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

Generation Inputs Study

BP-22-FS-BPA-06

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GENERATION INPUTS 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
DER	Dispatchable Energy Resource
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
ISD	Incremental Standard Deviation
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

1. INTRODUCTION

BPA's generation assets support its transmission system and are instrumental in maintaining its reliability. For ratemaking purposes, these uses of the capacity available to BPA are quantified and the costs associated with these uses are allocated to transmission rates under the ratemaking principle of cost causation. The uses of the generating capacity available to BPA to support the transmission system and maintain reliability are generally referred to as "generation inputs."

1.1 Purpose of Study

This Study explains the determination of the required reserve amount, cost allocation for generation inputs, and forecast revenues associated with provision of these generation inputs, and describes the methodology used to set the Ancillary and Control Area Services rates that recover the generation input costs. The revenues that are forecast in the Study are applied in ratemaking as revenue credits to power rates. *See* Power Rates Study, BP-22-FS-BPA-01, § 9.3. Generation inputs include capacity- and energy-related services that BPA uses to provide Ancillary and Control Area Services, support transmission, and maintain the reliability of the transmission system. The Ancillary and Control Area Services rates that are described in the Study are shown in the 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-22-A-02-AP02.

1.2 Summary of Study

BPA provides balancing reserve capacity generation inputs for Regulation and Frequency Response Service, Variable Energy Resource Balancing Service (VERBS), and Dispatchable Energy Resource Balancing Service (DERBS). The methodology for deriving the forecast amount of balancing reserve capacity needed to provide these services and the allocation of reserves among each generation type and load is described in Section 2 of this Study. Section 3 details the methodology for determining the forecast need for Operating Reserve (Contingency Reserve) services. The methodology for determining the cost of reserves is described in Section 4. Other generation inputs, including Synchronous Condensing, Generation Dropping, Redispatch Service, and Station Service are discussed in Sections 5, 6, 7, and 8. Section 9 of the Study contains the description of the rate design for the Ancillary and Control Area Service rates associated with generation inputs.

A summary of the revenue forecast for supplying these generation inputs is shown in Table 1 in Generation Inputs Study Documentation, BP-22-FS-BPA-06A, and the resulting Ancillary and Control Area Services rates are shown in the 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02.

2. BALANCING RESERVE CAPACITY QUANTITY FORECAST

2.1 Introduction

2.1.1 Purpose of the Balancing Reserve Capacity Quantity Forecast

The Balancing Reserve Capacity Quantity Forecast estimates the planned amount of balancing reserve capacity needed for BPA to provide balancing services, including regulating and non-regulating reserves, during the rate period for Schedules 3 and 10 of BPA's Tariff. This forecast reflects the quality of service and the methodology for determining the total balancing reserve capacity for balancing services as defined in the Balancing Reserve Capacity Business Practice. The forecast described in this section focuses on the data inputs needed for the Balancing Reserve Capacity Business Practice methodology to forecast balancing services for the rate period, including the total balancing reserve capacity. Also, the forecast described in this section describes the methodology used to allocate the balancing reserve requirements to load and different types of generation to establish the rates for these services and the revenue credit to Power Services associated with providing the balancing reserve capacity for the rate period. *See* §§ 4, 9.

2.1.2 Overview

As a balancing authority, BPA must maintain load-resource balance in its balancing authority area (BAA) at all times. All generators within the BPA BAA provide generation schedules to BPA that estimate the average amount of energy they expect to generate in the upcoming scheduling period (hour or 15-minute interval).

Transmission customers submit transmission schedules, identifying all energy to be transmitted across or within the BPA BAA in the upcoming scheduling period. BPA uses the transmission schedules to match generation inside the BPA BAA and imports of energy from other BAAs with loads served inside the BPA BAA and exports to other BAAs. The transmission schedules identified with each adjacent BAA are netted to determine interchange schedules. Also, BPA forecasts the average amount of load to be served in the BPA BAA in the upcoming hour, ensuring the summation of generation schedules will serve the forecasted load plus exports and minus imports.

The Automatic Generation Control (AGC) system regulates the output of specified Federal Columbia River Power System (FCRPS) generators or third-party providers of balancing reserves (BPA currently does not have any third-party providers of balancing reserves) in the BPA BAA in response to changes in load, generation, system frequency, and other factors to maintain the scheduled system frequency and scheduled interchanges with other BAAs. Schedules do not change when a generator deviates from its scheduled generation or a load deviates from the average hourly forecast. The BAA uses the specified FCRPS generation resources, assigned for balancing service and connected to the AGC system, to maintain within-hour load-resource balance in the BAA by offsetting differences between scheduled and actual generation and load, as measured by the Area Control Error (ACE) equation. If actual load increases or actual generation decreases compared to the amount scheduled, the AGC system increases (*inc*) output of balancing resources. If actual load decreases or actual generation increases compared to the amount scheduled, the AGC system decreases (*dec*) output of balancing resources. The cumulative *inc* and *dec* generation required to maintain within-hour load-resource balance forms the basis for the balancing reserve capacity that BPA must maintain to provide balancing services.

BPA's methodology for calculating the total balancing reserve capacity requirement is provided in the Balancing Reserve Capacity Business Practice. As explained in this business practice, BPA assumes a 99.7 percent planning standard for purposes of determining the total balancing reserve capacity requirement, the same standard used historically by BPA in past rate periods. BPA's balancing reserve capacity requirement consists of two components: regulating reserves and non-regulating reserves. Regulating reserves refer to the capacity necessary to provide for the continuous balancing of resources (generation and interchange) with load on a moment-to-moment basis. Non-regulating reserves refer to the capacity necessary to compensate for larger fluctuations in generation and load occurring over longer periods of time within the hour. The Balancing Reserve Capacity Quantity Forecast estimates the capacity needed to provide both of these balancing services.

The Balancing Reserve Capacity Quantity Forecast methodology is based primarily on (1) a forecast of wind, solar, hydroelectric, and thermal projects expected to be online in the BPA BAA during the FY 2022-2023 rate period; (2) solar sensor data from the University of Oregon Solar Radiation Monitoring Laboratory for the 72-month period from October 1, 2013, to September 30, 2019; and (3) BPA archived data from the 72-month period from October 1, 2013, to September 30, 2019. The BPA archived data from the 72-month period needed for the forecast includes the total wind generation, the total solar generation, the total FCRPS generation, the total FCRPS schedule, the total non-Federal thermal generation, the total non-Federal thermal schedule, the BAA load, and the BAA load forecast for the period. The following sections describe in detail how the forecast methodology data were obtained or developed. This dataset is used to estimate a netted imbalance signal for the BAA, representing the diversification of the combined load and generation error signals. It is this netted imbalance signal that is used in the percentile distribution calculations to identify the total balancing reserve capacity estimate.

2.2 Forecast of Generation Projects Online in the BPA BAA for the Rate Period

Developing the Balancing Reserve Capacity Quantity Forecast requires an estimate of the amount of generation that will be online within the BPA BAA during the rate period. This estimate includes both the actual generating projects that are online as of the time of the Study based on BPA records and a forecast of the projects that are either expected to enter or leave the BAA, decommission, or come online before the end of the FY 2022-2023 rate period. *See* Generation Inputs Study Documentation (Documentation), BP-22-FS-BPA-06A, Tables 2.1 and 2.2.

The forecast of projects that are expected to come online before or during the FY 2022-2023 rate period is based on a review of the pending requests in BPA's generator interconnection queue, information provided for the requests under BPA's Large Generator Interconnection Procedures (LGIP) and Small Generation Interconnection Procedures (SGIP), and the application of certain criteria. Forecasts of "future" projects throughout this Study are based on the assessment of the circumstances and information available at the time but are not intended to convey certainty about interconnection of a particular generating project.

To forecast which future generating projects will interconnect and the timing of such interconnections, BPA considered the status of interconnection requests in BPA's interconnection queue as of April 2021. The requested interconnection date in each interconnection request is only one of several factors considered to assess a potential interconnection date for a project. Prior to interconnecting, each future project must go through the interconnection study process, under which BPA completes a series of studies prior to offering an interconnection agreement and interconnection date. This can be an extended process, and the timing for completion can vary substantially; therefore, the evaluation of certain objective factors is necessary to make projections about the status of future projects. Some of the factors include:

1. The status of the interconnection study process. Requests in the earlier stages of the study process are less likely to interconnect during the FY 2022-2023 rate period.
2. The status of the environmental review process and interconnection customer permitting process for the request. As a Federal agency, BPA must conduct a review under the National Environmental Policy Act (NEPA) and other Federal laws before deciding whether to interconnect a particular generator. This review can take a substantial amount of time, and BPA typically coordinates its review to coincide with the customer's state or county environmental permitting process. Requests that are not far along in those processes are less likely to interconnect during the FY 2022-2023 rate period.
3. Interconnection and network project additions that affect the time required to complete an interconnection. As studies progress, BPA and the customer develop a more definite plan of service, and the time to construct is better defined. The particular network additions and interconnection facilities required to interconnect the generator and the time it would take to construct those facilities are taken into account.

4. Information received in direct discussions with each developer about its plans (*e.g.,* project scheduling, financing, Federal and state incentives, turbine-ordering commitment). A significant factor that affects the interconnection forecast is the date when a customer executes an engineering and procurement agreement, which allows BPA to incorporate the project in BPA's construction program schedule, begin work on the necessary interconnection facilities design, and begin ordering materials and equipment with a long procurement lead time.
5. The execution of an interconnection agreement and commitment by the customer to fund all BPA facilities necessary for the interconnection. A firm construction program schedule is included in the agreement. Executing an interconnection agreement usually occurs just prior to the construction phase of a project.

Documentation, BP-22-FS-BPA-06A, Table 2.1 identifies the amount of installed capacity that the Study assumes will be online during the FY 2022–2023 rate period for each type of generation accounted for in the Balancing Reserve Capacity Quantity Forecast. Over the rate period, the forecast of installed wind capacity is an average of 2,834 megawatts (MW); installed solar capacity is an average of 99 MW; non-Federal thermal capacity is an average of 1,548 MW; and non-AGC controlled FCRPS capacity is an average of 3,384 MW.

2.3 Forecasting Future Wind Generation Output Data

Forecasting the balancing requirements for the rate period requires estimating minute-by-minute generation output of all existing and future wind projects forecasted to be online in the BPA BAA for the FY2022-2023 rate period. For generation data of existing wind projects, 72 months of one-minute actual average generation data from BPA's Plant Information (PI) system are used. The data covers generation from all existing wind generators in the BPA BAA for the period from October 1, 2013, to September 30, 2019. For existing wind projects, a combination of estimated minute-by-minute generation levels (prior to their online date) and one-minute actual average generation data from BPA's PI system (after their online date) are used. For wind projects online or forecast to come online after September 30, 2019, only estimated minute-by-minute generation levels are used. These estimates are discussed below in Sections 2.3.1 and 2.3.2.

BPA implements reliability tools, such as Operational Controls for Balancing Reserves (OCBR) and the Oversupply Management Protocol, which impact balancing reserve deployments for the BAA. These reliability tools can require a wind operator to decrease the output of its project below the optimized wind profile, so these times are identified in the data and replaced with estimated minute-by-minute generation. All generation data obtained from BPA's PI system are reviewed for missing data and any missing data points are filled in using estimated minute-by-minute generation, and contingency reserves are credited back to any wind generation that used those contingency reserves. All of this helps ensure that the filled-in data reflects the trends of BPA's PI system archived data.

2.3.1 Methodology for Determining Correlations and Lead or Lag Times

To help estimate minute-by-minute generation for future projects and to aid in data-scrubbing of existing generator data, the correlations and time delays between existing wind projects in BPA's BAA and the locations of future and existing wind projects are used. Documentation, BP-22-FS-BPA-06A, Table 2.2 includes the locations by county of the variable energy resource (VER) projects in the Balancing Reserve Capacity Quantity

Forecast for the FY 2022-2023 rate period. A west-to-east wind pattern generally prevails in the locations of many future and existing wind projects in BPA's BAA, and generally the future wind project generation is predicted by using leading (earlier in time) generation values from an existing project that is west of the future project or lagging (later in time) values from an existing project that is east of the future project.

BPA determines the correlations and time delays in different ways depending on the data available for particular projects. For existing projects online prior to September 30, 2019, BPA derived correlations and time delays using actual minute-by-minute generation data from BPA's PI system. To derive correlations and time delays from the actual minute-by-minute data, a mathematical modeling tool, MATLAB, was used to calculate correlations between the minute-by-minute data for all existing wind projects at different time offsets. For each pair of existing wind projects, the time delay resulting in the highest correlation was used to define the correlation and time delay between those projects.

For projects that were not online prior to September 30, 2019, correlations and time delays were calculated using the numerical weather prediction model data provided by the National Renewable Energy Laboratory (NREL) and 3TIER, a wind forecasting company in Seattle, Washington. This data predicts wind speed at standard gridded locations across the Pacific Northwest for calendar year (CY) 2004-2006 at 10-minute intervals. Using the forecast of wind generation online in the BPA BAA described in Section 2.2 and its associated geographic coordinates (latitude and longitude), 10-minute interval time series data were extracted for all existing and future wind projects. To derive correlations and time delays from the numerical weather prediction model data, MATLAB was used to calculate correlations between the 10-minute interval time series data for all existing and future wind projects at different time offsets. For each pair of existing and future wind projects, the time delay resulting in the highest correlation was used to define the correlation and time delay between those projects.

Documentation, BP-22-FS-BPA-06A, Table 2.2 identifies the existing and future Variable Energy Resource (VER) projects that are forecast to be online during the rate period. The table is organized according to the month and year that the project went into service or is expected to be in service. Entries for existing projects include the installed capacity in MWs and the month and year that the project reached its installed capacity. Entries for future projects include the proposed installed capacity and the completion date (month and year) on which the project is expected to reach its installed capacity.

2.3.2 Estimating Wind Project Generation

Once the correlations and lead or lag times for each pair of wind projects are determined, the output of existing wind generation and installed capacity of the existing and future wind projects is used in conjunction with the correlations and leads or lags to calculate the estimated minute-by-minute generation of all future wind projects through the end of the rate period and to fill in any missing data for the existing projects. The most strongly correlated plant is used in the methodology described below, unless it also had a missing data point during its corresponding time-delayed point. In that case, the second-most strongly correlated plant would be used, and so on down the line.

The estimated minute-by-minute wind project generation is forecast using the following assumptions. To model the estimated project's generation output, the existing project's generation output is scaled by multiplying by the estimated project's FY 2022-2023 forecast capacity in MWs and dividing by the existing project's capacity. This calculation assumes a linear relationship between project capacity, wind flow, and generation output, and that a larger project with a greater capacity generates more energy from a particular amount of wind. Then, the total estimated project generation is determined by time-shifting the scaled generation of the existing project to the correct timeframe based on the calculated lead or lag time to the estimated project. This time shift helps express an estimated project's generation for a particular minute as a function of an existing project's generation.

The following example illustrates how the estimated project generation is calculated. In this example, a 150 MW wind project (Project A) has the strongest correlation with existing Project B (100 MW with a one-minute lag). Project A's estimated generation for any particular minute is determined using the following equation:

$$\textit{Project A} = (150/100) \times (\textit{Project } B^{-1minute})$$

These calculations are performed for all estimated wind generation through the end of the rate period. For the amount of installed wind assumed for each month of the rate period, the total wind generation is calculated by adding the minute-by-minute existing and estimated wind generation for that month. The resulting total wind generation is used to forecast the balancing reserve capacity requirements for the rate period.

2.4 Forecasting Future Solar Generation Output Data

Forecasting the balancing requirements for future solar generation during the rate period requires estimating future minute-by-minute generation output of all existing and future solar projects in the BPA BAA. For existing solar projects, up to 72 months (depending on the start date of the plant) of one-minute actual average generation data from BPA's PI system is used. The data covers generation from all existing solar generators in the BPA BAA for the period from October 1, 2013, to September 30, 2019. For solar projects that came online between October 1, 2013, and September 30, 2019, a combination of estimated minute-by-minute generation levels (prior to their online date) and one-minute actual average generation data from BPA's PI system (after their online date) are used. For solar projects online or forecast to come online after September 30, 2019, only estimated minute-by-minute generation levels are used. All generation data obtained from BPA's PI system are reviewed for missing data and any missing data points are filled in using the estimate minute-by-minute generation, and contingency reserves are credited back to any solar generation that used those contingency reserves. This helps ensure that the filled-in data reflect the trends of BPA's PI system archived data.

2.4.1 Historical Meteorological Sensor Data

To estimate the minute-by-minute solar generation levels for plants not yet online or to supplement plants that were not online for the entirety of the data set, historical meteorological sensor data is obtained and converted into a generation signal. This meteorological dataset is obtained from the University of Oregon Solar Lab, whose network of sensors across the Pacific Northwest capture irradiance, temperature, and various other data at varying time scales.

For the solar generation estimate, we select sensor data sites with one-minute time resolution that measure both direct and diffuse irradiances and are as close as possible to the locations of each of the solar plants forecast to come online during the rate period. In this Study, the data from the following four sensor locations were used: Cheney, WA; Hermiston, OR; Burns, OR; and Silver Lake, OR.

2.4.2 Calculating Total Irradiance

For each of the four sensor datasets, direct and diffuse irradiance must be appropriately converted and combined to represent the total irradiance that would be seen by a solar panel in that location. To calculate this, we calculate various time-of-day and day-of-year parameters based on the position (latitude and longitude) of the sensor location. These parameters include:

- Solar Time – an adjustment to local standard time based on the longitudinal shift within the time zone;
- Declination Angle – the Earth tilt angle for that particular date;
- Solar Altitude Angle – the angle at which the sun is seen at the site relative to the horizontal plane for that particular minute;
- Solar Azimuth Angle – the angle between due south and the horizontal projection of the sun for that particular minute;
- Tracking Angle – the angle of tilt of the solar panel as it tracks the sun for that particular minute, assumed to have a north-south tracking axis orientation; and
- Angle of Incidence – the angle at which the sun's rays hit the panel for that particular minute.

For the Declination Angle parameter, a value is computed for each day of the year. For each of the other parameters listed above, a value is computed for each minute of each day of the year. In doing so, the parameters respect the seasonal and daily differences in the sun's position in the sky relative to the given sensor location. Using these calculated parameters, along with the measured direct and diffuse irradiances referenced in Section 2.4.1, we are then able to compute the total irradiance that would be seen by a solar panel at the sensor location. To view the equations associated with each of these calculations, see Documentation, BP-22-FS-BPA-06A, Tables 2.3 and 2.4.

2.4.3 Conversion of Irradiance to Power

With total irradiance computed, the output must be translated to electrical power output. To do so, a thermal model is calculated to adjust for variations in power output with respect to panel and ambient temperatures. The inputs to these calculations include cell temperature coefficient, static temperature coefficient, and measured ambient temperature. The cell temperature coefficient and measured ambient temperature are used to calculate the minute-by-minute cell temperature. A minute-by-minute temperature adjustment is then calculated using the cell temperature and the static temperature coefficient. This temperature adjustment, along with overall panel efficiency, the DC nameplate, and the calculated total irradiance described in the previous section, are used to calculate the minute-by-minute estimated DC power output.

In the current Study, the following parameter settings are used:

- Cell temperature coefficient = 0.035 $^{o}C/(W/m^2)$
- Static temperature coefficient = 0.4%/^{o}C
- Overall panel efficiency = 83 percent
- Inverter loading ratio = 1.25

Note that the inverter loading ratio represents the ratio of DC nameplate to AC nameplate. The DC nameplate is calculated to be the AC nameplate multiplied by the inverter loading ratio. This ratio represents the increasing trend in industry to oversize total panel DC capacity with respect to the amount of power the inverters at the site can convert to AC to increase the capacity factor of these plants. To view the equations associated with each of these calculations, see Documentation, BP-22-FS-BPA-06A, Table 2.5.

2.4.4 Scaling Point-Source Power to Estimated Solar Project Generation

Next, DC power output must be scaled and converted to represent the AC power output for the given forecasted solar plant. Scaling the output to the proposed AC nameplate must capture the appropriate variability of the generation nameplate being estimated. In particular, variability should decrease as the size of a proposed plant increases, to reflect the decreasing impact of smaller weather events on an increasingly larger footprint. We employ a rolling average calculation to smooth the variability of the point source data used, with an increasing time interval to correspond with an increasing size of a proposed plant. Documentation, BP-22-FS-BPA-06A, Table 2.6, line 2. To determine the length of the rolling average interval, DC nameplate is used. The DC power output is then clipped to the AC nameplate. Any DC power produced above the AC nameplate will not be converted by the inverters, and thus any values above AC nameplate are simply set equal to the AC nameplate. Lastly, the estimated output is shifted forward or backward in time based on the longitude of the forecasted plant relative to the longitude of the sensor location, to account for the difference in time at which the plant will "see" the sun's position. To view the equations associated with each of these calculations, see Documentation, BP-22-FS-BPA-06A, Table 2.6.

2.5 Accounting for Other Non-AGC Controlled Generation

Estimating the balancing reserve capacity requirements during the rate period for all non-VER generation not controlled by AGC (Non-AGC Generation) requires analyzing historical minute-by-minute generation levels and corresponding schedules of the existing Non-AGC Generation in the BPA BAA and accounting for future use by all projects expected to be online during the rate period in the BPA BAA. For existing generation analysis, Non-AGC Generation is split into two subsets: non-controlled FCRPS generation and non-Federal thermal generation. Thermal generation includes nuclear plants, coal-fired plants, natural gas plants, combined-cycle plants, boiler or steam-driven plants, and biomass plants. Non-Federal hydroelectric generation is netted into the BAA load data, so the balancing reserve capacity requirements of such generation is included within the load balancing reserve capacity requirement as discussed in Section 2.6. Non-AGC FCRPS generation balancing reserve capacity requirements are assessed a separate balancing reserve capacity requirement, which is self-supplied by Power Services through the FCRPS.

2.5.1 Analyzing Historical Use by Existing Non-AGC Controlled Generation

For data on generation and schedules of existing Non-AGC Generation, 72 months of one-minute actual average generation and schedule data from BPA's PI system are used. The data covers generation and schedules from all existing Non-AGC Generation in the BPA BAA for the period from October 1, 2013, to September 30, 2019. The data is scrubbed for missing data periods, and contingency reserves are credited back to any Non-AGC Generation that used those contingency reserves. Actual data from Non-AGC Generation is included only after the generation comes online, as there is no reliable method to predict generation prior to commissioning of the plant.

2.5.2 Estimating Future Non-AGC Generation

Accounting for future Non-AGC Generation assumes that the historical usage trends continue in the rate period. To calculate the additional balancing reserve capacity requirements for future Non-AGC Generation, the balancing reserve capacity calculated in Section 2.8 for that type of generation (FCRPS or non-Federal thermal) is divided by the existing installed capacity for that type of generation to create a reserves-per-installed capacity factor. The forecast installed capacity for the future project is then multiplied by the reserves-per-installed capacity factor to determine the balancing reserve capacity requirements needed to operate the future project. Currently, no new Non-AGC Generation is forecast to come online in the FY 2022-2023 rate period.

2.6 Load Estimates

The following sections describe derivation of the actual BAA loads and the BAA load forecasts that correspond to particular levels of installed generation used in the forecast. Non-Federal hydroelectric generation is netted with the BAA loads and non-Federal hydroelectric schedules are netted with the BAA load forecasts for the entirety of this Study.

2.6.1 Accounting for Pump Load

Load estimates start with the BAA load posted on the BPA external operations website. BPA Balancing Authority Load and Total Wind, Hydro, and Thermal Generation, Chart and Data, Rolling 7 days, *available at* http://transmission.bpa.gov/Business/operations/Wind/default.aspx. The BAA load posted on the operations page reflects the total generation in the BPA BAA minus the total of all interchanges (transfers to and from adjacent BAAs). BPA's pump load is load associated with operating the pumps at Grand Coulee to fill Banks Lake for irrigation purposes, as determined by U.S. Bureau of Reclamation (Reclamation) requirements. Pump load is not part of the load forecast, because this load is scheduled at precise times; it is not affected by weather variation (it has the same power draw whether it is 30 degrees or 100 degrees F); and Grand Coulee generation serves this load directly. Thus, it does not affect the rest of the controlled hydro system or add any variation that requires the use of balancing reserve capacity. For these reasons, the pump load is subtracted from the BAA load prior to using the BAA load numbers in the balancing reserve capacity requirements calculations.

2.6.2 Actual BAA Load Amounts that Correspond with Generation Installed Capacity Levels

To simulate BAA load that corresponds to the rate period (FY 2022-2023), 72 months of BAA load that corresponds to the forecasted FY 2022 and FY 2023 load levels must be created. The actual BAA load data for each FY in the dataset (FY range from October 2013 through September 2019) is scaled by the load growth rate (growth or decay) between the actual historical FY load level seen and the forecasted FY load level in the Study. The table below shows the load growth rates from FY2014-2019 to FY 2022 and FY 2023. The load growth factors are based on forecasts for total BAA load from the BPA load forecasting group.

	FY 2022 Load	FY 2023 Load
FY 2014 Load	1.0156	1.0223
FY 2015 Load	1.0487	1.0556
FY 2016 Load	1.0447	1.0515
FY 2017 Load	0.9974	1.0039
FY 2018 Load	1.0058	1.0124
FY 2019 Load	0.9991	1.0057

2.6.3 BAA Load Forecasts

To determine the BAA load forecasts, system load estimates from BPA's PI system are used. The same load growth multipliers shown above in Section 2.6.2 are applied to this base forecast to determine the forecasts for the future years. The load forecast assumption in the Study takes into account the calculation used by BPA's AGC system in the real-time calculation of balancing reserves deployed. The error of the load forecast from BPA's PI system for the current hour is calculated at 10 minutes before the top of the hour and applied forward to the two-hour out-load forecast as an adjusted load forecast. The inputs to the adjusted load forecast are the average load from 10 minutes into the hour to 50 minutes into the hour and the system of record load forecasts for the current hour and two hours out.

2.7 VER Scheduling Accuracy Assumptions

VER schedules for existing plants are assumed to use the BPA-provided hourly numerical weather power forecast (BPA VER Forecast). For future plants or any missing forecast data for existing plants, a 35/60 persistence is used as a proxy; this is calculated such that the 60-minute scheduling period uses a schedule equal to the one-minute average of the actual or estimated generation output of the project 35 minutes prior to the start of the scheduling period (average output for XX:24 to XX:25). Because BPA has not used a numerical weather power forecast for solar plants prior to the FY 2022-2023 rate period, all solar plant schedules are represented using the 35/60 persistence proxy.

2.8 Calculation of Requirements for Total Balancing Reserve and Components

To calculate the capacity requirments for Total Balancing Reserves and the components of

Regulating Reserves and Non-Regulating Reserves, BPA must first calculate an error signal for each. To calculate the total error signal, BPA subtracts total actual FCRPS generation, total actual non-Federal thermal generation, total actual wind generation, and the total actual solar generation from the actual load to create a Load net Generation actual signal. BPA also creates a Load net Generation forecast signal by subtracting total FCRPS schedule, total non-Federal thermal schedule, total wind schedule, and the total solar schedule from the load forecast. The total error signal used to calculate the Total Balancing Reserve Capacity is then calculated as the Load net Generation actual signal minus the Load net Generation forecast signal. The total error signal is then used in accordance with the Balancing Reserve Capacity business practice to calculate the total reserve requirement by calculating a 99.7 percent percentile distribution, setting the reserve requirements at 0.15 percent for total decremental (*dec)* reserve and 99.85 percent for total incremental (*inc)* reserve.

The delineation between Regulating and Non-Regulating reserves in the Total Balancing Reserve Capacity signal is based on the five-minute dispatch signals that the EIM market creates. To calculate the components of Regulating and Non-Regulating Reserves, each generation type and load must be analyzed in accordance with how the EIM would create their dispatch signals. For variable energy resources, such as wind and solar, the market uses a persistence based forecast to feed the market optimization engine that originates from metered output of the VER generation at approximately 10 minutes prior to each five-minute interval. Similarly, the load forecast fed into the market optimization engine originates from metered BAA load on the same timeline as VERs. Thus, BPA chooses to use generation output from 10 minutes prior to each five-minute dispatch period to model the EIM market dispatch for VERs and to use metered BAA load from 10 minutes prior to each five-minute dispatch period to model the EIM market dispatch for load. For dispatchable resources, such as the non-Federal thermal generation and the FCRPS generation, the market engine assumes the generation resource will follow their submitted base schedules from prior to the hour of operation. Thus, the EIM optimization engine produces dispatches that equal the schedules submitted by the resources and, in turn, BPA assumes the EIM market dispatches will equal the schedules in the historical data.

Once EIM dispatch signals are created for each generation type and load, the Regulating Reserve signal is created. A combined Load net Generation EIM dispatch is created by subtracting total FCRPS five-minute dispatch, total non-Federal thermal five-minute dispatch, total wind five-minute dispatch, and the total solar five-minute dispatch from the load five-minute forecast. The Regulating Reserve signal is then calculated as the Load net Generation actual minus the Load net Generation EIM dispatch. In accordance with the Balancing Reserve Capacity business practice, a 99.7 percent percentile distribution is applied to the Regulating Reserve signal, resulting in 0.15 percent setting the *dec* Regulating Reserve requirement and 99.85 percent setting the *inc* Regulating Reserve requirement.

To avoid non-coincidental peaks, BPA calculates the Non-Regulating Reserve requirements as the difference between the total Balancing Reserves requirement and the Regulating Reserve requirement. For instance, *inc* Non-Regulating Reserve requirement is total Regulating Reserve requirement minus the *inc* Regulating Reserve requirement. To aid in the allocation process among generation types as discussed in Section 2.9 below, BPA calculates the Non-Regulating Reserve signal as the Load net Generation EIM dispatch signal minus the Load net Generation forecast signal.

2.9 Allocating the Total Balancing Reserve Capacity Requirement Between Generation and Load

Once the forecast of the total balancing reserve capacity requirements is determined, the total is allocated between the various generation types and load, based on the relative contributions of each. The goal in determining this allocation is to find a statistically valid method under which the sum of the parts always equals the total (*e.g.,* FCRPS regulating *inc* reserves + non-Federal thermal regulating *inc* reserves + solar regulating *inc* reserves + wind regulating *inc* reserves + load regulating *inc* reserves = total regulating *inc* reserves). To do this allocation in a statistically accurate manner, incremental standard deviation (ISD) is employed to allocate reserves to load and generation types based upon how each contributes to the joint load-generation regulating reserve requirement and non-regulating reserve requirement.

The ISD measures how much load and generation contribute to the total load net generation balancing reserve capacity need based on how sensitive the total balancing reserve capacity need is with respect to the individual load and generation components. Stated differently, ISD shows how much the total balancing reserve capacity standard deviation changes given a 1 MW change in the load and/or generation standard deviation. ISD recognizes the diversification between the load and generation error signals; *i.e.,* the fact that the load and generation error signals do not always move in the same direction. The result of that diversification is a joint load-generation balancing reserve capacity requirement that is less than the sum of the individual requirements for load and generation.

To accurately capture the diversification between load and generation and still attribute appropriate shares of the balancing reserve capacity requirements to each generation type and to load, the error signals for all balancing reserve capacity components are sorted into 24 hourly bins based on time of day. For example, total regulating reserves, load regulating reserves, wind regulating reserves, solar regulating reserves, non-Federal thermal regulating reserves, and FCRPS regulating reserves are all sorted among 24 bins: one bin for all data points falling in hour ending 1 (HE1), one bin for all data points falling in hour ending 2 (HE2), and so on. ISD is performed on each hourly bin to determine a balancing reserve capacity requirement for every component. An example of the ISD calculations is presented in Documentation, BP-22-FS-BPA-06A, Table 2.7. Then the maximum of the 24 hourly bin percentile distributions is found. Finally, the total reserve requirements calculated are disaggregated using the ratio of each component's maximum 24-hour requirement to the sum of all of the maximum 24-hour requirements. An example of these calculations for the load regulating *inc* reserve component is presented in Documentation, BP-22-FS-BPA-06A, Table 2.8.

2.10 Results

The Study forecasts the balancing reserve capacity requirements as a total for the BPA BAA and for the two components of balancing reserve capacity: regulating reserves and non-regulating reserves. The Study also forecasts the total balancing reserve capacity for each balancing reserve user type (generation types and load), and each of the two components for each user type.

Documentation, BP-22-FS-BPA-06A, Tables 2.9 through 2.14 include the results of the Balancing Reserve Capacity Quantity Forecast. All of these results are based on the assumption that VER generators schedule consistent with the BPA VER Forecast. Documentation, BP-22-FS-BPA-06A, Tables 2.9 through 2.14 include the *inc* and *dec* amounts for each component of the total balancing reserve capacity requirement and the component balancing reserve capacity requirement for load, wind, solar, FCRPS generation, and non-Federal thermal generation, respectively. These requirements cover the balancing reserve capacity requirements for 99.7 percent of the time as defined in the Balancing Reserve Capacity Business Practice.

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3. OPERATING RESERVE CAPACITY FORECAST

3.1 Introduction

Operating Reserve is the type of reserve that BPA is required to offer to transmission customers pursuant to Schedules 5 and 6 of BPA's Tariff. Transmission customers must either purchase this service from BPA or make alternative comparable arrangements to meet its Operating Reserve obligation. Operating Reserve backs up resources in the BPA BAA. Operating Reserve costs allocated to BPA Transmission Services are recovered through transmission rates and passed to BPA Power Services as an interbusiness-line transfer. Power Rates Study, BP-22-FS-BPA-01, § 9.3. Rates for Operating Reserve are developed in Section 9.4 of this Study and are shown in the ACS-22 rate schedule, 2022 Transmisson, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02. Operating Reserve is referred to in other contexts as "Contingency Reserve," such as in the North American Electric Reliability Corporation (NERC) reliability standard BAL-002-WECC-2a, but for purposes of this Study, BPA refers to such reserve as "Operating Reserve." WECC stands for Western Electricity Coordinating Council.

This section describes (1) the applicable Operating Reserve reliability standards that apply to the BPA BAA; and (2) BPA's methodology for forecasting the amount of Operating Reserve for the rate period.

3.2 Applicable Reliability Standards for Operating Reserve

The Tariff obligates BPA to offer Operating Reserve, which includes both spinning reserve capacity and non-spinning or supplemental reserve capacity. The Tariff requires at least half of the Operating Reserve to be spinning reserve. BPA determines the transmission customer's Spinning and Supplemental Operating Reserve requirement in accordance with applicable NERC, WECC, and Northwest Power Pool (NWPP) standards.

The current NERC reliability standard, BAL-002-WECC-2a, requires each BAA to maintain sufficient Operating Reserve equal to the greater of (1) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency or (2) the sum of 3 percent of hourly integrated load (generation minus station service minus Net Actual Interchange) and 3 percent of hourly integrated generation (generation minus station service).

3.3 Calculating the Quantity of Operating Reserve

BPA's Operating Reserve obligation forecast under BAL-002-WECC-2a (3 percent net generation plus 3 percent net load) is determined in the following steps: 1) compute the total Operating Reserve obligation for the BPA BAA; 2) identify the total amount that customers self- and third-party supply; and 3) compute BPA's Operating Reserve obligation by subtracting the amount of self- and third-party supply from the total BPA BAA obligation.

3.3.1 Total Operating Reserve Obligation

The first step in forecasting the total Operating Reserve obligation is to forecast load and generation in the BPA BAA as follows:

- Forecast load in the BPA BAA is based on load forecast sourced from the Agency Load Forecast (ALF). The annual percentage load growth in the BAA is applied to historical BAA loads. Monthly shaping based on historical averages is applied to the forecast annual load to generate the forecast loads in the BP-22 Rate Period.

- Generation forecast in the BPA BAA consists of four resources: hydro, thermal, wind, and solar. For each of these resource types, the forecasted inputs are applied to regression models to generate the forecast generation.
    - Hydro generation in the BPA BAA is based on regressions using streamflow forecasts provided by Power Services by each month of the rate period. The hydro forecast input is a forecast of streamflow at The Dalles for 80-water-year conditions. The Dalles is a proxy for streamflow conditions on the FCRPS as streamflow conditions indicate hydro generation in a given year.
    - Thermal generation in the BPA BAA is based on regressions that estimate an expected amount, given hydro, wind and load levels. When high hydro and wind conditions exist, this reduces thermal generation. When load increases, thermal generation tends to increase. Where thermal plants leave the BPA BAA, thermal generation is adjusted by reductions based on historical capacity factors.
    - Wind generation in the BPA BAA is based on expected wind capacity factor for each month. The capacity factor is applied to the forecast installed capacity for each month. When wind plants leave the BPA BAA, wind generation is adjusted by reductions based on historical capacity factors. When wind plants enter the BPA BAA, wind generation is increased for the installed capacity and adjusted by historical capacity factor.
    - Solar generation in the BPA BAA is based on expected solar capacity for each month. The solar nameplate is adjusted for plant factor to estimate output for average solar generation by month. When new solar plants enter the BPA BAA, solar generation is increased for the installed capacity and adjusted by historical capacity factor.

Using these forecast methods for load and generation, the total BPA BAA net load equals a monthly average of 6,239 MW for FY 2022 and 6,336 MW for FY 2023. The total BPA BAA net generation equals a monthly average of 12,813 MW for FY 2022 and 12,841 MW for FY 2023. Documentation, BP-22-FS-BPA-06A, Table 3.1.

The total Operating Reserve Obligation forecast for the BPA BAA is determined by taking 3 percent of the total generation plus 3 percent of the total load, which yields 571.6 MW in FY 2022 and 575.3 MW in FY 2023 (BP-22 average of 573.4 MW). Documentation, BP-22-FS-BPA-06A, Table 3.2, line 15.

3.3.2 Self- or Third-Party Supplied Operating Reserve Obligation

The second step involves determining the Operating Reserve obligation provided by self- and third-party supply. This determination is based on customer elections to self-supply or to obtain third-party supply as of May 1, 2021, for the BP-22 rate period. The calculation for self- and third-party supply is made by taking five-minute data from BPA's PI system for the last two full fiscal years of the total Operating Reserve Obligation and BPA Operating Reserve obligation. The total Operating Reserve obligation minus the BPA Operating Reserve obligation equals the amount for self- and third-party supply. A distribution curve of the self- and third-party supply data returns an expected value by month. The total self-supply and third-party provision is forecast to average 100.0 MW in BP-22. Documentation, BP-22-FS-BPA-06A, Table 3.2, line 31.

3.3.3 BPA Operating Reserve Obligation

The third step is calculating the BPA Operating Reserve obligation. The BPA Operating Reserve Obligation equals the difference of the total Operating Reserve obligation and the amount provided by self- and third-party supply. This calculation results in a forecast BPA Operating Reserve obligation of 471.6 MW in FY 2022 and 475.3MW in FY 2023 (473.4 MW average for BP-22). Documentation, BP-22-FS-BPA-06A, Table 3.2, line 47.

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4. CAPACITY COST METHODOLOGY

4.1 Introduction

Various Ancillary and Control Area Services provided through BPA's transmission rates require the use of generation capacity – specifically balancing and operating reserve services. All of this required capacity is sourced from the generating resources available to BPA and is considered a "generation input" into transmission rates. This section of the Study describes how the cost of this capacity is calculated.

The Ancillary and Control Area Services that require the use of capacity are Regulation and Frequency Response Service, Balancing Services (VERBS and DERBS), and Operating Reserve Services (Spinning and Supplemental). Capacity required for Regulation and Frequency Response Service and the Balancing Services is further categorized as either Regulation Reserves or Non-regulation Reserves. Both Regulation and Non-regulation Reserves are available for *inc* capacity or *dec* capacity. A forecast of the amount of balancing capacity required (including the amount needed for Regulation and Frequency Response) is described in Section 2. A forecast of the amount of required operating reserve capacity is described in Section 3.

The total cost of incremental capacity is calculated as the sum of two components: an embedded cost component and a variable cost component. The total cost of decremental capacity includes only a variable cost component. The embedded cost component accounts for the fixed cost of the Federal system. The variable cost component accounts for the lost efficiency (impact to available energy) associated with holding and deploying capacity. The calculation of the embedded costs is explained in detail in Section 4.2. The calculation of the variable costs is explained in detail in Section 4.3. The calculation of a rate design cost adjustment is explained in detail in Section 4.4. The calculation of total unit capacity costs and the associated revenue forecasts is described in Section 4.5.

Once the unit cost of capacity is determined, the unit cost is multiplied by the forecast amount of capacity to be provided by Power Services and is treated as a revenue credit to power rates. Power Rates Study, BP-22-FS-BPA-01, § 9.3. Conversely, this amount is treated as a cost to Transmission Services and is used to calculate Ancillary and Control Area Service rates. *See* Transmission Revenue Requirement Study Documentation, BP-22-FS-BPA-09A, Table 3-5.

4.2 Embedded Cost Methodology

BPA's embedded unit cost of capacity is calculated by dividing all of BPA's capacity costs by the amount of capacity available to BPA under 1937 water conditions. BPA's capacity costs are determined using a capacity-and-energy-cost-classification methodology, where fixed costs are classified as capacity and variable costs are classified as energy. In general, this methodology aims simply to associate the cost of building a plant with capacity, and the cost of fuel and other operational costs with energy while also encompassing the broader set of costs that BPA pays and accounting for the fuel constraints and regulations associated with hydroelectric generation. The costs classified as capacity as a result of this method are: capital-related costs, fish and wildlife program costs, a portion of power purchase costs, and two cost adjustments. The total amount of capacity available to BPA under 1937 critical water conditions is calculated as the sum of the monthly average one-hour capability of physical resources, any forecast or actual augmentation purchase amounts, and all capacity reserved for Transmission Services for Ancillary and Control Area Services.

4.2.1 Capacity Cost Classification

To calculate a capacity unit cost, BPA must first separate its revenue requirement into costs classified as capacity (fixed costs) and costs classified as energy (variable costs). For purposes of this calculation, fixed costs are defined as: (1) all capital-related costs, (2) costs that do not vary with resource output and are directly attributable to the generation capability of the resources available to BPA, and (3) the capacity-attributed portion of power purchase costs. For example, BPA's fish and wildlife program costs are attributable to capacity because these costs are an obligation directly attributable to the resources available to BPA that do not vary with resource output. Costs that are not defined as fixed costs are considered variable costs. An example of an energy-attributable cost is BPA's staffing cost because these costs are not directly attributable to the generation capability of the resources available to BPA.

Further, with only three exceptions, simplicity in the cost classification method is achieved by classifying 100 percent of each line item in the Cost of Service Analysis Disaggregated Costs and Credits table in RAM (*see* Power Rates Study Documentation, BP-22-FS-BPA-01A, Table 2.3.1.5) to either energy or capacity, with no split attributions. The first exception to this 100-percent-to-capacity or 100-percent-to-energy classification approach is in power purchases that provide both energy and capacity to BPA. The method for classifying power purchase costs is described in Section 4.2.1.3. The second exception is in the 4(h)(10)(C) credit where the credit is tied to specific costs. The 4(h)(10)(C) split is described in Section 4.2.1.4. The third exception is Synchronous Condensing where a portion of the costs of providing this service is associated with plant investment (capacity) and the other portion associated with energy. The net cost attributed to capacity for the rate period is $1,003,526,000 per year. Documentation, BP-22-FS-BPA-06A, Table 4.2, line 24.

4.2.1.1 Capital-Related Costs

As stated above, all capital-related costs are classified as capacity costs. Capital-related costs include depreciation, amortization, interest expense, decommissioning costs, and minimum required net revenues. Capital-related costs average $783,174,000 for the rate period. *Id.*, line 7. Due to the timing of the best available information and when different rate studies needed to be complete, there is a $1,268,000 rate period average variation between the capital-related costs used in RAM2022 and the capital-related costs used to calculate BPA's embedded cost of capacity.

4.2.1.2 Fish and Wildlife Costs

In addition to capital-related costs, fixed costs include costs that do not vary with resource output and are directly attributable to the generation capability of the resources available to BPA. The only costs that fit this definition are BPA's fish and wildlife program costs. In addition to direct BPA fish and wildlife costs, BPA pays U.S. Fish and Wildlife Service program costs associated with the Lower Snake River Hatcheries and pays the the Northwest Power and Conservation Council (NPCC) to help finance its Fish and Wildlife program (50 percent of BPA's payments to NPCC go toward fish and wildlife and the other 50 percent goes toward conservation). The total of all directly attributable fish and wildlife costs average $284,445,000 per year for the rate period. *Id.*, line 12.

4.2.1.3 Power Purchase Costs

Power purchase costs are included in the embedded cost of capacity calculation if they are flat annual blocks of power, such as system augmentation, or if they are the purchase of the output from a dispatchable resource. Power purchases from variable resources, such as wind and solar output, are attributed entirely to energy and are not relied upon for capacity. Power purchase costs are included because they increase the capacity available to BPA but are not captured by the inclusion of capital-related or fish and wildlife costs. Unlike BPA's physical resources – where a capacity-and-energy-cost-classification methodology can be used – the cost of power purchases often includes a single $/MWh cost only, with no visibility into the capacity and energy cost components. In these situations, a ratio of maximum-output to maximum-output-plus-average-generation is used to classify the portion of the total cost that is attributable to capacity. For a flat annual block of power, this method attributes 50 percent of the cost to energy and the other 50 percent to capacity. This is because, for a flat block of power, the maximum generation and average generation are the same. For example, the calculation for a 10 MW flat block of power would be 10/(10+10) = 10/20 = 50 percent attributed to capacity. For Clearwater Hatchery Generation, which is the only physical hydro resource that BPA currently pays for the output in a single $/MWh cost, this method attributes 39.6 percent to energy and 60.4 percent of the cost to capacity. The total rate period average of power purchase costs classified as capacity costs for purposes of calculating BPA's unit cost of capacity is $840,000 per year. *Id.*, line 18.

4.2.1.4 Cost Adjustments

Two cost adjustments are made to the total embedded costs, one for the 4(h)(10)(C) credit and another for Synchronous Condensing. The portion of the 4(h)(10)(C) credit that is associated with program costs is included because fish and wildlife program costs are included in the capacity cost calculation, and a portion of 4(h)(10)(C) credit is an offset to those costs. The portion of the 4(h)(10)(C) credit that is associated with the cost of balancing purchases is excluded because the cost of balancing purchases is classified as an energy cost. The portion of BPA's capacity costs that are allocated to Synchronous Condensing – the investments in plant modifications at the John Day and The Dalles projects that are necessary to provide Synchronous Condensing – are removed ($185,000 per year) to avoid double counting, since these capacity costs are associated with Synchronous Condensing and are already assigned to Transmission through that methodology, as described in Section 5 of this Study. *Id.,* line 21. The portion of the 4(h)(10)(C) credit associated with capacity and the removal of the costs associated with Synchronous Condensing totals an average of $64,933,000 per year for the rate period. *Id.*, line 23.

4.2.1.5 Treatment of Conservation

All costs associated with conservation are excluded from the calculation of the embedded capacity cost. This is because, although energy conservation provides both capacity and energy benefits, the amount of capacity provided from BPA's conservation investments is not readily available. Given this, both the costs of conservation and conservation's contribution to the system capability of the resources available to BPA are excluded.

4.2.2 The Capacity Available to BPA

The capacity of all the resources available to BPA, excluding conservation (*see* Section 4.2.1.5 above), is made up of (1) physical resources (regulated hydro, independent hydro, small hydro, and thermal); and (2) forecast or actual generation augmentation purchases.

Non-hydro renewable generation, described in detail in the Loads and Resources Study, BP-22-FS-BPA-03, Section 3.1.3, is excluded. Although these wind and solar resources produce energy, they are excluded from capacity because these forms of generation are variable. The capacity provided by physical resources and augmentation purchases are increased by the amount of capacity provided by Power Services to support Ancillary and Control Area Services. The sum of these two sources, as adjusted for the amount of capacity provided for Ancillary and Control Area Services, is equal to an annual average one-hour system capability (under 1937 critical water conditions) of 14,249 MW for the rate period. *See* Documentation, BP-22-FS-BPA-06A, Table 4.3, line 10.

4.2.2.1 Capacity from Physical Resources

BPA's primary source of capacity is from physical resources and is equal to 13,096 MW. Physical resource capacity is established as described in the Power Loads and Resources Study, BP-22-FS-BPA-03, Section 3.1.2. The 14-period one-hour capacity of each Federal resource type is averaged to create an annual average one-hour capacity under 1937 water conditions. These average annual one-hour capacities are then averaged across the two-year rate period, and reduced for transmission losses, to create rate period average one-hour capacities after losses. *See* Documentation, BP-22-FS-BPA-06A, Table 4.1.

4.2.2.2 Capacity from Power Purchases

BPA may also obtain additional capacity through forecast and actual power purchases. All forecast and actual power purchase amounts considered augmentation purchases are included in the total amount of capacity available to BPA. System augmentation is discussed in the Loads and Resources Study, BP-22-FS-BPA-03, Section 4.2, and System augmentation amounts are presented in that Study in Table 2. Any power purchased to serve loads at a Tier 2 rate is also included. All augmentation purchases, including purchases made to serve loads at a Tier 2 rate, are assumed to be made on a flat annual basis. These flat augmentation purchases increase the amount of capacity available to the Federal system by an equal amount in all months. *See* Documentation, BP-22-FS-BPA-06A, Table 4.1, lines 23-24.

4.2.2.3 Capacity Provided for Ancillary and Control Area Services

The amount of capacity forecast to be provided by Power Services to support Ancillary and Control Area Services is equal to 1,153 MW. Documentation, BP-22-FS-BPA-06A, Table 4.3, line 9. This amount is added to the capacity available to BPA from physical resources and power purchases because the capacity of the physical resources reflected in the Power Loads and Resources Study, BP-22-FS-BPA-03, § 3.1.2, has already been reduced for the balancing and operating capacity obligation.

4.2.3 Embedded Unit Cost Calculation

The embedded unit cost of capacity is calculated by taking the costs attributable to capacity (*see* § 4.2.1) and dividing by the capacity of the resources available to BPA. The embedded unit cost of capacity is equal to $5.87 per kilowatt (kW) per month. Documentation, BP-22-FS-BPA-06A, Table 4.3, line 16.

4.3 Variable Cost Pricing Methodology

4.3.1 Introduction and Purpose

When BPA holds capacity, it incurs variable costs due to efficiency losses. Efficiency losses impact the Federal system in regard to output in MWs, timing of energy generated, and revenues received. The Generation and Reserves Dispatch (GARD) Model is an R-based model designed to calculate the costs of the various forms of efficiency losses associated with ensuring that sufficient machine capability is ready and capable of responding to, and delivering, the balancing and operating reserve capacity. These efficiency costs are determined by measuring the difference between: (1) the costs of operating the Federal system at an optimal efficient level *without* holding capacity reserves; and (2) the cost of operating the Federal system at an optimal level *with* holding capacity reserves. The difference between those costs are generally referred to as variable costs.

The variable costs associated with providing a quantity of balancing reserve capacity are calculated in the GARD Model using inputs from the HYDSIM model, reserve requirement data, and Aurora© price forecasts. The purpose of the GARD Model is to calculate the variable costs incurred as a result of operating the Federal system with the necessary balancing reserve capacity to maintain reliability and for deploying the balancing reserve capacity to maintain load-resource balance within the BPA BAA. Load-resource balance is maintained by the automatic increase or decrease of generation in response to instantaneous changes in demand and/or power production. The ability to be ready and able to automatically increase generation is referred to as an *inc* reserve. Likewise, the ability to be ready and automatically decrease generation is referred to as a *dec* reserve.

The GARD Model calculates the costs associated with standing ready to provide capacity reserves. These costs are referred to as 'Stand-ready' costs and are comprised of the following:

1. Energy shift associated with providing *dec* reserves
2. Energy shift associated with providing non-spinning *inc* reserves
3. Energy shift associated with providing spinning *inc* reserves

4. Efficiency changes associated with providing *dec* reserves
5. Efficiency changes associated with providing non-spinning *inc* reserves
6. Efficiency changes associated with providing spinning *inc* reserves
7. Spill costs associated with providing non-spinning *inc* reserves
8. Spill costs associated with providing spinning *inc*

For each cost category, the GARD Model produces monthly cost and associated energy results for heavy load hours (HLH) and light load hours (LLH) by water year; the energy is denominated in megawatthour losses (positive losses are reflected as gains in the GARD Model). Sections 4.3.3 through 4.3.4 detail the definition and calculation of each identified cost element.

In considering the variable costs, the GARD Model seeks to efficiently commit and dispatch the units at projects armed for AGC response, generally referred to in this Study as "controller projects." The goal is to meet each controller project's generation request, meet the balancing reserve capacity obligation, and respond to a simulated balancing reserve capacity need. In the process of making controller projects capable of responding and then actually providing response, the efficiency of the generators changes.

After calculating the impacts of carrying and deploying balancing reserve capacity, costs are grouped into three general categories: (1) spinning *inc* costs, (2) non-spinning *inc* costs, and (3) *dec* costs. From these three general groupings, the total cost is subdivided by the reserve service: (1) Regulation Balancing, (2) Non-regulation Balancing, and (3) Operating Reserves. For further discussion regarding balancing reserve capacity, see Section 2.1.

4.3.2 Pre-Processes and Inputs

This section describes the preparation of the input data for the GARD Model.

4.3.2.1 Generation Request

The primary inputs into the GARD Model are tables of controller project-specific generation values calculated by HYDSIM. *See* the Power Loads and Resources Study, BP-22-FS-BPA-03, for information on the HYDSIM model. These generation tables are used to determine the generation request, which determines the controller project's unit commitment and dispatch. The generation request is the amount of HLH or LLH generation that a specific controller project is being asked to produce. The controller project's unit commitment and dispatch is the number, and/or combination, of online units required to meet the generation request and reserve obligation.

Determining the specific HLH and LLH generation request begins with monthly energy amounts for each of the 80 historical water years from HYDSIM. Monthly energy amounts are taken for Grand Coulee (GCL), Chief Joseph (CHJ), John Day (JDA), and The Dalles (TDA). All but four of the 31 projects in the Federal system are AGC-equipped. However, GCL, CHJ, JDA, and TDA are the only projects analyzed because these four controller projects are most often armed by the hydro duty scheduler for AGC response. The 80 years of monthly energy amounts from HYDSIM for the four controller projects are taken as inputs into a pre-processing spreadsheet before being input into the GARD Model.

The purpose of the pre-processing spreadsheet is to shape the HYDSIM energy into HLH and LLH generation amounts for each of the four projects. The shaping of energy into HLH and LLH generation quantities is a function of the historical relationship between average generation across all hours (average energy) and HLH generation for each of the controller projects, constrained by unit availability, 1 percent peak generation constraints, and minimum turbine flow constraints. Development of the functional relationships between average energy production and HLH generation relies on Supervisory Control and Data Acquisition (SCADA) data from January 1, 2002, through December 31, 2007. The 2002-2007 period balances the need for a robust data set with the desire for operations that are similar to current practice and bound by similar constraints. Additionally, there is little to no influence from wind generation in this period. After 2007, the relationship between average energy production and HLH generation is impacted by the amount of wind interconnected in the BPA BAA.

After the HLH and LLH generation are calculated for each controller project for each month of each historical water year based on the previously described function, the generation quantities are input into the GARD Model as the generation request. The generation request appears as a table of 12 months by 80 water years for HLH and LLH (a total of 1,920 generation values). The generation request values are used by the GARD Model to determine the unit commitment and dispatch for each of the controller projects. That is, for each month of each water year for HLH and LLH, generation values are given to the GARD Model for each controller project. Given these generation values, the GARD Model will find the plant efficiency-maximizing unit commitment and dispatch. This process simulates the basepoint setting process in which the hydro duty scheduler submits requested generation amounts to each controller project and the controller project commits and dispatches its units in the most efficient manner possible.

An additional secondary input to the GARD Model, also derived from the pre-processing spreadsheet, is a matrix of the amount of pre-existing *dec* capability for each controller project by month and historical water year. Pre-existing *dec* capability is defined as the difference between the calculated LLH generation and the minimum generation for each of the respective controller projects. The purpose of this input is to avoid unnecessarily moving energy out of HLH and into LLH when providing *dec* capability.

4.3.2.2 Reserves

Reserve requirements are an input into the GARD Model and are classified as either Balancing Reserves or Operating Reserves. Balancing Reserves are further classified into either regulation or non-regulation, each of which have *inc* and *dec* quantities. Given these reserve classifications, the GARD Model determines the required amounts of spinning and non-spinning reserve to meet *inc* obligations and the amount of generation required to meet *dec* obligations.

The determination of the quantities of spinning reserve versus the quantities of non-spinning reserve is derived from NERC requirements as well as system operator judgment. NERC requires that at least 50 percent of the BAA Operating Reserve obligation be met with spinning capability responsive to AGC. NERC also requires that 100 percent of the BAA Regulation Balancing Reserves must be carried on units with spinning capability responsive to AGC, due to the fact that Regulating Reserve must respond on a moment-to-moment basis. In contrast, Non-regulation Balancing Reserves do not have NERC-defined criteria, and therefore it is assumed that at least 50 percent of the *inc* following reserve must be carried as a spinning obligation and up to 50 percent as a non-spinning obligation.

The rationale for carrying at least 50 percent of the *inc* non-regulation requirement as spinning is to provide sufficient response over the first five minutes of movement while simultaneously providing enough time to synchronize non-spinning units and ramp the units through their suboptimal operation. Synchronization generally takes about three minutes, with the unit fully ramped over the next seven minutes. Should additional balancing reserve capacity be required to cover a growing imbalance, additional units are synchronized and ramped as the spinning portion of non-regulation reserve is consumed and the remaining non-regulation reserve capacity is deployed with non-spinning capability. By definition, all *dec* reserve capacity (the *dec* portion of the regulation and non-regulation) is spinning, because units must be generating (*e.g.,* with turbines spinning) in order to deploy *dec* reserve capacity.

4.3.2.3 Controller Project Responses

Controller project responses determine the relative balancing reserve capacity obligation for a given controller project as well as the relative reserve deployment quantity. As in actual operations, responses are input into the GARD Model as percentages, allocating the reserve capacity obligation among the controller projects. The response percentage prorates the reserve carrying and deployment across the selected controller projects. The response percentages are functions of water condition, time of year, and, ultimately, controller project flexibility.

Controller project responses are input into the GARD Model by month and water year to account for the changing reserve capacity carrying capability as dictated by hydrologic conditions and unit availability. The expected response scheme for July through March is 50 percent at GCL, 25 percent at CHJ, 15 percent at JDA, and 10 percent at TDA. The expected scheme for April through June is 60 percent at GCL, 30 percent at CHJ, 5 percent at JDA, and 5 percent at TDA. However, significant departures from the expected scheme can occur due to varying hydraulic conditions.

4.3.3 Stand-Ready Costs

To meet the potential balancing reserve capacity requirements in any given hour, BPA's system is set up in advance so that the required balancing reserve capacity is available during all operating hours. Stand-ready costs are those variable costs associated with holding the required reserve capacity from the Federal system. Three specific costs are incurred when preparing the Federal system to stand ready to deploy balancing reserve capacity as needed: energy shift, efficiency loss, and spill losses.

4.3.3.1 Stand-Ready Energy Shift

The GARD Model's first step in determining the stand-ready impacts of carrying balancing reserve capacity is to calculate how much energy is shifted out of the HLH period and into the LLH period. This movement of energy is referred to as the "energy shift" (also referred to as Hydro-shift). If the current generation request does not allow sufficient *inc* or *dec* capability, energy shift will occur. If the input generation request results in adequate balancing reserve capacity, energy shifting is not necessary, and no cost is assigned.

Energy may shift out of the HLH period to make *dec* capability available during the LLH period and/or to make sufficient non-spinning and/or spinning *inc* capability available during the HLH period. In the first instance, fuel normally used to meet peak generation needs is consumed during periods of lowest demand so that sufficient generation capability exists on the Federal system to fully deploy *dec* reserves without violating minimum generation requirements. The need to shift energy is typically driven by the need to generate during the graveyard period: 1 a.m. to 5 a.m. (Hour Ending (HE) 0200 through 0500). Depending on water conditions, energy may also be shaped into the shoulder LLH period, 11 p.m. to 1 a.m. and 6 a.m. to 8 a.m. (HE 2400 through 0100 and 0600 through 0700), to make available *dec* capability. In making available non-spinning and spinning *inc* capability, energy shift impacts typically manifest as a reduction first in the super peak period, 7 a.m. to 1 p.m. and 9 p.m. to 11 p.m. (HE 0800 through 1300 and 2200 through 2300), generating capability followed by a shifting into the shoulder HLH period; this typically consists of the period 1 p.m. to 9 p.m. (or HE 1400 through 2100). Should additional *inc* capability be required after completely flattening generation across the HLH period, such as in high-flow scenarios, energy is shifted into the shoulder LLH period and, eventually, into the graveyard period.

The GARD Model captures these effects by disaggregating the HLH and LLH periods each into two blocks, for a total of four blocking periods (Super Peak, shoulder HLH, shoulder LLH, and graveyard). This disaggregation is accomplished by shaping the input generation request using functional relationships based on actual operational data, unit availability, and minimum generation requirements. The same data set described in Section 4.3.2.1 was used to develop the necessary functional relationships used by the GARD Model. As energy is moved from one blocking period to another for a given reserve obligation, the GARD Model tracks and records these movements. This results in tables of energy shift by month, water year, and blocking period caused by making available the capability to provide *dec*, non-spinning *inc,* and spinning *inc* reserves.

Energy shift is valued as the price differential between the period from which energy is taken and the period into which energy is moved. *See* Documentation, BP-22-FS-BPA-06A, Tables 4.4-4.9. The cost of *inc* energy shift is included in the total variable cost that is included in rates. For FY 2022-2023, the total annual average energy shift is 747,336 MWh, worth $13,905,727. *Id.*, Table 4.8, line 4.

4.3.3.2 Stand-Ready Efficiency Change

For any given generation request, a controller project has a unit commitment and dispatch that maximizes controller project efficiency by minimizing the amount of water flow per megawatt generated. For each generation request and balancing reserve capacity requirement, the GARD Model seeks to commit and dispatch each of the controller projects most efficiently. The efficient dispatch is a function of the individual controller project's generation request, the controller project's response, the characteristics of a given controller project's unit families (groups of units having similar performance characteristics), the unit availability, the minimum amount of spinning balancing reserve capacity required, and the amount of non-spinning balancing reserve capacity.

The GARD Model optimizes the unit dispatch by loading each online unit such that the marginal cost of each unit is identical and the requested generation and balancing reserve capacity is met. Dispatching units at equal marginal costs results in the model meeting the objective of minimizing total turbine outflow per unit of fuel (water in thousands of cubic feet per second).

Changes in plant efficiency are calculated by month and water year for the HLH and LLH periods. Efficiency changes are calculated where *dec* balancing reserve capacity and non-spinning and spinning *inc* balancing reserve capacity are being provided. In calculating the amount of efficiency loss, the GARD Model calculates the most efficient unit commitment and dispatch for a given generation request without a balancing reserve capacity requirement and compares this efficiency to the efficiency obtained while meeting both the generation request and the input balancing reserve capacity requirement. To the extent that a given generation request results in an efficient dispatch with sufficient capability, no efficiency changes are calculated. Conversely, to the extent that a given generation request results in a unit commitment and dispatch with insufficient capability, the unit commitment and dispatch must be altered so that the required minimum balancing reserve capacity is carried.

Efficiency changes, unit commitment, and dispatch decisions are driven by the unit characteristics of each controller project. The unit characteristics are defined by polynomial functions relating unit generation for each controller project's individual unit families to unit water flow. The polynomial functions are derived from actual measured generator unit data obtained from the U.S. Army Corps of Engineers (Corps) and Reclamation. This results in 10 unit families across four controller projects: GCL has four families, CHJ has three, JDA has one, and TDA has two. In addition to determining controller project efficiency for a given level of generation, the efficiency curves determine the upper and lower bounds of unit level generation for JDA and TDA during the months of April through September. During this time period, the units at JDA and TDA must generate within 1 percent of peak efficiency pursuant to Fish Passage Plan requirements. This constraint is applicable both when standing ready to provide reserves and during the deployment of reserves.

The GARD Model explicitly tracks the efficiency effects and produces returning tables of efficiency impacts by month, water year, and blocking period due to making available the capability to provide *dec*, non-spinning *inc,* and spinning *inc* reserves.

Efficiency changes are valued at the HLH price from the market price forecast for each month of the rate period. The HLH price is used because efficiency impacts – losses and gains in energy – are taken out of or put into the HLH period. The total average annual efficiency change for FY 2022-2023 is a gain of 48,175 MWh, which reduces the total variable costs by $5,684,312. *Id.*, Table 4.8, line 8.

4.3.3.3 Stand-Ready Spill Losses

Spill losses may occur given the combination of a large *inc* balancing reserve capacity obligation and high river flows. Under these conditions, the GARD Model will flatten the generation pattern across all hours. The flattened generation profile maximizes the combined *inc* and *dec* capability across all hours. Should the GARD Model still fail to carry sufficient *inc* capability, it will begin spilling to achieve the joint objective of meeting the *inc* reserve obligation and the controller project flow requirements.

Spill losses are valued at the respective HLH or LLH price from the market price forecast for each month of the rate period. The total average annual spill loss for the FY 2022-2023 period is 145,718 MWh, worth $3,570,917. *Id.*, line 11.

4.3.4 Variable Cost of Reserves

The end goal of determining the variable cost of balancing reserve capacity is the ability to assign specific costs to specific types of balancing reserve capacity. Placing the output of the GARD Model into a post-processing spreadsheet containing market prices yields the cost of balancing reserve capacity by reserve type and, ultimately, by reserve service. The variable cost of balancing reserve capacity is apportioned proportional to *inc* and *dec* quantities while the cost of operating reserves is only apportioned to *inc* quantities because operating reserves are only provided as *inc* reserves. As discussed in Section 4.3.2.2, the type of reserve determines how the GARD Model carries the reserve (*i.e.,* as spinning or non-spinning), with the final result being cost. The cost of carrying balancing reserve capacity is subtotaled into the following five reserve categories, as listed in Section 4.3.1: regulation *inc*, regulation *dec*, non-regulation *inc*, non-regulation *dec*, and the spinning portion of Operating Reserves.

The aggregation of the GARD Model-calculated variable costs into the respective reserve service categories is shown in Documentation, BP-22-FS-BPA-06A, Table 4.9. The total average annual loss for the FY 2022–2023 period is 941,229 MWh, valued at $11,792,332. *Id.*, Table 4.8, line 12. The total annual average Federal system variable cost used for setting rates for FY 2022-2023 is $11,792,332. *Id.*, Table 4.9, line 8.

Documentation Table 4.9 also shows the variable costs for the Regulation (*inc* and *dec*), Non-regulation (*inc* and *dec*), and the spinning portion of Operating reserves.

4.3.5 Potential Variable Cost Offsets with EIM

If BPA begins EIM participation, the variable cost of holding non-regulation balancing reserves may be offset by the revenues generated through EIM participation and, as such, a discount to the costs represented in ACS rates is assumed for the BP-22 rate period. Pursuant to the BP-22 Settlement agreement, if BPA joins the EIM, BPA will provide a discount on ACS rates that correspond to variable capacity costs that may have the potential to be offset through bids of energy BPA makes in the EIM. The discounted ACS rates are calculated according to the following steps:

1) Recalculate the variable cost of reserves as discussed in Section 4.3.2.2 with the associated non-regulation Energy shift and Spill cost offsets for *inc* and *dec* balancing reserves.
2) Recalculate discounted unit capacity costs using the variable cost offsets from Step 1.
3) Pass the discounted unit costs from Step 2 to ACS rates model to calculate discounted rates.

The first step begins by evaluating the Energy shift and Spill costs calculated by GARD consistent with the undiscounted methodology as described above. For the BP-22 rate period, the annual average Energy shift costs are \$13,905,727; non-regulation *inc* reserves accounted for \$2,297,137 and non-regulation *dec* reserves accounted for \$2,610,016. Documentation, BP-22-FS-BPA-06A, Table 4.10, line 1. Annual average Spill costs are \$3,570,917; non-regulation *inc* reserves accounted for \$589,893 and non-regulation *dec* reserves accounted for \$670,238. *Id.,* line 3. The remaining Energy shift and Spill costs were allocated to regulation balancing services and to Operating Reserves. Next, a 50 percent cost offset is applied to the Energy shift and Spill costs allocated to non-regulation reserves. *Id.*, lines 5-6.

For the second step, the discounted unit cost calculations require different treatments for *inc* and *dec* reserves. The Energy shift and Spill cost offset is applied to the total balancing *inc* variable cost which is made up of both regulation and non-regulation *inc* balancing reserves. This is done to maintain the rate design cost adjustment of the $2.80/kW per month delta between regulation and non-regulation *inc* reserves as described in Section 4.4 of this study, and as a result, the offset also indirectly impacts the regulation *inc* unit costs. The offset is not applied to any portion of *inc* Operating Reserves. The discounted unit cost is calculated for non-regulation *dec* by breaking out the Energy shift and Spill costs allocated to *dec* between regulation and non-regulation balancing services. The cost offset is applied only to the non-regulation portion of the overall *dec* Energy shift and Spill costs. Discounted variable unit costs and the recalculated total unit costs after the rate design adjustments for each capacity type are shown in Documentation, BP-22-FS-BPA-06A, Table 4.12.

In the third step, the ACS rates are recalculated after the offsets have been applied to the unit capacity costs described above in the first and second steps. The ACS rates methodology is described in Section 9. The rates that would receive the EIM discount are Regulation and Frequency Response (RFR), Dispatchable Energy Resource Balancing Service (DERBS) *inc*, DERBS *dec*, Variable Energy Resource Balancing Service (VERBS) Wind, and VERBS Solar. *See* Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.3, lines 19-32 and Table 10.4, lines 79-104.

4.4 Rate Design Cost Adjustment Methodology

After embedded and variable costs have been calculated and before final reserve capacity rates are established, a rate design step is applied to incremental capacity reserves to reflect the relative opportunity costs associated with providing different types of capacity – fast and flexible capacity as compared to slower and less flexible capacity. The value delta is equal to the difference in costs between thermal generators designed for each type of reserve capacity type. The outcome of this benchmarking process illustrates that faster and more flexible capacity is more costly than slower and less flexible capacity. The process by which BPA applies the value delta to regulation and non-regulation *inc* balancing reserves and spinning and supplemental Operating Reserves is detailed in Section 4.5.1 below.

4.4.1 Fast and Flexible vs. Slower and Less Flexible Incremental Benchmarking

Measuring the cost differential between fast and flexible versus slower and less flexible reserves begins by selecting benchmarking generators that are appropriate for providing each type of *inc* service. The General Electric LMS100 combustion turbine is selected to benchmark costs associated with providing fast and flexible reserve services and the General Electric 7HA.02 combustion turbine is selected for providing slower and less flexible services. The LMS100 turbine is used to benchmark Regulation and Spinning Operating reserves due to its technical capability to provide fast and flexible reserve capacity. The 7HA.02 turbine, on the other hand, is a standard in providing slower and less flexible capacity due to its fuel efficiency and lower long-term costs. The 7HA.02 turbine is used to benchmark Non-regulation and Supplemental Operating reserves.

Benchmarking is conducted by calculating the annual average expense to own, operate and maintain the LMS100 and the 7HA.02 combustion turbines (CT). A detailed description of how annual fixed costs associated with the LMS100 CT are calculated is available in the Power Rates Study, BP-22-FS-BPA-01, Section 4.1.1.2.1 and shown in Power Rates Study Documentation, BP-22-FS-BPA-01A, Table 4.1. The same process is applied to the 7HA.02 CT to determine the annual average expense to own, operate and maintain the generator.

Documentation, BP-22-FS-BPA-06A, Table 4.11. The annual average expense is divided by 12 to calculate the monthly average cost to operate each generator. The average $/kW/month costs for the LMS100 and 7HA.02 CTs are compared to derive the cost differential. This cost differential is used to create the value delta between the spinning and non-spinning *inc* reserve capacity.

For FYs 2022-2023, the estimated average cost for the LMS100 CT is $9.67/kW/month and for the 7HA.02 CT is $6.88/kW/month. Power Rates Study Documentation, BP-22-FS-BPA-01A, Table 4.1, line 14; Documentation, BP-22-FS-BPA-06A, Table 4.11, line 14. The value delta for FYs 2022-2023 is thus $2.80/kW/month. Documentation, BP-22-FS-BPA-06A, Table 4.11, line 28, column J.

4.5 Capacity Cost Calculation

4.5.1 Unit Cost by Reserve Type

The variable costs allocated to *inc* balancing, *dec* balancing, and Operating Reserves are divided by their respective quantities of capacity to calculate a unit cost of the allocated variable costs. As discussed above, the GARD Model only calculates costs assocated with the Spinning portion of the Operating Reserve requirement; however, those variable unit costs are allocated into a general Operating Reserve cost bucket due to the fact that they are differentiated in a later rate design step that is described below.

- For *inc* balancing the unit cost of allocated variable costs is $0.44/kW/month
- For *dec* balancing the unit cost of allocated variable costs is $0.37/kW/month
- For Operating Reserves the unit cost of allocated variable costs is $0.80/kW/month

The embedded unit cost of \$5.87/kW/month (*id.*, Table 4.12, line 2) is added to the unit cost of allocated variable costs for *inc* balancing and Operating Reserves. The unit cost for *dec* reserves has no embedded cost component. The total unit cost of allocated embedded and variable costs for each type of capacity is as follows:

- The total unit cost for *inc* balancing is \$6.31/kW/month (*id.*, line 12)
- The total unit cost for *dec* balancing is \$0.37/kW/month (*id.*, line 13)
- The total unit cost for Operating Reserves is \$6.67/kW/month (*id.*, line 16)

Once the total unit cost is determined, a rate design step is applied to create a price differential between Regulation and Non-regulation *inc* Balancing Reserves as well as between Spinning and Supplemental Operating Reserves to reflect the differing opportunity costs (i.e., the value delta as described above) associated with providing these capacity types. The goal of this step is to make it so the unit cost of each capacity type is an equal amount away from the opportunity cost without collecting more revenue than the amount of costs allocated to each service prior to applying the rate design step.

The process of applying the rate design step begins with the total allocated costs (embedded and variable) of each service along with the total MW quantities forecasted for the two capacity types within each service (regulation and non-regulation for the balancing service and spinning and supplemental for the operating reserve service).

The following set of two equations are then applied to calculate the cost of the two balancing reserves types (Regulation and Non-regulation):

Balancing inc Reserves

$$UC_R - UC_{NR} = VD$$

$$UC_R(MW_R) + UC_{NR}(MW_{NR}) = TotalAllocatedCost_{Bal\_Inc}$$

Where:

UC_R refers to the unit cost for regulating *inc* reserves.

UC_{NR} refers to the unit cost for non-regulating *inc* reserves.

VD refers to the Value Delta (*i.e.*, the opportunity cost rate design goal) as described in Section 4.4.1 above and is equal to $2.80/kW/month.

MW_R refers to the quantity of Regulation *inc* reserves.

MW_{NR} refers to the quantity of Non-regulation *inc* reserves.

$TotalAllocatedCost_{Bal\_Inc}$ refers to the total costs allocated to *inc* balancing services.

The average annual Regulation Balancing *inc* reserves forecasted for the rate period is 309,000 kWh and Non-regulation Balancing *inc* reserves are 371,000 kWh. *Id.,* Table 4.12, lines 14, 16. The average annual amount of costs allocated to Regulation and Non-regulation Balancing *inc* is $51,493,000. *Id.,* lines 21, 23. Given this information, the Regulation Balancing *inc* service receives a value adjustment of +$1.53/kW/month and Non-regulation Balancing *inc* service receives a value adjustment of −$1.27/kW/month. *Id.*, Table 4.12, lines 21-22. After the rate design step is applied, the unit cost for Regulation *inc* balancing capacity is $7.84/kW/month, and the unit cost for Non-regulation *inc* balancing capacity $5.04/kW/month. *Id.*, lines 27, 29.

The following set of two equations are applied to calculate the cost of the two operating reserves types (spinning and supplemental):

$$\textit{Operating inc Reserves}$$

$$UC_{Spin} - UC_{Sup} = VD$$

$$UC_{Spin}\left(MW_{Spin}\right) + UC_{Sup}\left(MW_{Sup}\right) = TotalAllocatedCost_{OP}$$

Where:

UC_{Spin} refers to the unit cost for Spinning Operating reserves.

UC_{Sup} refers to the unit cost for Supplemental Operating reserves.

VD refers to the Value Delta (*i.e.*, the opportunity cost rate design goal) as described in Section 4.4.1 above and is equal to $2.80/kW/month.

MW_{Spin} refers to the quantity of Operating Spinning reserves.

MW_{Sup} refers to the quantity of Operating Supplemental reserves.

$TotalAllocatedCost_{OP}$ refers to the total costs allocated to Operating reserves service.

The average annual Operating Reserves forecasted for this rate period are 473,000 kWh, half of which are Spinning and half of which are Supplemental. *Id.*, Table 4.13, lines 10-11. The average annual amount of costs allocated to Operating Reserves is $37,894,000. *Id.*, line 29. Given this information, Spinning Operating Reserves receives a value adjustment of +$1.40/kW/month and Supplemental Operating Reserves an adjustment of –$1.40/kW/month. *Id.*, Table 4.12, lines 23-24. After the rate design step is applied, the unit cost is $8.07/kW/month for Spinning Operating Reserves capacity and $5.27/kW/month for Supplemental Operating Reserves capacity. *Id.*, lines 31-32.

4.5.2 Forecast of Revenue from Balancing Reserves for Load

The revenue from providing Regulation Reserves for Load is forecast by applying the unit costs to the Regulation Reserve *inc* and *dec* quantity forecasts. The revenue forecast is an average annual amount of $14,395,000. *Id.*, Table 4.13, lines 21-22, column C.

The revenue from providing Non-regulation Reserve for Load is forecast by applying the unit costs to the Non-regulation Reserve *inc* and *dec* quantity forecasts. The revenue forecast is an average annual amount of $9,687,000. *Id.*, lines 23-24, column C.

4.5.3 Forecast of Revenue from Balancing Reserves for Non-Federal Generation

The revenue from providing Regulation Reserves for Generation is forecast by applying the unit costs calculated to the Regulation Reserve *inc* and *dec* quantity forecasts. The revenue forecast is an average annual amount of $13,817,000. *Id.*, lines 21-22, column B.

The revenue from providing Non-regulation Reserve for Generation is forecast by applying the unit costs calculated to the Non-regulation Reserve *inc* and *dec* quantity forecasts. The revenue forecast is an average annual amount of $14,997,000. *Id.*, lines 23-24, column B.

4.5.4 Forecast of Revenue from Operating Reserves

The revenue from providing Spinning Operating Reserves is forecast by applying the unit cost calculated above to the Spinning Operating Reserves quantity forecast. The revenue forecast is an average annual amount of $22,924,000. *Id.*, line 27.

The revenue from providing Non Spinning Operating Reserve is forecast by applying the unit cost calculated above to the Non Spinning Operating Reserve quantity forecast. The revenue forecast is an average annual amount of $14,970,000. *Id.*, line 28.

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5. SYNCHRONOUS CONDENSING

5.1 Synchronous Condensing

This section describes the method used to determine the amount of energy consumed by those FCRPS hydro generators that operate as synchronous condensers, and the determination of the cost of that energy that is allocated to BPA Transmission Services. It also describes the costs allocated to Transmission Services associated with the investment in plant modifications necessary to provide synchronous condensing at the John Day and The Dalles projects. Synchronous condensing costs allocated to Transmission Services are recovered through transmission rates and passed to BPA Power Services as an interbusiness-line transfer.

5.2 Description of Synchronous Condensers

A synchronous condenser is essentially a motor with a control system that enables the unit to regulate voltage. These machines dynamically absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system. Some FCRPS generators operate in synchronous condenser or "condense" mode for voltage control and for other purposes (*e.g.,* to accommodate operational constraints associated with taking a unit offline). A generator operating in condense mode provides the same voltage control function as the unit does when generating real power. As with any motor, a unit operating in condense mode consumes real energy. Generators operating in condense mode in the FCRPS consume energy supplied by other units in the FCRPS.

5.3 Synchronous Condenser Costs

Synchronous condensing costs include the cost of (1) investment in plant modification at John Day and The Dalles projects necessary to provide synchronous condensing, and (2) energy consumed by FCRPS generators while operating in condense mode for voltage control.

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $185,000 per year. Documentation, BP-22-FS-BPA-06A, Table 5.3, line 1; Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Table 2F. These costs are the annual capital-related costs in the power revenue requirement associated with the investment that Power Services made in the plants at the request of Transmission Services to enable synchronous condense capability.

For the costs associated with the energy used in condense mode operations, the amount of forecast energy is priced at an average annual market price. The methodology to determine the amount and cost of energy consumption is described below.

5.4 General Methodology to Determine Energy Consumption

For the FY 2022-2023 rate period, the FCRPS generators capable of operating in condense mode are identified, and the number of hours that the generators would operate in condense mode for voltage control is forecast. The forecast is derived from historical synchronous condenser operations, based on an average of the most recent three years of data available, which are fiscal years 2018, 2019, and 2020. The average number of hours is multiplied by the fixed hourly energy consumption for the generators to determine the amount of energy consumed. The fixed hourly energy consumption is the motoring power consumption of the specific generator units when they are operated in condense mode. *See* Documentation, BP-22-FS-BPA-06A, Table 5.1. Finally, the market price forecast is applied to the amount of energy consumed to calculate the cost of synchronous condensing. The methodology for assigning historical synchronous condenser operations to the voltage control function and calculating the associated energy use for each of the FCRPS projects capable of operating in condense mode is described below.

5.4.1 Grand Coulee Project

Six generators (Units 19-24) at the Grand Coulee project are capable of operating as synchronous condensers, although only three are typically operated in condense mode. The Study forecasts the number of hours that the Grand Coulee units will operate in condense mode based on historical condenser operations for the three-year historical period. The transmission system typically needs additional voltage control from the Grand Coulee project during nighttime hours (generally hours 20:00 to 06:00), when the lightly loaded transmission system results in excess reactive power and causes excess voltage on the system. Historical reactive demand and unit operations are examined, and units operated in condense mode are allocated to either Transmission Services or Power Services, based on the reactive demand of the transmission system, the reactive capability of the units, the number of units on-line producing real power, and operation of the shunt reactor (which absorbs reactive power and reduces voltage). The method for assigning condensing units to the voltage control function and developing the forecast is described below.

For the forecast, BPA first determines the total measured reactive demand that the transmission system placed on the six units during the nighttime hours. This measured reactive demand is based on archived reactive meter readings for the historical three-year period. The total measured reactive demand represents the total reactive support (*e.g.*, megavolt amperes reactive) provided by all six units, regardless of whether the units are condensing or generating real power. Recall that units operating in generation mode also provide reactive support in addition to real power. For each hour, the total measured reactive demand is compared to the reactive capability of the units online generating real power plus, if not operating, the reactive capability of the shunt reactor. If the reactive capability of online units and the shunt reactor is less than the total measured reactive demand for the hour, one or more units operating in condense mode are allocated to voltage control for that hour. If a condensing unit is allocated to voltage control for a single nighttime hour, the condensing operation of that unit is allocated to voltage control for the entire nighttime period to reflect the fact that, in practice, a unit would not be started and stopped on an hourly basis. Condensing units are allocated to voltage control in whole increments until the total measured reactive demand is met or exceeded. The number of condensing hours for the three-year historical period is averaged, and energy consumption is determined by multiplying the average annual condensing hours by the fixed hourly energy consumption of the generators. The forecast of total energy consumed by the Grand Coulee generators operating in synchronous condense mode for voltage control is 13,024 MWh/yr. Documentation, BP-22-FS-BPA-06A, Table 5.1, line 4.

5.4.2 John Day, The Dalles, and Dworshak Projects

The John Day project has four generators (Units 11-14), The Dalles has six generators (Units 15-20), and the Dworshak project has three generators (Units 1-3) capable of operating as synchronous condensers. These three projects condense only when requested by Transmission Services, so all hours in condense mode are assigned to voltage control. The number of condensing hours for the three-year historical period is averaged, and energy consumption is calculated by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the applicable hydro units. The forecast of total energy consumed by the generators operating in condense mode for voltage control is 12,028 MWh/yr for John Day and The Dalles (*id.*, line 3), and 222 MWh for the Dworshak project (*id.*, lines 5-6).

5.4.3 Palisades Project

The Palisades project has four generators (Units 1-4) that are capable of synchronous condensing. Units are operated in condense mode pursuant to standing instructions from Transmission Services based on operational studies, so all hours in condense mode are assigned to voltage control. The number of condensing hours for the three-year historical period is averaged. Energy consumption is determined by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the project. The forecast of energy consumption by the Palisades generators operating in condense mode for voltage control is 1,854 MWh/yr. *Id.*, line 7.

5.4.4 Willamette River Projects

The Willamette River projects have seven generators capable of condensing, which include units in the Detroit project (Units 1-2), the Green Peter project (Units 1-2), and the Lookout Point project (Units 1-3). Historically these units have been operated at times in condense mode. However, BPA studies indicate that condensing is not required from these projects for voltage support except under rare conditions. Therefore, the energy for condensing operation for voltage control is forecast to be zero for the Willamette River projects. *Id.*, lines 8-10.

5.4.5 Hungry Horse Project

The Hungry Horse project has four generators (Units 1-4) capable of condensing. Although capable of condensing, Hungry Horse was not requested to operate in condense mode during the three-year historical period. Therefore, the energy consumption for the Hungry Horse generators is forecast to be zero. *Id.*, line 11.

5.5 Summary – Costs Assigned to Transmission Services

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $185,000 per year. *Id.*, Table 5.3, line 1; Power Revenue Requirement Study Documentation, BP-22-FS-BPA-02A, Table 2F.

The energy forecast to be consumed by FCRPS generators operating in condense mode totals 27,127 MWh. Documentation, BP-22-FS-BPA-06A, Table 5.1, line 13. The energy consumed for condensing operation is priced at the market price forecast. *See* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4. Applying the market price forecast of $27.20 per MWh to the energy consumed results in a total cost of $737,844 per year. Documentation, BP-22-FS-BPA-06A, Table 5.1, line 13. This amount is made up of $327,148 per year in energy costs for the Southern Intertie, and $410,696 associated with energy costs for voltage control for the Network. *Id.*, lines 3, 12. Total synchronous condensing cost allocated to TS, then, is the sum of the $185,000 per year in plant investments for the Southern Intertie and the total cost of energy consumed of $737,844, which equals $922,844 per year. *Id.*, Table 5.3, lines 1, 5.

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6. GENERATION DROPPING

6.1 Introduction

This section describes the method for allocating costs of Generation Dropping, including identifying the assumptions used in the methodology and establishing the generation input cost allocation that is applied to determine the annual revenue forecast for generation inputs.

6.2 Generation Dropping Requirement

The BPA transmission system is interconnected with several other transmission systems. To maximize the transmission capacity of these interconnections while maintaining reliability standards, Remedial Action Schemes (RAS) are developed for the transmission grids. These schemes automatically make changes to the system when a contingency occurs to maintain loadings and voltages within acceptable levels. Under one of these schemes, Transmission Services requests that Power Services instantaneously drop (disconnect from the system) large increments of generation (at least 600 MW). To satisfy this requirement, the generation must be dropped virtually instantaneously from a certain region of the transmission grid. Under the current configuration of the transmission grid and the individual generating plant controls, Power Services can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity).

6.3 General Methodology

The methodology for calculating the cost of Generation Dropping starts with two factors: the impact to the equipment involved and the lost revenue associated with that impact. These factors are applied to a single generating unit at the Grand Coulee Third Powerhouse to arrive at an estimate of a single generation drop. This number is then multiplied by the estimated average drops per year to arrive at an estimate of the cost of Generation Dropping for each year of the rate period. Generation Dropping causes additional wear and tear on equipment that will decrease the life and increase the maintenance of the unit. For each major component that is affected by this service, Documentation, BP-22-FS-BPA-06A, Table 6.1 shows the cost associated with incremental equipment deterioration, replacement, and overhaul, and the cost associated with incremental routine operation and maintenance.

Historical data for the Grand Coulee Third Powerhouse generating units and statistical data for other hydroelectric units provide capital cost, operation and maintenance costs, and frequency of operation information for the Generation Dropping analysis. Stresses on the equipment from Generation Dropping versus stresses during normal operation are compared. Through the application of this data, the capital and operation and maintenance costs for Generation Dropping are developed. The impacts are converted into a percentage change in equipment life and percentage increase in operations and maintenance for each operation.

6.4 Generation Dropping Cost

6.4.1 Incremental Equipment Deterioration, Replacement, or Overhaul Costs

One effect of additional deterioration because of Generation Dropping is a reduced period of time between major maintenance activities, such as major overhauls or replacements. For purposes of this analysis, a "major overhaul" is defined as a maintenance activity for which at least partial disassembly of the affected equipment is required. The analysis focuses on evaluating the costs of additional, short-term deterioration of specific

components or items for which statistical data are readily available. The costs of a major overhaul are derived from estimates or similar work performed in the past.
The percentage life reductions are determined using industry standards or actual project records. *See* Documentation, BP-22-FS-BPA-06A, Table 6.1, column B. For example, turbine overhaul is a major maintenance effort that will increase in frequency as a result of Generation Dropping.

Power Services previously contracted with Harza Engineering Company to work with Reclamation and the Corps (which own and operate the FCRPS projects) to evaluate the costs of providing Generation Dropping. The evaluation estimated the cost incurred by a typical Reclamation or Corps generating unit. These cost estimates are applied to a generating unit at the Grand Coulee Third Powerhouse. The costs in the original engineering study are updated using the Handy-Whitman Index to reflect price escalation of equipment and labor costs.

The Handy-Whitman Index multiplier is applied to the equipment costs in the study performed by Harza Engineering Company. The annual Incremental Equipment Deterioration, Replacement, and Overhaul Cost per drop for FY 2022–2023 is calculated by multiplying the percentage of Life Reduction per drop by the cost of a Major Overhaul. *Id.*, column D, line 6.

6.4.2 Incremental Routine Operation and Maintenance Costs

In addition to more frequent major overhauls, increases in routine operations and maintenance costs are expected due to the additional deterioration caused by Generation Dropping. The Incremental Routine Operations and Maintenance (O&M) Cost per drop is calculated using the Percentage Increase O&M Per Drop and expected annual operations and maintenance costs per major piece of equipment. The percentage increase in operations and maintenance costs is assumed to be equivalent to the percentage life reductions used to determine the incremental deterioration, replacement, or overhaul costs (*e.g.*, a 0.1 percent reduction in life per drop will result in a 0.1 percent increase in annual operations and maintenance costs). Annual O&M Costs are increased by an inflation factor of 2.53 percent for FY 2022-2023. The annual Incremental Routine O&M Cost per Drop for FY 2022-2023 is calculated by multiplying the Percentage Increase O&M Per Drop by the Annual O&M Cost. *See id.*, column G, line 6. It is assumed that these outages are longer than scheduled or unpredictable outages, and cannot be scheduled to avoid a loss in total project generation.

6.4.3 Incremental Lost Revenue in the Event of Replacement or Overhaul

The revenue lost during outages for the overhaul or replacement of equipment is significant for the large generating units with a capacity exceeding 600 MW. Lost revenues are calculated based on the forecast market price averaged over the rate period, FY 2022-2023.

The Downtime Cost is calculated by multiplying the marginal value from the most recent outage for base availability by the months of down time, multiplied by the forecast market price forecast. *See* Power Market Price Study, BP-22-FS-BPA-04, § 2.4. The annual Cost per Drop for FY 2022-2023 is calculated by multiplying the Probability of Failure by the Down Time Cost. Documentation, BP-22-FS-BPA-06A, Table 6.1, column K, line 6.

6.5 Costs to be Allocated to Transmission Services

The factors described above are analyzed for their application on a single generating unit at the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall cost associated with each generation drop. From these analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units is calculated to be $331,778. *Id.*, column L, line 6.

Historically, large generating units at Grand Coulee have been dropped 26 times over the last 24 years (1996 through 2020). Therefore, the average of approximately 1.1 drops per year is used as the Generation Dropping estimate.

Multiplying the 1.1 drops per year by the cost of a single drop ($331,778), the forecast annual cost is $364,955. *Id.*, column D, line 7. This cost is assigned to Transmission Services for recovery in transmission rates. The rate period annual average cost for Generation Dropping is a revenue credit to the power rates. *See* Power Rates Study, BP-22-FS-BPA-01, § 9.3.

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7. REDISPATCH

7.1 Introduction

Under the Tariff and the Redispatch and Curtailment Business Practice, Transmission Services can initiate redispatch as part of congestion management efforts. Generally, redispatch results in actions that can effectively relieve a transmission constraint that may impair the reliability of BPA's transmission system and to maintain service to loads.

In the past, Attachment M of the Open Access Transmission Tarif (OATT) has laid out the situations in which Transmission Services can request redispatch from Power Services. In the TC-20 proceeding, Attachment M was removed from BPA's Tariff, and the procedure for Transmission Services to request redispatch from Power Services was moved to the Redispatch and Curtailment Business Practice.

The Business Practice provides three types of redispatch that Transmission Services can request from Power Services to relieve congestion: Discretionary Redispatch, Network Transmission (NT) Redispatch, and Emergency Redispatch. Power Services may provide redispatch through *incs* and *decs* of Federal generation, through purchases and/or sales of energy, or through transmission purchases. The purposes of each of these types of redispatch are discussed further below. The price of redispatch is calculated based on one of two sources, depending on how the redispatch is provided: (1) for redispatch provided from Federal generation, market prices for incrementing and decrementing Federal generation at the time the redispatch is provided; or (2) for redispatch provided by purchases and/or sales of energy or purchases of transmission, the actual cost to Power Services of purchasing and/or selling power or purchasing transmission.

This Study forecasts the cost of redispatch that will be transferred as revenue to Power Services from Transmission Services for the provision of redispatch during the FY 2022-2023 rate period. The forecast is based on actual redispatch costs from October 2016 to August 2020, the most recent periods for which BPA has actual data.

7.2 Discretionary Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services may request Discretionary Redispatch from Federal resources to *inc* and *dec* generation prior to curtailment of any transmission schedules.

Discretionary Redispatch totaled $15,551 in FY 2016, $8,136 in FY 2017, $15,133 in FY 2018, $16,033 in FY 2019, and $0 in FY 2020 (through August), averaging $11,157. Documentation, BP-22-FS-BPA-06A, Table 7.1, column B provides the actual annual Discretionary Redispatch details for October 2016 to August 2020. For FY 2022 and FY 2023, Transmission Services forecasts Discretionary Redispatch of $11,000 per year.

7.3 Network Integration Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services requests Network Integration (NT) Redispatch from Power Services to maintain firm NT schedules. NT Redispatch can be requested only after all non-firm Point-to-Point and secondary NT schedules are curtailed in a sequence consistent with NERC curtailment priority. Power Services must provide NT Redispatch when requested by Transmission Services to the extent that it can do so without violating non-power constraints.

NT Redispatch totaled $137,715 in FY 2016, $153,773 in FY 2017, $887,672 in FY 2018, $286,534 in FY 2019, and $252,485 in FY 2020 (through August), averaging $349,460. *Id.*, columns C-D. Of this total amount from 2016 through August 2020, only $19,581 was associated with Power Services providing NT Redispatch through the redispatch of Federal generation or through power purchases or sales over this time period. The rest ($1,698,598 over the same period) represents payments from Transmission Services to Power Services associated with NT Redispatch provided through transmission purchases only. Documentation, BP-22-FS-BPA-06A, Table 7.1 provides, for FY 2016 through FY 2020 (through August), the actual annual NT Redispatch cost.

The NT Redispatch forecast for FY 2022-2023 is $359,000 per year. This is an increase from previous years' forecasts and is based on the higher-than-forecast actuals from NT Redispatch over the period FY 2016 through FY 2020 (through August).

7.4 Emergency Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services may request Emergency Redispatch from Power Services in order to minimize the risk and/or scope of a transmission system reliability condition. Power Services must provide Emergency Redispatch when requested.

Emergency Redispatch for FY 2016 totaled $22,117, $0 in FY 2017, $0 in FY 2018, $0 in FY 2019 and $0 in FY 2020 (through August). Documentation, BP-22-FS-BPA-06A, Table 7.1, column E. The average from FY 2016 to FY 2020 (through August) was approximately $4,498. *Id.*

Because Emergency Redispatch is a rare event, Emergency Redispatch is forecast to be $0 for FY 2022-2023. *Id*.

7.5 Revenue Forecast for Redispatch Service

Based on the analysis above, total revenues of $370,000 per year is forecast for FY 2022-2023 for Redispatch services provided by Power Services to TS. *Id.*, line 13.

8. STATION SERVICE

8.1 Introduction

Station service refers to real power that Transmission Services takes directly off the BPA power system for use at substations and other locations, such as facilities located on BPA's Ross Complex and Big Eddy/Celilo Complex. For purposes of this Study, station service does not include power that BPA purchases from another utility or that is supplied by another utility for station service purposes. Because there are locations on the system where BPA does not have meters to measure station service use, the amount of energy use at BPA substations and other facilities is estimated. The annual average forecast market price from the Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use. This section describes the station service energy use and the procedure used to determine the costs that are allocated to Transmission Services for station service energy use.

8.2 Overview of Methodology

The station service costing methodology consists of the following steps: First, a historical monthly average station service energy use was determined based on measured load data for a sample of BPA's substations based on size (large, medium, and small). Second, an average load factor of 9.45 percent was derived based on the ratio of installed station service transformation and energy use for those substations. Third, that average load factor of 9.45 percent is then applied to the total amount of installed transformation, measured in kilovolt amperes (kVA), at all BPA substations served directly by the BPA power system to determine a total usage. Fourth, the station service energy use for all facilities other than the Ross and Big Eddy/Celilo complexes is estimated by applying the average load factor to the total installed station service transformer capacity. This energy use is then added to the historical use for the Ross and Big Eddy/Celilo complexes to estimate total average monthly energy use. The monthly amount is multiplied by 12 to yield an annual average estimated total energy use for all substations, which is then adjusted for transmission losses by applying the BPA network loss factor, 2.04 percent. The annual average forecast market price from the Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use.

8.3 Assessment of Installed Transformation

This methodology begins by identifying the amount of installed transformation for all BPA substations. Installed transformation transforms power to a lower voltage to supply power to the buildings and equipment at the substations. The total installed transformation is 47,699 kVA. Documentation, BP-22-FS-BPA-06A, Table 8.2, line 6. Of this amount, the total amount of installed transformation at BPA substations for which load data exists is 15,456 kVA. *Id.,* Table 8.1, line 41.

8.4 Assessment of Station Service Energy Use

The historical average monthly use for the Ross Complex is 1,749,300 kWh, and for Big Eddy/Celilo Complex is 1,822,937 kWh, for a total of 3,572,237 kWh. *Id.*, Table 8.2, lines 4-5.

The total historical average monthly use for other BPA locations for which load data exists is 1,066,446 kWh. *Id.,* Table 8.1, line 41. Because not all use is metered, the total average monthly use for BPA substations is estimated based on the historical average monthly use multiplied by the average load factor. *See id.*, Table 8.2, lines 1-3.

8.5 Calculation of Average Load Factor

The average monthly load factor is calculated by dividing the total historical monthly use for BPA substations for which load data is available by the total installed station service transformation for these BPA substations. This yields an average 9.45 percent load factor. *Id.,* Table 8.1, line 41.

8.6 Calculating the Total Station Service Average Use

The total installed transformation is multiplied by the average calculated load factor to yield the calculated historical average monthly use for all facilities other than the Ross and Big Eddy/Celilo complexes. *See id.,* Table 8.2, lines 1-3. The historical station service energy use for the Ross Complex and the Big Eddy/Celilo Complex is then added to the calculated amount of energy use at all other BPA substations. *Id.,* lines 4-5. The total quantity of station service average use that Power Services supplies directly to BPA substations and other facilities is then adjusted for transmission losses by multiplying the average use by the BPA Transmission Network loss factor of 2.04 percent pursuant to Schedule 11 of BPA's Tariff. The adjusted quantity of station service average use supplied to BPA substations and other facilities after adding in the network losses is estimated to be 82,361 MWh per year. *Id.*, line 6.

8.7 Determining Costs to Allocate to Station Service

The annual average forecast market price (*see* Power Market Price Study and Documentation, BP-22-FS-BPA-04, § 2.4) applied to the estimated annual quantity of station service energy use, including network losses, yields the energy costs per year to be allocated to Station Service. The capacity rate for Real Power Losses (*see* Power Rates Study, BP-22-FS-BPA-01, § 4.4.2) applied to the estimated quantity of network losses, yields the capacity costs associated with network losses. The sum of the energy costs and the capacity costs associated with Real Power Losses equals the total costs to allocate to station service. This rate period annual average cost is $2,295,181. Documentation, BP-22-FS-BPA-06A, Table 8.2, line 6.

8.8 Impact on Power Rates and Transmission Rates

The rate period annual average cost for station service is a revenue credit to the power rates. *See* Power Rates Study, BP-22-FS-BPA-01, § 9.3.

These costs are assigned to the Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Generation Integration transmission segments based on the allocation of seven-year average Operations and Maintenance segmentation. *See* Transmission Revenue Requirement Study, BP-22-FS-BPA-09, § 2.4.

9. ANCILLARY AND CONTROL AREA SERVICES

9.1 Introduction

To supply generation inputs, Power Services sets aside available generation capacity on the FCRPS for Transmission Services. Power Services assigns the costs of these generation inputs to TS. Accordingly, Transmission Services sets the rates for Ancillary and Control Area Services to recover the generation input costs assigned to it by Power Services.

This rate study does not discuss the Ancillary Service rates for (1) Scheduling, System Control and Dispatch or (2) Reactive Supply and Voltage Control from Generation Sources. BPA addresses those rates in the Transmission Rates Study, BP-22-FS-BPA-08.

9.2 Ancillary Services and Control Area Services

This section of the Generation Inputs Study and the associated Documentation support the Ancillary Services and Control Area Services rate schedule (ACS-22 Rate Schedule) in the 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02.

The calculations for the Ancillary and Control Area Service rates are shown in the Transmission Rates Study and Documentation, BP-22-FS-BPA-08, in Table 10.4. Table 1 in the Documentation contains the forecast of generation inputs revenues. Documentation, BP-22-FS-BPA-06A, Table 1.

9.2.1 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the BAAs affected by the transmission service. As a Transmission Provider, BPA is required to provide, and transmission customers are required to purchase:

(1) Scheduling, System Control and Dispatch Service, and

(2) Reactive Supply and Voltage Control from Generation Sources Service.

As noted above, these Ancillary Services are discussed in the Transmission Rates Study and Documentation, BP-22-FS-BPA-08.

In addition, consistent with current NERC standards, BPA is required to offer to provide the following Ancillary Services to transmission customers serving load within the BPA BAA:

(3) Regulation and Frequency Response Service; and

(4) Energy Imbalance (EI) Service.

BPA is also required to offer, consistent with applicable NERC standards, the following Ancillary Services to transmission customers serving load or integrating generation within the BPA BAA:

(5) Operating Reserve – Spinning Service (Spinning Reserve Service); and

(6) Operating Reserve – Supplemental Service (Supplemental Reserve Service).

The transmission customer serving load or integrating generation in the BPA BAA is required to acquire these last four Ancillary Services listed above (numbers 3-6) from BPA, from a third party, or by self-supply.

9.2.2 Control Area Services

Control Area Service rates apply to transactions in the BPA BAA for which the reliability obligations have not been met through Ancillary Services or some other arrangement. The six Control Area Services are:

(1) Regulation and Frequency Response Service;
(2) Generation Imbalance (GI) Service;
(3) Operating Reserve – Spinning Reserve Service;
(4) Operating Reserve – Supplemental Reserve Service;
(5) Variable Energy Resource Balancing Service (VERBS); and
(6) Dispatchable Energy Resource Balancing Service (DERBS).

Entities with resources or loads in the BPA BAA must purchase Control Area Services from BPA to the extent those resources or loads do not otherwise satisfy the reliability obligations that their energy transactions impose on the BPA BAA.

9.2.3 Ancillary Services and Control Area Services Rate Schedule

The ACS-22 Rate Schedule includes rates for six Ancillary Services and six Control Area Services. All rates in the ACS-22 Rate Schedule are subject to the Rate Adjustment Due to FERC Order under Federal Power Act Section 212. *See* 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, GRSP II.C.

9.3 Regulation and Frequency Response Service Rate

Regulation and Frequency Response (RFR) service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining systemwide frequency at 60 cycles per second (60 hertz (Hz)). RFR service is accomplished by committing online generation whose output is raised (*inc*) or lowered (*dec*) (through the use of AGC equipment) as necessary to follow the within-hour changes in load. RFR is composed of two balancing reserve capacity components: regulating (moment-to-moment variability), and non-regulating (longer-duration within-hour variability, including differences between the scheduled and average load). NERC reliability standards require BPA to maintain sufficient within-hour reserve to cover the requirements of all load in the BPA BAA. Pursuant to Schedule 3 of the Tariff, BPA must offer this service when the transmission service is used to serve load within the BPA BAA. The transmission customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its RFR obligation. Customers may be able to satisfy the RFR obligation by providing generation to BPA with AGC capabilities.

There is no functional or cost difference between RFR offered as a Ancillary Service or a Control Area Service. The difference is that the Control Area Service is offered to customers serving load in the BPA BAA other than through the BPA Tariff.

RFR service provides capacity for meeting the balancing requirements of BPA's BAA, and the RFR rate recovers the costs through a charge applied to the customer's load in the BPA BAA.

9.3.1 RFR Sales Forecast

BPA forecasts RFR sales from the point-of-delivery load forecast for transmission customers serving load in the BPA BAA. The load forecast for RFR is the average energy served for each month of the rate period. The forecast of annual average load for RFR in the BPA BAA for the FY 2022-2023 rate period is 6,066 aMW. Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, line 30.

9.3.2 Non-EIM and EIM RFR Rate Calculation

The generation inputs cost for Power Services to provide RFR is $24.201 million, as shown in Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, line 33. This total cost also includes $122,000 of costs shifted from the DERBS rates as a result of the BP-22 Settlement, which limited the DERBS rate increase (see Section 9.6.1 for further details). All transmission customers serving load in the BPA BAA are charged for RFR service based on the customer's load in the BAA on an hour-by-hour basis. Dividing the generation inputs costs for regulation by the average load results in an Non-EIM RFR rate of 0.46 mills per kilowatthour (kWh). Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, line 34.

As described in Section 4.3.5, if BPA joins the EIM, a discount will be applied to balancing services. Dividing the generation inputs costs for regulation by the average load, Table 10.4, lines 83 and 80, results in an EIM RFR rate of 0.43 mills per kWh, *id.*, line 84. The RFR EIM discount rate includes $116,000 of costs shifted from the DERBS rates as a result of the BP-22 Settlement. *Id.*, line 81.

9.4 Operating Reserve Service Rates

All transmission customers with an Operating Reserve obligation must purchase or provide Operating Reserve. Pursuant to Schedules 5 and 6 of the Tariff, BPA must offer both Spinning and Non-Spinning (*e.g.*, Supplemental) Reserve in accordance with applicable NERC and NWPP standards. The transmission customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Operating Reserve obligation. Under BPA's Operating Reserve business practice, customers may elect to self-supply or acquire Operating Reserve service from a third party. For the FY 2022-2023 rate period, the customer's election to acquire Operating Reserve from a third party had to occur no later than May 1, 2021. Customers that elect to self-supply or third-party supply their Operating Reserve obligation but default on their obligation will pay a higher rate. *See* § 9.4.3. The Operating Reserve Requirement is based on NERC Reliability Standard BAL-002-WECC-2a, and is the sum of 3 percent of load and 3 percent of the generation located in the BPA BAA used to serve the transmission customer's firm load. The Operating Reserve requirement is split equally between Spinning and Non-Spinning.

9.4.1 Spinning Reserve Service

Spinning Reserve is provided by unloaded generating capacity that is synchronized to the power system and ready to serve additional demand. These resources must be able to respond immediately to serve load in the event of a system contingency. Spinning Reserve service is provided by generating units that are online and loaded at less than maximum output.

There is no functional or cost difference between Spinning Reserve service offered as a Control Area Service or Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by generators in the BPA BAA that may not have a transmission service agreement with BPA, but have energy transactions that impose a spinning reserve obligation on the BPA BAA.

The Spinning Reserve Service rate includes two rate components. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, ACS-22, §§ II.E, III.C. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Spinning Reserve Requirement. *See* § 3 above. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The customer purchases the energy at the market index price that was effective when the contingency occurred. The applicable market index is posted in the BPA Business Practices and is subject to change with 30-days notice. If BPA joins the EIM, Extended Locational Marginal Pricing (ELMP) will be used to price the energy delivered.

9.4.2 Supplemental Reserve Service

Supplemental Reserve Service is generating capacity that is not synchronized to the system but is capable of serving demand within 10 minutes, or interruptible load that can be removed from the system within 10 minutes. These reserves must be capable of fully synchronizing to the system and ramping to meet load within 10 minutes of a contingency.

There is no functional or cost difference between Supplemental Reserve service offered as a Control Area Service or an Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by generators (in the BPA BAA) that may not have a transmission service agreement with BPA but have energy transactions that impose a supplemental reserve obligation on the BPA BAA.

The Supplemental Reserve Service rate includes two rate components. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, ACS-22, § II.F, III.D. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Supplemental Reserve Requirement. *See* § 3 above. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The customer purchases the energy at the hourly market index price that was effective when the contingency occurred. The applicable market index is posted in the BPA Business Practices and is subject to change with 30-days notice. If BPA joins the EIM, the ELMP will be used to price the energy delivered.

9.4.3 Operating Reserve Rate Calculation

The cost allocation methodology and quantity forecast of Operating Reserve for the FY 2022-2023 period are described in Section 4 above. The annual revenue requirement for Operating Reserve-Spinning is $22.92 million. Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, line 22. The Operating Reserve–Spinning rate of 11.05 mills per kWh is calculated by dividing the Operating Reserve–Spinning revenue requirement by the billing factor. *Id.,* line 24. The annual average billing factor forecast is 236.72 MW for the spinning requirement. *Id.,* line 22. Customers that self-supply or third-party supply Operating Reserve-Spinning but default on their self-supply or third-party supply obligations will pay a default rate of 12.71 mills per kWh. *Id*., line 25. The default rate is calculated by including a 15 percent adder to the normal rate.

The annual revenue requirement for Operating Reserve-Supplemental is $14.97 million. *Id.,* line 23. The Operating Reserve-Supplemental rate of 7.22 mills per kWh is calculated by dividing the Operating Reserve-Supplemental revenue requirement by the billing factor. *Id.,* line 26. The annual average billing factor forecast is 236.72 MW for the Supplemental requirement. *Id.,* line 23. Customers that self-supply or third-party supply Operating Reserve-Supplemental but default on their self-supply or third-party supply obligations will pay a default rate of 8.30 mills per kWh. *Id.,* line 27. The default rate is calculated by including a 15 percent adder to the normal rate.

9.5 Variable Energy Resource Balancing Service (VERBS)

BPA provides VERBS as a Control Area Service to wind and solar generators in the BPA BAA. This service is necessary to support the differences between actual generation from wind and solar generation and their generation estimate *(e.g.,* schedule). BPA is required to offer to provide this service pursuant to Schedule 10 of the Tariff.

VERBS provides the capacity necessary to provide GI service pursuant to Schedule 9 of the Tariff, and Schedule 9E if BPA joins the EIM, as well as to provide regulation and frequency response for generation. These services are provided by raising or lowering the output of committed online generation (through the use of AGC equipment) as necessary to follow the moment-by-moment changes in wind and solar generation, including differences between the scheduled and average generation across the hour. The obligation to maintain the balance between resources (including wind and solar generation) and load lies with Transmission Services. The variable energy resource owner/operator must either purchase this service from Transmission Services or make alternative comparable arrangements to satisfy its VERBS obligation.

The VERBS rates in Section III.E.2.a and III.E.2.b of the ACS-22 Rate Schedule are capacity charges to be applied to the greater of the maximum one-hour generation or installed capacity of a wind or solar generating resource in the BPA BAA. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02. These rates recover the cost of balancing reserve capacity provided by the FCRPS. Like RFR, VERBS is composed of two balancing reserve capacity components: regulating (moment-to-moment variability) and non-regulating (longer-duration within-hour variability, which accounts for within-hour variability due to differences between the scheduled amount and average generation). The VERBS rates for wind and solar resources for each of these two balancing reserve capacity components are listed separately in the rate schedule to allow for formulation of rates for new technology pilot participants under Section III.G of the ACS-22 rate schedule. *See id.*

9.5.1 Non-EIM and EIM VERBS Rate Calculation for Wind Generators

The Power Service revenue requirement for VERBS-Wind is $12.4 million for regulating reserves, $14.8 million for non-regulating reserves, and $105,000 of costs shifted from DERBS as a result of the BP-22 Settlement, for a total of $27.3 million. Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, lines 45-47. The Non-EIM VERBS-Wind rate is determined by the total VERBS-Wind revenue requirement divided by the rate period average of installed wind capacity for BP-22 of 2175 MW, resulting in a rate of $1.047 per KW per month. *Id.*, line 48.

As described in Section 4.3.5, if BPA joins the EIM, a discount will be applied to balancing services. The EIM VERBS-Wind rate is determined by the total VERBS-Wind revenue requirement, which includes $100,000 in costs shifted from DERBS as a result of the BP-22 Settlement, *id.*, line 96, divided by the rate period average of installed wind capacity for BP-22 of 2,175 MW, resulting in a rate of $0.981 per KW per month. *Id.*, line 98.

9.5.2 Non-EIM and EIM VERBS for Solar Resources Calculation

The Power Service revenue requirement for Non-EIM VERBS-Solar is $0.35 million for regulating reserves, $0.23 million for non-regulating reserves, and $3,000 of costs shifted from DERBS as a result of the BP-22 settlement, for a total of $0.585 million. *Id.*, lines 51-53. The rate is determined by the total Non-EIM VERBS-Solar revenue requirement divided by the rate period average of installed solar capacity for BP-22 of 169 MW, resulting in a rate of $0.289 per KW per month. *Id.*, line 54.

As described in Section 4.3.5, if BPA joins the EIM, a discount will be applied to balancing services. The rate is determined by the total EIM VERBS-Solar revenue requirement, which contains $3,000 in costs shifted from DERBS as a result of the BP-22 Settlement, *id.*, line 102, divided by the rate period average of installed solar capacity for BP-22 of 169 MW, resulting in a rate of $0.275 per KW per month. *Id.*, line 104.

9.5.3 Direct Assignment Charge

The Direct Assignment Charge will recover the cost of BPA purchases of capacity during the rate period to provide VERBS to a specific customer. Customers who require incremental balancing reserve capacity purchases that are necessary to provide VERBS will be billed for all costs incurred above $0.168 per kW-day for any incremental balancing reserve capacity acquisitions, and the applicable VERBS rate. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, ACS-22, § III.E.3. The Direct Assignment Charge could trigger under three scenarios: (1) the customer elected to self-supply but is unable to continue self-supplying one or more components; (2) the customer has a projected generator interconnection date after FY 2023 but chooses to interconnect during the FY 2022-2023 rate period; or (3) the customer elected to dynamically transfer its resources out of the BPA BAA, but the resource remains in the BPA BAA after the date specified in the customer election.

9.6 Non-EIM and EIM Dispatchable Energy Resource Balancing Service (DERBS)

Pursuant to Schedule 10 of the Tariff, BPA must offer DERBS to all non-Federal dispatchable energy thermal resources in the BPA BAA. This Control Area Service provides the capacity necessary to provide GI service pursuant to Schedule 9 of the Tariff, and Schedule 9E if BPA joins the EIM, as well as to provide regulation and frequency response for generation. The dispatchable energy thermal resource must either purchase this service from BPA or make alternative comparable arrangements to satisfy its DERBS obligation. This balancing service for thermal generators is comparable to VERBS for wind and solar generators.

The capacity provided for DERBS is used to increase or decrease committed online FCRPS generation (through the use of AGC equipment) as necessary to follow the moment-by-moment changes in thermal generation relative to the schedule, including ramps between hours.

The DERBS rate in Section III.F of the ACS-22 Rate Schedule includes charges to be applied to the thermal generator's calculated monthly use of balancing reserve capacity. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02. For any hours that an imbalance is determined to be subject to a Persistent Deviation Penalty Charge, the customer is subject to a different and larger charge. *See* § 9.7.3 below.

9.6.1 Rate Calculation

The following values used to calculate Non-EIM DERBS rates have been adjusted per the

BP-22 Settlement. The Settlement limited the DERBS rate increase to 50 percent of the calculated impact in the Final Proposal compared to BP-20.

Hourly rates are calculated for use of *inc* and *dec* balancing reserve capacity. The forecast *inc* reserve capacity requirement is 10.9 MW, and the forecast *dec* reserve requirement is 11.6 MW. Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, lines 10-11. The forecast annual revenue requirement for Power Services to provide *inc* capacity for Non-EIM DERBS is $1.025 million and to provide *dec* capacity is $0.051 million, as shown in *id.*, lines 37 and 39. The BP-22 Settlement DERBS cost limitation reduced the cost of DERBS *inc* and *dec* capacity by roughly $220,000 and $11,000 respectively. *Id.*, lines 38, 40. This adjustment results in a final Non-EIM DERBS *inc* capacity cost of $805,000 and a *dec* capacity cost of $40,000.

As described in Section 4.3.5, if BPA joins the EIM, a discount will be applied to balancing services. The forecast annual revenue requirement for Power Services to provide *inc* capacity for EIM DERBS is $1.001 million and to provide *dec* capacity is $0.051 million, as shown in *id.*, lines 87 and 89. The DERBS cost limitation from the BP-22 Settlement was also applied. This reduced the cost of EIM DERBS *inc* and *dec* capacity by roughly $208,000 and $11,000, respectively. *Id.*, lines 88, 90. This adjustment results in a final EIM DERBS *inc* capacity cost of $793,000 and a *dec* capacity cost of $41,000, when rounded.

A non-Federal dispatchable energy thermal resource in the BPA BAA is charged for DERBS based on its hourly use of balancing reserve capacity in the BPA BAA, unless the non-Federal dispatchable energy thermal resource is able to self-supply or acquire third-party supply of balancing reserve capacity.

The DERBS billing factor uses the Station Control Error, which is the difference between the generation estimate and actual generator output. The generation estimate is the sum of the e-tags for each hour for generators that have e-tags for their scheduled output or the submitted hourly generation estimate in Customer Data Exchange (CDE) for customer's who do not schedule the output of their resource. Ramp periods between hours during which the generation estimate changes from the previous hour are calculated from 10 minutes before the start of the hour to 10 minutes after the start of the hour. Deviations from the calculated ramp represent Station Control Error during the ramp. For the DERBS *inc* billing factor, the five-minute maximum *inc* value each hour is summed across all hours of the month. Likewise, the DERBS *dec* billing factor uses the five-minute maxium *dec* value each hour summed over the month. The *inc* billing factor is calculated from the hourly maximum use of *inc* balancing reserve capacity that exceeds 3 MW as measured on a five-minute average basis for station control error. The *dec* billing factor is calculated similarly. The *inc* and *dec* charge each month is calculated for each individual generating facility as the respective *inc* and *dec* rate multiplied by the billing factor computed for the month.

It is not anticipated that any dispatchable energy resources will self-supply or acquire third-party supply of balancing reserves during the rate period. The forecast use of DERBS is based on a historical database of five-minute Station Control Error for each resource for the period October 2016 through July 2020. The data was adjusted to omit individual generators that are no longer or not anticipated to be in the BPA BAA during the FY 2022-2023 rate period.

A 3-MW dead band was applied to each generator's hourly station control error, and then the remaining *inc* and *dec* station control error was totaled across all generators. The forecast annual use is estimated from October 2016 through July 2020 actual DERBS usage, with adjustments to recognize that a number of generators were offline for extended periods. Such extended periods of offline generation are not anticipated to occur regularly in the rate period. This forecast is 3,102 MW of hourly deviation annually for *inc*, and 2,729 MW of hourly deviation annually for *dec*. Transmission Rates Study and Documentation, BP-22-FS-BPA-08, Table 10.4, lines 37, 39. These amounts are also applied to EIM DERBS.

Based on the forecast use of *inc* and *dec* balancing reserve capacity, the Non-EIM DERBS hourly *inc* rate is 21.629 mills per kW for use of *inc* balancing reserve capacity that exceeds 3 MW, measured as the hourly maximum of five-minute average data. *Id.,* line 41. The Non-EIM DERBS hourly *dec* rate is similarly calculated and is 1.230 mills per kW for use of *dec* balancing reserve capacity that exceeds 3 MW, measured as the hourly maximum of five-minute average data. *Id.,* line 42. EIM DERBS *inc* and *dec* rates are reflected in *id.*, line 91 and 92 respectivly. These rates are calculated in the same manner as described above and result in an *inc* rate of $21.303 and a *dec* rate of $1.240 mills per kW.

9.6.2 Direct Assignment Charges

Direct Assignment Charges will recover the cost of BPA purchases of capacity during the rate period to provide DERBS to specific customers. Customers who require incremental balancing reserve capacity purchases that are necessary to provide DERBS will be billed for all costs incurred above $0.168 per kW-day for any incremental balancing reserve capacity acquisitions, and the DERBS rate. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, § III.F.4.

The Direct Assignment Charge is triggered when a DERBS customer: (1) elects to self-supply but is unable to continue self-supplying DERBS; (2) was operating in another BAA, fails to elect to take DERBS service during the FY 2022-2023 rate period, and dynamically transfers into the BPA BAA during the FY 2022-2023 rate period; (3) has a projected generator interconnection date after FY 2023, but chooses to interconnect during the FY 2022-2023 rate period; or (4) elected to dynamically transfer its resource out of BPA's BAA but remains in the BPA BAA after the date specified in the customer election.

9.7 Energy Imbalance and Generation Imbalance Service

All debits or credits that Transmission Services calculates for imbalance rates are passed on to the provider of the energy dispatched for a given hour. Because the net amount on average is typically small, BPA does not forecast any revenue or cost associated with these services. BPA will post the average cost of energy dispatched for imbalance services, which will be applied when energy is taken or provided. The rates for GI Service and Energy Imbalance (EI) Service are energy charges, not capacity charges. BPA provides EI Service and GI Service under Schedules 4 and 9 of the Tariff, respectively. If BPA joins the EIM, EI Service and GI Service will be provided under Schedules 4E and 9E of the Tariff, respectively, when BPA is operating in the EIM.

9.7.1 Energy Imbalance Service

EI Service is provided for transmission within and into the BPA BAA to serve load in the BAA. All transmission customers serving load in the BPA BAA are subject to charges for EI unless they are BPA power customers receiving a service that provides demand and shaping to cover load variations. BPA provides the EI Service pursuant to Schedule 4 of the Tariff.

EI is the deviation, or difference, between actual load and scheduled load. A deviation is positive when the actual load is greater than the scheduled load, and a negative deviation is the reverse. The EI rate in Section II.D of the ACS-22 Rate Schedule establishes three imbalance deviation bands. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-FS-A-02-AP02. Band 1 applies to the portion of the deviation less than the greater of $\pm$ 1.5 percent of the schedule or $\pm$ 2 MW. If a deviation between a customer's load and schedule stays within imbalance deviation Band 1, the customer may return the energy at a later time. The customer must arrange for and schedule the balancing transactions. BPA uses deviation accounts to sum the positive and negative deviations from schedule over HLH and LLH periods. At the end of the month, any balance remaining in the accounts must be settled at BPA's average incremental cost for HLH and LLH periods.

BPA's incremental cost will be based on an hourly average cost of energy deployed by BPA for imbalances. Energy deployed from Federal resources will be priced at the posted energy index, and energy deployed from non-Federal resources will be priced at their deployment costs.

Deviation Band 2 applies to the portion of the deviation greater than Band 1 but less than $\pm$ 7.5 percent of the schedule or $\pm$ 10 MW. For each hour the energy taken is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost. For each hour the energy taken is less than schedule, the credit is 90 percent of BPA's incremental cost.

Finally, Deviation Band 3 is for the portion of the deviation greater than Band 2. For each hour the energy taken is greater than the energy scheduled, the charge is 125 percent of

BPA's highest incremental cost that occurs during that day determined separately for HLH and LLH. For each hour the energy taken is less than schedule, the credit is 75 percent of BPA's lowest incremental cost for any hour that occurs during that day, determined separately for HLH and LLH.

For any day that the Federal system is in a spill condition, no credit is given for negative deviations for any hour of that day. If the energy index is negative in any hour that the Federal system is in a spill condition, no credit will be given for negative deviations within Band 1, and the charge will be the energy index for that hour for negative deviations within Bands 2 and 3. For any hours that an imbalance is determined to be subject to a Persistent Deviation penalty charge, the customer is subject to a different and larger charge. *See* § 9.7.3.

9.7.2 Generation Imbalance Service

GI Service provides or absorbs energy to meet the difference between scheduled *(e.g.,* generation estimate) and actual generation delivered in the BPA BAA. All generators in the BPA BAA are subject to charges for GI Service if Transmission Services provides such service under an interconnection agreement or other arrangement. BPA provides this service under Schedule 9 of the Tariff.

The GI Service rate in Section III.B of the ACS-22 Rate Schedule establishes three imbalance deviation bands. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02. Band 1 applies to the portion of the deviation less than the greater of ± 1.5 percent of the schedule or ± 2 MW. If the difference between a generator's schedule and its delivery stays within Band 1, the customer may return energy at a later time. The customer will arrange for and schedule the balancing transactions. BPA uses deviation accounts to sum the positive and negative deviations over HLH and LLH periods. At the end of each month, any balance remaining in the accounts must be settled at BPA's average incremental cost for HLH and LLH periods.

BPA's incremental cost will be based on an hourly average cost of energy deployed by BPA for imbalances. Energy deployed from Federal resources will be priced at the posted energy index, and energy deployed from non-Federal resources will be priced at their deployment costs.

Deviation Band 2 applies to the portion of the deviation greater than Band 1 but less than the greater of ± 7.5 percent of the schedule or ± 10 MW. For each hour the generation energy delivered is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost. For each hour the generation energy delivered is greater than the energy scheduled, the credit is 90 percent of BPA's incremental cost.

Deviation Band 3 is for the portion of the deviation greater than Band 2. For each hour the generation energy delivered is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day, determined separately for HLH and LLH. For each hour the generation energy delivered is greater than the energy scheduled, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day, determined separately for HLH and LLH.

Deviation Band 3 will not apply to wind and solar resources and new generation resources undergoing testing before commercial operation for up to 90 days. Instead, all deviations

greater than Band 1 will be charged at the Band 2 rate unless specifically exempted. BPA will exempt solar resources from Band 3 due to the expected difficulty in forecasting the output of solar generation during changing cloud cover within an hour.
No credit is given for generation energy delivered during a scheduling period that is greater than the sum of remaining schedules when the generator has schedules curtailed for that period.

For any day that the Federal system is in a spill condition, no credit is given for negative deviations for any hour of that day. If the energy index is negative in any hour that the Federal system is in spill condition, no credit will be given for negative deviations within Band 1, and the charge will be the energy index for that hour for negative deviations within Bands 2 and 3.

9.7.3 Persistent Deviation

Persistent Deviation refers to a difference between scheduled and actual generation, or between scheduled and actual load, that continues in the same direction longer than a certain period of time (*e.g.,* four hours) and greater than a certain megawatt amount (*e.g.,* 20 MW). Persistent Deviation applies to both load (EI) and DERBS.

Persistent Deviation will apply both outside the EIM and if BPA joins the EIM. If BPA joins the EIM, the Persistent Deviation rate will be based on the higher of the applicable LMP at the nearest point of interconnection for DERBS customers, or the LAP for EI customers, or 100 mills per kWh. This rate will apply in lieu of any GI or EI charges. Because EIM Participating Resources will not settle GI directly with BPA, different rates will apply to EIM

Participating Resources to make Persistent Deviation charges equivalent to the charges for Non-Participating Resources.

9.7.4 Intentional Deviation

"Intentional Deviation" is defined in Section II of the Transmission General Rate Schedule Provisions. 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-22-A-02-AP02, GRSP II.L. In general, Intentional Deviation refers to a difference between a VER schedule and the BPA-provided schedule value. When a resource sets their schedule to the BPA-provided schedule value the Intentional Deviation Penalty does not apply. If a resource schedules to a value other than the BPA-provided schedule value, then the Intentional Deviation Penalty would apply if their imbalance is greater than what would have otherwise occurred had they used the BPA value. The Intentional Deviation rate is $100 MWh and applies both outside the EIM and if BPA joins the EIM.