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-14 Initial Rate Proposal

Generation Inputs Study

November 2012

BP-14-E-BPA-05

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COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement

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

1. INTRODUCTION

The Federal Columbia River Power System (FCRPS) hydroelectric projects support BPA's transmission system and are instrumental in maintaining its reliability. In the context of this Generation Inputs Study (Study), FCRPS is used to refer to only generation assets. For rate setting purposes, these uses of the FCRPS are quantified and the costs associated with these uses are allocated to transmission rates under the rate setting principle of cost causation. The uses of the FCRPS to support the transmission system and maintain reliability are generally referred to as generation inputs.

1.1 Purpose of Study

The Study explains the various cost allocations for generation inputs, forecasts 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 rate setting as revenue credits in the Power Rates Study, BP-14-E-BPA-01, section 4. Generation inputs include energy and balancing reserve capacity from the FCRPS that BPA uses to provide Ancillary and Control Area Services and to maintain the reliability of the transmission system. The Ancillary and Control Area Services rates that are described in the Study are shown in the Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10.

1.2 Summary of Study

BPA provides balancing reserve capacity generation inputs for Regulating Reserve, Following Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve, and Dispatchable

Energy Resource Balancing Service (DERBS) Reserve. The methodology for deriving the forecast amount of balancing reserve capacity needed to provide these services is described in section 2 of the Study. The cost allocation methodology for these services is described in section 3 of the Study. Section 4 of the Study addresses Operating Reserve (Contingency Reserve) and details the methodology for determining the forecast need and cost allocation for the Operating Reserve services. Other generation inputs, including Synchronous Condensing, Generation Dropping, Redispatch Service, and Station Service, are discussed in sections 5, 6, 7 and 9. Segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation Integrated Network and Delivery Facilities costs are discussed in section 8. Section 10 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 of the Study. Study Table 1 shows the annual average revenue forecast for each generation input for the rate period, including separate lines for embedded cost, variable cost, and where applicable, direct assignment cost revenues. For most of the generation inputs Study Table 1 provides the applicable quantities. Also, Study Table 1 shows an embedded unit cost for Regulating Reserve, VERBS Reserve, DERBS Reserve, and Operating Reserve. These unit costs are used to determine the forecast annual average revenue and should not be confused with the Ancillary and Control Area Services rates for these services. The calculation and assumptions for each line in Study Table 1 are explained in detail in the applicable sections of the Study. The Ancillary and Control Area Services rates are shown in Study Table 4.

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 amount of balancing reserve capacity needed for BPA to provide certain Ancillary and Control Area Services during the rate period. The forecast described in this section focuses on the balancing reserve capacity needed to provide regulating reserves, following reserves, and imbalance reserves, collectively called balancing services. The quantity of balancing reserve capacity that is forecast for each service is an essential input for the cost allocation methodology used to establish the rates for these services and the revenue credit associated with providing the balancing reserve capacity. *See* sections 3 and 10.

2.1.2 Overview

As a balancing authority, BPA must maintain load-resource balance in its balancing authority area at all times. All generators within the BPA balancing authority area provide hourly generation schedules to BPA that estimate the average amount of energy they expect to generate in the coming hour. Based on these schedules, BPA estimates the average amount of load to be served in the BPA balancing authority area in the coming hour.

Transmission customers submit hourly transmission schedules, identifying all energy to be transmitted across or within the BPA balancing authority area in the coming hour. BPA uses the transmission schedules to match generation inside the BPA balancing authority area and imports of energy from other balancing authority areas with loads served inside the BPA balancing

authority area and exports to other balancing authority areas. The transmission schedules identified with each adjacent balancing authority area are netted to determine interchange schedules. The interchange schedules are netted for the BPA balancing authority area to determine controller totals.

Controller totals are the sum of all energy transactions to and from the BPA balancing authority area. Controller totals are used in the BPA Automatic Generation Control (AGC) system to calculate the deviation between the actual interchange flows and the controller totals plus dynamic schedules that affect the controller total amount. The AGC system regulates the output of some specified Federal Columbia River Power System (FCRPS) generators in the BPA balancing authority area in response to changes in load, system frequency, and other factors to maintain the scheduled system frequency and interchanges with other balancing authority areas. The interchange schedules and controller totals do not change when a generator deviates from its scheduled generation or a load deviates from the average hourly estimate. The balancing authority area uses generation resources, assigned for balancing service and connected to the AGC system, to offset differences between scheduled and actual generation and to maintain within-hour load-resource balance in the balancing authority area.

BPA's AGC system adjusts the generation of projects on automatic control based on the differences between scheduled and actual load and generation. If load increases or generation decreases, the AGC system increases (*incs*) output of balancing resources. If load decreases or generation increases, the AGC system decreases (*decs*) output of balancing resources. The cumulative *inc* and *dec* generation required to maintain load-resource balance within the hour forms the basis for the balancing reserve capacity that BPA must have to provide balancing services.

Specific generating resources under AGC control are designated by BPA to provide the generation inputs necessary to supply balancing services. Utilizing the FCRPS resources to provide generation inputs for balancing services affects the hydraulic operation of those projects and limits the availability of water for other uses. The FCRPS will use water to generate additional power to replace generation from a resource within the balancing authority area that generates below its schedule or to serve a load that takes more energy than its schedule. Conversely, BPA will store water and/or withhold capacity (both hydraulic capacity in the form of reservoir space and turbine capacity) from other uses to adjust for a resource in the balancing authority area that generates above its schedule or a load that performs below its schedule. As the FCRPS generating resources reach the limit of their ability to provide *inc* and *dec* within-hour balancing reserves, third-party reserves may be needed to fulfill any deficit from the balancing reserve forecast. Third-party providers of reserves will operate in a similar manner to the FCRPS by using more or less fuel (and therefore more or less turbine capacity) or by adjusting variable loads to consume less or more power.

BPA's balancing reserve capacity requirement consists of three components: regulating reserve, following reserve, and imbalance reserve. Regulating reserve refers to the capacity necessary to provide for the continuous balancing of resources (generation and interchange) with load on a moment-to-moment basis.

Following reserve generally refers to spinning and non-spinning capacity to meet within-hour shifts of average energy due to variations of actual load and generation from forecast load and generation. The Balancing Reserve Capacity Quantity Forecast estimates the balancing reserve capacity needed to follow these average energy shifts according to a ten-minute clock cycle.

The imbalance reserve component refers to the impact on the following reserve amount due to the difference (*i.e.*, imbalance) between the average scheduled energy over the hour and the average actual energy over the hour. Taking imbalance into account when calculating the following reserve increases the following reserve amount due to the impact associated with assuming the error from imperfect scheduling prior to the hour. Imbalance does not affect the requirements for the regulating reserve component. The Balancing Reserve Capacity Quantity Forecast estimates the incremental amount of following reserve that must be set aside for imbalance and defines this amount as the imbalance reserve capacity component of the balancing reserve capacity requirements.

The Balancing Reserve Capacity Quantity Forecast methodology is based primarily on (1) a forecast of wind, solar, hydroelectric, and thermal projects expected to come online during the FY 2014–2015 rate period; (2) potential wind generation data (calculated from meteorological data by the wind generator owners) from October 1, 2009, to September 30, 2011; and (3) data from the 48-month period from October 1, 2007, to September 30, 2011. The data from the 48-month period needed for the forecast include the total wind generation, the total solar generation, the total hydroelectric generation, the total hydroelectric schedule, the total Federal thermal generation, the total Federal thermal schedule, the total non-Federal thermal generation, the total non-Federal thermal schedule, the balancing authority area load, and the balancing authority area load forecast for the period. Sections 2.2 through 2.6 describe in detail how the forecast methodology data were obtained or developed.

2.2 Existing and Future Generation Projects for the Rate Period

Developing the Balancing Reserve Capacity Quantity Forecast required to provide balancing services during the rate period requires an estimate of the amount of generation that will be

online during that 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 expected to come online before or during the FY 2014–2015 rate period. Generation Inputs Study Documentation, BP-14-E-BPA-05A (Documentation) Tables 2.1, 2.2, and 2.3.

The forecast of projects that are expected to come online before or during the FY 2014–2015 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 the application of certain criteria. References to "future" or "planned" projects throughout this Study indicate expectations with respect to the interconnection of certain generating projects 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 considers the status of interconnection requests in BPA's interconnection queue in June 2012. For the evaluation of the interconnection queue, 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 LGIP 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 the 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 in the near term and thus are more likely to be part of future rate periods.
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 in the FY 2014–2015 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 (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 Table 2.1 identifies the amount of installed capacity that the Study assumes will be online during the FY 2014–2015 rate period for each type of generation accounted for in the Balancing Reserve Capacity Quantity Forecast. The forecast of installed wind capacity is an average of 4,871 MW; installed solar capacity is an average of 15 MW; non-AGC controlled hydroelectric capacity is an average of 2,527 MW; non-Federal thermal capacity is an average of 5,192 MW; and Federal thermal capacity is 1,276 MW.

2.3 "Scaling in" Future Wind Generation

2.3.1 Methodology for Determining Correlations and Lead and Lag Times

Forecasting the balancing requirements for future wind generation during the rate period requires estimating future minute-by-minute generation levels of all existing and future wind projects in the BPA balancing authority area. For data on generation of the existing wind projects, 48 months of one-minute actual average generation data from BPA's Plant Information (PI) system are used. The data cover generation from all existing wind generators in the BPA balancing authority area for the period from October 1, 2007, to September 30, 2011. For wind projects that came online between October 1, 2007, and September 30, 2011, 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, 2011, only estimated minute-by-minute generation levels are used.

Beginning on October 1, 2009, several initiatives, such as Dispatcher Standing Order 216 (DSO 216), the Customer-Supplied Generation Imbalance pilot (CSGI) and the oversupply protocols, were implemented to assist BPA in managing the balancing reserves for the balancing authority area. These initiatives can require a wind operator to decrease the output of its project below the optimized wind profile. Many wind project operators calculate and retain a record of the potential generation output of their wind projects, which represents how the project could have performed if these initiatives were not in place. Although the accuracy of this value might vary based on a number of factors, for purposes of representing expected generation output during periods when DSO 216, CSGI, and oversupply protocols were in effect, this data may be more accurate than the data that would otherwise be available to BPA. For the period of October 1, 2009, through September 30, 2011, BPA requested this data from the wind owners or operators to assist in filling in these altered periods. For times of DSO 216 generator limitations and the oversupply protocols, potential generation was used in place of the recorded project's output for the time of the event to 5 minutes after the end of the event. Any data that fell in this timeframe for which a potential generation value was not provided were voided out of the data set and filled with the scaling methodology described in section 2.3.2. For time periods outside of DSO 216 generator limitations and the oversupply protocols, the potential generation was used for a CSGI project's output anytime it was greater than the generation value recorded in BPA's PI system.

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 balancing authority area and the locations of future and existing wind projects are used. Documentation Table 2.2 includes a map that shows the locations of the wind projects in the Balancing Reserve Capacity Quantity Forecast for the FY 2014–2015 rate period. A west-to-east wind pattern prevails generally in the locations of many future and existing wind projects in BPA's balancing authority area, and future wind project generation is assumed to be predicted

generally 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.

The Study determines the correlations and time delays in different ways depending on the data available for particular projects. For existing projects online prior to December 1, 2011, 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. The time offsets for this analysis were up to 730 minutes leading and up to 730 minutes lagging. 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. *See* Documentation Table 2.4.

For projects that were not online prior to December 1, 2011, 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. These data predicted wind speed at standard gridded locations across the Pacific Northwest for calendar year (CY) 2004–2006 at ten-minute intervals. Using the forecast of wind generation described in section 2.2 and its associated geographic coordinates (latitude and longitude), ten-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 ten-minute interval time series data for all existing and future wind projects at different time offsets. The time offsets for this analysis were up to 730 minutes leading and up to 730 minutes lagging. 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.

In addition to projects that were not online prior to December 1, 2011, all generation data obtained from BPA's PI system are reviewed for missing data. Any missing data points are filled in using the scaling method used to estimate minute-by-minute generation for future projects. This method helps ensure that the filled-in data reflect the trends of BPA's PI system data. Documentation Table 2.3 identifies the existing and future wind 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 megawatts and the month and year that the project reached its installed capacity. Entries for the future wind projects include the installed capacity and the completion date (month and year) on which the project is expected to reach its installed capacity. Documentation Tables 2.4, 2.5, and 2.6 identify the correlations, distances, and time delays in minutes, respectively, used in the scaling methodology. Section 2.3.2 discusses more about how these tables are used.

2.3.2 Estimating Future Wind Project Generation

Once the correlations and lead and lag times for each pair of wind projects are determined, the installed capacity of the existing and future wind projects is used in conjunction with the correlations and leads and 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. Rather than using one existing project to create the estimated minute-by-minute generation, trios of existing projects are used to reflect some of the operational variability or "diversity" that occurs between particular projects. Trios for the project to be estimated are

ranked by three criteria, in order: first, the multiplication of the three other projects' correlations to that project (greatest to least); second, the summation of the three other projects' distance from that project (least to greatest); and third, the summation of the three other projects' absolute time delay (least to greatest). The highest-ranked trio is used in the methodology described below, unless one or more of the trios also had a missing data point during its corresponding time-delayed point. In that case, the second-highest ranked trio would be used, and so on down the line. The estimated minute-by-minute wind project generation is forecast using the following assumptions. An example is provided for additional explanation.

First, each existing project in the trio is weighted based on the extent to which the output of the existing project assists in creating the minute-by-minute data for the estimated project's output. The weighting is calculated for each project as that project's correlation divided by the sum of all three correlations for each project in the trio. Documentation Table 2.4 lists the correlation of each project with every other project, from which these weightings can be calculated.

Second, the estimated project's generation is scaled in by multiplying the generation of each existing project in the trio by the planned or existing capacity in megawatts and dividing by the existing wind project 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.

Third, the generation of each existing project in the trio is time-shifted to the correct timeframe based on the lead or lag time from the existing project. This time shift helps express an estimated project's generation for a particular minute as a function of an existing project's generation. After being multiplied by the weighting factor and the installed capacity ratio as described above, the generation of each existing project in the trio is shifted to the minute under

the estimated project that corresponds to the lead or lag time. The scaled and time-shifted project output of the generation of each existing project in the trio is added to determine the total estimated project generation.

The following example illustrates how the estimated project generation is calculated. In this example, a 150 MW wind project (Project A) has a trio consisting of Project B (100 MW with a 0.98 correlation and 1-minute lagging), Project C (200 MW with a 0.97 correlation and 15-minute leading), and Project D (125 MW with a 0.97 correlation and 23-minute leading). Using these assumptions, Project A's generation for any particular minute is determined using the following equation:

$$\begin{aligned}\text{Project A} = {} & (150/100)\times(\text{Project B}^{-1\text{minute}})\times(0.98/(0.98+0.97+0.97) + \\ & (150/200)\times(\text{Project C}^{+15\text{minutes}})\times (0.97/(0.98+0.97+0.97) + \\ & (150/125)\times(\text{Project D}^{+23\text{minutes}})\times (0.97/(0.98+0.97+0.97)\end{aligned}$$

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 scaled-in wind generation forecast for that month. The resulting total wind generation is used to forecast the balancing reserve capacity requirements for the rate period.

2.4 Accounting for Other Non-AGC Controlled Generation

Estimating the balancing reserve capacity requirements during the rate period for all non-wind generation not controlled by AGC requires analyzing historical minute-by-minute generation levels of the existing non-AGC projects in the BPA balancing authority area and accounting for

future use by both existing projects and projects expected to come online during the rate period. For existing generation analysis, non-AGC generation is split into three subsets: hydroelectric generation, Federal thermal 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. Future solar generation is also included in the Balancing Reserve Capacity Quantity Forecast (section 2.2) and includes all projects that use photovoltaic arrays to produce power.

2.4.1 Analyzing Historical Use of Balancing Reserve Capacity

For data on generation of the existing non-AGC projects, 48 months of one-minute actual average generation data from BPA's PI system are used. For data on schedules of the existing non-AGC projects, 48 months of hourly schedule data from BPA's Real Time Operation Dispatch and Scheduling (RODS) system are used. The data cover generation and schedules from all existing non-AGC generators in the BPA balancing authority area for the period from October 1, 2007, to September 30, 2011. The data were scrubbed for missing data periods, and contingency reserves were credited back to any non-AGC projects that used those contingency reserves. Non-AGC projects are included only after they come online, as there is no reliable method to predict prior to their online date when or if they would be generating.

Non-Federal thermal generation was evaluated for operational improvements from October 1, 2010, to September 30, 2011, versus the previous year. This period coincides with BPA's notification to customers that the prior performance of the non-Federal thermal generators would result in a separate balancing rate; the forecast considers performance improvement during this time. For this evaluation, the 0.25th percentile and 99.75th percentiles of the station control error were calculated and compared. Any improvement seen from this analysis was credited

back to the non-Federal thermal generation through a percent reduction in the reserve requirements.

2.4.2 Accounting for Future Non-AGC Generation

Accounting for future non-AGC projects in the balancing reserve capacity requirements for the Balancing Reserve Capacity Quantity Forecast assumes that the historical usage trends continue in the rate period. To calculate the additional balancing reserve capacity requirements for a future non-AGC project, the balancing reserve capacity that was calculated in section 2.4.1 for that type of generation (hydroelectric 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.

2.4.3 Accounting for Solar Generation

Currently, no utility-scale scheduled solar generation plant exists in the BPA balancing authority area, which means that there is no source of regional minute-by-minute solar schedule and generation data available to incorporate into the Balancing Reserve Capacity Quantity Forecast. The forecast for this Study thus uses one-minute solar photovoltaic generation data for an unscheduled 1.655 MW Sacramento Municipal Utility District (SMUD) project for the 48-month period of study. The SMUD solar project is located approximately 300 miles south of Christmas Valley, Oregon, where BPA forecasts solar generation to come online. The SMUD data is scaled to a 15 MW solar project, as forecast to be online for the entire FY 2014–2015 rate period, by multiplying the generation data by 15 MW and dividing by the 1.655 MW installed capacity.

The solar data were provided without scheduling data, so schedules for the generation data were synthesized to result in proxy historical hour of day averages by month. All of the solar generation data were separated into bins by hour of day and month and averaged, resulting in a value to be used for the schedule for that hour of the day in that month. For example, all of the one-minute data for the hour ending 12 (11:00 a.m. to 11:59 a.m.) for all four of the Julys in the data set were averaged, and that average was used as the schedule for every hour ending 12 in all four Julys in the data set. This solar schedule and generation one-minute data are used in the study calculations described in section 2.7.

2.5 Load Estimates

The following sections describe derivation of the actual balancing authority area loads and the balancing authority area load forecasts that correspond to particular levels of installed wind used in the forecast.

2.5.1 Accounting for Pump Load

Load estimates start with the balancing authority area load posted on the BPA external operations Web site. BPA Balancing Authority Load & Total Wind, Hydro, and Thermal Generation, Chart & Data, Rolling 7 days, *available at* http://transmission.bpa.gov/Business/operations/Wind/default.aspx. The balancing authority area load posted on the operations page reflects the total generation in the BPA balancing authority area minus the total of all interchanges (transfers to and from adjacent balancing authority areas). 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 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); 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 balancing authority area load prior to using the balancing authority area load numbers in the balancing reserve capacity requirements calculations.

2.5.2 Actual Balancing Authority Area Load Amounts that Correspond with Wind Penetration Levels

In order to simulate balancing authority area load that corresponds to the rate period (FY 2014–2015), 48 months of balancing authority area loads that correspond to FY 2008 loads and wind penetration levels must first be created. The actual scrubbed BPA PI data from FY 2008 (October 2007 through September 2008) is used for the first 12 months of the study period. The balancing authority area load data from October 2008 through September 2009 is divided by the load growth from FY 2008 to FY 2009, which was a 4.62 percent decrease in balancing authority area load. The balancing authority area load data from October 2009 through September 2010 is divided by the load growth from FY 2008 to FY 2010, which was a 6.79 percent decrease in balancing authority area load. The balancing authority area load data from October 2010 through September 2011 is divided by the load growth from FY 2008 to FY 2011, which was a 3.99 percent decrease in balancing authority area load. To scale the balancing authority area load to the rate period, the load growth factors shown below are applied to the entire 48-month period; the load growth factors are based on the forecasts for total balancing authority area load from the BPA load forecasting group.

FY 2014 (4687 MW wind) Load = FY 2008 Load × 1.33% Load Decrease

FY 2015 (5055 MW wind) Load = FY 2008 Load × 0.79% Load Increase

2.5.3 Balancing Authority Area Load Forecasts

To determine the balancing authority area load forecasts, system load estimates from historical storage (*i.e.*, rotary accounts) are used. In order to change the historical system load estimates to a balancing authority area load forecast, the sum of hourly totals of the transfer customer schedules (another rotary account) are subtracted from the system load estimates. Transfer customers are located in other balancing authority areas and are therefore not included in the BPA balancing authority area load. The same load growth multipliers shown above 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 methods used by the hydro duty schedulers when setting up the system each hour. The actual load at ten minutes prior to the hour is used to calculate the estimated load at ten minutes past the hour, 30 minutes past the hour, and 50 minutes past the hour. This is the same calculation performed by the software used by the schedulers when setting up the system for the next hour. The inputs to these estimates are the load at ten minutes prior to the hour and the load forecasts for the current hour and the next two hours.

2.6 Wind Scheduling Accuracy Assumption

The scheduling accuracy of the wind fleet during the rate period is assumed to be equivalent to a 30-minute persistence measure. Under this assumption, the schedule for a wind project for a given scheduling period (60, 30, or 15 minutes) equals the one-minute average of the actual generation of the project 30 minutes prior to the scheduling period. Forty-five-minute persistence forecasting accuracy was calculated in the same manner, with the 45th minute prior to the scheduling period defining the schedule.

2.7 Balancing Reserve Capacity Requirements Methodology

2.7.1 Base Methodology

The methodology for forecasting the balancing reserve capacity requirements requires the following one-minute average data sets: actual balancing authority area load, balancing authority area load forecast, the total hydroelectric generation, the total hydroelectric schedule, the total Federal thermal generation (Columbia Generating Station or CGS), the total Federal thermal schedule, the total non-Federal thermal generation, the total non-Federal thermal schedule, total solar generation, total solar generation forecast, actual total wind generation, and total wind generation forecast. Each of these data sets is obtained or calculated in the manner described in sections 2.2 through 2.6. Using these data sets, the actual load net generation (actual balancing authority area load minus actual total hydroelectric generation minus actual total Federal thermal generation minus total actual non-Federal thermal generation minus actual total solar generation minus actual total wind generation) is determined on a minute-by-minute basis. Then the load net generation forecast (balancing authority area load forecast minus actual total hydroelectric schedule minus actual total Federal thermal schedule minus total actual non-Federal thermal schedule minus actual total solar generation schedule minus total wind generation forecast) is determined on a minute-by-minute basis. Note that future hydroelectric and future thermal projects forecasts are covered in section 2.4.2. Those data sets are not analyzed in the manner described within this section.

For each of the following data sets—actual balancing authority area load, actual total hydroelectric generation, actual total Federal thermal generation, actual total non-Federal thermal generation, actual total solar generation, actual total wind generation, and actual load net generation—a “perfect” schedule for each hour is developed that generally reflects how BPA’s AGC system utilizes generation schedules. The perfect schedule is developed by first calculating clock hourly averages for each data set. Minutes 11 through 49 of each hour are set to the clock

hourly average value. For minute 50 of the current hour through minute 10 of the next hour, the values between the clock hourly averages are ramped in on a straight-line basis. The same linear ramp method is used for the balancing authority area load estimates.

Ten-minute averages are developed for each of the following data sets: actual balancing authority area load, actual total hydroelectric generation, actual total Federal thermal generation, actual total non-Federal thermal generation, actual total solar generation, actual total wind generation, and actual load net generation. The actual data sets, forecast and ramped-in data sets, ten-minute averages, and ramped-in perfect schedules provide the foundation for the Balancing Reserve Capacity Quantity Forecast. Documentation Table 2.7 is a graph depicting the one-minute average, ten-minute average, perfect schedule, and estimated values for the load net generation data set for a sample three-hour period.

Three components make up the total balancing reserve capacity requirements: regulating reserves, following reserves, and imbalance reserves. For purposes of the forecast, the total balancing reserve capacity requirement is the difference between the minute-by-minute variations and the forecast schedules of the load net generation data set, also known as Station Control Error (SCE). The regulating reserves component is defined by the minute-by-minute variations around the ten-minute clock average of the load net generation data set. The following reserves component is defined by the difference minute by minute between the ten-minute clock average of the load net generation data set and the associated perfect schedule. The imbalance reserves component is defined as the incremental amount of additional following reserve that results from using forecast schedules instead of perfect schedules. Documentation Table 2.7 reflects the regulating reserves, following reserves, and imbalance reserves components in terms of the relationships between the one-minute averages, ten-minute averages, perfect schedules, and estimated schedules for a sample three-hour period.

2.7.2 Time Series of Studies

To forecast the overall balancing reserve capacity requirements, an *inc* and *dec* requirement is calculated for the regulating reserves, following reserves, and imbalance reserves components for each of the actual balancing authority area load, actual total hydroelectric generation, actual total Federal thermal generation, actual total non-Federal thermal generation, actual total solar generation, actual total wind generation, and actual load net generation data sets. The *inc* and *dec* amounts are calculated for the different amounts of wind penetration and load for FY 2014–2015.

Using percentile distribution, values from the upper and lower 0.25 percent are discarded for each component, leaving 99.5 percent of the values for calculating the capacity requirements of the BPA balancing authority area. This produces a forecast of the balancing reserve capacity that BPA needs to meet its balancing requirements 99.5 percent of the time. Using 99.5 percent of the values is generally consistent with BPA's historical method of using three standard deviations to calculate requirements (using three standard deviations would result in using 99.7 percent of the values in the calculations). By using 99.5 percent of the values, another 0.2 percent of variation that would otherwise factor into the forecast is not accounted for; however, BPA has performed well in meeting the requirements of the North American Electric Reliability Corporation and Western Electricity Coordinating Council balancing standards using the historical level of 99.7 percent, and therefore it is assumed that with existing reliability and operational protocols, an additional 0.2 percent of the movement in the balancing authority area is absorbed without compromising reliability. This decreases the overall balancing reserve capacity requirement slightly.

Using 99.5 percent of values for the load net generation data set, the balancing reserve capacity requirement forecast is calculated for the total balancing reserve capacity requirement, the total regulation requirement, and the total following requirement. The total imbalance requirement is calculated as the remainder of the total balancing reserve capacity requirement minus the total regulation requirement minus the total following requirement. The equations below describe these calculations. Section 2.7.3 describes the methodology used to disaggregate the balancing reserve capacity requirements for each resource and reserve type (*i.e.*, load regulation *inc*, wind regulation *inc*, hydro regulation *inc*, and so on).

Total Reserve Requirement

Total *inc* = p9975(Total SCE)

Total *dec* = p0025(Total SCE)

Total Regulation Requirement (Reg)

Total Reg *inc* = p9975(Total Regulation)

Total Reg *dec* = p0025(Total Regulation)

Total Following Requirement (Fol)

Total Fol *inc* = p9975(Total Following)

Total Fol *inc* = p0025(Total Following)

Total Imbalance Requirement (Imb)

Total Imb *inc* = Total *inc* – Reg *inc* – Fol *inc*

Total Imb *dec* = Total *dec* – Reg *dec* – Fol *dec*

where p9975 is the 99.75% percentile distribution

p0025 is the 0.25% percentile distribution

2.7.3 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 contributions from generation type and load. 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.*, Federal thermal regulation *inc* + non-Federal thermal regulation *inc* + solar regulation *inc* + wind regulation *inc* + hydro regulation *inc* + load regulation *inc* = total regulation *inc*). To do this allocation in a statistically accurate manner, incremental standard deviation (ISD) is employed to allocate reserves to load and generation type based upon how each contributes to the joint load-generation regulating reserve requirement, following reserve requirement, and imbalance 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 one-megawatt 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 diversification is a joint load-generation balancing reserve capacity requirement that is less than the sum of the individual requirements for load and generation. Through the ISD, the joint load-generation balancing reserve capacity requirement is disaggregated into the component contributions of load and

generation. The result of the disaggregation is a total balancing reserve capacity requirement fully reflecting the impacts of signal diversity. Having used the ISD method, the sum of the individual balancing reserve capacity requirements now equals the total balancing reserve capacity requirement.

In order 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 regulation, load regulation, wind regulation, solar regulation, hydro regulation, non-Federal thermal regulation, and Federal thermal regulation 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 Table 2.8. Then the maximum of the 24 hourly bin percentile distributions is found. Finally, the total reserve requirements calculated using the formulas in section 2.7.2 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 Table 2.9.

The data used to determine the balancing reserve capacity requirements are not normally distributed. Because the distribution of the data is not symmetrical, using the ISD to allocate between load and generation requires an additional step to correctly infer the balancing reserve capacity requirement at the desired percentile. The current balancing reserve capacity requirement is calculated at the 99.75th percentile for *incs* and 0.25th percentile for *decs*, which equates to ± 2.81 standard deviations (z-value), if assuming a standard normal distribution.

(That is, data that are normally distributed have 99.75 percent of their values occurring at 2.81 or fewer standard deviations from the mean. The distance or number of standard deviations from the mean is referred to as the z-value.) Rather than assuming that the load and generation type error signals are standard normal and using a z-value of ± 2.81 for purposes of the Balancing Reserve Capacity Quantity Forecast in this case, the z-value associated with the 99.75th percentile and the 0.25th percentile is calculated based on the empirical data. Specifically, each of the actual 99.75th percentile *inc* and the 0.25th percentile *dec* data are divided by the standard deviation of the component error signals to determine an "actual" *inc* and *dec* z-value. Multiplying the "actual" z-value by the ISD results in a disaggregated reserve requirement adjusted for the non-normality in the empirical data while accounting for the diversity among the signals.

2.7.4 Determining the Imbalance Reduction for Self-Supply

Once the allocation of the forecast of the total balancing reserve capacity requirement is determined, the entire allocation calculation is repeated with the wind generation/schedule signals split into separate self-supply and non-self-supply generation/schedule signals. The resulting self-supply imbalance reserve amount determines the reduction in balancing reserve capacity due to self-supply. This reduction is applied to the wind imbalance reserves, the BPA balancing authority area imbalance reserves, and the BPA balancing authority area total balancing reserve capacity requirement. Assumptions regarding the wind projects participating in self-supply of imbalance reserves for the FY 2014–2015 rate period are based on the data that is available for the current Customer-Supplied Generation Imbalance pilot participation. Customers that elect (by April 1, 2013) to participate in self-supply of the imbalance portion of their balancing reserve capacity requirement for the FY 2014–2015 rate period will be reflected in the Final Study.

2.8 Assuming 30-Minute Persistence on 30-Minute Schedules

The Study includes a separate forecast of the potential balancing reserve capacity requirement reductions associated with committed scheduling by the entire wind fleet in BPA's balancing authority area on a 30-minute basis. To develop this forecast, the Study assumes that all of the wind projects in the BPA balancing authority area schedule every 30 minutes, with accuracy based on 30-minute persistence scheduling. The Study assumes standard ramps of ten minutes before and after the top of the hour and five minutes before and after mid-hour. The Study uses the same methodology as described in section 2.7, assuming a total balancing reserve capacity of 99.5 percent and no self-supply. The full benefit of wind generation participating in committed scheduling on a 30-minute basis would be seen in the reduction of the total balancing reserve capacity for BPA's balancing authority area, because committed scheduling on a 30-minute basis by the entire wind fleet would reduce the aggregate load net generation error for the balancing authority area. Documentation Table 2.25, columns G and H. The Study analyzes the reduced aggregate error for reserve requirements and allocates the requirements to the different reserve components (regulation, following, and imbalance) and reserve types (load, thermal generation, and wind generation) using incremental standard deviation. The savings seen by the reduction of the total balancing reserve capacity for the balancing authority area are then credited against the forecast reserve requirement for wind.

The Study results for committed scheduling by the entire wind fleet on a 30-minute basis can be found in Documentation Table 2.26, columns G and H, which show that the average reduction in the forecast of the total balancing reserve capacity requirement for the rate period is approximately 27 percent for *inc* reserves and 28 percent for *dec* reserves.

2.9 Assuming 30-Minute Persistence on 15-Minute Schedules

The Study includes a separate forecast of the potential balancing reserve capacity requirement reductions associated with committed scheduling by the entire wind fleet in BPA's balancing authority area on a 15-minute basis. Staff is providing this forecast for informational purposes but is not proposing a 30/15 committed scheduling election or rate. To develop this forecast, the Study assumes that all of the wind projects in the BPA balancing authority area schedule every 15 minutes instead of every 60 minutes, with accuracy based on 30-minute persistence scheduling. The Study assumes standard ramps of ten minutes before and after the top of the hour, ten minutes from XX:10 to XX:20, ten minutes from XX:25 to XX:35, and ten minutes from XX:40 to XX:50. The Study uses the same methodology as described in section 2.7, assuming a total balancing reserve capacity of 99.5 percent and no self-supply. The full benefit of wind generation participating in committed scheduling on a 15-minute basis would be seen in the reduction of the total balancing reserve capacity for BPA's balancing authority area, because such scheduling by the entire wind fleet would reduce the aggregate load net generation error for the balancing authority area. Documentation Table 2.27, columns G and H. The Study analyzes the reduced aggregate error for reserve requirements and allocates the requirements to the different reserve components (regulation, following, and imbalance) and reserve types (load, thermal generation, and wind generation) using incremental standard deviation. The savings seen by the reduction of the total balancing reserve capacity for the balancing authority area are then credited against the forecast reserve requirement for wind.

The Study results for committed scheduling by the entire wind fleet on a 15-minute basis can be found in Documentation Table 2.28, columns G and H, which show that the average reduction in the forecast of the total balancing reserve capacity requirement for the rate period is approximately 38 percent for *inc* reserves and 42 percent for *dec* reserves.

2.10 Assuming 45-Minute Persistence on 60-Minute Schedules

The Study includes a separate forecast of the potential balancing reserve capacity requirement increase associated with 45-minute persistence scheduling by the entire wind fleet in BPA's balancing authority area on a 60-minute basis. To develop this forecast, the study assumes that all of the wind projects in the BPA balancing authority area schedule every 60 minutes with accuracy based on 45-minute persistence scheduling. The study assumes standard ramps of ten minutes before and after the top of the hour. The study uses the same methodology as described in section 2.7, assuming a total balancing reserve capacity of 99.5 percent and no self-supply. The full impact of wind generation scheduling at 45-minute persistence on 60-minute schedules would be seen in the increase of the total balancing reserve capacity for BPA's balancing authority area, because 45-minute persistence scheduling by the entire wind fleet would increase the aggregate load net generation error for the balancing authority area. Documentation Table 2.29, columns G and H. The Study analyzes the increased aggregate error for reserve requirements and allocates the requirements to the different reserve components (regulation, following, and imbalance) and reserve types (load, thermal generation, and wind generation) using incremental standard deviation. The impact seen by the increase of the total balancing reserve capacity for the balancing authority area is then applied against the forecast reserve requirement for wind.

The Study results for 45-minute persistence scheduling by the entire wind fleet on a 60-minute schedule can be found in Documentation Table 2.30, columns G and H, which show that the average increase in the forecast of the total balancing reserve capacity requirement for the rate period is approximately 22 percent for *inc* reserves and 25 percent for *dec* reserves.

2.11 Results

The Study forecasts the balancing reserve capacity requirements for the three different components of balancing reserve capacity: regulating reserves, following reserves (with perfect schedules), and imbalance reserves (following reserve with actual schedules and estimates).

Other non-AGC generation was accounted for in the Balancing Reserve Capacity Quantity Forecast in the following ways:

- Hydroelectric generation balancing reserve capacity requirements are incorporated into the load balancing reserve capacity requirement.
- Federal thermal generation balancing reserve capacity requirements are incorporated into the load balancing reserve capacity requirement.
- Non-Federal thermal generation balancing reserve capacity requirements are assessed a separate balancing reserve capacity requirement.
- Solar generation balancing reserve capacity requirements are assessed a separate balancing reserve capacity requirement.

Documentation Tables 2.10 through 2.24 include the results of the Balancing Reserve Capacity Quantity Forecast. All of these results are based on the assumption that wind generators schedule consistent with a 30-minute persistence model on a 60-minute scheduling period. Documentation Tables 2.10 through 2.16 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, hydroelectric generation, Federal thermal generation, and non-Federal thermal generation, respectively. These requirements cover the balancing reserve capacity requirements for 99.5 percent of the time and assume no self-supply of imbalance capacity by any generators during the rate period. Documentation Tables 2.18 through 2.24 include results of the Balancing Reserve Capacity Quantity Forecast assuming a level of

imbalance reserve self-supply as described in section 2.7.4 and shown in Documentation Table 2.17.

The results for 30/30 committed scheduling (30-minute persistence on 30-minute schedules) by the entire wind fleet can be found in Documentation Tables 2.25 and 2.26. The results for 30/15 committed scheduling (30-minute persistence on 15-minute schedules) by the entire wind fleet can be found in Documentation Tables 2.27 and 2.28. The results for 45/60 scheduling (45-minute persistence on 60-minute schedules) by the entire wind fleet can be found in Documentation Tables 2.29 and 2.30. Documentation Table 2.31 shows the results of the Balancing Reserve Capacity Quantity Forecast for each VERBS component as a percentage of nameplate capacity for solar and for the wind fleet under the 30/30, 30/60, and 45/60 scheduling elections.

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3. BALANCING RESERVE CAPACITY COST ALLOCATION METHODOLOGY

3.1 Introduction

The Federal Columbia River Power System (FCRPS) is used to provide balancing reserve capacity for various Ancillary and Control Area Services. This section of the Study describes the allocation of embedded costs, direct assignment costs, and variable costs for Regulating Reserve, Load Following Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Variable Energy Resource Balancing Service (VERBS) Reserve. Regulating Reserve is used to balance loads in the BPA balancing authority area on a moment-to-moment basis. Load Following Reserve is used to balance loads through the operating hour. DERBS Reserve is comprised of regulating, following, and imbalance reserves that are used to balance dispatchable generation moment-to-moment and through the operating hour in the BPA balancing authority area. VERBS Reserve is also comprised of regulating, following, and imbalance reserves that are used to balance the variable energy resource generation moment-to-moment and through the operating hour in the BPA balancing authority area. The section also describes the cost allocation methodologies for four types of balancing reserve capacity purchases.

The embedded cost allocation is based on the embedded costs of a defined portion of the existing FCRPS. Embedded costs are explained in detail in section 3.2. Direct assignment costs are a narrowly defined set of costs that will be recovered through the VERBS rate. The direct assignment costs are explained in detail in section 3.3. The variable cost methodology determines the cost associated with the loss of efficiency caused by providing balancing reserve capacity from the FCRPS. Variable costs are explained in detail in section 3.4. In addition to providing capacity from the FCRPS, BPA will attempt to purchase additional balancing reserve capacity when the balancing reserve capacity needs of the BPA balancing authority area exceed

the amount of balancing reserve capacity provided by the FCRPS. The cost allocation of such purchases is described in section 3.5.

3.1.1 Overview of Cost Allocation Methodology

The cost allocation for balancing reserve capacity is the sum of associated embedded costs, applicable direct assignment costs, and variable costs. The costs for Regulating Reserve, DERBS Reserve, and VERBS Reserve are assigned to Transmission Services (TS) to be recovered through the Ancillary and Control Area Services rate schedule, which is described in section 10 of this Study. The cost associated with Load Following Reserve is not assigned to TS; rather, these costs remain as part of the Power Services revenue requirement. The cost of Contingency Reserves, referred to in this study as Operating Reserves, is also assigned to TS. The Operating Reserve cost allocation is described in detail in section 4.

Forecast TS revenue from the sale of Regulation, DERBS, and VERBS reserves is treated as a revenue credit and allocated to the power rates. Power Rates Study, BP-14-E-BPA-01, section 4.3.

3.1.2 Cost Allocation Methodology Assumptions and Inputs

The assumptions for the base case in this section of the study are: (1) a quantity of balancing reserve capacity that allows BPA to support variable energy resources 99.5 percent of the time; (2) the wind fleet schedules at a 30-minute persistence scheduling accuracy level in a 60-minute scheduling period; and (3) a certain quantity of the imbalance portion of the VERBS Reserve will be self-supplied by customers. The amount of balancing reserve capacity required to provide Regulating, Load Following, DERBS, and VERBS Reserves is described in section 2.

In addition to the Balancing Reserve Capacity Quantity Forecast, BPA uses other inputs in its cost allocation methodologies. These inputs include the net revenue requirement for balancing reserve capacity for embedded costs from the Power Revenue Requirement Study, BP-14-E-BPA-02, Table 2E; the regulated hydro project information from the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1; the 120-hour regulated hydro peaking capacity developed from an Hourly Operation and Scheduling Simulator (HOSS) capacity analysis that forecasts the amount of 120-hour peaking capacity available from regulated hydro energy production under certain water conditions; the amount of Operating Reserve required by BPA from Power Services from section 4; and the market price forecast from the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4.

3.2 Embedded Cost Allocation Methodology

The embedded unit cost of Regulating Reserve, DERBS Reserve, and VERBS Reserve is calculated by taking the costs associated with the Big 10 hydro projects (described in section 3.2.1) and dividing those costs by the average annual capacity amount of the Big 10 hydro projects (adjusted for other requirements). The costs associated with the Big 10 hydro projects are power-related costs on a project-specific basis, an allocation of fish costs and general and administrative costs, and three revenue credit adjustments. The capacity amount is determined using BPA's hydro simulation model, HYDSIM, and the HOSS model. These models are used to compute the average annual 120-hour peaking capacity of the regulated hydro system. These 120-hour peaking capacity amounts are averaged for each month, resulting in an annual average amount of reliable monthly sustained capacity that will be available for operational planning purposes. The calculated embedded unit cost is then multiplied by the balancing reserve capacity quantity forecast for each type of reserve to yield the embedded cost allocation for that type of balancing reserve capacity.

3.2.1 Description of the Portion of the FCRPS Used to Provide Balancing Reserve Capacity

BPA has 14 Federal hydro projects whose coordinated individual generation forecasts are modeled in BPA's regulated hydro simulation model, HYDSIM. These projects are collectively called Federal system regulated hydro projects and are listed in Documentation Table 3.2. Within this group, 10 projects are used by BPA to provide balancing reserve capacity for regulating, load following, DERBS, and VERBS Reserves. The 10 projects are Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville. These 10 projects are referred to as the "Big 10 projects" because they are controlled in real time by Automatic Generation Control (AGC) and provide balancing reserve capacity. AGC is the computer system connected to these generating resources that allows them to respond immediately to the AGC computer signal to provide sufficient regulating margin to allow the balancing authority area to meet North American Electric Reliability Corporation (NERC) Control Performance Criteria.

3.2.2 Determining the Amount of Capacity Provided by the FCRPS

The Federal system regulated hydro projects are hydraulically linked in the Columbia River Basin. Hydro energy and capacity production at these projects is directly related to (1) the amount of water in the Columbia River Basin; (2) power and non-power requirements, such as flood control, fish operations, and recreation; (3) reliability and reserve requirements, such as the balancing reserve capacity used for VERBS and Load Following; and (4) turbine availability, which is the number of units not out of service due to planned maintenance and unplanned outages. For purposes of this Study, the amount of balancing reserve capacity available from the FCRPS is assumed to be up to 900 MW of *inc* reserves and up to 1100 MW of *dec* reserves. These limitations are used as an input into HYDSIM, which then forecasts the coordinated

energy production for these 10 projects for each of the 14 periods used in the hydro studies. (Each month of a fiscal year is a period except for the months of April and August, which are both split into two periods because the natural streamflows are significantly different in the first half and second half of these months.)

HYDSIM produces average energy amounts for each of the 14 periods by fiscal year for the 80 water years of record (October 1928 through September 2008) but does not produce forecasts of Heavy Load Hour (HLH) and Light Load Hour (LLH) energy amounts by period. Instead, the hourly detail is produced by BPA's HOSS model. The combination of the two hydro simulation models (HYDSIM and HOSS) is used to compute the average annual 120-hour peaking capacity for the 14 Federal regulated hydro resources. Though the HYDSIM and HOSS models are operated for the 80 water years of record, the focus of the cost allocation methodology is the 1958 water year, which represents an average water condition. These processes are described in the following sections.

3.2.3 Source and Description of Inputs and Outputs of the HYDSIM Model

HYDSIM simulates monthly energy hydro production under the physical characteristics and limits placed on the modeled Columbia River Basin projects, including hard project constraints (*e.g.*, flow limits, elevation limits), project outages (planned and forced outages), balancing reserve capacity requirements, one percent efficiency restrictions (required during fish passage season), and non-power requirements (flood control, variable draft limits, fish operations pursuant to the Biological Opinions, and Canadian Treaty operations). HYDSIM models these hydro projects to meet system load while continuing to meet Pacific Northwest regional power and non-power requirements for the 80 water years of record (October 1928 through September 2008). Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1.

The Federal system regional hydro projects are termed "regulated" hydro projects, because their coordinated operation is modeled in HYDSIM. BPA uses the HYDSIM energy generation forecasts for the 14 regulated hydro projects as the base energy for calculating a unit cost for capacity in the cost allocation methodology. Further information on the operation of HYDSIM is presented in the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1. The hydro energy generation forecast for the 14 Federal system regulated hydro projects under 1958 water conditions is a primary factor in the determination of the 120-hour hydro peaking capacity relationship derived in HOSS.

3.2.4 Source and Description of HOSS and Modifications

The embedded cost methodology focuses on availability of balancing reserve capacity from the Federal system regulated hydro projects. To analyze capacity, the HOSS model simulates hourly operation of the Federal system to meet hourly loads for each period of the 80 historical water conditions for the study period. The outputs of HOSS are not directly used for rate setting purposes. Rather, monthly Federal system regulated hydro generation energy relationships are developed to provide monthly HLH energy, LLH energy, and 120-hour hydro peaking capacity using outputs from HOSS, which are explained in more detail in sections 3.2.5 and 3.2.6.

The HOSS model uses HYDSIM monthly project flows, initial and ending conditions, reserve requirements, and other power and non-power constraints that are provided by the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1. HOSS incorporates the same monthly versions of the input data for Regulating Reserve, Operating Reserve, Load Following Reserve, DERBS Reserve, and VERBS Reserve as are used in HYDSIM. These are computed once for

each of the 14 periods in a year, and these values are used under all 80 water conditions. These reserve amounts affect the generating capacity and 120-hour hydro peaking capacity available.

The HYDSIM and HOSS inputs for Operating Reserve are calculated consistent with the reserve capacity forecast in the Operating Reserve Cost Allocation in section 4 (*i.e.*, 3 percent of the load and 3 percent of net generation), with one difference. Instead of using averages for the Operating Reserve requirements, the Operating Reserve requirement that is used in HOSS and HYDSIM is calculated based on historical peak balancing authority area generation at the 95th percentile by month. The peak 95th percentile is used instead of an average, because Operating Reserve constrains the system at high levels of generation. If HOSS and HYDSIM assumed an average Operating Reserve requirement, the study result would not adequately cover the Operating Reserves required for actual operations during periods of high generation.

The other inputs for balancing reserve capacity used in the HYDSIM and HOSS models are based on the Regulating Reserve, Load Following Reserve, DERBS Reserve, and VERBS Reserve forecast in the Balancing Reserve Capacity Quantity Forecast, described in section 2. Table 3.4 contains the total monthly *inc* and *dec* balancing reserve capacity amounts of Regulating Reserve, Load Following Reserve, DERBS Reserve, and VERBS Reserve used as inputs to HYDSIM and HOSS. The *inc* amounts were capped at 900 MW, and the *dec* amounts were capped at 1100 MW. Documentation Table 3.4.

The HOSS and HYDSIM models use both the *inc* and *dec* balancing reserve capacity amounts. As described in the Balancing Reserve Capacity Quantity Forecast in section 2, *inc* balancing reserve capacity is the capacity available to ramp up generation to meet increasing within-hour load or decreasing within-hour generation output. *Dec* balancing reserve capacity is the generating capacity available to ramp down to meet increasing within-hour generation output or

decreasing within-hour load. In HOSS and HYDSIM, the *inc* requirement is treated as a reduction to available capacity to generate power, and the *dec* requirement is treated as an increase in the minimum generation requirement at Grand Coulee, Chief Joseph, McNary, John Day, and The Dalles.

The resulting HOSS model generation study maximizes HLH Federal system hydro generation and creates hourly projections of hydro generation, by period, for each of the 80 water conditions of the study period. These estimates provide the basis for (1) Federal system hydro energy relationships that provide HLH and LLH energy splits that are shown in the Power Loads and Resources Study, BP-14-E-BPA-03, section 3.1.2.1, and its Documentation, BP-14-E-BPA-03A, Tables 2.1.2 and 2.1.3, and inputs to the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4; and (2) the 120-hour peaking capacity of the Federal hydro system for this Study, described below.

3.2.5 120-Hour Federal System Hydro Capacity

The hourly output data from HOSS provides BPA data to compute Federal system hydro energy-to-capacity relationships for each of the 14 periods and 80 water conditions for the study period. For the FY 2014–2015 rate period, HOSS 120-hour peaking capacity estimates represent the amount of capacity on the Federal hydro system that is available to reliably serve Federal system load obligations after meeting balancing reserve capacity obligations and the power and non-power requirements within any period or water condition. It is not meant to represent a time of system stress to meet large weather deviations, additional reserve obligations, or other extreme conditions on the Federal system. The 120-hour peaking capacity quantification is the same capacity planning standard used in BPA's short-term planning.

The 120-hour hydro capacity is defined as the average hourly HOSS Federal system hydro generation that is calculated from the highest six hours of generation for each of five weekdays of a four-week period. The split months of April and August use two 60-hour periods representing the highest six hours of generation for each of the five weekdays of each two-week period. The generation is calculated for all water conditions to obtain hydro energy to 120-hour peaking capacity curve relationships for the 80 water conditions for the study period. This Study uses only 1958 water conditions, however, which approximate average water conditions.

The 120-hour hydro peaking capacity values are constructed using the output of HOSS (calculation of these relationships is described in greater detail below) and are applied to the 14-period average energy amounts produced by HYDSIM. These 120-hour capacity values are averaged for FY 2014–2015, and this average is considered to be the amount of reliable monthly 120-hour hydro peaking capacity that would be available for operational planning purposes for this Study. Documentation Table 3.1.

3.2.6 Detailed Development of 120-Hour Hydro Peaking Capacity

Summaries of the hourly output of HOSS are used to develop relationships between the average energy during each of the 14 periods of the year and the associated 120-hour hydro peaking capacity for each of the 80 historical water years. These relationships are created through curves that define peaking capacity as a function of monthly energy for each of the 80 hydro conditions. The data from HOSS are entered into an Excel spreadsheet, and the curve-fitting function in Microsoft Excel is used to generate a peaking capacity equation for each period that reflects the 120-hour peaking capacity of the system for any given energy content for that period. The equation will produce a 120-hour peaking amount (Y) for any input average energy amount (variable X). Documentation Table 3.3 shows an example of the 120-hour peaking capacity

curves that are developed from the HOSS output. For any amount of Federal regulated hydro energy, there is an associated 120-hour Federal hydro capacity that is available to meet Federal obligations.

The 120-hour capacity equations (curves) are developed for each of the 14 periods of the year. For the purpose of this Study, 1958 water conditions were selected to represent average water conditions for the regulated hydro energy to 120-hour capacity relationship. The regulated hydro energy for 1958 water conditions was an input that was applied to the 120-hour capacity equations to produce the 120-hour hydro peaking capacity for each period. Documentation Table 3.1, lines 2, 5.

3.2.7 Big 10 Hydro 120-Hour Peaking Capacity for the Embedded Cost Methodology

To determine the 120-hour hydro peaking capacity of the Big 10 hydro projects used in the embedded cost methodology, the following steps are taken: (1) the capacity amounts for the regulated hydro projects are converted into annual averages for the FY 2014–2015 rate period (Table 3.1, lines 2, 5, and 8); (2) the annual average capacity for regulated hydro is adjusted for transmission losses by applying the capacity transmission loss factor of 3.35 percent, which was provided by BPA's Transmission Services (Table 3.1, lines 8, 10, and 11); and (3) because the HOSS model treats Federal regulated hydro as a system, not as individual hydro projects, to determine the 120-hour capacity amount for the Big 10 hydro projects the proportion of the 14 regulated hydro projects that represents the Big 10 hydro projects is calculated. The Big 10 projects represent 94 percent of the annual average energy forecasted to be produced by all 14 regulated hydro projects for FY 2014–2015, as shown in Documentation Table 3.2, line 17.

The 94 percent portion of the regulated hydro is used in the Regulating, VERBS, and DERBS Reserves cost allocations, shown in Documentation Table 3.6, line 7.

3.2.8 Embedded Unit Cost Calculation

The embedded unit cost of Regulating, DERBS, and VERBS Reserves is calculated by taking the embedded cost net revenue requirement associated with the Big 10 hydro projects and dividing this cost by the 120-hour peaking capacity total system uses. Documentation Table 3.6. The "total system uses" is the sum of the Big 10 hydro projects' 120-hour peaking capacity (adjusted for transmission losses) and the forecast quantities for Regulating Reserve, Operating Reserve, Load Following Reserve, VERBS Reserve, and DERBS Reserve. Study section 2; Documentation Table 2.18. The embedded costs are allocated based on the *inc* reserve forecast.

The Operating Reserve quantity includes both spinning and supplemental (non-spinning) reserve. The Operating Reserve quantity used in the embedded cost calculation is reduced to take into account that Supplemental (non-spinning) Operating Reserve can be carried on projects in addition to the Big 10 hydro projects. The Big 10 hydro projects provide 91 percent of the Operating Reserve of the hydro projects in the BPA balancing authority. The hydro projects capable of providing Operating Reserve are the 14 regulated hydro projects and the independent hydro projects within the BPA balancing authority area. This is a different adjustment from the 94 percent adjustment described above, which represents the Big 10 as a proportion of the 14 regulated hydro projects. The Supplemental Operating Reserve quantity, 279.5 MW, is reduced by nine percent to account for the portion that is carried on projects other than the Big 10 hydro projects. Documentation Table 3.6, line 3.

3.2.8.1 Net Revenue Requirement Associated with the Big 10 Projects

The embedded cost net revenue requirement associated with the Big 10 hydro projects is composed of (1) power-related costs of the Big 10 hydro projects on a project-specific basis; (2) an allocation of associated fish mitigation costs; (3) an allocation of administrative and general expense; and (4) three specific revenue credits. Documentation Table 3.5. The fish mitigation costs and the general and administrative costs are not set on a project-specific basis, so to allocate those costs to the Big 10 hydro projects, BPA takes 91 percent of these costs because, as stated above, the Big 10 projects comprise 91 percent of the hydro system in the BPA balancing authority area. The three specific revenue credits are 4(h)(10)(C) (non-operations) credits, Colville payment Treasury credit, and synchronous condensing. With the exception of the revenue credit for synchronous condensing (*Id.* line 20), the inputs for Table 3.5 are described in the Power Revenue Requirement Study, BP-14-E-BPA-02, Table 2E. The synchronous condensing costs are allocated to TS in a separate calculation (described in section 5 of this Study), so they are removed to avoid double-counting. The annual average net revenue requirement associated with the Big 10 projects for the rate period is $927,155,000. *Id.* line 21.

3.2.8.2 Calculation of the Embedded Unit Cost for Regulating, DERBS, and VERBS Reserves

The annual average net revenue requirement of the Big 10 hydro projects of $927,155,000 is divided by the total system uses of 11,153 MW to calculate the embedded unit cost of $6.93 per kilowatt per month for Regulating, DERBS, and VERBS Reserves. Documentation Table 3.6. The denominator is the sum of the *inc* reserve requirements supplied by the Big 10 hydro projects and the 120-hour peaking capacity of the Big 10 hydro projects. *Id.* lines 1-9.

3.2.8.3 Forecast of Revenue from Embedded Cost Portion of Regulating Reserve, VERBS Reserve, and DERBS Reserve

The embedded cost revenue from providing Regulating Reserve is forecast by applying the unit cost calculated above to the Regulating Reserve *inc* quantity forecast in Documentation Table 2.19, column F. The revenue forecast for the embedded cost portion is an average annual amount of $5,072,760. Documentation Table 3.6, line 14.

The embedded cost revenue from providing VERBS Reserve is forecast by applying the unit cost calculated above to the VERBS *inc* reserve quantity forecast in Documentation Table 2.20, column L. The revenue forecast for the embedded cost portion is an average annual amount of $43,409,520. Documentation Table 3.6, line 15.

The embedded cost revenue from providing DERBS Reserve is forecast by applying the unit cost calculated above to the DERBS *inc* reserve quantity forecast in Documentation Table 2.21, column L. The revenue forecast for the embedded cost portion is an average annual amount of $5,072,760. Documentation Table 3.6, line 16.

3.3 Direct Assignment of Costs

The cost category directly assigned to the VERBS rate is the Wind Integration Team (WIT) costs. This cost category is described in detail below.

3.3.1 WIT Costs

As a result of the FY 2009 Wind Integration Rate Settlement Agreement, BPA chartered an internal cross-agency WIT to resolve wind integration challenges presented by the interconnection of wind generation in the BPA balancing authority area. The WIT has developed and implemented numerous initiatives that have helped allow for a steady increase in

the amount of wind interconnected to BPA's balancing authority area. It is projected that in FY 2014–2015 additional work will be done to expand and advance the WIT initiatives to enhance BPA's capability to support the integration of additional wind generation in BPA's balancing authority area and the region.

The WIT budget is $3,725,000 for FY 2014 and $3,800,000 for FY 2015. This budget covers the costs incurred by Transmission Services, Power Services, Legal, and Corporate while working on WIT initiatives. The WIT costs cover employee, contractor, and vendor costs associated with the following WIT initiatives: Operational Controls (Dispatcher Standing Order 216), Intra-Hour Scheduling, Dynamic Transfer Limits study, Customer-Supplied Generation Imbalance, Enhanced Supplemental Service (including third-party supply), wind forecasting and state awareness tool development, and other initiatives that may be identified for the integration of variable energy resources.

3.4 Variable Cost Pricing Methodology

3.4.1 Introduction and Purpose

The FCRPS requires that a certain amount of machine capability be available to deliver the BPA balancing authority area's regulating, load following, and imbalance reserve capacity. The use of FCRPS capability to provide and deliver this balancing reserve capacity results in efficiency losses within the FCRPS. The Generation and Reserves Dispatch (GARD) Model was designed to calculate the costs associated with the various forms of efficiency losses associated with ensuring that sufficient machine capability is ready and capable of responding to and delivering the BPA balancing authority area's requirements for regulating reserve capacity, load following reserve capacity, and imbalance reserve capacity. These costs are generally referred to as variable costs.

The GARD Model was designed to capture efficiency losses while still functioning within the confines of the available rate development models. The variable costs associated with providing a quantity of balancing reserve capacity are assessed in the GARD Model using inputs from the HYDSIM model, actual system data, and a pre-processing spreadsheet. The purpose of the GARD Model is to calculate the variable costs incurred as a result of operating the FCRPS with the necessary balancing reserve capacity to maintain reliability and deploying the balancing reserve capacity to maintain load-resource balance within the BPA balancing authority area. 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 capable to automatically increase generation is referred to as an *inc* reserve. Likewise, the ability to be ready and capable to automatically decrease generation is referred to as a *dec* reserve.

The GARD Model is an MS Excel 2003-based model. All inputs and outputs are based in Excel spreadsheets. The core of the model is written in Visual Basic for Applications (VBA). The GARD Model analyzes variable costs in two general categories. The first category is the "stand-ready" costs, which are the costs associated with making a project capable of providing reserves. The second general cost category is the "deployment" costs, which are those costs incurred when the system uses its reserve capability to actually deliver in response to a reserve need. The deployment costs are calculated using the same inputs as the stand-ready costs in conjunction with a net balancing authority area station control error (SCE) signal. The net SCE signal is the sum of the difference between actual and scheduled balancing authority area generation and the difference between actual and scheduled balancing authority area load. The total difference between actual and schedule is calculated on a one-minute time-step, resulting in an amount of *inc* or *dec* that must be provided by AGC. The SCE signal is used within the GARD Model to

simulate the real-time movements of generation on a one-minute basis to calculate the cost of delivering reserves.

The GARD Model calculates the following costs associated with standing ready:

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. unit cycling costs associated with providing *dec* reserves
8. unit cycling costs associated with providing non-spinning *inc* reserves
9. unit cycling costs associated with providing spinning *inc* reserves
10. spill costs associated with providing non-spinning *inc* reserves
11. spill costs associated with providing spinning *inc* reserves

The GARD Model calculates the following costs associated with deploying balancing reserve capacity:

1. response losses associated with deploying *incs*
2. response losses associated with deploying *decs*
3. cycling losses associated with deploying *incs*
4. cycling losses associated with deploying *decs*
5. spill associated with *decs*

For each cost category, the GARD Model produces monthly cost and associated energy results for HLH and LLH by water year; the energy is denominated in megawatthour losses (in the

GARD Model, positive losses are reflected as gains). Sections 3.4.3 through 3.4.4 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 and at the same time 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) load regulation; (2) variable generation balancing; (3) the spinning portion of Operating Reserve; (4) thermal balancing; and (5) load following and energy imbalance. Variable generation balancing reserve capacity is a capacity reserve consisting of regulation, following, and imbalance. For further discussion regarding balancing reserve capacity, see Study section 2.1.

3.4.2 Pre-processes and Inputs

Section 3.4.2 describes the preparation of the input data into the GARD Model.

3.4.2.1 The Generation Request

The primary inputs into the GARD Model are tables of controller project-specific generation values calculated by HYDSIM. 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 of the Big 10 projects are capable of being, and at various times of the year are, armed for AGC response. 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, one-percent peak generation constraints, and minimum turbine flow constraints. Development of the functional relationships between average energy production and HLH generation relies on SCADA data from January 1, 2002, through December 31, 2007. The 2002–2007 period is used to balance 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 balancing authority area.

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. These quantities are put 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 is intended to mimic 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.

3.4.2.2 The Reserves

The balancing reserve capacity, limited to a maximum *inc* quantity of 900 MW and a maximum *dec* quantity of 1,100 MW, is input into the GARD Model by general reserve type. Specifically,

the reserves are input into the model by quantity of *inc* and *dec* regulation, *inc* and *dec* following, *inc* and *dec* imbalance, and total Operating Reserve. 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 the NERC requirements as well as system operator judgment. NERC requires that at least 50 percent of the balancing authority area Operating Reserve obligation be met with spinning capability responsive to AGC. NERC also requires that 100 percent of the balancing authority area Regulating Reserve 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, the reserve categories of following and imbalance 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. For imbalance reserve, up to 100 percent of the *inc* obligation may be met with non-spinning capability.

The rationale for carrying at least 50 percent of the *inc* following 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 rough zones. Synchronization generally takes about three minutes, with the unit fully ramped in 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 following reserve is consumed and the imbalance reserve capacity is deployed with non-spinning capability. By definition, all *dec* reserve capacity (the *dec* portion of the regulating, following, and imbalance

reserves) is spinning, because units must be generating (*i.e.*, the turbines are spinning) in order to deploy *dec* reserve capacity.

3.4.2.3 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. 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. As in actual operations, responses are input into the GARD Model as percentages, allocating the reserve capacity obligation among the controller projects.

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.

3.4.2.4 The Station Control Error File

The SCE file contains *inc* and *dec* signals for each minute of each month being studied. The SCE is used to calculate the deployment costs. It is not an input for the stand-ready cost calculation. As described in section 3.4.1, the SCE signal is the sum of the difference between actual and scheduled balancing authority area generation and the difference between actual and scheduled balancing authority area load. The total difference between actual and schedule is

calculated on a one-minute time-step, resulting in an amount of *inc* or *dec* that must be provided by AGC. The SCE signals for generation and load are allowed to net against one another in order to capture any diversity existing among the signals and avoid unnecessary generator movements. For example, assume that for a given minute total generation in the balancing authority area is above schedule by 500 MW, and total balancing authority area load is above schedule by 100 MW. Thus, the net condition in the balancing authority area is an overgeneration of 400 MW. In this example, the minute experiencing the 400 MW overgeneration requires a 400 MW *dec* deployment. The SCE signal read by the GARD Model originates from the Balancing Reserve Capacity Quantity Forecast. For further discussion regarding the SCE signal and its components, see section 2.7.1.

As the deployment of reserves is modeled, the SCE is allocated to a given controller project based on the controller project's response setting, where the response setting is an allocation of the total SCE to a given controller project denominated as a percentage. Continuing with the previous example and assuming a 50 percent response allocation to GCL, GCL will deploy 200 MW of *dec*.

The data in the SCE file limit the deployment of balancing reserve capacity to the maximum *inc* and *dec* obligation. In other words, reserves are never deployed in excess of what is being held based on the reserve obligation. Additionally, contingency reserve deployments are not included in the SCE file. The frequency, magnitude, and duration of contingency reserves have little measurable impact on the cost of deploying reserves. As a result, only the impact of carrying Operating Reserves (Contingency Reserves) is captured, and the impact of deploying Operating Reserves is not quantified.

3.4.3 Stand-Ready Costs

In order to meet the potential balancing reserve capacity requirements in any given hour, BPA's system is set up in advance such that the required balancing reserve capacity is available on all operating hours. Stand-ready costs are those variable costs associated with preparing to provide the required balancing reserve capacity from the FCRPS. Stand-ready costs are distinct from actually deploying balancing reserve capacity within the hour in response to the need. Four specific costs are incurred when preparing the FCRPS to stand ready to deploy balancing reserve capacity as needed: energy shift, efficiency loss, cycling losses, and spill losses.

3.4.3.1 Stand-Ready Energy Shift

The GARD Model's first step in determining the stand-ready effects 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." If the current generation request does not allow sufficient *inc* or *dec* capability, energy shift will occur. Should the input generation request result in adequate balancing reserve capacity, energy shifting is not necessary and no cost is assigned.

Energy may shift out of the HLH period in order to make *dec* capability available during the LLH period and/or to make available sufficient non-spinning and/or spinning *inc* capability 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 FCRPS 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 (clock hours 01:00 through 04:00). Depending on water conditions, energy may also be shaped into the shoulder LLH period (clock hours 23:00 through 00:00 and 05:00 through 06:00) to make available *dec* capability. In making available non-spinning and spinning *inc* capability,

energy shift impacts typically manifest as a reduction first in Super Peak generating capability followed by a shifting into the shoulder HLH period (this varies, but typically consists of clock hours 07:00 through 12:00 and 21:00 through 22:00). 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 3.4.2.1 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. Documentation Tables 3.7 through 3.10; Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. The cost of *inc* energy shift is included in the total variable cost that is included in rates. For FY 2014–2015, the total annual average energy shift is 1,845,055 MWh, worth $11,984,612. Documentation Table 3.11, lines 1-3.

3.4.3.2 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 the same 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 Corps of Engineers and the Bureau of Reclamation. This results in ten 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 one 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 tracks the efficiency effects explicitly 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. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. 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 efficiency change for FY 2014–2015 is a gain of 37,631 MWh, worth $929,237. Documentation Table 3.11, lines 4-6.

3.4.3.3 Stand-Ready Cycling Losses

Unit cycling losses originate from the additional synchronization and ramping of units. For cycling, the number of units cycled online or offline is calculated by comparing the online units for each unit family at a given controller project in the base case, assuming no balancing reserve capacity, to the online units in the case where the balancing reserve capacity requirement is being met. To the extent that more or fewer units are online, a cycling cost is realized. Because the GARD Model considers only HLH and LLH periods for this calculation, an observed unit cycle during any HLH or LLH period is said to occur for each day's HLH or LLH period within a month. For example, if one additional unit is online during the HLH period relative to a case without a reserve requirement, 31 unit cycles are assumed to occur; that is, one cycle for each of the 31 HLH periods in a 31-day month. The change in the number of units online is calculated for each of the controller projects.

Once the number of unit cycles for each controller project is tallied, the losses associated with cycling are calculated. The loss calculations are controller project-specific and are functions of the individual unit efficiency curves and the level of generation required from the individual units. For each unit on cycle, synchronization and ramping losses are calculated. For each unit off cycle, only ramp-down losses are calculated. During synchronization, water is lost as the unit is spun to synchronize grid frequency. Water losses during synchronization are equal to 10 percent of full gate flow for three minutes. Ramping losses occur as the unit ramps up to its required generation level. Losses associated with ramping are calculated by evaluating the integral of the specific unit efficiency function from minimum generation to requested generation. The GARD Model fully ramps units to their requested generation level over seven minutes. The calculation of cycling losses does not attempt to account for any additional maintenance costs that may be realized due to frequent cycling of the units. These additional

maintenance costs are not allocated in the GARD Model and are not accounted for in BPA's reserve pricing methodology.

Unit cycling losses are valued at the HLH price from the market price forecast for each month of the rate period. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. 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 cycling loss for the FY 2014–2015 period is 5,482 MWh, worth $170,803. Documentation Table 3.11, lines 7-9.

3.4.3.4 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. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. The total average spill loss for the FY 2014–2015 period is 63,951 MWh, worth $1,444,655. Documentation Table 3.11, lines 10-11.

3.4.4 Deployment Costs

In addition to the cost of having BPA's system set up to respond to balancing reserve capacity needs going into the operating hour, there are costs realized when the system is deployed by

AGC to meet the within-hour variations in loads and generating resources. The costs of meeting the within-hour variations in loads and generating resources are referred to as "deployment costs." Deployment costs are those variable costs incurred when the FCRPS automatically increases or decreases generation in order to balance the system. These costs are distinct from the stand-ready costs. The cost subcategories for deployment costs are response losses, cycling loss, and spill loss. For each subcategory of deployment cost, costs are calculated for HLH and LLH by balancing reserve capacity type for each month and water year.

3.4.4.1 Deployment Response Losses

Response losses are efficiency losses experienced when committed units are deploying *inc* or *dec* reserves in response to a balancing need. The GARD Model responds to a balancing need on a minute-to-minute basis, as directed by the SCE file (described in section 3.4.2.4 above), by dispatching committed units with the objective of maintaining load-resource balance while continuing to minimize total turbine outflow per unit of fuel from the given controller project. The GARD Model continually optimizes the unit dispatch by loading each online unit such that the marginal cost of each unit is identical while meeting the requested generation level and maintaining the Operating Reserve obligation. The efficiency changes are calculated on a minute-to-minute basis and tallied into monthly HLH and LLH bins.

Response losses are valued at the HLH price from the market price forecast for each month of the rate period. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. The HLH price is used, because the efficiency impacts—losses and gains in energy—are taken out of or put into the HLH period. The total average response loss for the FY 2014–2015 period is 42,397 MWh, worth $1,372,188. Documentation Table 3.11, lines 12-13.

3.4.4.2 Deployment Cycling Losses

Cycling losses are realized during the course of balancing reserve capacity deployment when committed units responding to a balancing need cannot continue deploying *inc* or *dec* balancing reserve capacity while staying within unit-specific operating constraints, and/or additional units are needed to continually maintain the Operating Reserve obligation. When committed units have reached their limits, additional units are brought online, in the event of continued *inc* deployment, or taken offline, in the event of continued *dec* deployment. The GARD Model determines how many units from each unit family are cycled by re-optimizing the unit commitment and dispatch. As generating units are cycled on or off, water is lost to synchronization and/or ramping.

The loss calculations are controller project-specific and are functions of the individual unit efficiency curves and the level of generation required from the individual units. For each unit on cycle, synchronization and ramping losses are calculated. For each unit off cycle, only ramp-down losses are calculated. Water lost during synchronization to grid frequency is assumed to equal 10 percent of full gate flow for three minutes. Losses associated with ramping are calculated by evaluating the integral of the specific unit efficiency function from minimum generation to requested generation. The GARD Model fully ramps units to their requested generation level over seven minutes. As with cycling losses for stand-ready cost, the calculation of cycling losses does not attempt to account for any additional maintenance costs that may be realized due to frequent cycling of the units.

Once the unit commitment has changed, the GARD Model will hold the new unit commitment for as long as practicable. The GARD Model tries to minimize changes in unit commitment to avoid excessive breaker operations and to minimize the thermal cycling (heating and cooling of machinery) of units, consistent with actual controller project operations.

Deployment cycling losses are valued at the HLH price from the market price forecast for each month of the rate period. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. The HLH price is used because the efficiency losses and water losses are taken out of the HLH period. The total average deployment cycling loss for the FY 2014–2015 period is 4,797 MWh, worth $157,629. Documentation Table 3.11, lines 14-15.

3.4.4.3 Deployment Spill Losses

Deployment spill arises if GCL receives a *dec* reserve deployment request requiring generation changes jeopardizing GCL's dynamic tailwater limitations. Should violation of tailwater constraints become a risk, GCL will have to spill water during the course of the *dec* deployment to maintain acceptable rates of change in tailwater elevation.

Deployment spill losses are valued at the respective HLH or LLH price from the market price forecast for each month of the rate period. Power Risk and Market Price Study, BP-14E-BPA-04, section 2.4. For FY 2014–2015, the average deployment spill loss incurred deploying *decs* is 79 MWh, worth $2,223. Documentation Table 3.11, line 16.

3.4.5 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 among load regulation, VERBS, Operating Reserves, DERBS, and the total of Load Following and energy imbalance. The variable cost

assigned to each of these categories is directly proportional to the quantity and type (*inc* and *dec* regulation, following, and imbalance) of reserve as calculated in the Balancing Reserve Capacity Quantity Forecast (Study section 2). As discussed in section 3.4.2.2, 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 six reserve categories, as listed in section 3.4.1: spinning (regulation *inc* plus the spinning portion of Operating Reserves) *inc*, regulation *dec*, following *inc*, following *dec*, imbalance *inc*, and imbalance *dec*. The proportional allocation of cost by reserve service is now possible, because each reserve service consists of some or all of the aforementioned reserve categories. Specifically, load regulation consists of spinning capability only; VERBS, comprised of regulation, following, and imbalance, consists of both spinning and non-spinning capability; Operating Reserve variable cost consists only of spinning capability; DERBS, comprised of regulation following an imbalance, consists of both spinning and non-spinning capability; and, finally, load following and energy imbalance consist of both spinning and non-spinning capability.

The aggregation of the GARD Model-calculated variable costs into the respective reserve service categories is shown in Documentation Table 3.12. The total average loss for the FY 2014–2015 period is 1,924,130 MWh, valued at $14,202,873. Documentation Table 3.11, line 17. The total annual average FCRPS variable cost used for setting rates for FY 2014–2015 is $14,202,873. Documentation Table 3.12, line 6.

Documentation Table 3.13 shows the variable costs for the VERBS regulating, following, and imbalance components. Documentation Table 3.14 shows the variable costs for the DERBS regulating, following, and imbalance components.

3.5 Cost Allocation for Purchases of Balancing Reserve Capacity

3.5.1 Introduction and Purpose

BPA estimates that it will be able to provide up to 900 MW of *inc* balancing reserve capacity and up to 1100 MW of *dec* balancing reserve capacity from the FCRPS for the FY 2014-2015 rate period. *See* Kerns *et al.*, BP-14-E-BPA-23. In certain situations described more fully below, however, the BPA balancing authority area need for balancing reserve capacity may exceed the amount of balancing reserve capacity available from the FCRPS. In these instances, BPA will attempt to purchase additional balancing reserve capacity when the *inc* balancing reserve capacity needs of the BPA balancing authority area exceed the balancing reserve capacity that BPA forecasts to be provided from the FCRPS. BPA will provide up to 1100 MW of *dec* balancing reserve capacity from the FCRPS but is not planning on purchasing *dec* balancing reserve capacity during the rate period. Therefore, this section 3.5 addresses only the purchase of *inc* balancing reserve capacity.

This section identifies the four types of balancing reserve capacity purchases and the method used to allocate the costs incurred by BPA for each type. Three of the purchase types (Types 1, 3, and 4, described in greater detail below) are caused by demand for additional balancing reserve capacity that can be linked to a particular customer or customer category. Consistent with the cost causation principle, the costs of these acquisitions are collected from the customer or customer category that caused the need for the purchase. Type 2 purchases are caused by an unplanned reduction in the supply of balancing reserve capacity from the FCRPS (*i.e.*, planned FCRPS-based balancing reserve capacity becomes unavailable during the rate period). Because Type 2 purchase costs are the result of rate case forecast error in the amount of planned FCRPS balancing reserve capacity (supply), Type 2 purchase costs are allocated more broadly than the other three types of acquisitions.

Balancing reserve capacity purchase costs allocated to load, Federal thermal, and non-AGC controlled hydro are assigned to Power Services and recovered through power rates. Power Services self-supplies balancing reserve capacity for these uses and does not pay an explicit Ancillary and Control Area Services Rate for these specific resources and the following and imbalance needs of load. Purchase costs allocated to variable and non-Federal thermal resources are recovered through formula rates in the VERBS and DERBS rate schedules. The VERBS and DERBS formula rates are addressed in detail in sections 10.5 and 10.6.

3.5.2 Types of Balancing Reserve Capacity Purchases

There are four types of balancing capacity purchases. Type 1 purchases are planned purchases needed to make up the shortfall, if any, between the planned Federal balancing reserve capability (900 MW) and the rate case planned balancing needs of the Base Service after adjusting for any self-supply of generation imbalance (CSGI or other self-supply). See Study Section 10.5 below for a description of VERBS Base Service and Full Service. Type 1 purchase costs are allocated to variable energy resource customers because, under BPA's cost allocation methodology, variable energy resources are creating the need for additional capacity beyond what the FCRPS can provide on a forecast basis. Documentation Table 3.17. Type 1 purchase costs are recovered through the VERBS Type 1 Purchases Charge. *See* Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, ACS-14 Ancillary and Control Area Services Rates (ACS-14 Rate Schedule) section III.E.6.

Type 2 purchases are needed when BPA is operationally unable to provide the planned Federal *inc* balancing reserve capacity (up to 900 MW). The acquisition amount needed depends on actual operations. The costs of these purchases will be allocated to all resources except AGC-controlled hydro resources because AGC-controlled hydro resources supply balancing reserve

capacity. Load is not allocated Type 2 purchase costs because load is already financially impacted by funding the VERBS Credit provided to variable energy resources. *See* section 3.6.2. The VERBS Credit and Type 2 purchases trigger off the same event, which is the FCRPS's inability to provide the planned *inc* balancing reserve capacity. The portion of Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources is collected through the VERBS and DERBS Type 2 Purchases Charges. *See* ACS-14 Rate Schedules sections III.E.6 and III.F.4. Purchase costs allocated to non-AGC-controlled hydro resources and Federal thermal resources will affect power customers through Power Services' financial reserves and the Slice True-up. Cost collection is handled differently for these resources because Power Services self-supplies the balancing reserve capacity for these resources, which negates the need to have an explicit Ancillary and Control Area Services Rate for these specific resources.

Type 3 purchases are needed to provide reserves for the VERBS Full Service balancing service option. The cost of these acquisitions will be collected from Full Service customers through the Type 3 Purchases Charge. The acquisition amount needed for Full Service is the difference between the amount needed for committed Base Service and the amount needed for Full Service. *See* ACS-14 Rate Schedules section III.E.6.

Type 4 purchases are needed to support an unplanned increase in balancing services needed by the balancing authority area. The balancing service need can be unexpectedly increased when (1) a wind, solar or non-Federal dispatchable energy resource elected to self-supply but is unable to continue self-supplying one or more components of VERBS or DERBS; (2) a wind, solar or non-Federal dispatchable energy resource has a projected interconnection date after FY 2015 but interconnects during the FY 2014–2015 rate period; (3) a wind resource commits to a specific

scheduling practice but does not maintain a scheduling performance consistent with or better than that committed scheduling practice; (4) a wind resource elected Base Service with a committed scheduling option but chooses to take Base Service with a longer scheduling period; or (5) a non-Federal dispatchable energy resource operating in another balancing authority area chooses to dynamically transfer into the BPA balancing authority area during the FY 2014-2015 rate period.

The costs of these purchases are directly assigned to the customer that receives the expanded balancing service through the VERBS and DERBS Type 4 Purchases Charge. *See* ACS-14 Rate Schedules sections III.E.6 and III.F.4.

3.5.3 Cost Allocation of Type 1 Balancing Reserve Capacity Purchases

The cost allocation methodology is applied equally and consistently to all uses of balancing reserve capacity in three "use categories" (Categories): (1) load; (2) dispatchable energy resources including Columbia Generating Station plus non-AGC-controlled hydro resources; and (3) variable energy resources. The cost allocation methodology is designed to identify which users of balancing reserve capacity are responsible for the need to purchase balancing reserve capacity beyond what the FCRPS can provide. Once identified, the costs of the purchased balancing reserve capacity are recovered in rates charged to the users responsible for the purchases.

The first step in the methodology is to proportionally allocate the planned balancing reserve capacity of the FCRPS to each Category based on each Category's size. The size of a Category for resources is the nameplate capacity. For load, it is the highest simulated schedule used in the Balancing Reserve Capacity Quantity Forecast as its nameplate equivalent. The amount of FCRPS balancing reserve capacity allocated to each Category is then compared to each

Category's balancing reserve capacity need, as identified in the Balancing Reserve Capacity Quantity Forecast, Study section 2.7. To the extent the balancing reserve capacity need of a particular Category is greater than the FCRPS reserve capacity allocated through the first step, that Category is preliminarily determined to be causing BPA's need to purchase additional balancing reserve capacity. The determination is a multi-step process when a Category (or multiple Categories) has a balancing reserve capacity need that is less than the MW amount of FCRPS reserves that could potentially be allocated to it in the first step. If this occurs, the methodology is reapplied to the Categories with remaining need until all needs are met or the methodology has proportionally spread the entire amount of the planned FCRPS balancing reserve capacity across the multiple Categories. After the planned FCRPS balancing reserve capacity has been allocated across all users, any remaining needs for balancing reserve capacity is assumed to have caused BPA's need to make Type 1 purchases.

For the FY 2014–2015 rate period, the FCRPS is estimated to provide a rate case average of 895 MW (maximum of 900 MW monthly) of *inc* balancing reserve capacity equal to 3.5 percent of the total of resource nameplate and the load equivalent (25,380 MW) in the BPA balancing authority area. The *inc* balancing reserve capacity need in the BPA balancing authority area is 3.6 percent, assuming 923 MW of need (including a reduction for self-supply of the generation imbalance component of VERBS). Documentation Table 3.19, lines 1-7. Because FCRPS *inc* reserves (900 MW) are not sufficient to provide the entire *inc* balancing reserve requirement (923 MW), Type 1 purchases of balancing reserve capacity are needed (approximately 27 MW on annual average). If a Category needs more balancing reserve capacity than 3.5 percent of its nameplate, it is preliminarily determined to be causing the cost of Type 1 purchase. If the Category needs less balancing reserve capacity than 3.5 percent of its nameplate, the allocation method meets those needs with FCRPS balancing reserve capacity and returns any excess to the pool to be distributed to the Categories with balancing reserve capacity needs above 3.5 percent

of their nameplate. This process is repeated until the balancing reserve capacity from the FCRPS is depleted. The Type 1 purchase costs are recovered from the Categories with remaining need. Application of the cost allocation methodology results in the cost of all Type 1 purchases allocated to Category 3 variable energy resources. Documentation Table 3.19.

3.5.4 Cost Allocation of Type 2 Balancing Reserve Capacity Purchases

Type 2 purchases are allocated to all resources except AGC-controlled hydro resources, since these resources provide balancing reserve capacity. These purchases are not allocated to loads since loads bear the financial impact of the VERBS Rate Credit. Similar to the method used for Type 1 purchases, cost responsibility is determined by first separating resources into three groups (Groups): (1) Federal thermal and non-AGC-controlled hydro; (2) non-Federal thermal; and (3) variable energy resources. Three Groups are created since each Group's balancing reserve capacity requirement is paid for differently. The balancing reserve capacity needed for Group 1, Federal thermal and non-AGC controlled hydro resources, is self-supplied by Power Services. The cost of the balancing reserve capacity needed for Group 2, non-Federal thermal resources, is collected through the DERBS rate. The cost of the balancing reserve capacity needed for Group 3, variable energy resources, is collected through the VERBS rate.

The allocation factor for each Group is based on each Group's balancing reserve capacity requirement relative to the total Group's balancing reserve capacity requirement. The allocation factor for Group 1 Federal thermal and non-AGC controlled hydro is a fixed percentage for the rate period. For the Initial Proposal, the allocation factor is 5 percent. The 5 percent is calculated as the forecast *inc* balancing reserve capacity requirement for Group 1 (33.46 MW) divided by the forecast *inc* balancing reserve capacity requirement for all three Groups (33.46 MW + 61 MW + 549.34 MW). Documentation Table 2.23, line 25; Table 2.24, line 25; Table

2.21, line 25; Table 2.20, line 25; and Table 2.22, line 25. A fixed allocation is used for these Group 1 resources because these resources do not have as much seasonal online/offline variation as non-Federal thermal resources or the amount of installed nameplate uncertainty as the growing variable energy resource fleet.

The remaining 95 percent of the Type 2 purchase costs is allocated to non-Federal thermal resources and variable energy resources. The allocation factors for non-Federal thermal resources and variable energy resources will be determined monthly based on the actual revenue received through the DERBS and VERBS Base Service rates each month. Fixed allocation factors are not used due to significant seasonal online/offline variation in the amount of non-Federal thermal resources generating in a month and the installed nameplate uncertainty of the growing variable energy resources fleet. The percent of the remaining costs allocated to non-Federal thermal resources is calculated as the total DERBS charges for the month divided by the sum of the total VERBS base charges and DERBS charges for that same month. The percent of the remaining costs allocated to variable energy resources is calculated as the total VERBS base charges for the month divided by the sum of the total VERBS base charges and DERBS charges for that same month. The sum of the VERBS percentage and DERBS percentage will be 100 percent.

3.5.5 Cost Allocation of Type 3 Balancing Reserve Capacity Purchases

Type 3 purchases are allocated 100 percent to the variable energy resources that take VERBS Full Service.

3.5.6 Cost Allocation of Type 4 Balancing Reserve Capacity Purchases

Type 4 purchases are allocated to the resource or resource group that caused the unplanned increase in balancing services. The purchase costs are directly assigned to the specific resource under the five conditions listed in section 3.5.2 above. *See* ACS-14 Rate Schedules sections III.E.6 and III.F.4.

3.6 Expected Value of the VERBS Credit for the Generation Inputs Revenue Forecast

A VERBS Credit is included in the VERBS rate schedule. ACS-14 Rate Schedule section III.E.7. This section explains the proposal to calculate the expected value of the VERBS credit for inclusion in the generation inputs revenue forecast.

3.6.1 Overview

The generation inputs revenue forecast was completed for the Initial Proposal before the calculation for the impact of the VERBS Credit was included in the revenue forecast. The forecast amount of the VERBS Credit is proposed to be included in the generation inputs revenue forecast when the final rate case numbers are run for the Final Study, which will be based on the best information available at that time. The following steps and inputs outline the proposal to estimate the financial impact of the VERBS Credit on the generation inputs revenue forecast.

3.6.2 Calculation of the VERBS Credit

A VERBS Credit (ACS-14 Rate Schedule section III.E.7) compensates customers when, due to hydro conditions, BPA is unable to supply the full amount of reserves forecast to be provided by the FCRPS. The VERBS Credit for *inc* is $7.30/kW/month of balancing reserve capacity and the

VERBS Credit for *dec* is $0.60/kW/month of balancing reserve capacity. These credits are based on both embedded and variable costs. Study Table 3. Applying these credits to the estimate of the reduced availability of balancing reserve capacity yields the revenue forecast adjustment made to account for the VERBS Credit. The reduction in balancing reserve capacity availability is estimated as a percentage of time on an annual average basis that the FCRPS is forecast not to be able to provide the balancing reserve capacity to VERBS. Based on current information, it is estimated that the FCRPS will be unable to supply the rate case forecast amount of balancing reserve capacity approximately 2 percent of the time, on an annual average basis. *See* Kerns *et al.*, BP-14-E-BPA-23, section 4. Applying the VERBS Credit *Inc* and *Dec* Balancing Reserves rates to this estimate yields a VERBS Credit of approximately $1.0 million annually. Documentation Table 3.21.

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4. OPERATING RESERVE COST ALLOCATION

4.1 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 Open Access Transmission Tariff (OATT). Operating Reserve backs up resources in the BPA balancing authority area. Power rates are reimbursed through revenue credits for the costs of providing Operating Reserve. Power Rates Study, BP-14-E-BPA-01, section 4.3. Rates for Operating Reserve are developed in section 10.4 of this Generation Inputs Study and are shown in the ACS-14 rate schedule, BP-14-E-BPA-10. The reserve that BPA uses for Schedules 5 and 6 of the OATT may be referred to in other contexts as "Contingency Reserve," but for purposes of allocating and assigning costs, BPA refers to such reserve as "Operating Reserve."

This section describes (1) the applicable Operating Reserve regional reliability standards that apply to the BPA balancing authority area; (2) BPA's methodology for forecasting the amount of Operating Reserve for the rate period; and (3) BPA's cost allocation methodology for Operating Reserve.

4.2 Applicable Regional Reliability Standards for Operating Reserve

BPA is obligated under the OATT to offer Operating Reserve, which includes both spinning reserve capacity and non-spinning or supplemental reserve capacity. The OATT 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 North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards.

The current WECC standard requires each balancing authority area to maintain sufficient Operating Reserve to meet the NERC Disturbance Control Standard BAL-STD-002-0. The amount must be 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 5 percent of the load responsibility served by hydro generation and 7 percent of load responsibility served by thermal generation. At least half of the total requirement must be spinning reserve.

Each NWPP member with variable generation (*i.e.*, wind and solar) in its balancing authority area must maintain Operating Reserve equal to 5 percent of the generation for which the balancing authority has load responsibility.

On March 25, 2009, NERC submitted a petition to the Federal Energy Regulatory Commission (Commission) seeking approval of a WECC-developed regional reliability standard designated as BAL-002-WECC-1, Contingency Reserves, and the concomitant retirement of BAL-STD-002-0. *Version One Regional Reliability Standard for Resource and Demand Balancing*, FERC Docket No. RM09-15, Petition of NERC (Mar. 25, 2009). The proposed WECC standard, BAL-002-WECC-1 (BAL-002), states that the minimum Operating Reserve requirement would be the greater of (1) the most severe single contingency, or (2) the sum of 3 percent of load (generation minus station service minus Net Actual Interchange) and 3 percent of net generation (generation minus station service). At least half of the total requirement must be spinning reserve.

On October 21, 2010, the Commission issued a remand for BAL-002 to NERC. *Version One Regional Reliability Standard for Resource and Demand Balancing*, FERC Docket No. RM09-15, Order No. 740, 133 FERC ¶ 61,063 (2010). In addressing concerns of the FERC

Order No. 740 remand, BAL-002 was resubmitted and passed in the March 2012 WECC Operating Committee by a member vote (117 affirmative, 31 negative, 10 abstain, 16 did not vote), and subsequently approved by the WECC Board in June 2012. BAL-002, as of September 2012, is currently under consideration for NERC approval; if it receives NERC approval, it will be forwarded for Commission approval. If approved, BAL-002 would become effective the first day of the first calendar quarter that is six months beyond the date it is approved by the Commission.

BPA must base its Operating Reserve forecast on the best information available regarding the WECC standard for Operating Reserve. Based on the estimated timing of approval by NERC and the Commission followed by at least six months for implementation, BPA is assuming that BAL-002 will be implemented on or before the start FY 2014–2015 rate period.

4.3 Calculating the Quantity of Operating Reserve Using the Proposed Standard BAL-002-WECC-1

The BPA balancing authority area Operating Reserve obligation under BAL-002 is determined as follows. First, the BPA balancing authority area load is forecast using BPA balancing authority area load in FY 2011 as the base year. The forecast of the loads through FY 2015 is determined through the BPA Agency load forecast, resulting in balancing authority area load growth of 1.15 percent in FY 2013, 1.89 percent in FY 2014, and 2.14 percent in FY 2015. *See* Documentation Table 4.1. Second, BPA balancing authority area generation is forecast based on a ratio of balancing authority area generation to balancing authority area load of approximately 2:1 observed from FY 2010 through FY 2012. Third, the total BPA balancing authority area Operating Reserve obligation is calculated by summing 3 percent of the forecast load and 3 percent of the forecast generation. The total BPA balancing authority area Operating Reserve

obligation under the BAL-002 standard is forecast to be 599.2 MW in FY 2014 and 612.0 MW in FY 2015 (605.6 MW average for FY 2014–2015). Documentation Table 4.2.

Operating Reserve obligation provided by self-supply and third-party supply is based on customer elections as of May 1, 2011, of self-supply and third-party provision of Operating Reserve for the FY 2012–2013 rate period. The total self-supply and third-party provision is 108 MW. The FY 2012–2013 basis for election will be used for FY 2014–2015 until elections are updated by May 1, 2013. For the FY 2014–2015 rate period, there are two adjustments made to the base election level. First, the stated election is adjusted to an expected provision basis. The hourly self-supply and third-party provision for FY 2012 is analyzed on a cumulative probability function. Based on the historical data, an expected value, or 50th percentile, of usage is determined to be 81 MW. Second, because the proposed standard is based on 3 percent of load and 3 percent of generation in the balancing authority area, an additional step is needed to adjust the reserve obligation for third-party and self-suppliers. The adjustment accounts for the change from 5.2 percent to 6 percent and for customers that have generation or loads, but not both, in the BPA balancing authority area. The obligation changes from 5.2 percent to 6 percent if the third-party and self-suppliers have load and generation in the BPA balancing authority area, or from 5.2 percent to 3 percent if load or generation is outside the BPA balancing authority area. As a result, the FY 2014–2015 forecast of self-supply and third-party supply under the proposed standard is 46.7 MW.

The difference of the total BPA balancing authority area Operating Reserve obligation and the amount provided by self-supply and third-party supply yields the Operating Reserve obligation to be provided by BPA. Assuming Commission approval of the proposed BAL-002 standard, the PS Operating Reserve obligation would be 552.4 MW in FY 2014 and 565.3 MW in FY 2015 (558.9 MW average for FY 2014–2015). Documentation Table 4.2. Shaped monthly Operating

Reserve amounts for FY 2014–2015, shown in Documentation Table 4.3, are based on the FY 2005–2011 percentage of BPA balancing authority area loads and BPA balancing authority area generation. BPA uses the FY 2014–2015 average forecast amounts in the calculation of the unit cost of Operating Reserve.

4.4 Cost Allocation for Operating Reserve

This section describes the method used to allocate embedded costs for the balancing reserve capacity uses of the FCRPS for Operating Reserve. In addition to the embedded costs, variable costs are allocated to TS for the spinning component of Operating Reserve. Study section 3.4.

4.4.1 General Methodology for Pricing the Embedded Cost Portion of Operating Reserve

The embedded unit cost of Operating Reserve is calculated by dividing the costs associated with all the hydro projects capable of providing Operating Reserve by the annual average capacity amount of those same hydro projects (adjusted for other requirements). The cost allocation methodology and the 120-hour peaking capacity calculation for the Big 10 projects are explained in Study section 3.2.

Calculating the capacity amount used to allocate Operating Reserve cost is similar to calculating the capacity amount used to allocate balancing reserve capacity cost, except that the Operating Reserve cost allocation includes the independent hydro projects that are capable of providing operating reserves in addition to the Big 10 projects. Documentation Table 4.4. As described in Study section 3.2, the Operating Reserve, Regulating Reserve, Variable Energy Resource Balancing Service (VERBS) Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Load Following Reserve that are removed from the HYDSIM and HOSS model analyses are added to the regulated and independent hydro capacity amounts to establish

total system capacity uses. The net revenue requirement for the system that provides Operating Reserve is then divided by the total system capacity uses to determine a base unit cost. The Spinning and Supplemental Operating Reserve obligations are identified, and the unit cost is multiplied by the forecast obligation for each to determine the embedded cost allocation forecast. The cost allocation forecast for Spinning Operating Reserve adds in the variable cost component to derive the unit cost and total cost allocation, as described in Study section 4.4.5.

4.4.2 Identify the System That Provides Operating Reserve

The first step in calculating the embedded cost for Operating Reserve is to determine the amount of capacity provided by the FCRPS. The annual average capacity amounts of the independent hydro projects in the BPA balancing authority area capable of providing Operating Reserve are added to the regulated hydro 120-hour peaking capacity amount. Documentation Table 4.4.

The annual average total hydro peaking capacity for purposes of calculating the embedded cost portion of capacity for Operating Reserve is 10,659 MW. Documentation Table 4.6, line 7. The other capacity use forecast quantity that covers Operating Reserve, Regulating Reserve, VERBS Reserve, DERBS Reserve, and Load Following Reserve is 1,454 MW, which is added to the hydro peaking capacity to obtain the Capacity System Uses of 12,113 MW. *Id.* lines 8-9.

4.4.3 Calculation of the Embedded Unit Cost of Operating Reserve Capacity

The embedded cost net revenue requirement for Operating Reserve is composed of (1) power-related costs of the relevant hydro projects on a project-specific basis; (2) an allocation of associated fish mitigation costs; (3) an allocation of administrative and general expense; and (4) three specific revenue credits. Documentation Table 4.5; *see also* Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2. The synchronous condensing costs are

allocated to TS in a separate calculation (described in section 5 of this Study), so those costs are removed (Documentation Table 4.5, line 20) to avoid double-counting.

The annual average revenue requirement of $1,054,766,000 is divided by 12,113 MW (the Capacity System Uses) to calculate the embedded unit cost of Operating Reserve, $7.26 per kW per month of reserve need. Documentation Table 4.6, line 13.

4.4.4 Forecast of Revenue from Embedded Cost Portion of Operating Reserve

The revenue forecast applies the unit cost calculated above to the forecast Operating Reserve quantity needed by TS. The forecast need on an annual average basis for the rate period is 558.9 MW. Documentation Table 4.3. The revenue forecast for the embedded cost portion is $48,691,368 per year. Documentation Table 4.6, line 14. As stated above, half of the Operating Reserve quantity, 279.45 MW, is Spinning Operating Reserve, and half is Supplemental Operating Reserve. The embedded cost revenue forecast for each service is half of the total, $24,345,684. Study Table 1, lines 15 and 18.

4.4.5 Total Cost Allocation and Unit Prices for Spinning Operating Reserve

In addition to the embedded cost for Operating Reserve, there is a variable cost component for Spinning Operating Reserve. The calculation of this variable cost component is documented in section 3.4. The cost allocation for the variable cost of Spinning Operating Reserve is $2,247,867. Documentation Table 3.12, line 3. The total forecast cost allocation for Spinning Operating Reserve, including both the embedded cost ($24,345,684) and the variable cost, is $26,593,551. Study Table 1, lines 15-17.

The variable unit cost for Spinning Operating Reserve is $0.67 per kW per month of reserve need, which is derived by dividing the total dollars allocated to the variable cost of Spinning Operating Reserve by the forecast amount of Spinning Operating Reserve converted to kilowatts per month. *Id.* line 16. The variable unit cost for Spinning Operating Reserve is added to the embedded unit cost to calculate a total unit cost for Spinning Operating Reserve of $7.93 per kW per month of reserve need. *Id.* line 17.

5. SYNCHRONOUS CONDENSING

5.1 Introduction

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. Thus, costs of synchronous condensing are allocated to Transmission Services (TS). 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). Generators operating in condense mode provide the same voltage control function as they do 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.

5.2 Synchronous Condenser Costs

Synchronous condensing costs are allocated to TS and recovered through transmission rates. Those revenues are then passed to Power Services (PS) as part of an inter-business line Memorandum of Agreement for Generation Inputs. Synchronous condensing costs include the cost of (1) energy consumed by FCRPS generators while operating in condense mode for voltage control; and (2) investments in plant modifications at John Day and The Dalles projects necessary to provide synchronous condensing that were not part of the original design. This investment was made because adding voltage support from these plants could best serve line loading concerns related to the Southern Intertie. Because both this investment and the operation of these synchronous condensers are primarily to serve Southern Intertie needs, these costs are broken out separately from other synchronous condensers' costs, which primarily serve the BPA balancing authority.

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $287,000 per year. Generation Inputs Study Documentation, BP-14-E-BPA-05A (Documentation), Table 5.2, line 9; Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Tables 2G and 2H. These costs are the annual capital-related costs in the Power revenue requirement associated with the investment that PS made in the plants at the request of TS 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, as described below.

5.3 General Methodology to Determine Energy Consumption

For the FY 2014–2015 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 2007, 2008, and 2009. The average number of hours of use during these three years is then 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. Documentation Table 5.1. Finally, the market price forecast shown in Table 5.1 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.

5.3.1 Grand Coulee Project

Six generators (Units 19–24) at Grand Coulee 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 Grand Coulee during nighttime hours (generally 10 p.m. to 6 a.m.) when the lightly loaded transmission system generates excess reactive power and causes voltage on the system to be high. If units online generating real power are insufficient to provide the needed voltage control during the night, then units in condense mode are assigned to voltage control.

For the forecast, the total measured reactive demand that the transmission system placed on the six units during the nighttime hours is determined, based on reactive meter readings for the historical three-year period. The total measured reactive demand represents the total reactive support (*i.e.*, megavolt amperes reactive) provided by the six units, regardless of whether the units are condensing or generating 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 (which absorbs reactive power and reduces voltage on the transmission system). 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 27,368 MWh. *Id.* line 4.

5.3.2 John Day, The Dalles, and Dworshak Projects

John Day has four generators (Units 11–14), The Dalles has five generators (Units 15–20), and Dworshak has three generators (Units 1–3) capable of operating as synchronous condensers. These three projects condense only when requested by TS, so all hours in condense mode are for voltage control. The number of condensing hours using meter data 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 15,091 MWh for John Day and The Dalles (*id.* line 3) and 884 MWh for Dworshak. *Id*. lines 5 and 6.

5.3.3 Palisades Project

Palisades has four generators (Units 1–4) that are capable of synchronous condensing. Units are operated in condense mode pursuant to standing instructions from TS based on operational studies, so all hours in condense mode are for voltage control. The number of condensing hours

using meter data 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 1,054 MWh. *Id.* line 7.

5.3.4 Willamette River Projects

The Willamette River projects have seven generators capable of condensing, which include units in Detroit (Units 1–2), Green Peter (Units 1–2), and Lookout Point (Units 1–3). Historically, these units have been operated at times in condense mode. However, BPA studies indicate that condensing is not required 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.

5.3.5 Hungry Horse Project

Hungry Horse 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.

5.4 Costs Allocated to Transmission Services

The investments in plant modifications at John Day and The Dalles result in an average cost of $287,000 per year. Documentation Table 5.2; Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Tables 2G and 2H.

The energy forecast to be consumed by FCRPS generators operating in condense mode totals 44,397 MWh. Documentation Table 5.1. The energy consumed for condensing operation is priced at the market price forecast as shown in the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. Applying the market price forecast of $29.10 per MWh to the energy consumed results in a total cost of $1,291,953 per year. Documentation Table 5.1, line 13.

Total synchronous condensing cost allocated to TS is $1,579,000 per year. Documentation Table 5.3, line 5. This amount is made up of $439,000 per year in energy costs (*id.* line 2) and $287,000 per year in plant investments for the Southern Intertie (*id.* line 1), and $853,000 associated with energy costs for voltage control for the Network. *Id.* line 4.

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

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, Power Services (PS) is requested by Transmission Services (TS) to 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, PS 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 Forecast Amount of Generation Dropping

Historically, large generating units at Grand Coulee have been dropped 18 times over the last 17 years (1996–2012). Therefore, the estimate of “large generating units dropped” is an average of approximately one drop per year.

6.4 General Methodology

The overall valuation approach considers two factors. First, the desired Generation Dropping Service or "forced outage duty" 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, Generation Inputs Study Documentation, BP-14-E-BPA-05A (Documentation), Table 6.1 shows the cost associated with equipment deterioration, replacement, and overhaul and the cost associated with routine operation and maintenance.

PS previously contracted with Harza Engineering Company to work with Reclamation and COE (which own and operate the Columbia River system plants) to evaluate the costs of providing this "generation drop" service. The evaluation estimated the cost incurred by a typical Reclamation or COE 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.

Second, lost revenues resulting from the outages required during replacement or overhaul of the equipment are computed. The market price forecast is applied to the energy amounts to determine the costs. Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4. Documentation Table 6.1, columns H–K, shows the calculation of this lost revenue.

6.5 Determining Costs to Allocate to Generation Dropping

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 during "forced outage duty" versus stresses during "normal operation" are compared. Through the application of this data, the capital and operation and maintenance costs for the generation drop

service are developed. The impacts are converted into a percentage change in equipment life for each operation. Finally, the estimated costs and lost revenue for the most likely type of overhaul or replacement that would need to be made are evaluated for a reduced life expectancy of the equipment. Documentation Table 6.1 shows the percentage reductions in life expectancies per generation drop.

In addition to capital and operation and maintenance costs, 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. Although some outages for routine maintenance could be scheduled to avoid large revenue losses, other outages cannot be scheduled to avoid lost revenues. Thus, such lost revenues are calculated based on the market forecast price averaged over the rate period, FY 2014–2015. It is assumed that these outages are unpredictable or longer than scheduled, and cannot be scheduled to avoid a loss in total project generation. Documentation Table 6.1, columns H–K, shows the calculation of the lost revenue.

6.6 Equipment Deterioration, Replacement, or Overhaul

The 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. For example, turbine overhaul is a major maintenance effort that will be increased in frequency as a result of more frequent severe duty cycles.

6.7 Costs to be Allocated to TS

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 the analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units is calculated to be $334,707. Documentation, Table 6.1, line 6. Because the estimate of large generating units dropped is an average of one drop per year, the annual cost is $334,707. This cost is assigned to TS for recovery in transmission rates. The rate period annual average cost for Generation Dropping is a revenue credit to the power rates. Power Rates Study, BP-14-E-BPA-01, section 4.3.

7. REDISPATCH

7.1 Introduction

Under Open Access Transmission Tariff (OATT) Attachment M, Transmission Services (TS) initiates redispatch of Federal resources as part of congestion management efforts. Generally, redispatch results in decrementing *(dec)* resources that can effectively relieve flowgates that are at or near Operating Transfer Capability (OTC) limits and incrementing *(inc)* other resources to maintain service to loads. TS is paid for the decrementing of resources and pays for the incrementing of resources. This concept is intended to keep the incrementing and decrementing resource whole financially.

In the case of a decrementing resource, the resource owner avoids certain costs associated with generation, such as fuel costs and operation and maintenance costs, and decrementing the resource also reduces the risk that a curtailment may be necessary to relieve the congestion. As a result, the owner of the decrementing resource pays TS the equivalent of its avoided costs and reduces the risk of curtailments.

In the case of an incrementing resource, the resource generates energy that it could have otherwise sold. To keep the incrementing resource whole financially, TS pays the resource owner for the value of that generation. In practice, under OATT Attachment M, Power Services (PS) is the provider of both the *inc* and the *dec* resource. This typically results in a net payment to PS for each redispatch event. In this document the term “revenue” or “amount” refers to the net revenue associated with the PS *inc* and *dec* redispatch activity.

There are three levels of redispatch under OATT Attachment M that TS can request from PS to relieve flowgate congestion: Discretionary Redispatch, NT Firm Redispatch, and Emergency Redispatch. PS may provide redispatch under Attachment M through redispatch of Federal generation, through purchases and/or sales of energy, or through transmission purchases. The purpose of each of these types of redispatch is discussed further below. The actual revenue PS receives from TS for providing redispatch under Attachment M is calculated based on one of two sources, depending on how the redispatch is provided: either based on market prices for incrementing and decrementing Federal generation at the time the redispatch is provided, for redispatch provided from Federal generation; or based on the actual cost to PS of purchasing and/or selling power or purchasing transmission, for redispatch provided by purchases and/or sales of energy or purchases of transmission.

This Study forecasts revenues PS expects to receive from TS for the provision of redispatch under Attachment M. The revenue forecast for PS providing redispatch for FY 2014–2015 is developed by identifying the costs from PS providing redispatch in FY 2010–2011, the most recent rate period for which BPA has actual data, and comparing this amount to the forecast for the same period. The forecast is adjusted up or down based on this comparison and on the variables that drive the costs of redispatch. The forecast may be adjusted upward to reflect potential increases due to increased uncertainty or anticipated increases in market prices; or it may be adjusted downward to reflect unusual redispatch events that are not expected to recur, increased constraints on PS's ability to provide redispatch, or anticipated decreases in market prices.

7.2 Discretionary Redispatch

Under OATT Attachment M, TS may request bids for Discretionary Redispatch from Federal resources to *inc* and *dec* generation prior to curtailment of any transmission schedules. PS may respond to requests for Discretionary Redispatch by offering, at each generating project, either no Discretionary Redispatch or any amount of Discretionary Redispatch up to the amount requested.

For FY 2010 and FY 2011, TS forecast payments to PS for Discretionary Redispatch of $175,000 per year. Actual PS revenues from the Discretionary Redispatch that PS provided to TS totaled $46,439 in FY 2010 and $11,355 in FY 2011. Documentation Table 7.1, lines 28-29. Documentation Table 7.1 provides the actual monthly Discretionary Redispatch revenues and other details for FY 2010 and FY 2011. For FY 2012 and FY 2013, TS again forecast payments to PS for Discretionary Redispatch of $175,000 per year.

As described above, the actual PS revenues for FY 2010 and FY 2011 were considerably lower than the $175,000 per year forecast for both the FY 2010–2011 rate period and the FY 2012–2013 rate period. PS's provision of Discretionary Redispatch and the resulting revenues have been declining over time as the FCRPS becomes more constrained. PS's provision of Discretionary Redispatch and associated actual revenues in FY 2011 were extraordinarily low compared to the forecast costs due in part to an extremely high water year. High water conditions limit flexibility on the FCRPS and thus limit PS's ability to provide redispatch of Federal generation.

The forecast for FY 2014 and FY 2015 Discretionary Redispatch is $50,000 per year. This is a reduction from previous years' forecasts and is based on the lower-than-forecast actual revenues

in FY 2010 and FY 2011 and increasing constraints on PS's ability to provide Discretionary Redispatch on a monthly and seasonal basis. The forecast amount for FY 2014 and FY 2015 is greater than actual average revenues in previous years to reflect the unpredictable nature of transmission congestion and the need for Discretionary Redispatch, and the risk inherent in forecasting Discretionary Redispatch costs.

7.3 NT Firm Redispatch

NT Firm Redispatch is provided under OATT Attachment M. TS requests NT Firm Redispatch from PS to maintain firm NT schedules after all non-firm Point-to-Point and secondary NT schedules are curtailed in a sequence consistent with NERC curtailment priority. PS must provide NT Firm Redispatch when requested by TS to the extent that it can do so without violating non-power constraints.

For FY 2010–2011, TS forecast payments to PS for NT Firm Redispatch of $225,000 per year. Actual revenues to PS from NT Firm Redispatch provided to TS totaled $49,261 in FY 2010 and $470,500 in FY 2011 (averaging $259,881 per year). Documentation Table 7.2, lines 26-27. This revenue represents only payments from TS to PS associated with NT Firm Redispatch provided through transmission purchases. There were no PS revenues associated with PS providing NT Firm Redispatch through the redispatch of Federal generation or through power purchases or sales over this time period. Documentation Table 7.2 provides the actual monthly NT Firm Redispatch revenues, the megawatthours redispatched, dollars per megawatthour for FY 2010 and FY 2011, and the constrained path.

For FY 2012–2013 the forecast for NT Firm Redispatch costs remained at $225,000 per year. Given the increase in the need for NT Firm Redispatch in FY 2011, which we expect to continue,

the resulting higher-than-forecast average annual revenues in the FY 2010–2011 rate period, and the variability in transmission and power prices on a monthly and seasonal basis, the forecast for NT Firm Redispatch in FY 2014–2015 is $350,000 per year.

7.4 Emergency Redispatch

Emergency Redispatch is provided under OATT Attachment M. TS requests Emergency Redispatch from PS when TS declares a System Emergency as defined by NERC. PS must provide Emergency Redispatch when requested by TS even if PS may violate non-power constraints.

The forecast of costs from the provision of Emergency Redispatch by PS to TS was $0 for the FY 2010–2011 and FY 2012–2013 rate periods. Actual revenues from Emergency Redispatch provided by PS to TS for FY 2010 totaled $1,510, resulting from one Emergency Redispatch event. No Emergency Redispatch was provided in FY 2011.

Due to the unlikely nature of Emergency Redispatch and the low actual revenues of Emergency Redispatch for FY 2010 and FY 2011, the cost of Emergency Redispatch is forecast to be $0 for FY 2014–2015.

7.5 Revenue Forecast for Attachment M Redispatch Service

Based on the analysis above, a total of $400,000 per year is forecast for FY 2014–2015 for Discretionary and NT Firm Redispatch services provided by PS to TS under OATT Attachment M.

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8. SEGMENTATION OF U.S. ARMY CORPS OF ENGINEERS AND U.S. BUREAU OF RECLAMATION TRANSMISSION FACILITIES

8.1 Introduction

The U.S. Army Corps of Engineers (COE) and U.S. Bureau of Reclamation (Reclamation) own transmission facilities associated with their respective generating projects within the Federal Columbia River Power System (FCRPS). All COE and Reclamation costs are assigned to the generation function in the Power Revenue Requirement Study, BP-14-E-BPA-02. Therefore, this study identifies COE and Reclamation transmission-related investment so that the proper portion of the annual cost of these transmission facilities may be assigned to Transmission Services (TS). The annual cost of these transmission facilities includes operations and maintenance (O&M) expenses, depreciation, interest expense, and Minimum Required Net Revenue (MRNR).

The COE and Reclamation transmission-related investment is associated with three Federal Columbia River Transmission System (FCRTS) segments: (1) Generation Integration, (2) Integrated Network, and (3) Utility Delivery. The Generation Integration investment is assigned to Power Services (PS) to be recovered through power rates. The average annual cost of the Network and Utility Delivery investments over the rate period is allocated to TS, and the resulting revenues are credited to the PS revenue requirement. The definitions of these segments are consistent with the definitions used in the Transmission Segmentation Study, BP-14-E-BPA-06, section 2. The relevant segment definitions and cost treatment are described below.

8.2 Generation Integration

Generation Integration facilities connect Federal generation to the BPA Network. This segment includes generator step-up transformers (GSUs) and the substation terminals and lines that integrate the Federal generation into the network. The COE and Reclamation Generation Integration costs remain functionalized to the generation function.

8.3 Integrated Network

Integrated Network facilities provide for bulk transmission of electric power within the Pacific Northwest and operate at voltages of 34.5 kilovolts (kV) and above. This Study identifies the COE and Reclamation transmission costs that are associated with Network facilities and allocates these costs to TS.

8.4 Utility Delivery

Utility Delivery facilities deliver power to BPA utility customers at voltages below 34.5 kV. The COE and Reclamation transmission costs that are associated with Utility Delivery facilities are allocated to TS.

8.5 COE Facilities

The transmission facilities owned by the COE are primarily GSUs and associated equipment at the projects. These facilities are all associated with Generation Integration, which remains functionalized to the generation function. There is one exception at the Bonneville Project. At Bonneville Powerhouse No. 1, the COE owns the switching equipment located on the dam that performs both Network and Generation Integration functions. This switching equipment is segmented between Network and Generation Integration as described in the documentation for this study, BP-14-E-BPA-05A (Documentation), Table 8.1.

8.6 Reclamation Facilities

Reclamation owns the lines and switchyards in the substations at its plants within the FCRPS. The primary function of these facilities is to connect the generators to the Network, but at some substations there are facilities that perform Network and Utility Delivery functions. The Documentation shows the information used to assign the lines and substation investment at each Reclamation project to the appropriate segment. Documentation Tables 8.2 and 8.3 describe the Columbia Basin project (Grand Coulee), and Table 8.5 describes the other Reclamation projects: the Hungry Horse Project, the Roza and Kennewick Divisions of the Yakima Project, the Rogue River (Green Springs) Project, the Minidoka and Palisades Divisions of the Minidoka-Palisades Project, and the Boise Project (Anderson Ranch and Black Canyon).

The available Reclamation investment data does not disaggregate costs to the equipment level. Therefore, to develop investment by segment(s), typical costs are used as a proxy for major pieces of equipment. Documentation Tables 8.4 and 8.5. The proxy investment by segment is divided by the total proxy investment for each switchyard or facility to develop a percentage for each segment. These percentages are then multiplied by the actual total switchyard or facility investment to estimate the actual investment for each segment. *Id.* The segment percentage is multiplied by the total transmission investment for each facility to determine the segment investment. Documentation Tables 8.3 and 8.5.

The investment of the land associated with the Reclamation switchyard equipment is included in the total investment. As shown on Reclamation financial statements, the total investment of the land associated with the switchyards at the Roza Division of the Yakima Project, the Minidoka Division of the Minidoka-Palisades Project, and the Boise Project totals $10,458, or about 0.06 percent of the combined $18,937,411 investment of these projects. Documentation Table 8.5.

8.6.1 Columbia Basin Transmission Investment

The Columbia Basin project includes generation equipment and associated switchyard equipment. The Reclamation transmission facilities start at the generator side (low side) of the step-up transformer and include the step-up transformers but not the powerhouse switching equipment. The Columbia Basin project investment also includes the 115/12.5 kV facilities at the Coulee Left Switchyard, which are used for station service and to deliver power at 12.5 kV to the Town of Coulee Dam, Nespelem Valley Electric Cooperative at Lone Pine, and Grant PUD. Documentation Tables 8.3 and 8.4. Because these facilities serve both Generation Integration and Utility Delivery functions, the investment at these facilities is segmented accordingly.

In calculating the investment for the Columbia Basin project, interest during construction (IDC) and other general costs are allocated based on investment. The IDC allocated to each segment is based on the IDC for the entire project divided by the total project investment, or an interest rate of 11.6 percent, using FY 2011 data. Documentation Table 8.3, line 5. The investment in the Columbia Basin project does not include construction work in progress.

The inclusion of land costs increases the Columbia Basin investment by $70,623, or 0.03 percent of the total investment. *Id.* line 12. In accordance with Reclamation practice, IDC is not applied to land associated with Columbia Basin transmission costs.

The Generation Integration segment comprises 67.8 percent of the transmission investment in the Columbia Basin project; the Integrated Network segment comprises 31.1 percent; and the Utility Delivery segment comprises 1.1 percent. *Id.* line 31.

8.7 Annual Cost of the COE and Reclamation Facilities allocated to TS

The investment for COE and Reclamation transmission facilities totals $200.9 million for Generation Integration, $77.5 million for Integrated Network, and $2.4 million for Utility Delivery. Documentation Table 8.6, line 7. The proportion of the investment associated with Integrated Network and Utility Delivery facilities compared to the total hydro system investment is used to develop the proportion of the total hydro system costs allocated to TS.

For each facility, the annual forecast of total hydro system O&M expense is multiplied by the ratio of the facility's transmission investment (Integrated Network plus Utility Delivery) to the total hydro system investment to determine the amount of the total hydro system O&M expense that is allocated to TS. Power Revenue Requirement Study, BP-14-E-BPA-02, chapter 2, Tables 2I and 2J. The O&M expense allocated to TS at each facility is then further allocated between the Integrated Network and Utility Delivery segments according to the allocated investment in each segment for the facility. The segmented O&M costs across all the facilities are added to determine the annual total O&M costs allocated to TS.

The depreciation expense for each facility is calculated based on the gross transmission investment in the facility and the appropriate depreciation rates. *Id.* The depreciation at each facility is allocated between the Integrated Network and Utility Delivery segments according to the allocated investment in each segment for the facility. The segmented depreciation costs across all the facilities are added to determine the annual total depreciation costs allocated to TS.

A portion of the general costs to be recovered across all power rates is included in the transmission costs associated with the COE and Reclamation facilities because they are part of the FCRPS. This includes both the hydro system net interest expense and hydro system MRNR. *Id*. These costs are multiplied by the ratio of the COE and Reclamation transmission net plant

investment to the hydro system net plant investment to calculate the portion of the hydro system interest expense and MRNR allocated to TS, which are further allocated to the Integrated Network and Utility Delivery segments according to the investment allocated to each segment from all COE and Reclamation facilities.

Adding the costs from each category results in a total annual cost allocated to TS of $6.353 million for FY 2014 and $6.146 million for FY 2015. *Id*. The power revenue requirement is reduced by these amounts, and the transmission revenue requirement is increased by these amounts, for each respective year of the rate period.

9. STATION SERVICE

9.1 Introduction

Station Service refers to real power that Transmission Services (TS) takes directly off the BPA power system for use at substations and other locations, such as facilities located on the Ross Complex and the 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 Risk and Market Price Study, BP-14-E-BPA-04, section 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to TS for station service energy use. This section describes the station service energy use and determines the costs that are allocated to TS for station service energy use.

9.2 Overview of Methodology

The Station Service costing methodology consists of the following steps. First, the amount of installed transformation is established, measured in kilovolt amperes (kVA) at all BPA substations served directly by the BPA power system. Second, the historical monthly average station service energy use is determined for substations for which load data exists. Third, an average load factor is derived based on the ratio of installed station service transformation and energy use for those substations for which load data exists. Fourth, the station service energy use for all facilities other than the Big Eddy/Celilo and Ross 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 give an annual average

estimated total energy use for all substations, which is then adjusted for transmission losses by applying the BPA network loss factor, 1.9 percent. The annual average forecast market price from the Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to TS for station service energy use.

9.3 Assessment of Installed Transformation

The 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 46,214 kVA. Documentation Table 9.2, line 6. Of this amount, the total amount of installed transformation at BPA substations for which load data exists is 15,456 kVA. Documentation Table 9.1, line 41.

9.4 Assessment of Station Service Energy Use

The historical average monthly use for Big Eddy/Celilo Complex is 1,822,937 kWh and for Ross Complex is 1,749,300 kWh, for a total of 3,572,237 kWh. Documentation Table 9.2, lines 4-5.

The total historical average monthly use for other BPA locations for which load data exists is 1,066,446 kWh. Documentation Table 9.1, 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. Documentation Table 9.2, lines 1-3.

9.5 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. Documentation Table 9.1, line 41.

9.6 Calculating the Total Quantity of Station Service

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. Documentation Table 9.2, 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 1.9 percent. BPA Open Access Transmission Tariff Schedule 11. 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 82,665,068 kWh per year. *Id.* line 6.

9.7 Determining Costs to Allocate to Station Service

The annual average forecast market price (Power Risk and Market Price Study, BP-14-E-BPA-04, section 2.4) applied to the estimated annual quantity of station service energy yields the costs per year to be allocated to Station Service. The rate period annual average cost for Station Service is $2,405,552. *Id.*

9.8 Impact on Power Rates and Transmission Rates

The rate period annual average cost for Station Service is a revenue credit to the power rates. Power Rates Study, BP-14-E-BPA-01, section 4.3.

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 three-year average Operations & Maintenance segmentation. Transmission Revenue Requirement Study, BP-14-E-BPA-08.

10. ANCILLARY AND CONTROL AREA SERVICES

10.1 Introduction

To supply generation inputs, Power Services (PS) provides a portion of available generation from the FCRPS to Transmission Services (TS). PS assigns the costs of these generation inputs to TS. Accordingly, TS sets the rates for Ancillary and Control Area Services to recover the generation input costs assigned to it by PS.

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-14-E-BPA-07.

10.2 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-14 Rate Schedule) in the Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10.

The calculations for the Ancillary and Control Area Service rates are shown in this Study in Table 4. Table 1 in this Study contains the forecast of generation inputs revenues.

10.2.1 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the balancing authority areas 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, BP-14-E-BPA-07.

In addition, consistent with current North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards, BPA is required to offer to provide the following Ancillary Services to transmission customers serving load within the BPA balancing authority area:

(3) Regulation and Frequency Response Service; and

(4) Energy Imbalance Service.

BPA is also required to offer to provide, consistent with applicable NERC and WECC standards, the following Ancillary Services to transmission customers serving load or integrating generation within the BPA balancing authority area:

(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 is required to acquire these last four Ancillary Services (numbers 3 – 6) from BPA, from a third party, or by self-supply.

10.2.2 Control Area Services

Control Area Service rates apply to transactions in the BPA balancing authority area 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 (RFR) Service

(2) Generation Imbalance Service

(3) Operating Reserve – Spinning Reserve Service

(4) Operating Reserve – Supplemental Reserve Service

(5) Variable Energy Resource Balancing Service (VERBS)

(6) Dispatchable Energy Resource Balancing Service (DERBS)

Resources or loads in the BPA balancing authority area 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 balancing authority area.

10.2.3 Ancillary Services and Control Area Services Rate Schedule

The ACS-14 Rate Schedule includes rates for six Ancillary Services and six Control Area Services. All rates in the ACS-14 Rate Schedule are subject to the *Rate Adjustment Due to FERC Order under Federal Power Act Section 212*. Transmission, Ancillary and Control Area Service Rate Schedules, BP-14-E-BPA-10, General Rate Schedule Provision (GRSP) II.D.

The following Ancillary and Control Area Service rates are subject to adjustment under BPA's Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and National Marine Fisheries Service FCRPS Biological Opinion (NFB) Mechanisms: RFR, Spinning Reserve Service, Supplemental Reserve Service, VERBS, and DERBS. *Id.* GRSP II.H.

10.3 Regulation and Frequency Response Service Rate

RFR service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining system-wide frequency at 60 cycles per second (60 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 moment-by-moment changes in load. WECC reliability standards require BPA to maintain sufficient regulating reserve to cover the requirements of all load in the BPA balancing authority area. BPA must offer this service when the transmission service is used to serve load within the BPA

balancing authority area. 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.

The Control Area RFR service is the same technical service, at the same rate, as the Ancillary RFR service. The difference is that the Control Area service is offered to customers serving load in the BPA balancing authority area other than by BPA OATT transmission service.

The RFR service provides capacity for meeting the balancing requirement, and the RFR rate recovers the costs through a charge applied to the customer's load in the BPA balancing authority area.

10.3.1 RFR Sales Forecast

BPA forecasts RFR sales from the point-of-delivery load forecast for transmission customers serving load in the BPA balancing authority area. The load forecast for RFR is the average energy served for each month of the rate period. *See* Study Table 4, line 36. The forecast of annual average load for RFR in the BPA balancing authority area for the FY 2014–2015 rate period is 5,876 aMW. *Id.*

10.3.2 RFR Rate Calculation

The generation inputs cost for PS to provide regulation is $5.983 million, as calculated in sections 3.2.8.2, 3.2.8.3, and 3.4 above, and Study Table 1. All transmission customers serving load in the BPA balancing authority area are charged for RFR service based on the customer's load in the balancing authority area on an hour-by-hour basis. Dividing the generation inputs

costs for regulation by the average load results in an RFR rate of 0.12 mills per kilowatthour. Study Table 4, line 37.

10.4 Operating Reserve Service Rates

BPA assumes that the proposed WECC Operating Reserve Standard BAL-002-WECC-1 (BAL-002) will be effective on or before the beginning of the FY 2014-2015 rate period. BAL-002 states that the minimum Operating Reserve requirement will be the greater of (1) the most severe single contingency or (2) the sum of three percent of load (generation minus station service minus net actual interchange) and three percent of net generation (generation minus station service).

Under WECC standards, all transmission customers with an Operating Reserve obligation must purchase or provide Operating Reserve. BPA must offer both Spinning and Non-Spinning (*i.e.*, Supplemental) Reserve when the transmission customer takes this service in accordance with applicable NERC, WECC, 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 2014–2015 rate period, the customer's election to acquire Operating Reserve from a third party must have occurred no later than April 1, 2013. BPA determines the transmission customer's obligation in accordance with effective NERC, WECC, and NWPP standards. Customers that elect to self-supply or third-party supply their Operating Reserve obligation but default on their self- or third-party supply obligation will pay a higher rate. *See* section 10.4.3.

10.4.1 Spinning Reserve Service

Spinning Reserve Service is a portion of the total Operating Reserve. 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. BPA must offer this service to customers with generation in the BPA balancing authority area when the customer is not receiving this service under a BPA transmission service agreement. Customers may supply Spinning Reserve Service from qualifying resources conforming with applicable NERC, WECC, and NWPP standards. The transmission customer must purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation.

The Spinning Reserve Service that is identified as a Control Area Service is the same technical service, at the same rate, as the Spinning Reserve Service that is identified as an Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by generators in the BPA balancing authority area that may not have a transmission service agreement with BPA but have energy transactions that impose a spinning reserve obligation on the BPA balancing authority area.

The Spinning Reserve Service rate includes two rate components. ACS-14 Rate Schedule sections II.E and III.C. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Spinning Reserve Requirement. Study Table 4, line 44. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by BPA or purchasing 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.

The Operating Reserve Requirement, based on anticipated approval of BAL-002, is the sum of three percent of load and three percent of the generation located in the BPA balancing authority area used to serve the transmission customer's firm load. Half of the Operating Reserve Requirement is the Spinning Reserve component. BPA will adjust the Spinning Reserve Requirement when and if WECC and NWPP standards change.

10.4.2 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. BPA must offer this service to customers with generation in the BPA balancing authority area when the customer is not receiving this service under a BPA transmission service agreement. BPA determines the transmission customer's obligation in accordance with NERC, WECC, and NWPP standards. The transmission customer must purchase this service from BPA or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. Customers may supply Supplemental Reserve Service from qualifying resources conforming with applicable NERC, WECC, and NWPP standards.

The Supplemental Reserve Service that is identified as a Control Area Service is the same technical service, at the same rate, as the Supplemental Reserve Service that is identified as an Ancillary Service. In contrast to the Ancillary Service, the Control Area Service is taken by

generators (in the BPA balancing authority area) that may not have a transmission service agreement with BPA but have energy transactions that impose a supplemental reserve obligation on the BPA balancing authority area.

The Supplemental Reserve Service rate includes two rate components. ACS-14 Rate Schedule sections II.F and III.D. The first component recovers the costs of providing reserves through a charge that is applied to the customer's Supplemental Reserve Requirement. Study Table 4, line 46. The second rate component charges the customer for energy actually delivered when a system contingency occurs. The customer has the option of returning the energy at times specified by BPA or purchasing 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.

The Operating Reserve Requirement, based on anticipated approval of BAL-002, is three percent of load and three percent of the generation located in the BPA balancing authority area used to serve the transmission customer's firm load. Half of the Operating Reserve Requirement is the Supplemental Reserve component. BPA will adjust the Supplemental Reserve Requirement when and if WECC and NWPP standards change.

10.4.3 Operating Reserve Rate Calculation

The cost allocation methodology and quantity forecast of Operating Reserve for the FY 2014–2015 period are described in section 4 of this Study. The annual revenue requirement for Operating Reserve – Spinning is $26.594 million. Study Table 4, line 39. The Operating Reserve – Spinning rate of 10.86 mills per kilowatthour is calculated by dividing the Operating Reserve – Spinning revenue requirement by the spinning reserve billing factor. *Id.* line 44. The

annual average billing factor forecast is 279 MW for the spinning requirement. *Id.* line 42. Customers that self-supply or third-party supply Operating Reserve Spinning Reserve but default on their self-supply or third-party supply obligations will pay a default rate of 12.49 mills per kilowatthour. *Id*. line 45. The default rate is calculated by increasing the normal rate by 15 percent.

The annual revenue requirement for Operating Reserve – Supplemental is $24.346 million. *Id.* line 40. The Operating Reserve – Supplemental rate of 9.95 mills per kilowatthour is calculated by dividing the Operating Reserve – Supplemental revenue requirement by the supplemental reserve billing factor. *Id.* line 46. The annual average billing factor forecast is 279 MW for the Supplemental requirement. *Id.* line 43. Customers that self-supply or third-party supply Operating Reserve Supplemental Reserve but default on their self-supply or third-party supply obligations will pay a default rate of 11.44 mills per kilowatthour. *Id.* line 47. The default rate is calculated by increasing the normal rate by 15 percent.

10.5 Variable Energy Resource Balancing Service (VERBS)

BPA provides VERBS as a Control Area Service to wind and solar generators in the BPA balancing authority area. This service is necessary to support the differences between actual generation from wind and solar generation and their generation estimate *(i.e.*, schedule).

VERBS is 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. The obligation to maintain the balance between resources (including wind and solar generation) and load lies with TS. The variable energy resource owner/operator must either

purchase this service from TS or make alternative comparable arrangements to satisfy its VERBS obligation.

VERBS Base Service ("Base Service") provides a level of quality of service at 99.5 percent. Base Service customers will be required to elect the type of scheduling that they intend to use for the rate period: (1) 30/60 committed scheduling; (2) 30/30 committed scheduling; or (3) uncommitted scheduling.

VERBS Full Service is an optional service except as provided in section 2.c.3 of the VERBS rate schedule. Under VERBS Full Service, the amount of balancing reserve capacity available to the customer under Base Service is augmented through BPA purchases of additional balancing reserve capacity.

The VERBS rates in section III.E.2.a and III.E.4.a of the ACS-14 Rate Schedule are capacity charges to be applied to the generator's installed wind or solar generating capacity, respectively, in the BPA balancing authority area. These rates recover the cost of balancing reserve capacity provided by the FCRPS. VERBS for wind resources is composed of three balancing reserve capacity components: regulation (moment-to-moment variability), following (longer-duration within-hour variability), and imbalance (within-hour variability due to differences between the scheduled amount and average generation). The VERBS rates for wind resources for each of these three balancing reserve capacity components are listed separately in the rate schedule for the elected scheduling period to allow for self-supply of the components.

VERBS for solar resources is composed of two balancing reserve capacity components: regulation (moment-to-moment variability) and following (longer-duration within-hour variability). The VERBS rates for solar resources for each of these two balancing reserve

capacity components are listed separately in the rate schedule to allow for self-supply of the components.

Formula rates (ACS-14 Rate Schedule section III.6) recover the cost of purchases of balancing reserve capacity that are needed to provide VERBS.

10.5.1 VERBS Base Service Rate Calculation

The 30/60 committed scheduling VERBS Base Service rates for wind generators are:

Regulation Reserves: $0.08 per kilowatt-month (Study Table 4, line 2)

Following Reserves: $0.36 per kilowatt-month (*Id.* line 3)

Imbalance Reserves: $0.70 per kilowatt-month (*Id.* line 4)

Adding those rates results in a 30/60 committed scheduling VERBS Base Service rate of $1.14 per kilowatt-month. *Id*. line 5.

The 30/30 committed scheduling rate for VERBS Base Service for wind generators is based on a discount to the imbalance component from the 30/60 committed scheduling VERBS rate shown above. *See* section 2.8. The imbalance component discount is based on the application of a 27 percent reduction to the total balancing reserve capacity requirement for VERBS. *Id.* The 30/30 committed scheduling VERBS Base Service rates for wind generators are:

Regulation Reserves: $0.08 per kilowatt-month (Study Table 4, line 7)

Following Reserves: $0.36 per kilowatt-month (*Id.* line 8)

Imbalance Reserves: $0.39 per kilowatt-month (*Id.* line 9)

Adding those rates results in a 30/30 committed scheduling VERBS Base Service rate of $0.83 per kilowatt-month. *Id*. line 10.

The VERBS Base Service rate for customers that elect uncommitted scheduling consists of a premium applied to the imbalance component from the 30/60 committed scheduling VERBS rate shown above. *See* section 2.10. The premium is based on a 22 percent increase to the total balancing reserve capacity requirement for VERBS. The uncommitted scheduling VERBS Base Service rates for wind generators are:

Regulation Reserves: $0.08 per kilowatt-month (Study Table 4, line 12)

Following Reserves: $0.36 per kilowatt-month (*Id.* line 13)

Imbalance Reserves: $0.95 per kilowatt-month (*Id.* line 14)

Adding the components results in an uncommitted scheduling VERBS Base Service rate of $1.39 per kilowatt-month. *Id*. line 15.

Variable energy resources (wind and solar resources) in the BPA balancing authority area are charged for VERBS based on the greater of the maximum one-hour generation or nameplate of the wind or solar resource in kilowatts, unless the resource self-supplies or acquires third-party supplies of balancing reserve capacity.

The average installed amount of wind generation in the BPA balancing authority area for the FY 2014–2015 rate period is forecast to be 4,871 MW. Documentation Table 2.1. The imbalance component of the balancing reserve capacity requirement is based on the installed capacity less the amount of self-supply. The average amount of self-supply is forecast to be 1,505 MW. Section 2.7.4; Documentation Table 2.17. The annual average revenue requirement for PS to provide balancing reserve capacity for VERBS is $54.186 million. Study Table 1, line 7; Study Table 2, line 10. The annual average revenue requirement is comprised of $4.933 million for regulation, $21.063 million for following, and $28.190 million for imbalance. Study Table 2, lines 1-8.

In addition to the VERBS Base Service rates, there are four formula purchases charges that will apply to VERBS Base Service for wind generators under certain circumstances to recover the costs of purchases of balancing reserve capacity for VERBS. These formula purchases charges are discussed below.

10.5.2 VERBS for Solar Resources Calculation

Based on the reserve requirement of 0.34 MW *inc* and 0.34 MW *dec* for the 15 MW of expected interconnected solar resources during the FY 2014-2015 rate period, and the revenue requirement of $44,499 the total VERBS Solar rate is $0.25 per kilowatt-month. Study Table 4, line 23; Documentation Table 3.18.

Because a utility-scale scheduled solar generation plant does not yet exist in the BPA balancing authority area, BPA used one-minute solar photovoltaic generation data for an unscheduled 1.655 MW Sacramento Municipal Utility District (SMUD) plant. BPA scaled up the 1.655 MW plant to 15 MW, which is the amount of solar generation projected to be online in the BPA balancing authority area for the FY 2014–2015 rate period, and synthesized schedules based on the average hourly generation per month. *See* section 2.4.3.

In addition to the VERBS for solar resources rates, solar resources are subject to Type 1, Type 2, and Type 4 Purchases Charges. These formula charges are discussed below.

10.5.3 Type 1 Purchases Charge

The Type 1 Purchases Charge applies to wind and solar resources and recovers the Type 1 purchase costs allocated to variable energy resources. The cost allocation methodology determined that 100 percent of BPA's Type 1 purchase costs will be collected from variable

energy resources during the FY 2014–2015 rate period. *See* section 3.5.3. The Type 1 Purchases Charge is applied to all variable energy resources and is in addition to the VERBS Base Service rates and VERBS for solar rates. The VERBS Base Service rates and VERBS for solar rates recover the costs of the *inc* and *dec* balancing reserve capacity that is forecast to be supplied from the FCRPS. The monthly Type 1 Purchases Charge is equal to each variable energy resource's monthly *inc* reserve requirement, described in section 10.5.3.1, multiplied by the the total monthly cost of Type 1 purchases divided by the total monthly *inc* reserve requirement for all variable energy resources, described in section 10.5.3.2.

10.5.3.1 Type 1 Purchases Billing Factor

The Type 1 Purchases Charge applies to all variable energy resources taking the VERBS Base Service or the VERBS for solar. A variable energy resource's monthly billing factor used to calculate the Type 1 Purchases Charge is equivalent to the resource's individual *inc* reserve capacity requirement for each component of VERBS Base Service and VERBS for solar. A resource's individual *inc* reserve capacity requirement, for the VERBS Base Service it takes from BPA, is determined by multiplying the percentage of reserve capacity for regulation, following, and imbalance by the resource's nameplate capacity, for the schedule election of the resource. Documentation Table 2.31 illustrates the *inc* reserve capacity percentage for each component for the resource and its scheduling election.

10.5.3.2 Type 1 Purchases Unit Cost

The monthly Type 1 Purchases unit cost is equal to the sum of the Type 1 purchase costs incurred for that month divided by the sum of the billing factors for that same month as described in section 10.5.3.1.

10.5.4 Type 2 Purchases Charge

The Type 2 Purchases Charge recovers the Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources. The cost allocation methodology determined that 95 percent of BPA's Type 2 purchase costs will be collected from variable energy resources and non-Federal thermal resources. *See* section 3.5.4. The monthly Type 2 Purchases Charge is equal to each variable energy resource's monthly *inc* reserve requirement, described in section 10.5.4.1, multiplied by the monthly Type 2 Purchases unit cost described in section 10.5.4.2.

10.5.4.1 Type 2 Purchases Billing Factor

The Type 2 Purchases Charge applies to variable and dispatchable energy resources. A variable energy resource's monthly billing factor used to calculate the Type 2 Purchases Charge is equivalent to the resource's individual *inc* reserve capacity requirements for each component of VERBS Base Service and VERBS for solar. A resource's individual *inc* reserve capacity requirement, for the VERBS Base Service it takes from BPA, is determined by multiplying the percentage of reserve capacity for regulation, following, and imbalance by the resource's nameplate capacity, for the schedule election of the resource. Documentation Table 2.31 illustrates the *inc* reserve capacity percentage for each component for the resource and its scheduling election.

10.5.4.2 Type 2 Purchases Unit Cost

Three steps are taken to calculate the Type 2 Purchases unit cost for variable energy resources. The first step is to determine the monthly percentage of the Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources that will be collected from variable energy resources. This monthly percentage is equal to the amount paid for VERBS Base Service (under Base Service rates in section 2.a of the VERBS rate) and VERBS for solar customers for a month divided by the amount paid for VERBS Base Service, VERBS for solar, and DERBS for

that same month. The second step is to multiply the Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources by the monthly percentage calculated in the first step. This results in the amount of costs that are allocated to variable energy resources. The third step is to divide the costs allocated to variable energy resources (in step 2) by the sum of that month's billing factors for variable energy resources as described in section 10.5.4.1.

10.5.5 Type 3 Purchases Charge

The Type 3 Purchases Charge recovers the Type 3 purchase costs allocated to variable energy resources that take Full Service. The cost allocation methodology determined that 100 percent of BPA's Type 3 purchase costs will be collected from variable energy resources that take Full Service. *See* section 3.5.5. The monthly Type 3 Purchases Charge is equal to each resource's monthly billing factor multiplied by the applicable monthly Type 3 Purchases unit cost.

10.5.5.1 Type 3 Purchases Billing Factor

The Type 3 Purchases Charge applies to all variable energy resources that take Full Service. A variable energy resource's monthly billing factor used to calculate the Type 3 Purchases Charge is the same billing factor used for VERBS Base Service as established in section III.E.2.b of the Variable Energy Resource Balancing Service section of the ACS-14 Rate Schedule.

10.5.5.2 Type 3 Purchases Unit Cost

The monthly Type 3 Purchases Rate is equal to the sum of the Type 3 purchase costs incurred for that month divided by the sum of the billing factors for that same month as described in section 10.5.5.1.

10.5.6 Type 4 Purchases Charge for Direct Assignment to a Customer

The Type 4 Purchases Charge will recover the cost of BPA purchases of generation inputs during the rate period to provide VERBS to a specific customer. This charge does not address the costs associated with the replacement of FCRPS generation inputs for VERBS that become unavailable during the rate period, which are addressed by the Type 2 Purchases Charge above.

The purchase costs that would be directly assigned to a variable energy resource for the Type 4 Purchases Charge will be triggered under four scenarios. BPA shall directly assign to the VERBS customer the cost of *inc* balancing reserve capacity purchases that are necessary to provide VERBS because (1) the customer elected to self-supply in accordance with section III.E.2.c but is unable to continue self-supplying one or more components to VERBS; (2) the customer has a projected generator interconnection date after FY 2015 but chooses to interconnect during the FY 2014-2015 rate period; (3) the customer committed to a specific scheduling option (*e.g.*, 30/30 committed scheduling or 30/60 committed scheduling) but does not maintain its scheduling performance consistent with or better than BPA's requirements for committed scheduling; or (4) the customer committed to a specific scheduling option but chooses to change its Base Service scheduling option (in accordance with BPA-TS business practices) during the rate period to an option with a longer scheduling period.

10.5.7 VERBS Credit for VERBS Forecast but not Provided

The VERBS Credit adjustment will reimburse customers taking all three components of VERBS for the cost associated with incremental or decremental balancing reserve capacity for VERBS that was forecast to be available from the FCRPS but is not provided to customers because of hydro system conditions. The VERBS Credit is assessed on a monthly basis for the regulation, following, and imbalance components of the total VERBS Base Service rate. The VERBS Credit amount is not to exceed the resource's total monthly VERBS charges for the base rates.

When balancing reserve capacity is reduced, there is a negligible impact on Customer-Supplied Generation Imbalance (CSGI) pilot participants because they self-supply the imbalance component of VERBS; therefore, CSGI participants are not eligible for the VERBS Credit.

10.5.7.1 VERBS Credit Calculation for VERBS Forecast but not Provided

The VERBS Credit adjustment applies to the regulation, following, and imbalance components of the VERBS rate. ACS-14 Rate Schedule section III.E.7. The VERBS Credit is available for both *inc* and *dec* balancing reserve capacity. The rate for each is the variable and embedded costs of reserves. Study section 3.6.2.

The VERBS credit adjustment is the cost of the monthly average reduction of balancing reserve capacity divided by a customer's proportion of the VERBS service. The average reduction of balancing reserve capacity provided for the month is the average hourly balancing reserve capacity forecast to be provided by the FCRPS less the hourly balancing reserve capacity actually provided by the FCRPS. This quantity, in kilowatts, is multiplied by the credit rate in the ACS-14 Rate Schedules, section III.E.7.b, to determine to total available credit amount for variable energy resources.

The total available credit amount is applied to each resource's VERBS charge by the variable energy resources billing factor ratio. To determine the billing factor ratio for a variable energy resource, the resource's billing factor is divided by the total of the billing factors of all variable energy resources' billing factors. ACS-14 Rate Schedule section III.E.7.c. The billing factors are established in section III.E.2.b of the Variable Energy Resource Balancing Service section of the ACS-14 Rate Schedule.

The VERBS Credit adjustment will be applied independently of the Type 1 Purchases Charge, Type 2 Purchases Charge, Type 3 Purchases Charge, and Type 4 Purchases Charge.

10.6 Dispatchable Energy Resource Balancing Service (DERBS)

BPA is offering DERBS to all non-Federal dispatchable energy resources in the BPA balancing authority area. This Control Area Service is necessary to support the within-hour deviations of dispatchable energy resources from the hourly generation estimate (*i.e.*, generation schedule). The dispatchable energy 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.

DERBS is provided by increasing or decreasing committed online Federal 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 obligation to maintain this balance between resources and load lies with TS.

The DERBS rate in section III.F of the ACS-14 Rate Schedule includes charges to be applied to the thermal generator's calculated monthly use of balancing reserve capacity for regulation, following, and imbalance in the BPA balancing authority area.

10.6.1 Rate Calculation

Hourly rates are calculated for use of *inc* and *dec* balancing reserve capacity. The forecast *inc* reserve capacity requirement is 52 MW, and the forecast *dec* reserve requirement is 74 MW. Study Table 4, lines 25-26. The forecast annual revenue requirement for PS to provide *inc*

capacity for DERBS is $4.644 million and to provide *dec* capacity is $0.512 million, as specified in section 3 of this Study and shown on Study Table 4, lines 27-28.

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

The *inc* and *dec* charge each month is calculated for each individual generating facility as the sum, across all hours in the month, of the respective *inc* and *dec* hourly rate multiplied by the billing factor calculated each hour. The *inc* billing factor is calculated from the hourly maximum use of *inc* balancing reserve capacity that exceeds 2 MW as measured on a five-minute average basis for station control error. The *dec* billing factor is calculated similarly.

Station control error is the difference between the generation estimate and actual generator output. For generators that have e-Tags for their scheduled output, the generation estimate is the sum of the e-Tags for each hour. 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 are station control error during the ramp.

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 *inc* and *dec* balancing reserve capacity use by dispatchable energy resources is based on a historical database of five-minute station control error for each resource for the period October 2011 through September

2012. The data were adjusted to omit individual generators not anticipated to be in the BPA balancing authority area during the FY 2014–2015 rate period.

A 2 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 2011 through September 2012 actual DERBS usage, with adjustments to recognize that a number of generators were offline for extended periods that are not anticipated to occur regularly in the rate period. This forecast is 204,221 MW of hourly deviation annually for *inc*, and 188,422 MW of hourly deviation annually for *dec*. Study Table 4, lines 30-31.

Based on the forecast use of *inc* and *dec* balancing reserve capacity, the hourly *inc* rate is 22.74 mills per kW for use of *inc* balancing reserve capacity that exceeds 2 MW, measured as the hourly maximum of five-minute average data. *Id.* line 32. The hourly *dec* rate is similarly calculated and is 2.71 mills per kW for use of *dec* balancing reserve capacity that exceeds 2 MW, measured as the hourly maximum of five-minute average data. *Id.* line 33.

10.6.2 Formula Purchases Charges

In addition to the base DERBS *inc* and *dec* rates above, two formula charges apply to DERBS. The cost allocation methodology determined that DERBS customers are not subject to Type 1 Purchases Charge for the FY 2014-2015 rate period. *See* section 3.5. In addition, Type 3 costs are inapplicable to dispatchable energy resources. *Id.* DERBS customers, however, are subject to Type 2 and Type 4 costs, which are recovered under the associated Type 2 and Type 4 Purchases Charges described in more detail below.

10.6.2.1 Type 2 Purchases Charge

The Type 2 Purchases Charge recovers the Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources. *Id.* The cost allocation methodology determined that 95 percent of BPA's Type 2 purchase costs will be collected from variable energy resources and non-Federal thermal resources. *Id.* The monthly Type 2 Purchases Charge is equal to each dispatchable energy resource's monthly billing factor, described in section 10.6.2.1.1, multiplied by the monthly Type 2 Purchases unit cost described in section 10.5.4.2.

10.6.2.1.1 Type 2 Purchases Billing Factor

The Type 2 Purchases Charge applies to variable and dispatchable energy resources. A non-Federal thermal resource's monthly billing factor used to calculate the Type 2 Purchases Charge is equivalent to the billing factor used for DERBS as established in section III.F.2.a of the Dispatchable Energy Resource Balancing Service section of the ACS-14 Rate Schedule.

10.6.2.1.2 Type 2 Purchases Unit Cost

Three steps are made to calculate the Type 2 Purchases unit cost for non-Federal thermal resources. The first step is to determine the monthly percentage of the Type 2 purchase costs allocated to variable energy resources and non-Federal thermal resources that will be collected from non-Federal thermal resources. This monthly percentage is equal to the amount paid for DERBS for a month divided by the amount paid for VERBS Base Service, VERBS for solar, and DERBS for that same month. The second step is to multiply the Type 2 purchase costs allocated to variable energy resource and non-Federal thermal resources by the monthly percentage calculated in the first step. This results in the amount of costs that are allocated to non-Federal thermal resources. The third step is to divide the costs allocated to non-Federal thermal resources (step 2) by the sum of that month's billing factors for non-Federal thermal resources as described in section 10.6.2.1.1.

10.6.3 Type 4 Purchases Charge for Direct Assignment to a Customer

The Type 4 Purchases Charge will recover the cost of BPA purchases of generation inputs during the rate period to provide DERBS to a specific customer. Type 4 purchase costs are directly assigned to the DERBS customer that caused the trigger event. This charge does not address the costs associated with the replacement of FCRPS generation inputs that become unavailable during the rate period, which are addressed by the Type 2 Purchases Charge.

The Type 4 Purchases Charge is triggered when a DERBS customer: (1) elected to self-supply but is unable to continue self-supplying one or more components to DERBS; (2) was operating in another balancing authority area and dynamically transfers into the BPA balancing authority area during the FY 2014–2015 rate period; or (3) has a projected generator interconnection date after FY 2015, but chooses to interconnect during the FY 2014–2015 rate period.

The Type 4 Purchases Charge for a DERBS customer is equal to the Type 4 purchase costs incurred as a result of the trigger event caused by that DERBS customer.

10.7 Energy Imbalance and Generation Imbalance Service

All revenues or credits that TS 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 Generation Imbalance Service and Energy Imbalance Service are energy charges, not capacity charges.

10.7.1 Energy Imbalance Service

Energy Imbalance Service is provided for transmission within and into the BPA balancing authority area to serve load in the balancing authority area. All transmission customers serving load in the BPA balancing authority area are subject to charges for Energy Imbalance unless they are BPA power customers receiving a service that provides demand and shaping to cover load variations.

Energy Imbalance 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 Energy Imbalance rate in section II.D of the ACS-14 Rate Schedule establishes three imbalance deviation bands. Band 1 applies to the portion of the deviation less than the greater of ± 1.5 percent of the schedule or ± 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 ± 7.5 percent of the schedule or ± 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 a Persistent Deviation, the customer is subject to a different and larger charge. *See* section 10.8.

10.7.2 Generation Imbalance Service

Generation Imbalance Service provides or absorbs energy to meet the difference between scheduled *(i.e.,* generation estimate) and actual generation delivered in the BPA balancing authority area. All generators in the BPA balancing authority area are subject to charges for Generation Imbalance Service if TS provides such service under an interconnection agreement or other arrangement.

The Generation Imbalance Service rate in section III.B of the ACS-14 Rate Schedule establishes three imbalance deviation bands. 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 Imbalance Deviation 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. Customers that choose to participate in 30/30 committed scheduling (or the shortest scheduling period available for committed scheduling) for the rate period are exempt from the ± 10 percent charge under Deviation Band 2, and the charge or credit for energy within Band 2 will be 100 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.

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 Deviation Band 1 will be charged at the Deviation 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. For any hours that an imbalance is determined to be a Persistent Deviation, the customer is subject to a different and larger charge. *See s*ection 10.8.

10.8 Persistent Deviation for Imbalance Services

10.8.1 Introduction

This section discusses BPA's observations regarding Persistent Deviations in FY 2012 and explains BPA's proposed change to fully exempt committed "intra-hour" (30/30 committed scheduling) and committed "hourly" (30/60 committed scheduling) schedules from Persistent Deviation penalties.

10.8.2 Study Summary

BPA has gained significant experience with the Persistent Deviation penalty charge during the FY 2010–2011 rate period and FY 2012. For the FY 2012–2013 rate period, BPA implemented changes to the Persistent Deviation Penalty that added to the types of events identified as Persistent Deviations, and consequently more events were identified than during the prior rate period.

10.8.3 Definitions of Relevant Terms

For the purposes of this Study, the following terms are defined:

Positive deviation: actual generation is less than scheduled, or energy taken is greater than the scheduled energy.

Negative deviation: actual generation is greater than scheduled, or energy taken is less than the scheduled energy.

Imbalance Energy Accumulation: a buildup of energy stored into or released from the FCRPS over a period of time.

Persistence scheduling: establishing a schedule for a variable energy resource based on the actual generation output at a specific time prior to the delivery period. For example, 30-minute persistence for hourly scheduling means setting the hourly schedule to the actual generation level measured 30 minutes prior to the delivery hour. Persistence scheduling can also be applied for intra-hour schedules; for example, the actual generation level at 25 minutes prior to the delivery hour can be used to establish the schedule for the first half of the delivery hour, and the actual generation at 5 minutes past the top of the hour can be used to set the schedule for the second half of the delivery hour.

10.8.4 Persistent Deviations During FY 2012

Table 10.1 in the Documentation illustrates the number of Persistent Deviation events for which penalties were imposed. The percentage of hours affected by Persistent Deviation penalties has increased with implementation of the new rules at the start of FY 2012 but continues to remain very low. Penalties are being avoided 99.5 percent of the time on average by wind generators, even with the new rules; loads are avoiding the penalties about 99.4 percent of the time; and thermal generators avoid the penalties 99.9 percent of the time. Almost 38 percent of the Persistent Deviation incidents for wind generators were incurred by three plants. Over 99 percent of the Persistent Deviation events accrued to less than half of the wind fleet.

In the previous rate period, wind plants that elected to participate in the Committed Intra-Hour Program were able to avoid Persistent Deviation completely. Three wind plants implemented Committed Intra-Hour scheduling and received full exemption from Persistent Deviation.

In order to further encourage the wind plants to schedule more accurately, for the FY 2014–2015 rate period the Persistent Deviation exemption for 30/30 committed scheduling continues and is extended to wind plants that participate in 30/60 committed scheduling.

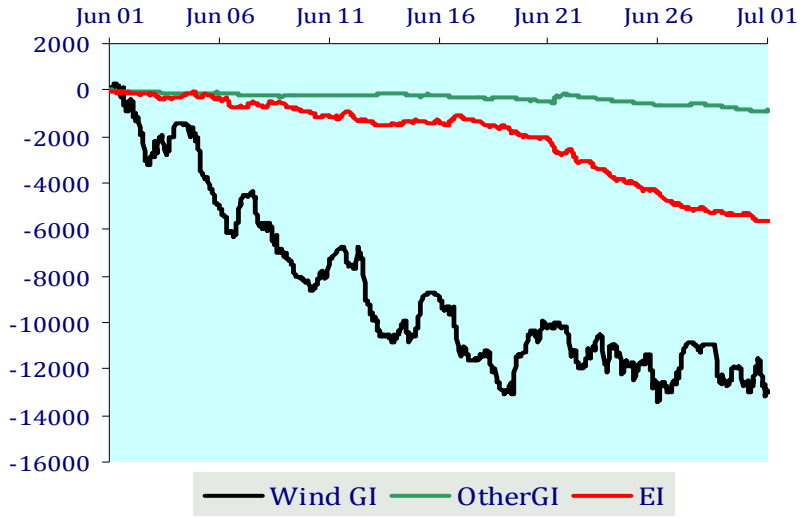
The frequency of wind ramps that meet the three-hour Persistent Deviation criteria were examined. As illustrated in Documentation Table 10.2, over a two-year period wind ramps exceeded the three-hour persistent deviation criteria for two consecutive hours only 1.8 percent of the time, and they exceed the criteria for three consecutive hours only 0.43 percent of the time. Therefore, wind ramps alone are unlikely to cause large and persistent schedule errors.

10.8.5 Operational Impacts of Persistent Deviations

As a balancing authority, BPA must maintain load and resource balance at all times. When persistent or biased schedule errors occur, energy imbalance is accumulated in the FCRPS. A positive accumulation occurs when BPA must provide energy; conversely, a negative accumulation occurs when BPA stores imbalance energy. When there is sufficient market depth, BPA uses the market (*i.e.*, attempts to buy or sell energy) to decrease the amount of imbalance energy on the Federal system. However, market depth may be limited due to oversupply of energy in the marketplace. One indication of lack of market depth is negative or near-zero energy market prices. When energy market prices are negative or near zero, market opportunities to sell accumulated imbalance energy are severely limited. Even when prices are not negative, however, it can be difficult to find buyers or sellers on short notice.

Because the direction of energy accumulation is highly unpredictable, BPA can find itself both selling and buying over fairly short time periods. Figure 10.1 shows one example month of imbalance accumulation to illustrate this variability. As illustrated, the energy imbalance accumulation from wind generation often fluctuates 1,000 to 2,000 MWh over very short time periods, even within a day. This increase in forced marketing disrupts BPA's marketing and operational planning and potentially reduces the value of short-term sales.

Figure 10-1: Accumulation of Imbalance Energy (MWh)



Figures 10.2 and 10.3 below illustrate the rolling 24-hour accumulation of imbalance energy that would be associated with wind generation persistence scheduling (30/60 scheduling in Figure 10.2 and 30/30 scheduling in Figure 10.3) as compared to actual historical schedule data (Figure 10.4). As illustrated in Figure 10.2, 30-minute persistence scheduling for hourly schedules would yield a relatively even (*i.e.*, unbiased) distribution, with imbalance accumulations only occasionally exceeding 3,000 MWh up or down over a 24-hour period. Figure 10.3 shows the general pattern of imbalance energy BPA would expect to observe from unbiased 30/30 scheduling practices, which would result in even less imbalance accumulation.

Figure 10-2: Rolling 24-Hour Accumulated Imbalance From 30-Minute Persistence Hourly Scheduling for the BPA Wind Fleet

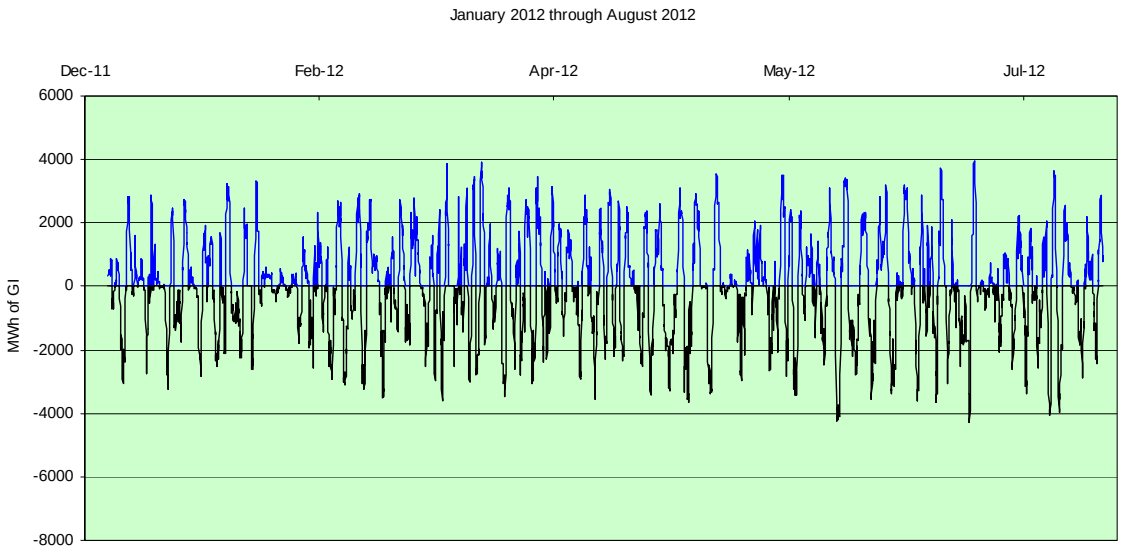
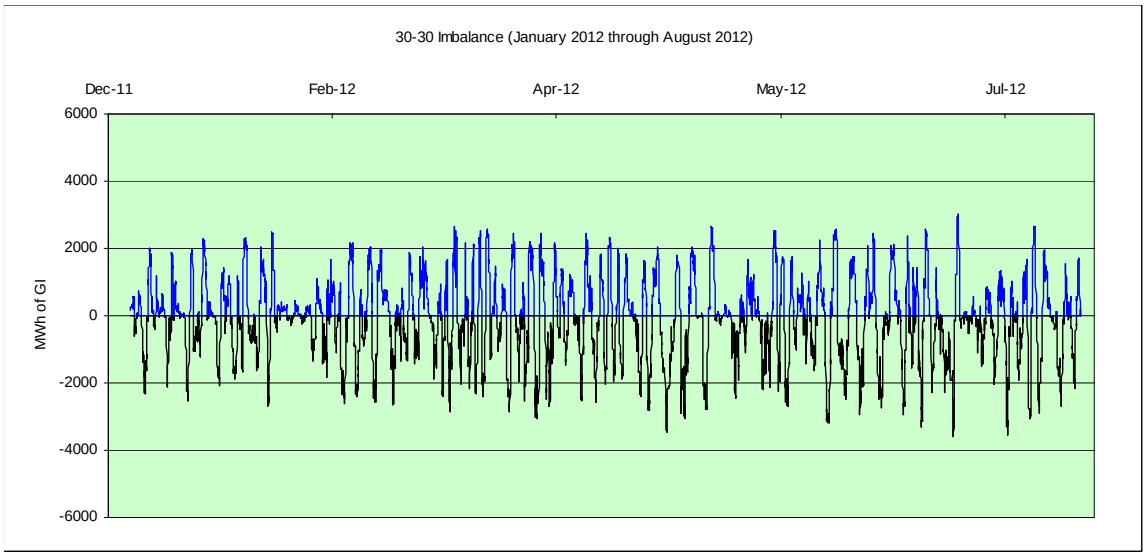
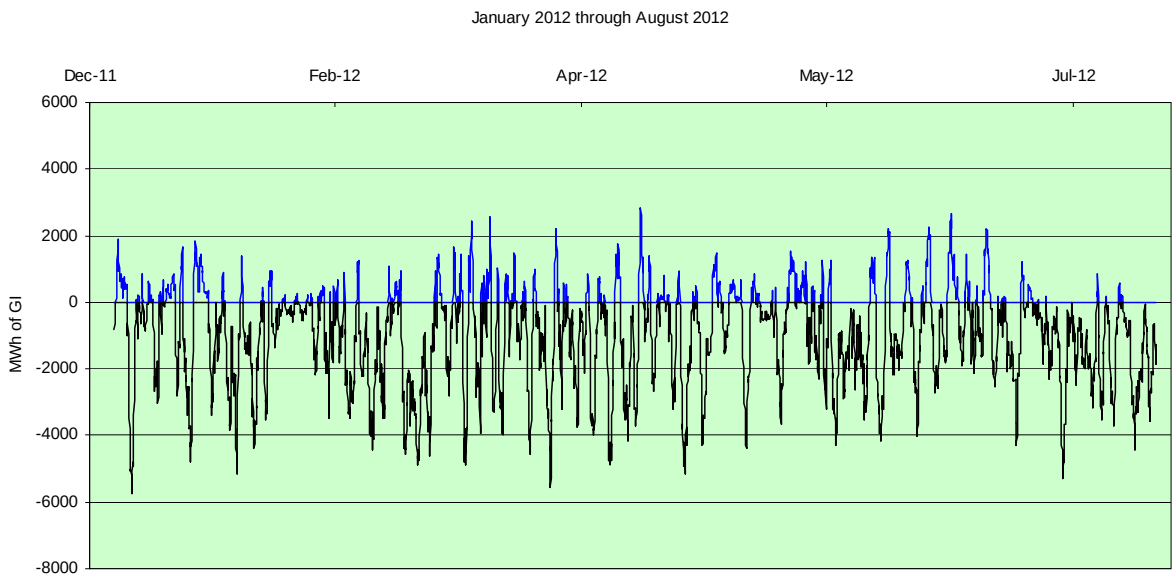


Figure 10-3: Rolling 24-Hour Accumulated Imbalance From 30-Minute Persistence Half-Hourly Scheduling for the BPA Wind Fleet



In contrast, Figure 10.4 shows actual accumulated imbalance energy from the wind fleet for January through August 2012. Figure 10.4 indicates a significant bias toward negative imbalance, with frequent occurrences of imbalance accumulation much larger than 3,000 MWh, particularly for negative imbalances. On several dates, negative imbalance accumulations (resulting from generation significantly above schedule for more plants than were under-scheduling) over 5,000 MWh occurred. By reducing schedule bias, BPA can reduce imbalance accumulation. This is one of the reasons BPA proposes to exempt customers that participate in the committed scheduling programs from persistent deviation penalties. However, as illustrated in the difference between hourly and 30/30 committed scheduling, total capacity use and total imbalance accumulation increase with longer schedule period

Figure 10-4: Rolling 24-Hour Accumulated Imbalance From the BPA Wind Fleet



It is possible for customers to schedule in a manner that avoids persistent deviation penalties but still forces accumulated imbalance onto BPA's system. Figure 10.5 represents a zigzag pattern of scheduling error for a wind plant. As illustrated in the figure, the wind plant experienced large station control errors that exceeded the Persistent Deviation threshold, followed by short

periods of smaller station control errors that fell within the Persistent Deviation threshold. The scheduling behavior in Figure 10.5 put large amounts of accumulated energy into the Federal system but did not result in a Persistent Deviation event under Part A of the Persistent Deviation definition (though it increased the wind plant's risk of a Persistent Deviation incident). A discernable pattern of such schedule errors may result in a Persistent Deviation penalty under Part C of the Persistent Deviation definition.

Figure 10-5: Example of a Zigzag Scheduling Behavior

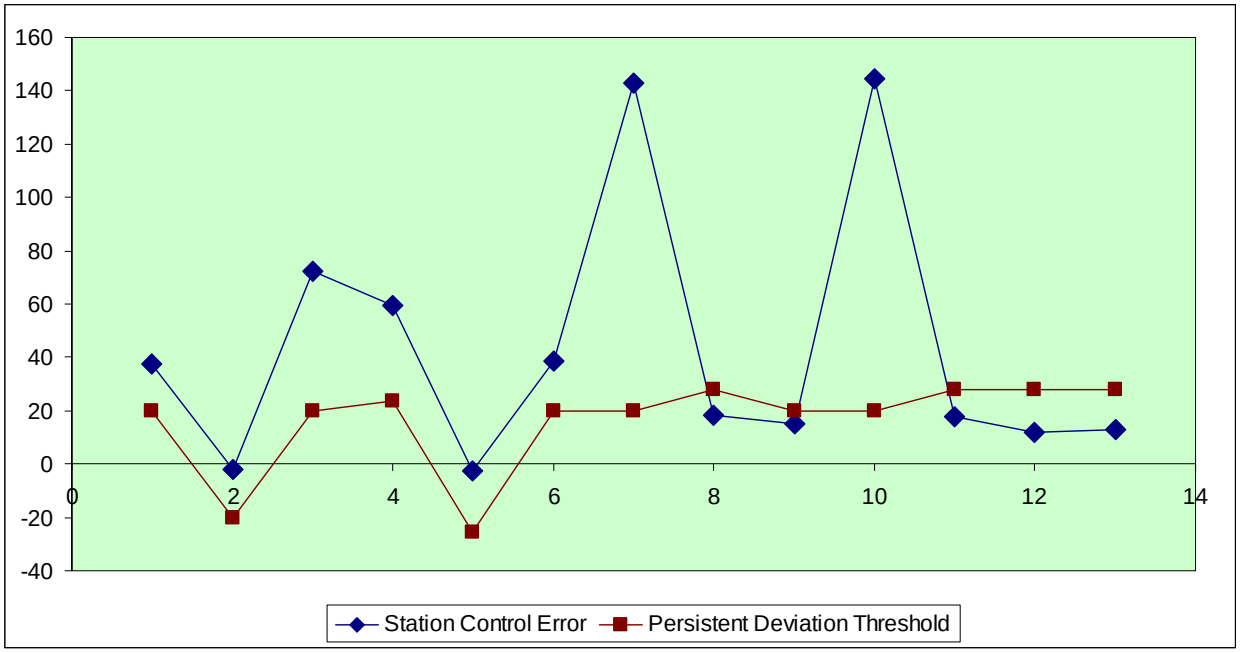


Table 1: Power Services' Generation Inputs Revenue Forecast for FY 2014-2015
99.5% Level of Service with Self Supply of Generation Imbalance

	A	B	C	D	E
	Generation Inputs	**Quantity**	**Per Unit Cost ($/kW/month)**	**Annual Average Revenue for FY 2014-FY 2015**	***Inc* and *Dec* ($)**
1	Regulating Reserve - Embedded Cost Portion	61 MW	$ 6.93	$ 5,072,760	
2	Regulating Reserve - Variable Cost Portion	61 MW *inc* 60 MW *dec*		$ 910,042	
3	**Regulating Reserve Total**			**$ 5,982,802**	
4	Variable Energy Resource Balancing Service Reserve - Embedded Cost Portion	522 MW	$ 6.93	$ 43,409,520	
5	Variable Energy Resource Balancing Service Reserve - Direct Assignment Portion	522 MW *inc* 658 MW *dec*		$ 3,762,500	
6	Variable Energy Resource Balancing Service Reserve - Variable Cost Portion	522 MW *inc* 658 MW *dec*		$ 7,013,678	
7	**Variable Energy Resource Balancing Service Reserve Total**			**$ 54,185,698**	
8	**Variable Energy Resource Balancing Service for Solar** 1/	0.34 MW *inc* 0.34 MW *dec*		$ 44,132	
9	**Adjustment for Committed Intra-Hour Scheduling** (27% * VERBS Rate *12 * 1000 *571)	571 MW		$ (2,109,046)	
10	**Adjustment for VERBS Credit**				
11	Dispatchable Energy Resource Balancing Service Reserve - Embedded Cost Portion	61 MW	$ 6.93	$ 5,072,760	
12	Dispatchable Energy Resource Balancing Service Reserve - Variable Cost Portion	61 MW *inc* 74 MW *dec*		$ 830,820	
13	**Dispatchable Energy Resource Balancing Service Reserve Total** 2/			**$ 5,903,580**	
14	Dispatchable Energy Resource Balancing Service Reserve *Inc*				$ 5,392,026
15	Dispatchable Energy Resource Balancing Service Reserve *Dec*				$ 511,554
16	Operating Reserve - Spinning (Embedded Cost Portion)	279.45 MW	$ 7.26	$ 24,345,684	
17	Operating Reserve - Spinning (Variable Cost Portion)	279.45 MW	$ 0.67	$ 2,247,867	
18	**Operating Reserve - Spinning Total**	279.45 MW	$ 7.93	**$ 26,593,551**	
19	**Operating Reserve - Supplemental Total**	279.45 MW	$ 7.26	**$ 24,345,684**	
20	**Operating Reserve Total**	**558.9 MW**		**$ 50,939,235**	
21	**Synchronous Condensing**	44,397 MWh		$ 1,578,953	
22	**Generation Dropping**	1 drop/year		$ 334,707	
23	**Redispatch**			$ 400,000	
24	**Segmentation of COE/Reclamation Network and Delivery Facilities**			$ 6,251,000	
25	**Station Service**	82,665 MWh		$ 2,405,552	
26	**Generation Inputs Total**			**$ 125,872,481**	
27	1/ VERBS for Solar revenue forecast is identified separately. The costs are part of the VERBS costs on lines 4 and 6.				
28	2/ These numbers do not include a proposed 15% reduction in the balancing reserve capacity requirement for DERBS. With a 15% reduction in *inc* balancing reserve capacity for DERBS, the expected DERBS revenue forecast is reduced to $5,155,140. *See* Jackson, *et al.*, BP-14-E-BPA-28, section 8 (describing Staff's proposal to consider a 15% reduction in the DERBS reserve requirement); Transmission, Ancillary and Control Area Services Rate Schedules, BP-14-E-BPA-10, ACS-14 rate schedule, section III.F. When considering a 15% reduction in the DERBS balancing reserve capacity requirement, the DERBS rate is 22.74 mills/kW for *inc* and 2.71 mills/kW for *dec*. *Id.*				

Table 2: Cost Allocation of VERBS Components for 99.5% Level of Service with Self Supply of Generation Imbalance Proportion of VERBS Rate for Embedded, Variable and Direct Assignment Cost

	A	B	C	D	E	F	G	H	I	J
	Component	Total Rate $/kW/month of Installed Capacity	Embedded Cost Portion of VERBS Cost Allocation	Embedded Portion of VERBS Rate	Variable Cost Portion of VERBS Cost Allocation	Variable Portion of VERBS Rate	Direct Cost Portion of VERBS Cost Allocation	Direct Portion of VERBS Rate	*Inc* and *Dec* Reserve Quantity	Total Cost
			$ 43,409,520		$ 7,013,678		$ 3,762,500			$54,185,698
1	Regulating Reserve *inc*	0.08	$ 3,825,360	0.07	$ 372,429	0.01	$ 209,073	-	46	$ 4,406,862
2	Regulating Reserve *dec*	-		-	$ 316,593		$ 209,073	-	46	$ 525,666
3	Regulating Reserve Component	0.08		-		-		-		$ -
4	Following Reserve *inc*	0.32	$ 16,632,000	0.28	$ 1,173,148	0.02	$ 909,015	0.02	200	$18,714,163
5	Following Reserve *dec*	0.04		-	$ 1,417,186	0.02	$ 931,740	0.02	205	$ 2,348,926
6	Following Reserve Component	0.36				-		-		$ -
7	Imbalance Capacity *inc*	0.61	$ 22,952,160	0.57	$ 813,608	0.02	$ 606,715	0.02	276	$24,372,483
8	Imbalance Capacity *dec*	0.09		-	$ 2,920,714	0.07	$ 896,883	0.02	408	$ 3,817,597
9	Imbalance Capacity Component	0.70				-				$ -
10	Total	1.14	$ 43,409,520	$ 0.92	$ 7,013,678	$ 0.14	$ 3,762,499	$ 0.08		$54,185,697

Table 3: VERBS Credit for Unavailable FCRPS Balancing Reserves from Rate Case Planned Level Due to Hydro Conditions

Table 3 VERBS Credit for Unavailable FCRPS Balancing Reserves from Rate Case Planned Level Due to Hydro Conditions				
	A	B	C	D
	Component	VERBS Credit ($/kW/month of Balancing Reserve Capacity)	Embedded Portion of VERBS ($/kW/month of Balancing Reserve Capacity)	Variable Portion of VERBS ($/kW/month of Balancing Reserve Capacity)
1	VERBS *Inc* Credit	$ 7.30	$ 6.93	$ 0.37
2	VERBS *Dec* Credit	$ 0.60	$ -	$ 0.60
3	$6.93/kW/month is calculated in Table 3.6, line 13			
4	$0.37/kW/month is calculated in Table 3.13, line 7			
5	$0.36/kW/month is calculated in Table 3.13, line 8			

Table 4: Proposed Rates for Reserve-Based Ancillary and Control Area Services for FY 2014–2015

	A	B	C	D	E	F	G
	Rate	FY14/15 Costs	FY14 Sales	FY15 Sales	FY14/15 Sales	Proposed Rates	Units
		($000)	(MW)	(MW)	(MW)		
1	**Variable Energy Resource Balancing Service (VERBS) for Wind**						
2	Regulating component					$ 0.08	$/kW-mo
3	Following component					$ 0.36	$/kW-mo
4	Imbalance component					$ 0.70	$/kW-mo
5	**Total VERBS for Wind for Committed 30/60 Scheduling**					$ 1.14	$/kW-mo
6	**VERBS Rate Discount for Committed 30/30 Scheduling**					27%	
7	Regulating component					$ 0.08	$/kW-mo
8	Following component					$ 0.36	$/kW-mo
9	Imbalance component					$ 0.39	$/kW-mo
10	**Total VERBS Rate for Committed 30/30 Scheduling**					$ 0.83	$/kW-mo
11	**VERBS Rate Premium for Uncommitted Scheduling**					22%	
12	Regulating component					$ 0.08	$/kW-mo
13	Following component					$ 0.36	$/kW-mo
14	Imbalance component					$ 0.95	$/kW-mo
15	**Total VERBS Rate for Uncommitted Scheduling**					$ 1.39	$/kW-mo
16	**VERBS Rate Credit for Unavailable Balancing Reserves Due to Hydro Conditions**						
17	VERBS *inc*					$ 7.30	$/kW-mo
18	VERBS *dec*					$ 0.60	$/kW-mo
19	**Variable Energy Resource Balancing Service (VERBS) for Solar**						
20	Regulating component					$ 0.04	$/kW-mo
21	Following component					$ 0.21	$/kW-mo
22	Imbalance component					0.00	Not Applicable
23	**Total VERBS for Solar**					$ 0.25	
24	**Dispatchable Energy Resources Balancing Service (DERBS)**						
25	Reserve Requirement *inc*		52	52	52		
26	Reserve Requirement *dec*		74	74	74		
27	Annual average costs *inc*	4,644					
28	Annual average costs *dec*	512					
29	Total DERBS annual average costs	5,155					
30	Annual sum of Hourly MW deviation beyond 2 MW deadband *inc*		204,221	204,221	204,221		
31	Annual sum of Hourly MW deviation beyond 2 MW deadband *dec*		188,422	188,422	188,422		
32	Hourly rate *inc* (costs / Annual deviation)					22.74	mills/kW
33	Hourly rate *dec* (costs / Annual deviation)					2.71	mills/kW
34	**Regulation & Frequency Response (RFR)**						
35	Average annual costs	5,983					
36	Balancing Authority Area load forecast (annual average)		5,862	5,890	5,876		
37	Rate (costs / load forecast)					0.12	mills/kWh
38	**Operating Reserves (OR)** also known as contingency reserves						
39	Annual average costs - spinning reserves	26,594					
40	Annual average costs - supplemental reserves	24,346					
41	Balancing Authority Area total reserve obligation		552	565	559		
42	Balancing Authority Area spinning reserve obligation (1/2 total)		276	283	279		
43	Balancing Authority Area supplemental reserve obligation (1/2 total)		276	283	279		
44	OR spinning rate (costs / reserve obligation)					10.86	mills/kWh
45	Default Rate (normal rate * 1.15)					12.49	mills/kWh
46	OR supplemental rate (costs / reserve obligation)					9.95	mills/kWh
47	Default Rate (normal rate * 1.15)					11.44	mills/kWh

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