.2.1.3 Agency Upper Financial Reserves Threshold

The Agency (BPA) Upper Financial Reserves Threshold is the sum of the Power and Transmission Lower Financial Reserves Thresholds plus 30 days Agency cash. The Agency days cash dollar amounts are shown in Table 4.

4.2.2 Power Risk Mitigation Tools

4.2.2.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For purposes of BP-22 rate period risk modeling, Power Services has three sources of liquidity: (1) Power Services reserves (2) the Treasury Facility and (3) Agency Liquidity. These liquidity sources are described further in Section 2.3.

4.2.2.1.1 Power Services Reserves

Power Services reserves at the start of FY 2021 are $435.3 million. This value was calculated as *total* financial reserves (see Section 2.3) attributed to Power Services of $504.8 million less $69.5 million of financial reserves not for risk as of the end of BPA fiscal year 2020. *See* Q4 Quarterly Business Review Technical Workshop Package, BPA (Nov. 19, 2020), available at https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/qbrd ocs/FY20%20Q4%20QBR%20Technical%20Workshop%20materials.pdf; Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 9.

4.2.2.1.2 The Treasury Facility

For the purpose of TPP modeling, all $750 million of the Treasury Facility is modeled to be available for Power Services risk as Borrowing Liquidity.

4.2.2.1.3 Agency Liquidity in Excess of TPP

Power Services meets the TPP standard before accouting for any additional Agency Liquidity. Therefore, the Power Services Agency Liquidity reliance is $0.

4.2.2.1.4 Within-Year Liquidity Need

BPA needs to maintain access to short-term liquidity for responding to within-year needs, such as uncertainty due to the unpredictable timing of cash receipts or cash payments, or known timing mismatches. An illustrative timing mismatch is the large Energy Northwest bond payment due in the spring. Priority Firm (PF) Power 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. The Power Services within-year liquidity need of $320 million was determined in the BP-14 rate proceeding, and that amount continues to be used for ratemaking risk mitigation purposes.

4.2.2.1.5 Within-year Liquidity Borrowing Level

For this Study, $320 million of Power Services Borrowing Liquidity is considered to be available only for within-year liquidity needs.

4.2.2.1.6 Within-year Liquidity Reserves Level

The Power Services within-year liquidity need is met through Borrowing Liquidity. Therefore, the within-year liquidity reserves level is $0.

4.2.2.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted during rate development using current projections of Power Services reserves and other sources of liquidity. If the TPP is below the 95 percent two-year standard required by BPA's Financial Plan, then the projected financial reserves, along with whatever other risk mitigation is considered in the risk study, are not sufficient to reach the TPP standard. This may be 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 Power Services reserves, and therefore increase TPP.

PNRR needed to meet the TPP standard is calculated using the ToolKit, described in Section 3.1.5. If the ToolKit calculates TPP below 95 percent, PNRR can be added to the model in one or both years of the rate period (typically, PNRR is added evenly 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-22-FS-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.

PNRR is not needed to meet the TPP standard for this Study. However, $31 million per year in PNRR has been added to the revenue requirement as described in the Settlement Agreement for Rates for Fiscal Years 2022-23 (BP 22-A-02, Appendix A) and the Power Revenue Requirement Study (BP-22-FS-BPA-02, Table 3, line 39).

4.2.2.3 Risk Adjustment Mechanisms

In most power rates in effect since 1993, BPA has employed CRACs or Interim Rate Adjustments as upward rate adjustment mechanisms that can respond relatively quickly to financial circumstances BPA may experience, *i.e.,* before the next opportunity to adjust rates in a rate proceeding. BPA has included three risk adjustment mechanisms for Power in BP-22: the Power CRAC, Power RDC, and Power FRP Surcharge. *See* §§ 2.4, 4.2.2.3.1-3. The Power rates and products subject to these risk adjustment mechanisms are Load Following, Block, the Block portion of Slice/Block, power purchased at the PF Melded rate, power purchased at the Industrial Firm Power rate, and power purchased at the New Resource Firm Power rate. *See* Power GRSPs II.O–P.

For BP-22, Power rates include an average of $40 million per year in revenue financed capital. The Study assumes that if PS reserves are below the FRP Surcharge threshold at the end of a fiscal year, BPA's Administrator would redeploy the planned revenue financing in the current year to replenish PS reserves back to the threshold.

If revenue financing is reduced in the operating year, the Slice share of the reduction will be returned to Slice customers through the Slice True-Up. The remainder of the revenue financing reduction will result in an increase to PS reserves. Therefore, only the Non-Slice share of the revenue financing amount is relied upon for risk mitigation. The Non-Slice share is $30 million in FY 2022 and $31 million in FY 2023.

4.2.2.3.1 Power Cost Recovery Adjustment Clause (CRAC)

As described in Section 2.4 and Power GRSP II.O, the CRAC for FY 2022 and FY 2023 is a potential annual upward adjustment in various power rates. The Power CRAC could increase rates for FY 2022 based on Power Services reserves at the end of FY 2021. It also could increase rates for FY 2023 based on Power Services reserves at the end of FY 2022. The CRAC implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves fall below $0. *See* Appendix A, §4.2.3.

The thresholds for triggering the CRAC are described in Section 4.2.1. If Power Services reserves are below the thresholds, a shortfall has occurred. The shortfall is equal to the Power Services CRAC threshold minus Power Services reserves. The shortfall is first assumed to be replenished through redeploying the planned revenue financing in the applicable year. *See* §§ 2.4, 4.2.2.3. If there is a remaining shortfall, the Power CRAC will recover 100 percent of the first $100 million of the remaining shortfall. 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, if Power Services reserves are negative $250 million at the end of FY 2021 then the shortfall is $250 million. The shortfall is reduced by Non-Slice share of the revenue financing amount ($30 million), leaving a remaining shortfall of $220 million. The CRAC then triggers, collecting 100 percent of the first $100 million, and 50 percent of the remaining $120 million, for a total CRAC of $160 million. The Power CRAC will only trigger if the amount to be collected by the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2022 and FY 2023 rates will be made early in that fiscal year based on end-of-year actual Power Services Reserves For Risk. If the

CRAC triggers, an upward rate adjustment will be calculated for December through September of the fiscal year. *See* Power GRSP II.O.

4.2.2.3.2 Power Reserves Distribution Clause (RDC)

The Power RDC implements the FRP requirement for a financial reserves distribution in the event that financial reserves are above upper financial reserves thresholds. *See* Appendix A, § 4.1.

The thresholds for triggering the RDC are described in Section 4.2.1. The Power RDC is triggered if both BPA reserves (the sum of Power Services reserves and Transmission Services reserves) *and Power Services* reserves are above specified thresholds. Above-threshold financial reserves will be considered for providing a downward adjustment to the same Power rates and products subject to the Power CRAC or for being deployed to other high-value business line-specific purposes. The total distribution is capped at $500 million per fiscal year. The RDC will only trigger if the RDC distribution amount is greater than or equal to $5 million. *See* Power GRSP II.P.

4.2.2.3.3 Power Financial Reserves Policy (FRP) Surcharge

The Power FRP Surcharge is a potential annual upward adjustment in various power rates. The Power FRP Surcharge applies to the same power rates that are subject to the Power CRAC. The Power FRP Surcharge implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves are below the Lower Financial Reserves Threshold. *See* Appendix A, §§ 4.2.1, 4.2.2.

The thresholds for triggering the FRP Surcharge are described in Section 4.2.1. If Power Services reserves are below the thresholds, a shortfall has occurred. The shortfall is equal to the Power Services FRP Surcharge threshold minus Power Services reserves. The shortfall is first assumed to be replenished through redeploying the planned revenue financing in the applicable year. *See* §§ 2.4, 4.2.2.3. If there is a remaining shortfall, the Power FRP Surcharge will collect that remaining shortfall, up the the Power FRP Surcharge cap of $40 million per year. If the Power FRP Surcharge Amount calculation results in a value less than $5 million, then the amount is deemed to be zero. *See* Power GRSP II.Q.

4.2.3 ToolKit

The ToolKit model is described in Section 3.1.5. The inputs to the ToolKit for Power are shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 10.

4.2.3.1 ToolKit Inputs and Assumptions for Power

4.2.3.1.1 RevSim Results

The ToolKit reads in risk distributions generated by RevSim that are created for the current year, FY 2021, and the rate period, FY 2022-2023. TPP is measured for only the two-year rate period, but the starting financial reserves for FY 2022 depend on events yet to unfold in FY 2021; these runs reflect that FY 2021 uncertainty. See Section 4.1.1 for more details on the operating risk models.

4.2.3.1.2 Non-Operating Risk Model

The ToolKit reads in P-NORM distributions that are created for FY 2021-2023 and that reflect the uncertainty around non-operating expenses. See Section 4.1.2 of this Study for more detail on P-NORM.

4.2.3.1.3 Treatment of Treasury Deferrals

In the event that ToolKit forecasts a Treasury principal payment deferral, the ToolKit assumes that BPA will repay this balance as soon as liquidity is available to make the payment.

4.2.3.1.4 Starting Power Services Reserves

The FY 2021 starting Power Services reserves have a forecast value of $435.3 million. See Section 4.2.2.1.1 above for a description of Power Services reserves.

4.2.3.1.5 Power Services Within-year Liquidity Reserves Level

The Power Services Within-year Liquidity Reserves Level is an amount of Power Services 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. *See* § 4.2.2.1.6 above. Within-year cash flow needs for power are handled through adustments to the Liquidity Borrowing Available amount.

4.2.3.1.6 Liquidity Borrowing Available

This Study relies on all $750 million of BPA's Treasury Facility. This borrowing availability is reduced by $320 million for within-year liquidity needs, as described in Section 4.2.2.1.4 above, leaving $430 million for liquidity borrowing. The liquidity borrowing amount is increased by any Agency Liquidity relied upon by Power Services. The liquidity borrowing amount is decreased by any Agency Liquidity provided by Power Services. Both amounts are $0, so the total liquidity borrowing amount is $430.

4.2.3.1.7 Interest Rate Earned on Financial Reserves

Interest earned on financial reserves is modeled through P-NORM. *See* § 4.1.2.1.6 above.

4.2.4 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 9.

4.2.4.1 Ending Power Services Reserves

Starting Power Services reserves for FY 2021 are $435.3 million. The expected values of ending financial reserves are $448 million for FY 2021, $520 million for FY 2022, and $488 million for FY 2023. Over 3,200 games, the range of ending FY 2023 financial reserves is $17 million to $1,029 million. The 50 percent confidence interval for ending financial reserves for FY 2023 is $334 million to $637 million. Financial reserves distributions are shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 9.

4.2.4.2 TPP

The two-year TPP is greater than 99.9 percent. In 3,200 games, there are no deferrals for FY 2021, FY 2022, or FY 2023.

4.2.4.3 CRAC, RDC, and FRP Surcharge

The Power CRAC does not trigger in any of the 3,200 games for FY 2022 or FY 2023.

The Power RDC triggers in 0.2 percent of games for FY 2022, yielding an average amount of $40 thousand (measured as the average amount across all 3,200 games). The Power RDC triggers in 30 percent of games for FY 2023, yielding an average amount of $31 million.

The Power FRP Surcharge does not trigger for FY 2022. The Power FRP Surcharge triggers for FY 2023 in 4 percent of games. The average Power FRP Surcharge amount is $1 million for FY 2023 (measured as the average amount across all 3,200 games).

Power CRAC, RDC, and FRP Surcharge statistics are shown in Table 9. The thresholds and caps for the Power CRAC, Power RDC, and Power FRP Surcharge applicable to rates for FY 2022 and FY 2023 are shown in Tables 5, 6, and 8. The BPA RDC Thresholds are shown in Table 7.

4.3 Power Qualitative Risk Assessment and Mitigation

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. The qualitative analysis considers 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, then additional risk treatment might be necessary. The two categories of risk analyzed here are (1) financial risks to BPA or to Tier 1 costs arising from BPA's provision of service at Tier 2 rates; and (2) financial risks to BPA or to Tier 1 costs arising from BPA's provision of Resource Support Services (RSS).

4.3.1 Risks Associated with Tier 2 Rate Design

For the FY 2022-2023 rate period, there are two Tier 2 rates with contractually committed sales at those rates: the Tier 2 Short-Term rate and the Tier 2 Load Growth rate. *See* Power Rates Study, BP-22-FS-BPA-01, § 3.2.2. BPA expects to meet its load obligations for Tier 2 in FY 2022 and FY 2023 using firm power from the FCRPS. *See id.* § 3.2.2.1. One of the objectives guiding risk mitigation for the FY 2022–2023 rate period is to prevent risks associated with Tier 2 from increasing costs for Tier 1 or requiring increased mitigation for Tier 1. *See id.* § 2.1.

4.3.1.1 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:

- The contracted-for power is not delivered to BPA.
- A customer's actual load is lower than the forecast amount used to set its Above-Rate Period High Water Mark (Above-RHWM) Load.
- A customer's actual load is higher than the forecast amount used to set its Above-RHWM Load.
- A customer does not pay for its Tier 2 service.
- The cost of BPA power purchases to meet Tier 2 obligations is higher than the cost allocated to the Tier 2 pool.

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

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

This risk is not applicable in BP-22 because all power needs for service at Tier 2 rates are expected to be sourced from the Federal system. Prior to BP-20, however, BPA executed 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. BPA expects any future purchases it makes for Tier 2 to be standard WSPP Schedule C contracts.

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-22-FS-BPA-01, Sections 5.4.5 and 5.6.1.5, explains how the TCMS calculation is performed for service at Tier 2 rates. BPA will base the TCMS cost on the amount of megawatt hours 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 or Tier 1 would incur a net cost.

4.3.1.1.2 Risk: A Customer's Actual Load is Lower than the Forecast Amount Used to Set Its Above-RHWM Load

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, 2016, with some modifications by October 31, 2020, for FY 2022 and FY 2023. Using the Above-RHWM Loads that were computed in the RHWM Process, which concluded in September 2020, and the customers' elections, BPA has determined each customer's Above-RHWM Load served at a Tier 2 rate for the BP-22 rate period.

If the customer's actual load is lower than the BPA forecast used to calculate the customer's Above-RHWM Load amounts, then 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 Tier 2 rates. This approach protects BPA and Tier 1 purchasers from financial impacts of this event. The customer's load reduction could 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 or Tier 1.

4.3.1.1.3 Risk: A Customer's Actual Load is Higher than the Forecast Amount Used to Set Its Above-RHWM Load

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 retains the primary obligation to pay for the additional power, and there would be no net cost to BPA or Tier 1.

4.3.1.1.4 Risk: A Customer Does Not Pay for its Tier 2 Service

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 BPA 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.

4.3.1.1.5 Risk: The Cost of BPA Power Purchases to Meet Tier 2 Obligations is Higher than the Cost Allocated to the Tier 2 Pool

This risk is not applicable in BP-22 because all power needs for service at Tier 2 rates are expected to be sourced from the Federal system. This risk has been relevant in the past and could be relevant in the future. In the event that BPA makes power purchases to meet its Tier 2 obligations in future rate periods, there is a risk that the cost of the purchase is greater (or less) than the cost applied to the Tier 2 cost pool. If the purchase cost is greater, then the Power net revenue will be reduced by the amount of the difference. If BPA makes a power purchase to serve load at Tier 2 rates in FY 2022 and FY 2023, then the cost of those purchases will be allocated to the Tier 2 cost pool. *See* Power Rates Study, BP-22-FS-BPA-01, § 3.2.2.1. Therefore, there is no risk that power purchase costs for Tier 2 service will be higher than the cost allocated.

If BPA does not make a power purchase to serve load at Tier 2 rates, or there is a remaining Tier 2 obligation not met with power purchases, then BPA will serve such load with firm power from the FCRPS. This unpurchased amount of Tier 2 energy is priced at the Remarketing Value for purposes of cost allocation. The Remarketing Values for FY 2022 and FY 2023 will either be equal to: (1) the price for a flat annual power block of power, if BPA makes a transaction for such power between November 1, 2020, and June 1, 2021, to be delivered in a fiscal year in the upcoming Rate Period; or (2) the average Intercontinental Exchange (ICE) Mid-C settlement prices from two separate, five-consecutive-business-day periods (the last full week in September 2020 and the last full week in March 2021), plus $0.50 per MWh. The $0.50 per MWh adder is used to convert the financial settlement prices to ICE to a physically delivered price. *See* Power Rates Study, BP-22-FS-BPA-01, § 3.2.2.6.

The ICE Mid-C financial settlement prices, plus the adder for converting to physical delivery, represent the cost BPA could transact in advance for Tier 2 energy. Such forward market prices inherently include a risk premium for locking in a power purchase well in advance of delivery. This risk premium in the Remarketing Value used for Tier 2 energy costs helps ensure that Tier 2 rates are not subsidized by Tier 1 rates.

4.3.2 Risks Associated with Resource Support Services Rate Design

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-22-FS-BPA-01A, Table 3.11.

4.3.2.1 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 difficult. BPA does not intend to quantify the cost of each operational decision, which means that BPA is not 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 $1 million annually. *See* Power Rates Study Documentation, BP-22-FS-BPA-01A, Tables 9.2. The magnitude of the risk of miscalculation of these RSS costs is not large enough to affect TPP calculations.

4.3.3 Qualitative Risk Assessment Results

4.3.3.1 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.

4.3.3.2 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.

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5. TRANSMISSION RISK

5.1 Transmission Quantitative Risk Assessment

This chapter describes the uncertainties pertaining to Transmission Services' finances in the context of setting transmission rates. Section 5.2 describes how BPA determines whether its risk mitigation measures are sufficient to meet the TPP standard given the risks detailed in this chapter.

Variability in Transmission revenues is modeled in RevRAM, as described in Section 5.1.1. Variability in Transmission expenses and Net-Revenue-to-Cash (NRTC) adjustments are modeled in T-NORM, as described in Section 5.1.2. The results of these quantitative risk models are provided to ToolKit, which performs quantitative risk mitigation, as described in Section 5.2.

5.1.1 RevRAM – Revenue Risk

See Section 3.1.2.2 for an overview of RevRAM. The following sections describe the uncertainties modeled in RevRAM.

5.1.1.1 Network Integration Service Revenue Risk

Risks in the network integration (NT) revenue forecast arise from uncertainty in the load forecast, which is the basis for the NT sales and revenue forecast. The load forecast is based on predicted year-to-year NT load growth. Actual loads can vary from the forecast because economic conditions may be different from those forecast and load center temperatures may differ from the normalized temperatures on which the forecast is based.

Risk in the growth rate is modeled with a triangular risk distribution defined by a high value, a low value, and a most likely value (or mode). The most likely value is the forecast rate of year-to-year load growth. The high value is an optimistic load growth rate that serves as the 80th percentile of the triangular distribution, and the low value is a pessimistic load growth rate that serves as the 20th percentile of the distribution.

The optimistic load growth rate is determined by adding the predicted year-to-year NT load growth rate to an optimistic forecast of Gross Domestic Product (GDP) obtained from IHS Markit (formerly known as Global Insight), an economic forecasting and analysis firm. Similarly, the pessimistic load growth rate is determined by adding the predicted year-to-year NT load growth rate to a pessimistic GDP forecast obtained from IHS Markit. The resulting distribution around growth rate serves as the first component of NT revenue risk.

The impact of temperature variability on the load is also modeled. The load forecast is based on normalized temperature, so the risk arises from the variability of load center temperatures. Variability in these temperatures induces variability in the load. The distribution of temperatures in a 30-year period follows a normal distribution (a bell curve symmetrical around the mean) calculated from historical temperatures.

The NT revenue risk distributions have standard deviations of $9.3 million for FY 2022 and $9.7 million for FY 2023.

5.1.1.2 Long-Term Network Point-to-Point Service Revenue Risk

Risks in revenue from long-term PTP service are related to assumptions about new service and potential deferrals of the service commencement date, exercise of renewals under BPA's Open Access Transmission Tariff (OATT), conversions of Formula Power

Transmission (FPT) service to PTP service, and possible customer default. BPA also models revenue risk related to service that has not been granted yet but that might be granted during the rate period.

BPA models risk for forecast revenue from new transmission service (that is, service that has been offered to customers but has not yet begun) because the customer has a right to defer the service commencement date for up to five years. A deferral delays the revenue from that service for the period of the deferral. The revenue risk associated with deferrals is based on a comparison of the service commencement date on the service reservation to the probable service commencement date after deferrals.

BPA identifies possible deferrals by determining whether the service appears to be related to a Large Generator Interconnection Agreement (LGIA). If the generation in-service date has been forecast, then risk around the forecast LGIA generation in-service date is modeled using a triangular distribution defined by maximum, most likely, and minimum values. The transmission service commencement date is assumed to match the risk-adjusted generation in-service date (that is, the analysis assumes the customer would defer its transmission service commencement date to match the generation in-service date). If the generation in-service date has not been forecast, the risk of deferral is identified based on information from BPA's account executive for the customer. The likelihood of deferral is based on the account executive's level of confidence that the request will begin on its current service commencement date.

BPA also models risk associated with revenue from new service to be offered as a result of new transmission infrastructure that BPA will energize in the rate period. A PERT distribution is used to model possible delays to the in-service date for these projects (and resulting delays in the start of service and receipt of revenue).

Risk is also modeled for service that is eligible to be renewed during the rate period. Historical data is gathered on the frequency of renewal of long-term PTP service for service reservations that have been eligible for renewal over the past five years. A normal distribution is identified using the historical frequency of renewals for service requests that are eligible for renewal. That distribution is applied to the service requests that are eligible for renewal during the rate period to identify the probability of the service being renewed.

Risk is modeled for service that is eligible to convert from FPT service to PTP service by gathering information from BPA's account executives for the customers on the likelihood that individual requests will convert either after the expiration or prior to the expiration of the FPT contracts. The likelihood of conversion is based on the account executive's level of confidence that the request will be converted to PTP service during the rate period.

Risk of default is modeled for all current and anticipated service. The probability of default for each customer is modeled using information from Standard & Poor's. BPA applies Standard & Poor's credit rating for each entity and refers to Standard & Poor's Global Corporate Average Default Rate for the level of default risk associated with that credit rating. Standard & Poor's conducts its default studies on the basis of groupings called static pools. Static pools are formed by grouping issuers by rating category at the beginning of each year covered by the Study. Annual default rates are calculated for each static pool, first in units and later as percentages with respect to the number of issuers in each rating category. Finally, these percentages are combined to obtain cumulative default rates for the 30 years covered by the Study. If a default occurs in the model, the capacity held by the defaulting customer is assumed to return to inventory to be resold for a portion of the remaining months of the fiscal year. Assuming the capacity is resold for only a portion of the year accounts for the time it takes to process and offer the new contract for the service.

Risk associated with additional sales of service that have not yet been requested (the possibility that revenues will be higher than forecast due to these sales) is modeled based on three different sources : (1) new sales associated with new generation that is included in the LGIA forecast but for which long-term service has not yet been requested; (2) new sales from transmission inventory that becomes available due to customer default, as described above; and (3) new sales as a result of competitions performed in accordance with Section 17.7 of the OATT (deferral competitions). Sales due to new generation are modeled using a PERT distribution and information from Transmission Services's customer service engineering organization on expected in-service dates. Modeling of sales from inventory that becomes available due to customer default is described above. To model sales that occur after competitions, it is assumed that zero to six competitions will be performed per year. For each competition performed there is a 50 percent chance that the competition will be successful and result in additional revenue.

The long-term PTP revenue risk distribution results in standard deviations of $10.3 million for FY 2022 and $11.3 million for FY 2023.

5.1.1.3 Short-Term Network Point-to-Point Service Revenue Risk

The short-term PTP revenue forecast carries significant risk due to the nature of the product. This service is not reserved far in advance with an existing contract, but instead is requested on an hourly, daily, weekly, or monthly basis. Short-term PTP service is sensitive to market conditions and streamflow, so we model the risks around the price spread between the North of Path 15 (NP-15) hub and the Mid-C hub, as well as streamflow. Modeling risk around the Mid-C and NP-15 prices incorporates variability around natural gas prices and streamflow. Natural gas volatility is important because natural gas-fired electricity generation is often the marginal resource in western power markets, and therefore plays an important role in setting the market price of power. Fluctuations in natural gas prices lead to fluctuations in power prices.

Streamflow variability is important for two reasons. First, the Mid-C and NP-15 price spread is positively correlated with streamflow. As streamflow increases, Mid-C prices decrease and the price spread widens. Second, streamflow has a high correlation with short-term transmission reservations made by Power Services. The short-term PTP forecast is developed using a regression analysis, so risk of errors is incorporated in the relationships identified between historical sales, streamflow, and price spread. The short-term PTP risk distribution resulting from the methodology outlined above results in standard deviations of $14.0 million for FY 2022 and $14.1 million for FY 2023.

5.1.1.4 Long-Term Southern Intertie Service Revenue Risk

Long-term capacity on the Southern Intertie (IS) is almost fully subscribed in the north-to-south direction. This means that BPA cannot make additional sales unless existing agreements terminate or are not renewed, or until reliability upgrades on the Pacific DC Intertie (PDCI) increase transfer capability. In addition, there is a queue of transmission service requests that are seeking long-term IS service but that have not been granted service because no long-term IS capacity is available for sale. Requests in the queue are expected to replace any contracts that expire. Thus, BPA identified a high service commencement probability, with a normal distribution, for these requests. In addition, default risk for service on the IS is modeled using the same method described for long-term

PTP service. The long-term IS risk distribution results in standard deviations of $2.0 million for FY 2022 and $1.5 million for FY 2023.

5.1.1.4.1 Short-Term Southern Intertie Service Revenue Risk

The revenue forecast for short-term IS service carries significant risk due to the nature of the product. This service is not reserved far in advance with an existing contract, but instead is requested on an hourly, daily, weekly, or monthly basis. Short-term IS service is sensitive to market conditions, so BPA models the risks around the NP-15 minus Mid-C price spread and South of Path 15 (SP-15) minus Mid-C spread. The forecast is developed using a regression analysis, so BPA also models risk of errors in correlations identified between historical sales, streamflow, and price spread. The short-term IS revenue risk distribution results in standard deviations of $0.3 million for FY 2022 and $0.3 million for FY 2023.

5.1.1.5 Other Transmission Revenue Risk

The risk related to other transmission revenues arises from variability in Utility Delivery and Direct-Service Industry (DSI) Delivery revenues, revenues from fiber and wireless contracts, and revenues from other fixed-price contracts. This risk is modeled based on the historical variance between rate case revenue forecasts for these products and actual revenue. Data from FY 2016 through FY 2020 is used and the mean average deviation is applied, resulting in a deviation of $0.1 million per year for Utility and DSI Delivery revenue, $0.6 million per year for fiber and wireless contract revenue, and $2.0 million per year for other fixed-price contract revenue.

5.1.1.6 Ancillary and Control Area Services Revenue Risk

BPA models the revenue risk associated with the ancillary service Scheduling, System Control, and Dispatch (SCD), which applies to customers taking both firm and non-firm transmission service. SCD revenue is based on sales of NT, long-term PTP, short-term PTP, long-term IS, and short-term IS. As such, the revenue variability for SCD follows the risk associated with those services, and SCD revenue risk is not modeled individually. Instead, variations in SCD revenues are assumed to be directly proportional to variations in the revenue from those services.

BPA does not model revenue risk associated with the Ancillary Service Reactive Supply and Voltage Control from Generation Sources (GSR) because that rate is a formula rate that is currently set at zero. As a result, it generates no revenue. The formula rate for GSR is calculated for each quarter but has been calculated to be zero in every quarter since 2009.

Generation Inputs services comprise Regulation and Frequency Response (RFR), Dispatchable Energy Resource Balancing Service (DERBS), Variable Energy Resource Balancing Service (VERBS), Energy and Generation Imbalance (EI/GI), and Operating Reserve (OR) – Spinning and Supplemental. These sources of revenue are sorted into two categories based on their characteristics and their impact on Transmission Services net revenue: (1) variable revenue with fixed expense, and (2) variable revenue with variable expense.

Transmission Services will pay Power Services for providing reserves for the Generation Inputs services, offset by Transmission revenue recovery, during the rate period.

Generation Inputs services whose revenues and expenses have generally equivalent variability and are correlated – that is, any potential change in Transmission Services revenue is matched by an offsetting change in Transmission Services expense – create insignificant uncertainty in Transmission Services net revenue. Therefore, no uncertainty in net revenue from these services is modeled.

5.1.1.7 Total Transmission Revenue Risk

The Transmission Revenue Risk worksheets compute the revenue risk and the resulting expected value for transmission revenues from these products. The revenue uncertainty from all transmission services is aggregated. The variability of the total transmission revenues (as measured by the standard deviation) is less than the sum of the variabilities (standard deviations) of the individual services. The standard deviation of the distribution of total transmission revenue for the FY 2022 is $22.4 million and for FY 2023 is $24.0 million. In each game, the total transmission revenue is linked into the income statement in T-NORM.

5.1.2 T-NORM Inputs

5.1.2.1 Inputs to T-NORM

To obtain the data used to develop the probability distributions used by T-NORM, BPA analyzed historical data and consulted with subject matter experts for their assessment of the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. Table 10 shows the 5th percentile, mean, and 95th percentile results from each of the risk models described below, along with the deterministic amount that is assumed in the revenue requirement for that item. *See* Transmission Revenue Requirement Study Documentation, BP-22-FS-BPA-09A, Table 3-1.

5.1.2.1.1 Transmission Operations

T-NORM models variability in transmission operations expense using PERT distributions for FY 2021 and for each of the two fiscal years in the rate period, FY 2022 and FY 2023. For FY 2021, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009-2020) compared to rate case projections. The minimum value is 16 percent lower than the expected level of expense in the revenue requirement and the maximum value is equal to the expected level of expense in the revenue requirement.

5.1.2.1.2 Transmission Maintenance

To model variability in transmission maintenance expense, PERT distributions are used for FY 2021 and for each of the two fiscal years in the rate period. For FY 2021, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009-2020) compared to rate case projections. The minimum value is 8 percent lower, and the maximum value is 5 percent higher, than the expected level of expense in the revenue requirement.

5.1.2.1.3 Agency Services General and Administrative

To model variability in agency services general and administrative costs, PERT distributions are used for FY 2021 and for each of the two fiscal years in the rate period. For FY 2021, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values come from the historically observed minimum and maximum actual values (FY 2009-2020) compared to rate case projections. The minimum value is 5 percent lower, and the maximum value is 17 percent higher, than the expected level of expense in the revenue requirement.

5.1.2.1.4 Interest Expense and Earnings

T-NORM captures the impact of interest rates, capital uncertainty, and Transmission Services reserves levels on interest expense and earnings. Interest expense risk is modeled for FY 2021, FY 2022, and FY 2023 using a normal distribution with the expected values set at the revenue requirement amount and the standard deviations set at $1.5 million for FY 2021, $1.7 million for FY 2022, and $5.0 million for FY 2023. T-NORM models interest earnings risk for FY 2021, FY 2022, and FY 2023 using a uniform distribution with the maximum set at the revenue requirement amount and the minimum set at $0.

5.1.2.1.5 Transmission Engineering

To model variability in transmission engineering expense, PERT distributions are used for FY 2021 and for each of the two fiscal years in the rate period. For FY 2021, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009-2020) compared to rate case projections. The minimum value is 15 percent lower and the maximum value is 45 percent higher than the expected level of expense in the revenue requirement. For FY 2021, half of the historical variation is applied, resulting in a minimum value of 7.5 percent lower, and a maximum value of 22.5 percent higher than the expected level.

5.1.2.2 T-NORM Results

The output of T-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 net-revenue-to-cash (NRTC) adjustments for each game for FY 2021, FY 2022, and FY 2023. 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 Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 11.

5.1.3 Net-Revenue-to-Cash Adjustment

T-NORM calculates 3,200 NRTC adjustments in order to make the necessary changes to convert RevRAM and T-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate financial reserves values in each game and thus calculate TPP. *See* § 3.1.4 (NRTC Adjustments). The NRTC Adjustment is the same across all 3,200 games in T-NORM, based on the deterministic expected values for each fiscal year's cash adjustments and non-cash adjustments. The NRTC table is shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Table 22.

5.2 Transmission Quantitative Risk Mitigation

The preceding sections of this chapter describe the risks that are modeled explicitly, with the output of T-NORM and RevRAM quantitatively portraying the financial uncertainty faced by Transmission Services in each fiscal year. This section describes the tools used to mitigate these risks – TS reserves, Agency Liquidity, PNRR, the CRAC, the FRP Surcharge, and the RDC – and how BPA evaluates the adequacy of this mitigation.

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 its fiscal year, to fully meet its obligation to the Treasury for that fiscal year. BPA's TPP standard, described in Section 2.4 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a 5 percent probability of any deferrals of BPA's Treasury payment in a two-year rate period). TPP and the ability of the rates to meet the TPP standard are measured in the ToolKit by applying the risk mitigation tools described in this section to the modeled financial risks described in the previous sections.

A second risk addressed in this Study is 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 that year. In each recent rate proceeding, a need for financial reserves for within-year liquidity (liquidity reserves) has been defined.

5.2.1 Thresholds for CRAC, RDC, and FRP Surcharge

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A. The lower and upper thresholds are used to determine when rate actions will be taken to increase or decrease financial reserves. These rate actions are implemented through the FRP Surcharge and the RDC. The FRP also establishes a $0 threshold for each business line, below which an additional rate action must be taken. This rate action is implemented through the CRAC.

The Transmission CRAC thresholds are shown in Table 12. The Transmission RDC thresholds are shown in Table 13. The Agency RDC thresholds are shown in Table 7. The Transmission FRP Surcharge thresholds are shown in Table 14.

5.2.1.1 Transmission Services Lower Financial Reserves Threshold

The Lower Financial Reserves Threshold for Transmission is the greater of 60 days cash or what is necessary to meet the TPP Standard. For this Rate Case, no additional financial reserves are needed to meet the TPP Standard, so the Lower Threshold for Transmission is set at 60 days cash. The calculations of Transmission operating expenses and translations into days cash dollar amounts are shown in Table 11.

5.2.1.2 Transmission Services Upper Financial Reserves Threshold

The Upper Financial Reserves Threshold for Transmission is the Lower Threshold plus 60 days cash. The calculations of Transmission operating expenses and translations into days cash dollar amounts are shown in Table 11.

5.2.1.3 Agency Upper Financial Reserves Threshold

The Agency (BPA) Upper Financial Reserves Threshold is the sum of the Power and Transmission Lower Financial reserves Thresholds plus 30 days Agency cash. The Agency days cash dollar amounts are shown in Table 4.

5.2.2 Transmission Risk Mitigation Tools

5.2.2.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For purposes of BP-22 rate period risk modeling, Transmission Services has two sources of liquidity: (1) Transmission Services reserves and (2) Agency Liquidity. Transmission Services reserves are described further in Section 2.3.

5.2.2.1.1 Transmission Services Reserves

Transmission Services reserves at the start of FY 2021 are $272.3 million. This value was calculated as *total* financial reserves (see Section 2.3 above) attributed to Transmission Services of $384.7 million less $112.4 million of financial reserves not for risk as of the end of BPA fiscal year 2020. *See* Q4 Quarterly Business Review Technical Workshop Package, BPA (Nov. 19, 2020), available at https://www.bpa.gov/Finance/FinancialPublicProcesses/QuarterlyBusinessReview/qbrdocs/FY20%20Q4%20QBR%20Technical%20Workshop%20materials.pdf; Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 12.

5.2.2.1.2 Agency Liquidity in Excess of TPP

Transmission Services meets the TPP standard before accouting for any additional Agency Liqudity. Therefore, the Transmission Services Agency Liquidity reliance is $0.

5.2.2.1.3 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. The Transmission Services within-year liquidity need of $100 million was determined in the BP-16 rate proceeding, and that amount continues to be used for ratemaking risk mitigation purposes.

5.2.2.1.4 Within-year Liquidity Borrowing Level

For this Study, Transmission does not rely on any Borrowing Liquidity. Therefore, the within-year liquidity borrowing level is $0.

5.2.2.1.5 Within-year Liquidity Reserve Level

The Transmission Services within-year liquidity reserve level is $100 million. As these reserves are set aside to meet the within-year liquidity need and not available to meet the TPP standard, a TPP miss is modeled to occur when Transmission Services reserves fall below $100 million.

5.2.2.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted during rate development using current projections of Transmission Services reserves. If the TPP is below the 95 percent two-year standard required by BPA's Financial Plan, then the projected financial reserves, along with whatever other risk mitigation is considered in the risk study, are not sufficient to reach the TPP standard. This may be 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 Transmission Services reserves, and therefore increase TPP.

PNRR needed to meet the TPP standard is calculated in the ToolKit, described in Section 3.1.5. 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 Transmission Revenue Requirement Study (BP-22-FS-BPA-09), 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. PNRR is not needed to meet the TPP standard for this Study.

5.2.2.3 Risk Adjustment Mechanisms

The Transmission CRAC was first adopted in the BP-18 rate proceeding. *See* Power and Transmission Risk Study, BP-18-FS-BPA-05. BPA has included three risk adjustment mechanisms for Transmission in BP-22: the Transmission CRAC, Transmission RDC, and Transmission FRP Surcharge. *See* §§ 2.4, 5.2.2.3.1-3.

The Transmission rates subject to these risk adjustment mechanisms are the Network Integration Rate (NT-22), the Point-to-Point Rate (PTP-22), the Formula Power Transmission Rate (FPT-22.1), the Southern Intertie Point-to-Point Rate (IS-22), the Scheduling, Control, and Dispatch Rate (ACS-22 Sections II.A and S V.B), the Utility Delivery Rate (Transmission GRSPs II.A.1.b.), and the Montana Intertie Rate (IM-22). *See* Transmission GRSP II.G-I.

For BP-22, Transmission rates include $40 million per year in revenue financed capital. The Study assumes that if Power Services reserves are below the FRP Surcharge threshold at the end of a fiscal year, BPA's Administrator would redeploy the planned revenue financing in the current year to replenish reserves back to the threshold.

5.2.2.3.1 Transmission Cost Recovery Adjustment Clause (CRAC)

As described in Section 2.4 and Transmission GRSP II.G, the CRAC for FY 2022 and FY 2023 is a potential annual upward adjustment in various Transmission rates. The Transmission CRAC explained here could increase rates for FY 2022 based on Transmission Services reserves at the end of FY 2021. It also could increase rates for FY 2023 based on Transmission Services reserves at the end of FY 2022. The CRAC implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves fall below $0. *See* Appendix A, § 4.2.3.

The thresholds for triggering the CRAC are described in Section 5.2.1. If Transmission Services reserves are below the thresholds, a shortfall has occurred. The shortfall is equal to the Transmission Services CRAC threshold minus Transmission Services reserves. The shortfall is first assumed to be replenished through redeploying the planned revenue financing in the applicable year. *See* §§ 2.4, 5.2.2.3. If there is a remaining shortfall,the Transmission CRAC will recover 100 percent of the remaining shortfall, up to a cap of $100 million. The Transmission CRAC will only trigger if the amount to be collected by the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2022 and FY 2023 rates will be made early in that fiscal year based on end-of-year actual Power Services reserves. If the CRAC triggers, an upward rate adjustment will be calculated for December through September of the fiscal year. *See* Transmission GRSP II.G.

5.2.2.3.2 Transmission Reserves Distribution Clause (RDC)

The Transmission RDC implements the FRP requirement for a financial reserves distribution in the event that financial reserves are above upper financial reserves thresholds. *See* Appendix A, § 4.1.

The thresholds for triggering the RDC are described in Section 5.2.1. The Transmission RDC is triggered if both BPA reserves (the sum of Power Services reserves and Transmission Services reserves) *and Transmission Services* reserves are above specified thresholds. Above-threshold financial reserves will be considered for providing a downward adjustment to the same Transmission rates that are subject to the Transmission CRAC or for being deployed to other high-value business line-specific purposes. The total distribution is capped at $200 million per fiscal year. The RDC will only trigger if the RDC distribution amount is greater than or equal to $5 million. *See* Transmission GRSP II.H.

5.2.2.3.3 Transmission Financial Reserves Policy (FRP) Surcharge

The Transmission FRP Surcharge is a potential annual upward adjustment in various transmission rates. The Transmission FRP Surcharge applies to the same Transmission rates that are subject to the Transmission CRAC. The Transmission FRP Surcharge implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves are below the lower financial reserves threshold. *See* Appendix A, §§ 4.2.1, 4.2.2.

The thresholds for triggering the FRP Surcharge are described in Section 5.2.1. If Transmission Services reserves are below the thresholds, a shortfall has occurred. The shortfall is equal to the Transmission Services FRP Surcharge threshold minus Transmission Services reserves. The shortfall is first assumed to be replenished through redeploying the planned revenue financing in the applicable year. *See* §§ 2.4, 5.2.2.3. If there is a remaining shortfall, the Transmission FRP Surcharge will collect that remaining shortfall, up the the Transmission FRP Surcharge cap of $15 million per year. If the Transmission FRP Surcharge amount calculation results in a value less than $5 million, then the amount is deemed to be zero. *See* Transmission GRSP II.I.

5.2.3 ToolKit

The ToolKit model is described in Section 3.1.5. The inputs to the ToolKit for Transmission are shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 13.

5.2.3.1 ToolKit Inputs and Assumptions for Transmission

5.2.3.1.1 RevRAM Results

The ToolKit reads in risk distributions generated by RevRAM that are created for the current year, FY 2021, and the rate period, FY 2022-2023. TPP is measured for only the two-year rate period, but the starting financial reserves for FY 2022 depend on events yet to unfold in FY 2021; these runs reflect that FY 2021 uncertainty. See Section 5.1.1 for more details on RevRAM.

5.2.3.1.2 Non-Operating Risk Model

The ToolKit reads in T-NORM distributions that are created for FY 2021-2023 and reflect the uncertainty around non-operating expenses. See Section 5.1.2 for more detail on T-NORM.

5.2.3.1.3 Treatment of Treasury Deferrals

In the event that ToolKit forecasts a Treasury principal payment deferral, the ToolKit assumes that BPA will repay this balance as soon as liquidity is available to make the payment.

5.2.3.1.4 Starting Transmission Services Reserves

The FY 2021 starting Transmission Services reserves have a forecast value of $272.3 million. See Section 5.2.2.1.1 above for a description of Transmission Services reserves.

5.2.3.1.5 Transmission Services Within-year Liquidity Reserves Level

The Transmission Services within-year liquidity reserves level is an amount of Transmission Services reserves set aside (*i.e.*, not available for TPP use) to provide liquidity for within-year cash flow needs. This amount is set to $100 million. *See*§ 5.2.2.1.5 above.

5.2.3.1.6 Liquidity Borrowing Available

The Transmission Services liquidity borrowing amount is decreased by any Agency Liquidity provided by Transmission Services. Both amounts are $0, so the total liquidity borrowing amount is $0.

5.2.3.1.7 Interest Rate Earned on Financial Reserves

Interest earned on financial reserves is modeled through T-NORM. *See* § 5.1.2.1.4 above.

5.2.4 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 15.

5.2.4.1 Ending Transmission Services Reserves

Starting Transmission Services reserves for FY 2021 are $272.3 million. The expected values of ending financial reserves are $166 million for FY 2021, $165 million for FY 2022, and $165 million for FY 2023. Over 3,200 games, the range of ending FY 2023 financial reserves is from $76 million to $420 million. The 50 percent confidence interval for ending financial reserves for FY 2023 is $132 million to $191 million. Financial reserves distributons are shown in Power and Transmission Risk Study Documentation, BP-22-FS-BPA-05A, Figure 12.

5.2.4.2 TPP

The two-year TPP is 99.5 percent. In 3,200 games, there are no deferrals for FY 2021 or FY 2022. There are deferrals in 0.5 percent of games (16 out of 3,200) for FY 2023.

5.2.4.3 CRAC, RDC, and FRP Surcharge

The Transmission CRAC and FRP Surcharge do not trigger in any of the 3,200 games for FY 2022 or FY 2023.

The Transmission RDC triggers in 1 percent of games for FY 2022, yielding an average amount of $0.3 million (measured as the average amount across all 3,200 games). The Transmission RDC triggers in 4 percent of games for FY 2023, yielding an average amount of $1 million.

Transmission CRAC, RDC, and FRP Surcharge statistics are shown in Table 15. The thresholds and caps for the Transmission CRAC, Transmission RDC, and Transmission FRP Surcharge applicable to rates for FY 2022 and FY 2023 are shown in Tables 12, 13, and 14. The BPA RDC Thresholds are shown in Table 7.

TABLES

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Table 1: RevSim Net Revenue Statistics for FY 2022 and FY 2023
(Dollars in millions)

	FY - 2022	FY - 2023
Mean	$136,383	$97,467
Median	$133,961	$99,469
StDev	$151,808	$145,690
Min	($211,801)	($224,853)
Max	$706,975	$574,761

Percentile	FY - 2022	FY - 2023
1%	($134,378)	($167,734)
5%	($96,814)	($134,193)
10%	($68,251)	($105,180)
15%	($40,520)	($68,433)
20%	($8,397)	($38,690)
25%	$14,238	($16,517)
30%	$38,276	$7,854
35%	$64,432	$32,551
40%	$91,785	$56,998
45%	$112,891	$80,647
50%	$133,961	$99,469
55%	$157,929	$118,474
60%	$179,873	$139,304
65%	$200,983	$157,847
70%	$222,419	$177,108
75%	$245,993	$200,331
80%	$271,531	$222,281
85%	$298,258	$252,281
90%	$336,109	$290,094
95%	$394,670	$341,424
99%	$476,940	$436,620
100%	$706,975	$574,761

Table 2: P-NORM Risk Summary
(Dollars in millions)

	A	B	C	D	E	F	G
	P-NORM Risk Summary						
	Study Section	***Risk Title***	***Fiscal Year***	***Forecast***	***5th Percentile***	***Mean***	***95th Percentile***
1	4.1.2.1.1	CGS Operations and Maintenance (O&M)	2021	318.7	317.9	318.1	318.3
2			2022	278.6	270.7	278.8	287.7
3			2023	304.7	296.1	305.0	314.7
4	4.1.2.1.2	U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation	2021	418.9	418.9	419.8	423.9
5			2022	404.8	404.8	406.6	410.8
6			2023	405.5	405.5	407.3	411.5
7	4.1.2.1.3	Conservation Expense	2021	76.8	74.7	76.5	78.0
8			2022	73.4	69.5	72.8	75.6
9			2023	73.4	69.5	72.8	75.7
10	4.1.2.1.4	Power Services Transmission Acquisition and Ancillary Services	2021	79.4	78.5	79.3	79.9
11			2022	85.2	83.3	84.9	86.3
12			2023	86.5	84.6	86.5	88.2
13	4.1.2.1.5	Fish & Wildlife Expenses	2021	281.0	275.0	277.0	279.1
14			2022	280.5	270.2	274.1	278.2
15			2023	276.2	266.3	270.3	274.3
16	4.1.2.1.6	Interest Expense and Earnings Risk	2021	284.9	284.4	289.6	294.8
17			2022	21.8	21.2	27.5	33.9
18			2023	250.2	247.7	256.0	264.4
19	4.1.2.1.7	CGS Refueling Outage Risk	2021	N/A	-4.5	-0.9	0.8
20			2022	N/A	0.0	0.0	0.0
21			2023	N/A	-11.0	-2.5	1.3

Table 3: Power Days Cash and Financial Reserves Thresholds
(Dollars in millions)

		A	B
		FY 2022	**FY 2023**
1	Total Expenses	$2,656	$2,660
	Less		
2	Net Interest Expense	$240	$228
3	Depreciation and Amortization	$499	$500
4	Contracted Power Purchases	$91	$88
5	Sum of rows 3-5	$830	$816
6	Operating Expenses (row 2 less row 6)	$1,827	$1,844
7	Operating Expenses divided by 365 (row 7/365)	$5.00	$5.05
8	Rate period average (average of row 8 column A and B)	$5.03	
9	**Lower Financial Reserves Threshold (row 9 * 60)**	**$301.6**	
10	**30 days cash on hand (row 9 * 30)**	**$150.8**	
11	**Upper Financial Reserves Threshold (row 9 * 120)**	**$603.3**	

Table 4: Agency Upper Financial Reserves Threshold
(Dollars in millions)

		BP-22 Thresholds
1	Power Lower Financial Reserves Threshold	$301.6
2	Transmission Lower Financial Reserves Threshold	$101.8
3	Power 30 days cash on hand	$150.8
4	Transmission 30 days cash on hand	$50.9
5	**Agency Upper Financial Reserves Threshold (sum of rows 2 through 5)**	**$605.0**

Table 5: Power CRAC Thresholds and Caps
(Dollars in millions)

Power RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2021	2022	$0	$30	$300
2022	2023	$0	$31	$300

Table 6: Power RDC Thresholds and Caps
(Dollars in millions)

Power RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Power RFR Threshold	Maximum RDC Amount (Cap)
2021	2022	$603	$500
2022	2023	$603	$500

Table 7: BPA RDC Annual Threshold
(Dollars in millions)

BPA RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	BPA RFR Threshold
2021	2022	$605
2022	2023	$605

Table 8: Power FRP Surcharge Thresholds
(Dollars in millions)

Power RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Power RFR Threshold	Revenue Financing Amount	Base Surcharge
2021	2022	$302	$30	$40
2022	2023	$302	$31	$40

Table 9: Power Risk Mitigation Summary Statistics
(Dollars in millions)

	A	B	C	D
		FY 2021	**FY 2022**	**FY 2023**
1	Two-Year TPP	*NA*	>99.9%	
2	PNRR		$0	$0
3	CRAC Frequency		0%	0%
4	Expected Value (EV) CRAC Revenue		$0	$0
5	RDC Frequency		0%	30%
6	EV RDC		$0	$31
7	FRP Surcharge Frequency		0%	4%
8	EV Surcharge Revenue		$0	$1
9	Treasury Deferral Frequency	0.0%	0.0%	0.0%
10	EV Treasury Deferral	$0	$0	$0
11	EV End of Year Financial Reserves	$448	$520	$488
12	Financial Reserves, 5th percentile	$389	$302	$142
13	Financial Reserves, 25th percentile	$419	$393	$334
14	Financial Reserves, 50th percentile	$445	$515	$498
15	Financial Reserves, 75th percentile	$472	$632	$637
16	Financial Reserves, 95th percentile	$518	$784	$810
17	Probability Reserves Fall below $0	0%	0%	0%

Table 10: T-NORM Risk Summary
(Dollars in millions)

	A	B	C	D	E	F	G
	T-NORM Risk Summary						
	Study Section	***Risk Title***	***Fiscal Year***	***Forecast***	***5th Percentile***	***Mean***	***95th Percentile***
1	5.1.3.1.1	Transmission Operations	2021	68.8	63.9	67.0	68.7
2			2022	168.7	156.8	164.3	168.4
3			2023	171.6	159.5	167.1	171.3
4	5.1.3.1.2	Transmission Maintenance	2021	186.6	178.0	185.8	192.9
5			2022	177.6	169.4	176.8	183.6
6			2023	179.9	171.6	179.1	186.0
7	5.1.3.1.3	Agency Service G&A	2021	105.6	102.2	107.8	115.1
8			2022	103.2	99.9	105.3	112.5
9			2023	104.7	101.3	106.8	114.1
1	5.1.3.1.4	Interest Expense and Earnings	2021	140.7	137.9	140.4	142.9
1			2022	158.1	156.2	159.1	162.0
1			2023	161.9	154.5	162.8	171.1
1	5.1.3.1.5	Transmission Engineering	2021	87.0	77.9	91.3	108.2
1			2022	56.6	50.7	59.4	70.4
1			2023	57.1	51.1	59.9	71.0

Table 11: Transmission Days Cash and Financial Reserves Thresholds
(Dollars in millions)

		A	B
		FY 2022	FY 2023
1	Total Expenses	$1,103	$1,119
	Less		
2	Net Interest Expense	$142	$146
3	Depreciation and Amortization	$345	$350
4	Contracted Power Purchases	$0	$0
5	Sum of rows 3-5	$488	$496
6	Operating Expenses (row 2 less row 6)	$616	$624
7	Operating Expenses divided by 365 (row 7/365)	$1.69	$1.71
8	Rate period average (average of row 8 column A and B)	$1.70	
9	**Lower Financial Reserves Threshold (row 9 * 60)**	**$101.8**	
10	**30 days cash on hand (row 9 * 30)**	**$50.9**	
11	**Upper Financial Reserves Threshold (row 9 * 120)**	**$203.7**	

Table 12: Transmission CRAC Thresholds and Caps
(Dollars in millions)

Transmission RFR as of the end of Fiscal Year	CRAC Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Maximum CRAC Amount (Cap)
2021	2022	$0	$40	$100
2022	2023	$0	$40	$100

Table 13: Transmission RDC Thresholds and Caps
(Dollars in millions)

Transmission RFR as of the end of Fiscal Year	RDC Applied to Fiscal Year	Transmission RFR Threshold	Maximum RDC Amount (Cap)
2021	2022	$204	$200
2022	2023	$204	$200

Table 14: Transmission FRP Surcharge Thresholds and Caps
(Dollars in millions)

Transmission RFR as of the end of Fiscal Year	FRP Surcharge Applied to Fiscal Year	Transmission RFR Threshold	Revenue Financing Amount	Base Surcharge
2021	2022	$102	$40	$15
2022	2023	$102	$40	$15

Table 15: Transmission Risk Mitigation Summary Statistics
(Dollars in millions)

	A	B	C	D
		FY 2021	FY 2022	FY 2023
1	Two-Year TPP	*NA*	99.5%	
2	PNRR		$0	$0
3	CRAC Frequency		0%	0%
4	Expected Value (EV) CRAC Revenue		$0	$0
5	RDC Frequency		1%	4%
6	EV RDC		$0	$1
7	FRP Surcharge Frequency		0%	0%
8	EV Surcharge Revenue		$0	$0
9	Treasury Deferral Frequency	0.0%	0.1%	0.4%
10	EV Treasury Deferral	$0	$0	$0
11	EV End of Year Financial Reserves	$166	$165	$165
12	Financial Reserves, 5th percentile	$136	$115	$105
13	Financial Reserves, 25th percentile	$153	$143	$132
14	Financial Reserves, 50th percentile	$165	$164	$163
15	Financial Reserves, 75th percentile	$178	$185	$191
16	Financial Reserves, 95th percentile	$199	$218	$236
17	Probability Reserves Fall below $0	0%	0%	0%

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Appendix A: Financial Reserves Policy

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APPENDIX A: FINANCIAL RESERVES POLICY

1. Background and Purpose

The Financial Reserves Policy (Policy) provides a consistent, transparent, and financially prudent method for determining BPA's target ranges for financial reserves available for risk (financial reserves). The Policy establishes upper and lower financial reserves thresholds for Power Services, Transmission Services, and the agency as a whole, which define the target ranges. The Policy also describes the actions BPA may take when financial reserves levels either fall below a lower threshold or exceed an upper threshold. The Policy supports BPA's requirement to establish the lowest possible rates consistent with sound business principles.

Prior to the Policy, BPA did not have a consistent way to establish financial reserves target ranges and upper and lower financial reserves thresholds for each business line and BPA. This is of particular importance because financial reserves levels and financial reserves policies and practices have a direct effect on BPA's credit rating, which is determined at the aggregate BPA level. BPA, however, sets rates to recover costs for each business line individually. The lack of a consistent policy across the business lines and for BPA as a whole allows for *ad hoc* financial reserves decisions and different treatment for each business line.

Establishing prudent financial reserves lower thresholds over time for the business lines helps to maintain BPA's credit rating, solvency, and rate stability, which is consistent with sound business principles. Establishing prudent financial reserves upper thresholds for the business lines and BPA as a whole ensures that financial reserves do not grow to unnecessarily high levels but rather are invested back into the business or distributed as rate reductions, both of which lower revenue requirement costs.

2. Scope of the Financial Reserves Policy

The Policy affects financial reserves available for risk (financial reserves) attributed to Power Services (Power) and Transmission Services (Transmission).

The Policy establishes lower and upper financial reserves thresholds for Power Services and Transmission Services, and upper financial reserves thresholds for the agency at the ends of fiscal years. The Policy also provides guidance on the actions BPA should take when financial reserves fall below established lower threshold levels or rise above established upper threshold levels at the ends of fiscal years.

The Policy does not preclude or hinder in any way the Administrator's authority to use financial reserves for purposes deemed necessary by the Administrator.

The Policy is intended to provide a consistent framework within which BPA can manage its financial reserves. To that end, the Policy will constitute precedent that BPA will adhere to in future rate cases absent a determination by the Administrator that the Policy must be modified to meet BPA's changing operating environment.

3. Financial Reserves Thresholds

3.1 Definitions

Financial reserves available for risk. Financial reserves available for risk (financial reserves) consist of cash, market-based special investments, and deferred borrowing, all of which are highly liquid and unobligated for BPA to use to mitigate financial risk, less any outstanding balance on the Treasury Facility.

Days Cash on Hand Metric. Days cash on hand is the number of days a business can continue to operate using its own cash on hand with no new revenue. Days cash on hand is a common industry liquidity metric measuring the relationship between the amount of cash a business holds and the amount of average daily expenses incurred in operating the business.

3.2 Business Line Financial Target Ranges

Financial reserves target ranges for each business line shall be calculated independently each rate period, and consist of upper and lower financial reserves thresholds, which define the upper and lower ends of the target ranges.

3.3 Lower Financial Reserves Thresholds

Lower financial reserves thresholds shall be calculated independently for Power and Transmission each rate period based on the greater of: (1) 60 days cash on hand, and (2) what is necessary to meet the Treasury Payment Probability (TPP) Standard. For each business line, if financial reserves fall below the lower threshold, a rate action shall trigger the following fiscal year to recover, in part or in whole, the shortfall.

3.4 Upper Financial Reserves Thresholds

Upper financial reserves thresholds shall be calculated independently for Power and Transmission each rate period and will be the financial reserves' equivalent of 60 days cash on hand above the lower financial reserves thresholds. The agency upper threshold is the sum of Power and Transmission's lower thresholds plus 30 days cash on hand for the agency.

3.4.1 Financial Reserves Distributions

If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.

3.5 Calculation of Lower and Upper Financial Reserves Thresholds

3.5.1 – Power Services		
Power lower financial reserves threshold	=	The greater of: (1) 60 days * (Power operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Power upper financial reserves threshold	=	Power lower financial reserves threshold plus 60 days * (Power operating expenses / 365 days)
Where:		
Power operating expenses	=	Power total expenses – (Power depreciation and amortization + Power net interest expense + Power non-federal debt service + Power purchases)

3.5.2 – Transmission Services		
Transmission lower financial reserves threshold	=	The greater of: (1) 60 days * (Transmission operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Transmission upper financial reserves threshold	=	Transmission lower financial reserves threshold plus 60 days * (Transmission operating expenses / 365 days)
Where:		
Transmission operating expenses	=	Transmission total expenses – (Transmission depreciation & amortization + Transmission net interest expense)

3.5.3 – Agency		
Agency upper financial reserves threshold	=	The sum of the Power lower financial reserves threshold and the Transmission lower financial reserves threshold plus 30 days cash on hand for the agency
Where:		
30 days cash on hand for the agency	=	30 days * (agency operating expenses / 365 days)
Agency operating expenses	=	Power operating expenses + Transmission operating expenses

4. Implementation

4.1 Overview

The Policy will be implemented each rate period through the Power and Transmission rate schedules and GRSPs. The lower and upper financial reserves thresholds for each business line will be recalculated each time BPA establishes new Power and Transmission rates. Lower and upper financial reserves thresholds will remain constant throughout each rate period. Lower and upper financial reserves thresholds will be computed using forecast rate period average operating expenses from the Power and Transmission revised revenue tests.

Implementation shall include parallel rate mechanisms for each business line each rate period that will trigger if financial reserves are below the lower financial reserves thresholds. Implementation shall also include parallel Financial Reserves Distributions for each business line each rate period that will trigger if financial reserves are above upper financial reserves thresholds.

4.2 Provisions for Increasing Financial Reserves

The methodologies for increasing financial reserves are described below. The specific rate mechanisms to achieve 4.2.1 through 4.2.3 will be determined in the applicable rate proceeding.

4.2.1 Except as provided in Section 4.2.2, if financial reserves attributable to a business line are below its lower threshold, then the annual rate action will be the lower of the following two, unless a larger increase in reserves is necessary to achieve the TPP standard:

(1) $40 million per year in Power rates, if recovering Power financial reserves; $15 million per year in Transmission rates, if recovering Transmission financial reserves; or

(2) the amount needed to fully recover financial reserves up to the applicable business line lower threshold.

4.2.2 The $40 million per year rate action described above in Section 4.2.1(1) is being phased in for Power until Fiscal Year (FY) 2022. In FY 2022 and thereafter, the $40 million per year rate action in Section 4.2.1(1) will apply and this Section 4.2.2 will be inapplicable. In FY 2020 and FY 2021, if financial reserves attributable to Power are below its lower threshold, then the annual rate action will be the lower of the following two, unless a larger increase in reserves is necessary to achieve the TPP standard:

(1) $30 million per year in Power rates; or

(2) the amount needed to fully recover financial reserves up to the Power lower threshold.

4.2.3 In addition to the rate action described above in Sections 4.2.1 and 4.2.2, Bonneville will initially propose in each rate case a rate mechanism to increase each business line financial reserves in the event they fall below $0. Such rate mechanism will include the following parameters:

(1) When financial reserves are below $0 for Power Services, Bonneville will recover in each year of the rate period the first $100 million dollar-for-dollar. Bonneville will recover only fifty cents on the dollar for any amounts greater than $100 million. This provision will be limited to an annual cap of $300 million; and

(2) When financial reserves are below $0 for Transmission Services, Bonneville will recover in each year of the rate period the first $100 million dollar-for-dollar. This provision will be limited to an annual cap of $100 million.

Implementation of the methodology described above, including the timing of when the calculations in (1) and (2) will be performed, will be determined each rate period through the Power and Transmission rate schedules and GRSPs. Such implementation may include *de minimis* thresholds.

BONNEVILLE POWER ADMINISTRATION
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