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

2012 BPA Final Rate Proposal

Generation Inputs Study

July 2011

BP-12-FS-BPA-05

GENERATION INPUTS STUDY
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TABLES

FIGURES

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COMMONLY USED ACRONYMS AND SHORT FORMS

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

GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
ICE	IntercontinentalExchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget

OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service

UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION

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 ratesetting purposes, these uses of the FCRPS are quantified and the costs associated with these uses are allocated to transmission rates under the ratesetting 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 ratesetting as revenue credits in the Power Rates Study, BP-12-FS-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 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-12-A-02C.

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 through 9. 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. 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 Table 1 provides the applicable quantities. Also, 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 Service rates for these services. The calculation and assumptions for each line in Table 1 are explained in detail in the applicable sections of the Study. The Ancillary and Control Area Service rates are shown in Table 3.

The VERBS rate contains three components, regulation, following, and imbalance. Costs assigned to the VERBS are allocated to these three components and these costs are shown in Table 2. The three components are used to calculate the VERBS rate. Table 3. The VERBS rate is based on a 99.5 level of service described in section 2. As explained in section 10, the Administrator retains the discretion under certain circumstances to increase the level of service for the VERBS above 99.5 percent and adopt a higher rate during the rate period.

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 of this Study. In addition, the Balancing Reserve Capacity Quantity Forecast is used to define the amount of balancing reserve capacity that BPA will make available for purposes of operational limits imposed under Dispatcher Standing Order 216 (DSO 216).

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 identifies an estimate of 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 loads deviate from the average hourly estimate, and the Balancing Authority Area must use its own generation resources 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 plants 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*) FCRPS generation. If load decreases, or generation increases, the AGC system decreases (*decs*) FCRPS generation. 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 FCRPS 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 facilities 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 loads that perform below their schedules.

BPA's balancing reserve capacity requirements 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 facilities expected to come online during the rate period; (2) total non-Federal thermal generation and scheduling data for the BPA Balancing Authority Area from October 2009 to April 2010 and October 2010 to April 2011, and (3) data from a 24-month period from October 1, 2007, to September 30, 2009. The data from the 24-month period needed for the forecast includes the total wind 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 facilities that are online as of the time of the Study based on BPA records (*see* http://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_current.xls) and a forecast of the facilities that are expected to come online before or during the FY 2012–2013 rate period. *See* Generation Inputs Study Documentation, BP-12-FS-BPA-05A (Documentation), Tables 2.1, 2.2, and 2.3.

The forecast of facilities that are expected to come online before or during the FY 2012–2013 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. The majority of new generating facilities that are expected to come online prior to or during the rate period are wind facilities; therefore, the estimates about future facilities pertain primarily to wind generation. References to "future" or "planned" facilities throughout this Study indicate expectations with respect to the interconnection of certain generating facilities 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 facility.

To forecast which future generating facilities will interconnect and the timing of such interconnections, BPA considers balancing service elections submitted by generators and the status of interconnection requests in BPA's interconnection queue in May 2011. 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 are more likely to be delayed past the requested online date.
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 near term.

3. Interconnection and network facility 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, 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 2012–2013 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 4,693 MW; installed solar capacity is an average of 21 MW; non-AGC controlled hydroelectric capacity is an average of 2,604 MW; non-Federal thermal capacity is an average of 5,784 MW; and Federal thermal capacity is 1,276 MW.

2.3 "Scaling in" Future Wind Generation

2.3.1 Methodology for Determining 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 facilities in the BPA Balancing Authority Area. For data on generation of the existing wind facilities, 24 months of one-minute actual average generation data from BPA's Plant Information (PI) system is 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, 2009. For wind facilities that came online between October 1, 2007, and September 30, 2009, 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) is used. For wind facilities online or forecast to come online after September 30, 2009, only estimated minute-by-minute generation levels are used.

To help estimate minute-by-minute generation for future facilities and to aid in data scrubbing for larger sections (greater than 20 minutes) of existing generator data, the 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 2012–2013 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 time delays in different ways depending on the data available for particular projects. For existing projects online prior to January 1, 2011, BPA derived time delays using actual minute-by-minute generation data from BPA's PI system. To derive 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 used for this analysis were up to 240 minutes leading and up to 240 minutes lagging. For each pair of existing and future wind projects, the time delay resulting in the highest correlation was used to define the time delay between those projects.

For projects that were not online prior to January 1, 2011, the Study uses either data reflecting common delays between existing projects and future project locations that were used in the FY 2010–2011 rate case or time delays derived from numerical weather prediction model data. BPA obtained both the data regarding the common time delays used in the FY 2010–2011 rate case and the numerical weather prediction model data from 3TIER, a wind forecasting company in Seattle, Washington. The time-delay data include a number of zero-minute values that indicate minimal or no difference (lead or lag) in the ramp up or down time between particular facilities or locations, but observations based on existing wind facilities indicate that wind facilities seldom ramp up or down at exactly the same time. As a result, if the most prevalent lead or lag time in the 3TIER data reflecting the common delays is zero minutes, the data are adjusted to reflect a lead or lag based on BPA Staff observations and knowledge of the area in question. With this adjustment, zero value leads or lags are minimized in the data used to scale in the future wind facilities.

For projects that were not included in the 3TIER time-delay study for the FY 2010–2011 rate case, time delays were calculated using the numerical weather prediction model data provided by 3TIER, which 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 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 used for this analysis were up to 240 minutes leading and up to 240 minutes lagging. For each pair of existing and future wind projects, the time delay resulting in the highest correlation was used to define the time delay between those projects. These time delays also resulted in a number of zero-minute values that indicate minimal or no difference (lead or lag) in the ramp up or down time between particular facilities or locations. As a result, if the most prevalent lead or lag time in the 3TIER data reflecting the common delays is zero minutes, the data were adjusted to reflect a lead or lag based on Staff's observations and knowledge of the area in question. With this adjustment, zero-value leads or lags are minimized in the data used to scale in the future wind facilities.

In analyzing the lead or lag between a specific future project and an existing project, data for more than one existing project are used. Using multiple existing projects helps to reflect some of the "diversity" or operational variability that occurs between particular projects. In addition, all generation data obtained from BPA's PI system are reviewed for missing data. Any missing data points that are less than or equal to 20 continuous sections (minutes) are filled in using linear interpolation from the existing data and by manually filling in certain points (particularly for values that are near zero). Any sections of missing data points larger than 20 minutes are filled in using the scaling method used to estimate minute-by-minute generation for future facilities. 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 facilities that are forecast to be online during the rate period. The table is organized according to the month and year that the facility went into service or is expected to be in service. Entries for existing facilities include the installed capacity in megawatts and the month and year that the facility 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. The information in columns D through F titled "Reference Plant [1, 2, or 3]" identifies the facilities used to scale the generation of a particular facility. Columns J through L titled "Reference Plant [1, 2, or 3] Time Offset (minutes)" includes the lead and/or lag times in minutes from the relevant reference plant to the facility being scaled.

2.3.2 Estimating Future Wind Project Generation

Once the lead and lag times for each wind project are determined, the installed capacity of the existing and future wind projects is used in conjunction with the leads and lags to calculate the estimated minute-by-minute generation of all future wind projects through the end of the rate period. The future wind project generation is forecast using the following assumptions. An example is provided for additional explanation.

First, when more than one existing wind project is used to estimate the generation of a future project, each existing project is weighted based on the extent to which the output of the existing project appears to assist in estimating the output of the future project. For many facilities, the forecast assumes that each existing project's output is equally accurate when used to estimate the future project's output and assigns equal weight to each existing project. However, more weight is assigned to a particular existing project if the data indicate that the existing project's output more accurately estimates the future project's output. Columns G through I titled "Reference

Plant [1, 2, or 3] Scale" in Documentation, Table 2.3 indicate the weight assigned to each reference project.

Second, the future project's generation is scaled in by multiplying the existing plant's generation by the planned capacity (or proportion thereof) 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 scaled wind project generation is time-shifted to the correct timeframe based on the lead or lag time from the existing project. This time shift helps express a future project's estimated generation for a particular minute as a function of an existing project's generation. The existing project's generation for a minute is moved to the minute under the future project that corresponds to the lead or lag time, which is then multiplied by the weighting factor and the installed capacity ratio as described above. If more than one existing project is used to scale in a future project, the scaled and time-shifted project output is added to determine the total future project generation.

The following example illustrates how the generation for each future project is calculated. In this example, a future 150 MW wind project (Project A) has a one-minute lag after the 126 MW Biglow Canyon project and a ten-minute lead before the 96 MW Goodnoe Hills project. Both Biglow Canyon and Goodnoe Hills are equally indicative of Project A's generation; thus, each project is assigned equal weight. Using these assumptions, Project A's generation for any particular minute is determined using the following equation:

$$\text{Project A} = (150/126)\times(\text{Biglow}^{-1\text{minute}})\times 0.5 + (150/96)\times(\text{Goodnoe}^{+10\text{minutes}})\times 0.5$$

These calculations are performed for all future 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 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 for all non-wind generation not controlled by AGC during the rate period requires analyzing historical minute-by-minute generation levels of the existing non-AGC facilities in the BPA Balancing Authority Area and accounting for future use by both existing facilities and facilities 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 facilities 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 facilities, 24 months of one-minute actual average generation data from BPA's PI system are used. For data on schedules of the existing non-AGC facilities, 24 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, 2009. The data were scrubbed for missing data periods, and contingency reserves were credited back to any non-AGC facilities that used those contingency reserves. Non-AGC facilities 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 2010 to May 2011 versus the previous year. This period was selected to coincide with notification that the prior performance of the non-Federal thermal generators would result in a separate balancing rate and performance improvement during this time was considered in determining the Balancing Reserve Capacity Quantity Forecast. For this evaluation, the 0.25^{th} percentile and 99.75^{th} 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 reduction in the reserve requirements.

2.4.2 Accounting for Future Non-AGC Generation

Accounting for future non-AGC facilities 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 facility, 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 facility.

2.4.3 Accounting for Solar Generation

The Study’s method for accounting for future solar generation facilities in the balancing reserve capacity requirements for the rate case assumes that the use of balancing reserve capacity for solar will be similar to that of wind generation. Literature shows that solar generation has a bell shape throughout the course of a sunny day, but can vary rapidly with different weather phenomena (*e.g.*, clouds, ambient temperature, precipitation). Thomas N. Hansen, U.S. Dep't of Energy, Utility Solar Generation Valuation Methods 4, 9, 13-17 (2007), *available at* http://www.docstoc.com/docs/28536624/Utility-Solar-Generation-Valuation-Methods; *see also* Andrew Mills *et al.*, Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System 4-5 (2009), *available at* http://eetd.lbl.gov/EA/EMP. The rapid variation of solar output demonstrates the need for balancing reserve capacity to be assigned to solar generation.

Currently, no utility-scale scheduled solar generation plant exists in the Pacific Northwest, which means that there is no source of regional minute-by-minute solar generation and schedule data available to incorporate into the Balancing Reserve Capacity Quantity Forecast. Due to the lack of minute-by-minute generation and schedule data for solar generation in the Pacific Northwest, the Study cannot forecast the specific balancing reserve capacity requirements for solar generation in a manner similar to the forecast for wind or thermal resources. Under these circumstances, the Study uses the balancing reserve capacity requirements for wind generation as a starting point for developing a reasonable proxy for solar generation balancing reserve capacity requirements.

The Study assumes that the balancing reserve capacity requirement for a solar facility would be one-half of the balancing reserve capacity requirement of a wind generator of the same capacity because solar facilities would, at most, produce electricity only during daylight hours (*i.e.*, about half the time). To forecast the balancing reserve capacity requirements for the solar facilities expected to be online during the rate period, the sum of the regulating reserve and following reserve components of balancing reserve capacity for wind generation is divided by the installed capacity for wind generation to create a reserves-per-megawatt installed capacity factor. The forecast installed capacity for the future solar project is then multiplied by the reserves-per-megawatt installed capacity factor and divided in half to forecast the balancing reserve capacity requirements.

2.5 Load Estimates

The following sections describe how 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 are derived.

2.5.1 Accounting for Pump Load

Load estimates start with the Balancing Authority Area load posted on the BPA external operations Web site. *See* 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 2012 to FY 2013), 24 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. For the remaining 12 months of the study period, the load data from October 2008 through September 2009 is divided by the load growth from FY 2008 to FY 2009. The growth factor observed between FY 2008 and FY 2009 was a 4.6296 percent decrease in Balancing Authority Area load. To scale the load to the rate period, the load growth factors shown below are applied to the entire 24-month period; the load growth factors are based on the forecasts for total Balancing Authority Area load from the BPA load forecasting group.

FY 2012 (4147 MW wind) Load = FY 2008 Load × 5.0338% Load Reduction

FY 2013 (5238 MW wind) Load = FY 2008 Load × 3.6896% Load Reduction

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) is 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 facility for a given hour equals the one-minute average of the actual generation of the facility 30 minutes prior to the hour.

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 datasets: 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, actual total wind generation, and total wind generation forecast. Each of these datasets is obtained or calculated in the manner described in sections 2.2 through 2.6. Using these datasets, 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 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 total wind generation forecast) is determined on a minute-by-minute basis. Note that future hydroelectric and future thermal facilities forecasts are covered in section 2.4.2, and solar generation is covered in section 2.4.3. Those datasets are not analyzed in the manner described within this section.

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 wind generation, and actual load net generation datasets, 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 dataset. Minutes 11 through 49 of each hour are set to the clock hourly average value. For minute 50 of the current hour through minute ten 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 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 wind generation, and actual load net generation datasets are developed. The actual datasets, forecast and ramped-in datasets, ten-minute averages, and ramped-in perfect schedules provide the foundation for the Balancing Reserve Capacity Quantity Forecast. Documentation, Table 2.4 is a graph depicting the one-minute average, ten-minute average, perfect schedule, and estimated values for the load net generation dataset 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 dataset, 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 dataset. The following reserves component is defined by the difference minute by minute between the ten-minute clock average of the load net generation dataset 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 2.4 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 wind generation, and actual load net generation datasets. The *inc* and *dec* amounts are calculated for the different amounts of wind penetration and load for FY 2012–2013.

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 the 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, and therefore it is assumed that an additional 0.2 percent of the movement in the Balancing Authority Area is absorbed from this point forward. This decreases the overall balancing reserve capacity requirement slightly.

Using 99.5 percent of values for the load net generation dataset, 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,* etc.).

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

The Study also includes a forecast of the balancing reserve capacity requirements that BPA needs to meet its balancing requirements 99.7 percent of the time. The forecast using 99.7 percent results in a slightly larger balancing reserve capacity requirement, equivalent to the historical probability method of three standard deviations. The 99.7 percent forecast was developed using the same methods and data as described in this Study, except that the 0.15 percent of each *inc* and *dec* component was discarded in the time series study.

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* + wind regulation *inc* + hydro regulation *inc* + load regulation *inc* = total regulation *inc*). To do this 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 each contributes 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 decomposition 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, 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 2.5. 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 2.6.

The data used to determine the balancing reserve capacity requirements are not normally distributed. The distribution of the data is not symmetrical; as a result, 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 at times 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 is 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 facilities participating in self-supply of imbalance reserves for the FY 2012–2013 rate period are based on the data that is available for the current Customer-Supplied Generation Imbalance pilot participation. Customers that elected (by May 1, 2011) to participate in self-supply of the imbalance portion of their balancing reserve capacity requirement for the FY 2012–2013 rate period are reflected in the Study.

2.8 Committed Intra-Hour Scheduling Pilot

The Study includes a separate forecast of the potential balancing reserve capacity requirement reductions associated with committed intra-hour scheduling by the entire wind fleet in BPA's Balancing Authority Area. To develop this forecast, the study assumes that all of the wind projects in the BPA Balancing Authority Area schedule every 30 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 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 intra-hour scheduling pilot would be seen in the reduction of the total balancing reserve capacity for BPA's Balancing Authority Area, because committed intra-hour scheduling by the entire wind fleet would reduce the aggregate load net generation error for the Balancing Authority Area. Documentation, Tables 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 are then credited against the forecast reserve requirement for wind.

The study results for committed intra-hour scheduling by the entire wind fleet can be found in Documentation, Table 2.26, columns G and H, that shows the average reduction in the forecast of the total balancing reserve capacity requirement for the rate period is approximately 34 percent. For those entities participating in committed intra-hour scheduling pilot, an adjustment will be made to give a credit of 34 percent of the VERBS rate.

2.9 Study of Quality of Service Levels in Excess of 99.5 Percent

The Study also quantifies the additional *inc* balancing reserve capacity needed above the 99.5 percent level to achieve different frequencies of DSO 216 under-generation tag curtailment events. To perform this analysis, estimates of DSO 216 under-generation tag curtailment frequency were needed for incremental increases of the *inc* balancing reserve capacity allocated to wind above the 99.5 percent level of service. Using the one-minute time series data for generation and load, and schedules for load, wind, hydro generation, Federal thermal generation, and non-Federal thermal generation, an aggregate "load net generation" SCE was calculated by subtracting the "load net generation" schedules from the "load net generation" actuals. The aggregate "load net generation" SCE was analyzed to capture all of the times in which a DSO 216 event would have occurred. The following criteria were used:

- The threshold for analysis was defined as 90 percent of the total balancing authority area *inc* balancing reserve requirement, because that is the threshold at which DSO 216 triggers.
- Top-of-the-hour ramps from ten minutes before to ten minutes after the hour were excluded from the analysis, pursuant to the current DSO 216 implementation.
- One event per clock hour (per direction) was allowed, because a DSO 216 directive carries through until top of the hour. The study assumed that an *inc* (under-generation) and a *dec* (over-generation) event could occur in the same clock hour.
- Events lasting multiple clock hours were split into multiple events.

Each month of the rate period was analyzed separately using its associated 24 months of one-minute data with the forecast installed wind capacity and load growth. The results for augmenting the wind *inc* balancing reserve capacity for entire balancing authority are presented in Documentation, Tables 2.27 and 2.28. The results are presented as the multiples of additional reserves needed above the 99.5 percent *inc* wind balancing reserve capacity requirement (Documentation, Table 2.9) that correspond to a particular number of DSO 216 curtailments. For example, the average *inc* wind balancing reserve capacity requirement without Self Supply is 620 MW, and the average magnitude of additional reserves needed to lower the DSO 216 tag curtailment frequency to 11 events per year is 0.9, so an average of 1,178 MW (620 MW × 1.9) of total *inc* wind balancing reserve capacity would be needed to achieve this DSO 216 frequency.

2.10 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 incorporated into the wind balancing reserve capacity requirement.

Documentation, Tables 2.7 through 2.24 include the results of the Balancing Reserve Capacity Quantity Forecast. All of these tables reflect the results assuming that wind generators are scheduling consistent with a 30-minute persistence model. Documentation, Tables 2.7 through 2.10 include the *inc* and *dec* amounts for each component of the total balancing reserve capacity requirement, the load balancing reserve capacity requirement, the wind balancing reserve capacity requirement, and the non-Federal thermal generation balancing reserve capacity requirement, 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 2.11 through 2.14 provide the same information for load and each type of generation at the 99.7 percent probability and assuming no self-supply. Documentation, Tables 2.15 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.

The results for committed intra-hour scheduling by the entire wind fleet can be found in Documentation, Tables 2.25 and 2.26. The results for the study of quality of service levels in excess of 99.5 percent, which quantifies the requirements for augmenting the wind *inc* balancing reserve capacity of the entire balancing authority, are presented in Documentation, Tables 2.27 and 2.28.

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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 in the BPA Balancing Authority Area moment-to-moment and through the operating hour. VERBS Reserve, formerly known as Wind Balancing Service Reserve, is also comprised of regulating, following, and imbalance reserves that are used to balance the variable energy resource generation in the BPA Balancing Authority Area moment-to-moment and through the operating hour.

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. 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 rates 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 composite cost pool in the calculation of power rates. See the Power Rates Study, BP-12-FS-BPA-01, section 4.

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; and (3) a certain quantity of the imbalance portion of the VERBS Reserve will be customer-supplied *(i.e.,* self-supplied). 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 Documentation, BP-12-FS-BPA-02A, section 2.3; the regulated hydro project information from the Power Loads and Resources Study, BP-12-FS-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 section 4; and the market price forecast from the Power Risk and Market Price Study, BP-12-FS-BPA-04, section 2.

This Study introduces several changes to the cost allocation methodologies, including: (1) direct assignment to VERBS of costs for the Wind Integration Team (WIT); (2) direct assignment to VERBS of costs for a *dec* Acquisition Pilot; (3) streamlined treatment of deriving the 120-hour peaking capacity of the Big 10 hydro projects; and (4) a new cost allocation for DERBS Reserve.

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. This results 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 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. The coordinated energy production for these storage projects is forecast by HYDSIM 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 70 water years of record (October 1928 through September 1998) 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 quantify the amount of available capacity for the 14 Federal regulated hydro resources. Though the HYDSIM and HOSS models are operated for the 70 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, 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 70 water years of record (October 1928 through September 1998). Power Loads and Resources Study, BP-12-FS-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 analyzing capacity in the cost allocation methodology. Further information on the operation of HYDSIM is presented in the Power Loads and Resources Study, BP-12-FS-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 70 historical water conditions for the study period. The outputs of HOSS are not directly used for ratesetting 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-12-FS-BPA-03, section 3.1.2.1. HOSS incorporates hourly versions of the input data for Regulating Reserve, Operating Reserve, Load Following Reserve, DERBS Reserve, and VERBS Reserve. These are computed once for each of the 14 periods in a year, and these values are used under all 70 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 reserves forecast in the Operating Reserve Cost Allocation in section 4 *(i.e.,* seven percent of thermal and five percent of hydro, wind, and other resources for FY 2012, and three percent of the load and three percent of net generation for FY 2013), 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 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 70 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-12-FS-BPA-03, section 3.1.2.1 and Power Loads and Resources Documentation, BP-12-FS-BPA-03A, Tables 2.1.2 and 2.1.3, and inputs to the Power Risk and

Market Price Study, BP-12-FS-BPA-04, section 2; 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 70 water conditions for the study period. For the FY 2012–2013 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 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.

One hundred twenty-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 70 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 2012–2013, 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.

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 70 historical water years. These relationships are created through curves that define peaking capacity as a function of monthly energy for each of the 70 hydro conditions. The data from HOSS is 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). 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.

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

The 120-hour hydro peaking capacity methodology described above calculates the available capacity from the 14 Federal system regulated hydro projects. 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 2012–2013 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; 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 93 percent of the 120-hour peaking capacity produced by all 14 regulated hydro projects, as shown in Table 3.2, line 17.

The 93 percent portion of the regulated hydro is used in the Regulating, DERBS, and VERBS Reserves cost allocations, shown on 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 these costs by the 120-hour peaking capacity total system uses. 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, Load Following Reserve, DERBS Reserve, and VERBS Reserve. *See* Study, section 2, and Documentation, Table 2.16. *See also* Study, section 4 and Documentation, Table 4.6, line 13. The embedded costs are allocated based on the *inc* reserve forecast.

The Operating Reserve quantity used is adjusted 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 comprise 91 percent of the hydro projects in the BPA Balancing

Authority Area capable of providing Operating Reserves. The hydro projects capable of providing Operating Reserves are the regulated hydro projects and the independent hydro projects within the BPA Balancing Authority Area. See the WP-10 Final Generation Inputs Study, WP-10-FS-BPA-08, section 3.4. This is a different adjustment from the 93 percent adjustment described above, which represents the Big 10 as a proportion of the 14 regulated hydro projects. In this Supplemental Operating Reserve adjustment, the 91 percent represents the portion of a larger subset of FCRPS hydro projects than the 14 regulated hydro projects. The Supplemental Operating Reserve quantity 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), Colville payment Treasury credit, and synchronous condensing. With the exception of the revenue credit for synchronous condensing (Documentation, Table 3.5, line 18), the inputs for Table 3.5 are described in the Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, section 2.3. 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 $876,768,000. Documentation, Table 3.5, line 19.

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 $876,768,000 is divided by the total system uses of 10,929 MW to calculate the embedded unit cost of $6.69 per kW 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.* at 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 2.17, column F. The revenue forecast for the embedded cost portion is an average annual amount of $4,816,800. 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 2.18, column L. The revenue forecast for the embedded cost portion is an average annual amount of $37,731,600. 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 2.19, column L. The revenue forecast for the embedded cost portion is an average annual amount of $4,094,280. Documentation, Table 3.6, line 16.

3.3 Direct Assignment of Costs

Two cost categories are directly assigned to the VERBS rate. The categories are a portion of Wind Integration Team (WIT) costs and *dec* Acquisition Pilot costs. These cost categories are 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 2012–2013 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 $8,289,125 for FY 2012 and $6,980,277 for FY 2013. Funding for the WIT budget is divided between Power Services (PS) and TS. The TS WIT costs of $4,170,125 in FY 2012 and $4,259,277 in FY 2013 are directly assigned to the VERBS rate. The TS WIT costs cover employee costs associated with the following WIT initiatives: Dispatcher Standing Order 216, Intra-Hour Scheduling, Dynamic Transfer Limits study, and Customer-Supplied Generation Imbalance.

At the end of FY 2011, BPA forecasts some unspent Green Energy Premiums (GEP) revenues, which have been collected over the previous two rate periods, FY 2007-2011. These revenues are available for BPA to reinvest in research, development, and demonstration. PS's share of the WIT budget will be funded through these GEP revenues, as determined in the Integrated Program Review process. IPR Close-out Report for FY 2012–2013 Program Levels at 40-41 (available at http://www.bpa.gov/corporate/Finance/IBR/IPR/). The costs covered by PS's share of the WIT budget are mainly the Wind Forecasting Initiative and associated employee costs, half the Corporate Strategy and Legal employee costs associated with the WIT, and Technology Innovation's costs associated with renewables.

3.3.2 *Dec* Acquisition Pilot Costs

In FY 2012–2013, BPA will implement a *dec* Acquisition Pilot program. The pilot would incorporate BPA purchases of *decs* provided by non-Federal generation to be used for balancing reserve capacity, thus reducing the *dec* reserves the FCRPS needs to supply. To implement this pilot program, BPA needs to develop some new systems, automate some of its existing systems, and update communication links to provide BPA the capability to purchase and deploy *decs* provided by non-Federal resources to support variable energy resources.

BPA will directly assign $4 million per year to the VERBS rate for this purpose. The $4 million in expense for the *dec* Acquisition Pilot program in the power revenue requirement will be offset by the additional $4 million in VERBS revenue credit as part of the generation inputs revenue credit to power rates. This pilot will not have an impact on power rates. To the extent that these funds are used to purchase *dec* balancing reserve capacity that displaces *dec* balancing reserve capacity provided by the FCRPS, BPA will reduce the variable cost portion of the VERBS cost allocation. See section 3.4.5 of this Study for a full description of this adjustment to the variable cost component. These dollars are separate from those identified for WIT costs and are not covered by GEP revenues.

Of this $4 million per year, $1 million will be used to develop and upgrade the systems needed for implementation. As currently envisioned, the systems would include a reliability dispatch tool used to set a merit dispatch order for the Federal and non-Federal *dec* projects available to

BPA. The reliability dispatch tool will need to incorporate cost and availability of *dec* projects along with system conditions in developing the merit dispatch. In addition, BPA's AGC system would need to be upgraded to incorporate input from the reliability dispatch tool. BPA will also need a tool to pull data from the Supervisory Control and Data Acquisition (SCADA) system to provide knowledge of variability within BPA's Balancing Authority Area. This tool would provide dispatchers with information about deployment of balancing reserve capacity, the reasons leading to the deployment of the reserves, and projected conditions for the remainder of the hour, thus improving the dispatchers' ability to take preventive measures. The tool could also provide situational awareness information to the reliability dispatch tool for consideration as the dispatch order is developed. Along with these tools, BPA will need to update the communication links between BPA and the non-Federal generators providing the *dec* reserves. In addition, communication links will need to be updated with other balancing authority operators for those projects not in BPA's Balancing Authority Area.

The remaining $3 million will be used to purchase non-Federal *dec* reserves. BPA will evaluate the market and ability of the FCRPS to provide *dec* reserves in certain months to determine the most efficient strategy for purchasing non-Federal *dec* reserves. For purposes of the *dec* Acquisition Pilot, non-Federal *dec* reserves are expected to cost approximately the same as the variable cost of Federal *dec* reserves. Combining this cost expectation with not having to provide the *dec* reserves from the FCRPS translates into a $3 million reduction in the variable cost component of the VERBS cost allocation. As a result, the cost allocation forecast net effect of directly assigning the $3 million for *dec* purchases to the VERBS rate is $0. In addition, the FCRPS is capable of providing $3 million of added value to secondary net revenues. The revenue forecast for short-term market sales includes the additional $3 million, as shown in the Power Rates Study, BP-12-FS-BPA-01, section 4. Also see Study, section 3.4.5 for a full description of this adjustment to the variable cost component.

For purposes of adjusting the imbalance, following, and regulation components of the VERBS rate, the $3 million of costs deducted from the variable cost component of the VERBS cost allocation is deducted proportionately from the regulating, following, and imbalance components based on the ratio of the component's *dec* balancing reserve capacity amount to the total *dec* balancing reserve capacity amount for VERBS on a rate period annual average basis. Study, Table 2, column D.

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 reserves. The use of FCRPS capability to provide and deliver these reserves results in various forms of efficiency losses within the FCRPS. The Generation and Reserves Dispatch (GARD) Model was designed to calculate the costs associated with these 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 reserves, load following reserves, and imbalance reserves. 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 reserves 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 of an automatic increase in generation is referred to as an *inc* reserve. Likewise, the ability to be ready and capable of an automatic decrease in 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 Balancing Authority Area 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 produces 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, and
11. spill costs associated with providing spinning *inc* reserves.

The GARD Model also produces 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*, and
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 denominated in MWh 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,” such that each controller project’s generation request is met while at the same time meeting the balancing reserve capacity obligation and responding 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 sub-divided 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 70 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 70 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 through 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 70 water years for HLH and LLH (a total of 1,680 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 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 Operation 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 reserves be required to cover a growing imbalance, additional units are synchronized and ramped as the following reserve is consumed and the imbalance reserve is deployed with non-spinning capability. By definition, all *dec* reserves (the *dec* portion of the regulating, following, and imbalance reserves) are spinning, because units must be generating *(i.e.,* the turbine is spinning) in order to deploy *dec* reserves.

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 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 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 reserve 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 ensuring that the FCRPS is capable of providing the required balancing reserve capacity. Stand ready costs are distinct from actually deploying balancing reserve capacity within the hour in response to the need. To ensure that the FCRPS is standing ready to deploy balancing reserve capacity as needed, four specific costs are incurred: 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 to ensure 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. *See* Tables 3.7 through 3.10 and Power Risk and Market Price Study, BP-12-FS-BPA-04, section 2. The cost of *inc* energy shift is included in the total variable cost that is included in rates. For FY 2012–2013, the total annual average energy shift is 1,800,970 MWh, worth $23,594,099. Documentation, Table 3.11, at 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 kcfs [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, non-spinning *inc*, 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 to ensure 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 be generating 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-12-FS-BPA-04, section 2. 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 2012–2013 is a gain of 24,509 MWh, worth $896,753. Documentation, Table 3.11, at 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 were 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 as well as 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-12 FS-BPA-04, section 2. 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 2012–2013 period is 4,927 MWh, worth $195,602. Documentation, Table 3.11 at 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 in conjunction with 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-12-FS-BPA-04, section 2. The total average spill loss for the FY 2012–2013 period is 41,744 MWh, worth $1,337,094. Documentation, Table 3.11 at 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 sub-categories for deployment costs are response losses, cycling loss, and spill loss. For each sub-category 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 a type of efficiency loss 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-12 FS-BPA-04, section 2. 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 2012–2013 period is 37,309 MWh, worth $1,494,977. Documentation, Table 3.11 at 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 off-line, 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 as well as 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-12 FS-BPA-04, section 2. 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 2012–2013 period is 4,447 MWh, worth $178,060. Documentation, Table 3.11 at 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 its 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-12 FS-BPA-04, section 2. For FY 2012–2013, as shown on Table 3.11, the average deployment spill loss incurred deploying *decs* is 90 MWh, worth $2,916. 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 (e.g., 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 on Table 3.12. The total average loss for the FY 2012–2013 period is 1,864,979 MWh, valued at $25,905,994. Documentation, Table 3.11, line 17. The total annual average FCRPS variable cost used for setting rates for FY 2012–2013 is $22,905,994. *Id.* at Table 3.12, line 6. The reduction in variable cost reflects $3 million directly charged to VERBS for the acquisition of third-party *dec* capacity. The acquisition of third-party *dec* capacity relieves some of the reserve burden from the FCRPS. Alleviating some of the reserve burden from the FCRPS is expected to reduce the VERBS variable cost by $3 million. *See* section 3.3.2 and Documentation, Table 3.12, line 2 and footnote.

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

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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 (spinning and supplemental) backs up resources in the BPA Balancing Authority Area. Power rates are reimbursed for the costs of providing these Operating Reserves through revenue credits. *See* Power Rates Study, BP-12-FS-BPA-01, section 4. Rates for Operating Reserves are developed in section 10.4 of this Generation Inputs Study, and are shown in the ACS-12 rate schedule, BP-12-A-02C. 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 Study describes (1) the applicable Operating Reserve regional reliability standards that apply to the BPA Balancing Authority Area; (2) BPA's methodology for forecasting amounts 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 is an amount of spinning and non-spinning, or supplemental, reserves. At least half of the Operating Reserve must 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:

(a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or

(b) The sum of five percent of the load responsibility served by hydro generation and seven percent of load responsibility served by thermal generation.

In addition to this standard, each NWPP member with wind generation in its balancing authority area must maintain Operating Reserve equal to five percent of the wind 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 RM09-15, Petition of NERC (Mar. 25, 2009). The proposed WECC standard, BAL-002-WECC-1, states that the minimum Operating Reserve requirement is the greater of (1) the sum of three percent of load (generation minus station service minus Net Actual Interchange) and three percent of the net generation (generation minus station service); or (2) the most severe single contingency. At least half of the total requirement must be spinning reserve. On October 21, 2010, the Commission decided to remand BAL-002-WECC-1 to NERC. *Version One Regional Reliability Standard for Resource and Demand Balancing*, FERC Docket RM09-15, Order No. 740, 133 FERC ¶ 61,063 (2010). On April 15, 2011, WECC posted revisions to address the reasons for the FERC Order No. 740 remand. The revised standard was posted for a WECC Operating Council (WECC OC) vote on May 19, 2011, with expectation of Commission approval before or near the end of the 2011 calendar year. The WECC OC vote (22 yes, 22 no, 5 abstain) did not pass the standard on May 19, 2011. Currently, the WECC OC is working on a modification and resubmittal of BAL-002-WECC-1. It is expected that the modifications to the standard will result in passage at the WECC OC and subsequently Commission approval. When approved by the Commission, the BAL-002-WECC-1 is likely to be implemented and effective within 90 days.

BPA must base its Operating Reserve forecast on the best information available regarding the WECC standard for Operating Reserve. Based on the delay in the WECC OC passage and time necessary for the Commission's proposal, BPA is assuming that the proposed standard will be implemented during the FY 2012–2013 rate period. See section 4.4 below.

4.3 Calculating the Quantity of Operating Reserve Using the Current BAL-STD-002-0

As discussed above, the current WECC and NWPP standards require the BPA Balancing Authority Area to maintain Operating Reserve for five percent of hydro, five percent of wind, and seven percent of thermal online generation. The weighted average of the standards for all Federal generation resources *(i.e.,* Federal hydro and Columbia Generating Station generation) is approximately 5.2 percent. This weighted average is used for billing purposes under the Operating Reserve ancillary service rates to determine the Operating Reserve obligation for customers that take power from the Federal Columbia River Power System (FCRPS).

In accordance with the current WECC and NWPP standard, Transmission Services (TS) forecasts the quantity of Operating Reserve obligation to be provided by Power Services (PS) using the following methodology. The total BPA Balancing Authority Area Operating Reserve obligation forecast is based on a regression analysis of historical total BPA Balancing Authority Area Operating Reserve obligation. First, the hourly historical total BPA Balancing Authority Area Operating Reserve obligation is summed from October 2001 through April 2011 to yield sub-totals by month. The sub-totals by month are then divided by the hours in the month to calculate the average hourly total Operating Reserve obligation by month, shown in Table 4.1. The annual average total BPA Balancing Authority Area Operating Reserve obligation is then calculated and a regression analysis is performed on the average annual reserve obligation against time (FY 2002 through FY 2010 values are actuals while FY 2011 uses forecast values). Documentation, Table 4.2. Finally, a linear fitting function in Microsoft Excel is used as the regression curve to forecast the obligation for FY 2012–2013. The total BPA Balancing Authority Area obligation forecast calculated from the regression formula is 717.9 MW in FY 2012 and 726.3 MW in FY 2013 (722.1 MW average for FY 2012–2013). Documentation, Table 4.3, column B.

The amount of Operating Reserve obligation provided through self-supply and third-party supply is forecast based on the customer elections of self-supply and third-party supply for the rate period, which was 107.7 MW. This amount is assumed to continue for both FY 2012 and FY 2013. *Id.* 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, 610.2 MW in FY 2012 and 618.6 MW in FY 2013 (614.4 MW average for FY 2012–2013). *Id.*

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

The proposed WECC standard BAL-002-WECC-1 states that the reserve obligation shall be the greater of the amount of reserve equal to the loss of the most severe single contingency or an amount of reserve equal to the sum of three percent of the load (generation minus station service minus net actual interchange) and three percent of net generation (generation minus station service).

The BPA Balancing Authority Area Operating Reserve obligation under the proposed BAL-002-WECC-1 standard is determined as follows. First, the BPA Balancing Authority Area load is forecast using BPA Balancing Authority Area load in FY 2010 as the base year. The forecast of the loads through FY 2013 is determined through the BPA load forecast, resulting in Balancing Authority Area load growth of 2.0 percent in FY 2011, -0.1 percent in FY 2012, and 1.4 percent in FY 2013. Second, BPA Balancing Authority Area generation is forecast based on a ratio of Balancing Authority Area generation to Balancing Authority Area load of approximately two-to-one observed historically from FY 2005 through FY 2010. Next, the total BPA Balancing Authority Area Operating Reserve obligation is calculated by summing the products of three percent times the forecast load and three percent times the forecast generation. The total BPA Balancing Authority Area Operating Reserve obligation under the proposed BAL-002-WECC-1 standard is forecast to be 554.3 MW in FY 2012 and 562.1 MW in FY 2013 (558.2 MW average in FY 2012–2013), as shown on Documentation, Table 4.4.

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. Because the proposed standard is based on three percent of load and three 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. The forecast of self- and third-party supply under the proposed standard is 62.1 MW in FY 2012 and FY 2013. 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 standard, the PS Operating Reserve obligation would be 492.2 MW in FY 2012 and 500.0 MW in FY 2013 (496.1 MW average in FY 2012 and FY 2013), as shown on Documentation, Table 4.5.

4.5 Calculating the Operating Reserve Obligation Forecast

BPA assumes BAL-STD-002-0 will continue to be in effect for FY 2012 and that the Commission will approve BAL-002-WECC-1 by FY 2013. Therefore, the Operating Reserve obligation forecast is 610.2 MW in FY 2012 and 500.0 MW in FY 2013 (555.1 MW average in FY 2012 and FY 2013). The monthly amounts are based on the percentage shaping of historical BPA Balancing Authority Area loads from FY 2005 through FY 2010, as shown on Documentation, Table 4.6. BPA uses the FY 2012–2013 average forecast amounts in the calculation of the unit cost of Operating Reserve.

4.6 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. See Study, section 3.4 and Documentation, section 3.

4.6.1 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 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 4.7. As described in section 3.2, the Operating Reserve, Regulating Reserve, 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, as described in section 4.5, 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 section 4.6.5.

4.6.2 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 4.7.

The annual average total hydro peaking capacity for purposes of calculating the embedded cost portion of capacity for Operating Reserve is 10,705 MW. Documentation, Table 4.9, line 7. The other capacity use forecast quantity that covers Operating Reserve, Regulating Reserve, VERBS Reserve, DERBS Reserve, and Load Following Reserve is 1,347 MW, which is added to the hydro peaking capacity to obtain the Capacity System Uses of 12,052 MW. *Id.* at lines 8-9.

4.6.3 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, all detailed in Documentation, Table 4.8. The inputs for Documentation, Table 4.8 are described in the Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, section 2.3. 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 4.8, line 18) to avoid double-counting.

The annual average revenue requirement of $1,007,173 is divided by 12,052 MW (the Capacity System Uses) to calculate the embedded unit cost of Operating Reserve, $6.96 per kW per month of reserve need. Documentation, Table 4.9.

4.6.4 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 555.1 MW. Documentation, Table 4.6. The revenue forecast for the embedded cost portion is $46,353,600 per year. Documentation, Table 4.9, line 14. As stated above, half of the Operating Reserve quantity, 277.55 MW, is Spinning Operating Reserve and half is Supplemental Operating Reserve. The embedded cost revenue forecast for each service is half of the total, $23,176,800. Study, Table 1, lines 14 and 17.

4.6.5 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

$4,100,264, as shown on Documentation, Table 3.12, line 3. The total forecast cost allocation for Spinning Operating Reserve, including both the embedded cost ($23,176,800) and the variable cost, is $27,277,064. Study, Table 1, lines 14-16.

The variable unit cost for Spinning Operating Reserve is $1.23 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.* at line 15. 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 $8.19 per kW per month of reserve need. *Id.* at line 16.

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5. SYNCHRONOUS CONDENSING

5.1 Synchronous Condensing

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

5.2 Description of Synchronous Condensers

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

5.3 Synchronous Condenser Costs

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

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $307,000 per year. *See* Generation Inputs Study Documentation, BP-12-FS-BPA-05A (Documentation), Table 5.2, line 9; Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, section 2.3. 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. The methodology to determine the amount and cost of energy consumption is described below.

5.4 General Methodology to Determine Energy Consumption

For the FY 2012–2013 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 is multiplied by the fixed hourly energy consumption for the generators to determine the amount of energy consumed. The fixed hourly energy consumption is the motoring power consumption of the specific generator units when they are operated in condense mode. *See* Documentation, Table 5.1. Finally, the market price forecast is applied to the amount of energy consumed to calculate the cost of synchronous condensing. The methodology for assigning historical synchronous condenser operations to the voltage control function and calculating the associated energy use for each of the FCRPS projects capable of operating in condense mode is described below.

5.4.1 Grand Coulee Project

Six generators (Units 19-24) at the Grand Coulee project are capable of operating as synchronous condensers, although only three are typically operated in condense mode. The Study forecasts the number of hours that the Grand Coulee units will operate in condense mode based on historical condenser operations for the three-year historical period. The transmission system typically needs additional voltage control from the Grand Coulee project during night-time 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 on-line 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 night-time 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 on-line 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 on-line units and the shunt reactor is less than the total measured reactive demand for the hour, one or more units operating in condense mode is allocated to voltage control for that hour. If a condensing unit is allocated to voltage control for a single night-time hour, the condensing operation of that unit is allocated to voltage control for the entire night-time 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.* at line 4.

5.4.2 John Day, The Dalles, and Dworshak Projects

The John Day project has four generators (Units 11-14), The Dalles has five generators (Units 15-20), and the Dworshak project has three generators (Units 1-3) capable of operating as synchronous condensers. These three projects condense only when requested by 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.* at line 3), and 884 MWh for the Dworshak project. *Id*. at lines 5 and 6.

5.4.3 Palisades Project

The Palisades project has four generators (Units 1-4) that are capable of synchronous condensing. Units are operated in condense mode pursuant to standing instructions from 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.* at line 7.

5.4.4 Willamette River Projects

The Willamette River projects have seven generators capable of condensing, which include units in the Detroit project (Units 1-2), the Green Peter project (Units 1-2), and the Lookout Point project (Units 1-3). Historically these units have been operated at times in condense mode. However, BPA studies indicate that condensing is not required 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.* at lines 8-10.

5.4.5 Hungry Horse Project

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

5.5 Summary – Costs Assigned to Transmission Services

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $307,000 per year. *See* Documentation, Table 5.2 and Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02, section 2.3.

The energy forecast to be consumed by FCRPS generators operating in condense mode totals 44,397 MWh. *See* Documentation, Table 5.1. The energy consumed for condensing operation is priced at the market price forecast. Power Risk and Market Price Study, BP-12-FS-BPA-04, section 2.4. Applying the market price forecast of $35.67 per MWh to the energy consumed results in a total cost of $1,583,641 per year. Documentation, Table 5.1, line 13.

Total synchronous condensing cost allocated to TS is $1,890,641 per year. Documentation, Table 5.3, line 5. This amount is made up of $538,296 per year in energy costs (*id.* at line 2) and $307,000 per year in plant investments for the Southern Intertie (*id.* at line 1), and $1,045,345 associated with energy costs for voltage control for the Network. *Id.* at 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 large increments of generation (at least 600 MW). To satisfy this requirement, the generation must be dropped (disconnected from the system) 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 14 times over the last 14 years (1996-2009). Therefore, the estimate of “large generating units dropped” is an average of one drop per year. This is a reduced occurrence from the FY 2010–2011 rate period expectation of 1.5 drops per year, which was based on a four-year average.

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-12-FS-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 engineering study provided estimates of 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-12-FS-BPA-04, section 2.4. Documentation, Table 6.1 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 2012–2013. It is assumed that these outages are unpredictable, longer than scheduled, and cannot be scheduled to avoid a loss in total project generation. Documentation, Table 6.1 shows the calculation of the lost revenue.

6.6 Equipment Deterioration, Replacement, or Overhaul

The effect of additional deterioration due to 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 maintenance activities where 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 Summary

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 $376,503. Documentation, Table 6.2. Because the estimate of large generating units dropped is an average of one drop per year, the annual cost is $376,503. *Id.* This cost is assigned to TS for recovery in transmission rates. It then becomes revenue to PS that is a revenue credit to the power rates.

7. REDISPATCH

7.1 Introduction

Under the 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 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 incrementing a resource, the resource generates energy that it could have otherwise sold at a future time. To keep the incrementing resource whole financially, TS pays the resource owner for the value of that generation.

There are three levels of redispatch under Attachment M of the OATT that TS can request from Power Services (PS) to relieve flowgate congestion: Discretionary Redispatch, Network (NT) Redispatch, and Emergency Redispatch. This Study forecasts revenues PS expects to recover from TS for redispatch services. The FY 2012–2013 revenues PS expects to recover from TS for redispatch services are forecast by quantifying the amount of redispatch service provided by PS in FY 2009-2010 and adjusting this amount by excluding unusual events that are not expected to recur.

7.2 Discretionary Redispatch

Under the 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 redispatch or any amount of redispatch up to the amount requested at each generating project.

Actual costs of Discretionary Redispatch incurred by TS for FY 2009 totaled $170,157, and for FY 2010, $46,439. Documentation, Table 7.1, lines 48-49. Table 7.1 provides the actual monthly Discretionary Redispatch costs, along with other details for FY 2009 and FY 2010.

For FY 2010 and FY 2011, the revenue TS forecasted for payment to PS for Discretionary Redispatch totaled $175,000 per year. While the actual costs for FY 2010 totaled only $46,439, the actual costs for FY 2009 were close to $175,000. Due to the unpredictable nature of transmission congestion and the need for redispatch, and the variability in redispatch costs on a monthly and seasonal basis, the forecast for FY 2012 and FY 2013 Discretionary Redispatch remains at $175,000 per year.

7.3 NT Redispatch

NT Redispatch is provided under Attachment M of the OATT. TS requests NT 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. NT Redispatch includes transmission and/or power purchases or sales to maintain NT firm schedules during planned or unplanned outages. PS must provide NT Redispatch when requested by TS to the extent that it can do so without violating non-power constraints.

Actual costs of NT Redispatch incurred by TS for FY 2009 totaled $392,162, and for FY 2010, $49,261. Documentation, Table 7.2 provides the actual monthly NT Redispatch costs, the megawatthours redispatched, and dollars per megawatthour for FY 2009 and FY 2010. These NT Redispatch requests represent only transmission and power purchases for planned and unplanned outages to maintain firm NT schedules.

For FY 2010–2011, TS forecasted payments to PS for NT Redispatch of $225,000 per year. The actual costs of $392,162 during FY 2009 for NT Redispatch exceeded the forecast amounts for FY 2010–2011 by approximately $167,000. However, actual FY 2010 NT Redispatch costs were lower than forecast. Due to the unpredictable nature of the need for NT Redispatch and the variability in transmission and power prices on a monthly and seasonal basis, the forecast for NT Redispatch in FY 2012–2013 remains at $225,000 per year.

7.4 Emergency Redispatch

Emergency Redispatch is provided under Attachment M of the OATT. 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.

Actual costs of Emergency Redispatch incurred by TS for FY 2009 totaled $964, and for FY 2010, $1,510. The Emergency Redispatch costs for FY 2009 were attributable to two events, while the FY 2010 Emergency Redispatch costs were attributable to one event.

Due to the unlikely nature of Emergency Redispatch and the low actual costs of Emergency Redispatch for FY 2009 and FY 2010, no cost for Emergency Redispatch is forecast for FY 2012–2013.

7.5 Revenue Forecast for Attachment M Redispatch Service

Based on FY 2009-2010 actual costs and the analysis above, a total of $400,000 per year in revenue is forecast for FY 2012–2013 for Discretionary and NT Redispatch services provided to TS under Attachment M of the OATT.

8. SEGMENTATION OF CORPS OF ENGINEERS AND BUREAU OF RECLAMATION TRANSMISSION FACILITIES

8.1 Introduction

The COE and Reclamation own transmission facilities associated with their respective generating projects. All COE and Reclamation costs are assigned to the generation function in the Power Revenue Requirement Study. Therefore, the Generation Inputs Study, BP-12-FS-BPA-05, 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 COE and Reclamation transmission-related investment is associated with three segments: Generation Integration (GI); Network; and Utility Delivery. The GI investment is assigned to generation to be recovered through power rates. The annual cost of the Network and Utility Delivery investments is allocated to TS, and the resulting revenues are credited to the power revenue requirement. The definitions of these segments are consistent with the definitions used in BPA's most recent Transmission Segmentation Study. 2002 Final Transmission Proposal Segmentation Study, TR-02-FS-BPA-02. The relevant segment definitions and cost treatment are described below.

8.2 Generation Integration

GI facilities connect the Federal generators to the BPA Network. This segment includes generator step-up transformers (GSU). GI costs remain functionalized to the generation function, consistent with Federal Energy Regulatory Commission direction.

8.3 Integrated Network

Integrated Network facilities provide the bulk of transmission of electric power within the Pacific Northwest and operate at voltages of 34.5 kilovolts (kV) and above. The 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 GSU and associated equipment at the projects. These costs are all GI, which remain 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 is used for both Network and GI. This switching equipment is segmented between Network and GI as described in the Generation Inputs Study Documentation, BP-12-FS-BPA-05A (Documentation), Table 8.1.

8.6 Reclamation Facilities

Reclamation usually owns the lines and switchyards in the substations at its plants. The primary function of these facilities is to connect the generators to the Network, but at some substations there are facilities that perform Network or Utility Delivery functions. The Study shows the information used to assign to the appropriate segment the lines and substation investment at each Reclamation project. Documentation, Tables 8.2 and 8.3 describe the Columbia Basin project (Grand Coulee), and Table 8.5 describes the other Reclamation projects: the Roza Division of the Yakima Project, the Minidoka Division of the Minidoka-Palisades Project, and the Boise Project.

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, Table 8.4. The proxy investment by segment is divided by the total proxy investment for each switchyard to develop a percentage for each segment. These percentages are then multiplied by the actual total switchyard investment to ascertain the actual investment for each segment. *Id.* The segment percentage is multiplied by the total transmission investment for each station to determine the segment investment. Documentation, Table 8.3, lines 6, 15, and 25.

The cost of the land associated with the Reclamation switchyard equipment is included in the total costs. As shown on Reclamation financial statements, the total cost 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 totaled $8,634, or about 0.27 percent of the combined $19,055,431 cost of these projects. Documentation, Table 8.5.

8.6.1 Columbia Basin Transmission Costs

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 Lonepine, and Grant PUD. Documentation, Table 8.4, lines 18 and 19. Because these facilities serve both Generation

Integration and Delivery functions, the costs of these facilities are segmented accordingly. The 500 kV additions for the Coulee-Bell line are included in the investment.

In calculating the investment for the Columbia Basin project, interest during construction (IDC) and other general costs are allocated based on investment. The IDC adder is based on an interest rate of 11.94 percent, using FY 2009 data. Documentation, Table 8.3, lines 7, 18, and 28. The investment in the Columbia Basin project does not include construction work in progress.

The inclusion of land costs in the total Columbia Basin costs has a negligible effect, increasing the costs of the GI segment by about $52,000 (0.04%), and of the Network segment by about $19,000 (0.03%). These figures are derived by multiplying the land cost, *id.* at line 11, by the segment allocation percentage, *id.* at line 14. In accordance with Reclamation practice, IDC is not applied to land associated with Columbia Basin transmission costs.

The GI segment comprises 70.52 percent of the transmission investment in the Columbia Basin project; the Network segment comprises 29.11 percent; and the Utility Delivery segment comprises less than one-half percent. Documentation, Table 8.2, lines 3-5.

8.7 Revenue Requirement for Investment in COE and Reclamation Facilities

The investment for COE and Reclamation transmission facilities is GI, $161.862 million; Network, $66.244 million; and Utility Delivery, $1.163 million. Documentation, Table 8.6. The investment associated with Network and Utility Delivery facilities is used in the development of the costs necessary for ratemaking from the annual generation revenue requirements. Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, section 2.3. This results in a revenue requirement of $7.258 million for FY 2012 and $7.105 million for FY 2013. Documentation, Table 8.7; Power Revenue Requirement Study Documentation, BP-12-FS-

BPA-02A, section 2.3. These annual revenue requirements are averaged to obtain the $7.183 million rate period average. Documentation, Table 8.7. The power revenue requirement is reduced by this amount and the transmission revenue requirement is increased by this amount each year during the rate period.

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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 station service that BPA purchases from another utility or that is supplied by another utility. Because there are locations on the system where BPA does not have meters to measure station service usage, the amount of energy usage at BPA substations and other facilities is estimated. This Study describes the station service energy usage and determines the costs that are allocated to TS for station service energy usage.

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 usage 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 usage for those substations for which load data exists. Fourth, the station service energy usage 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 usage is then added to the historical use for the Ross and Celilo/Big Eddy 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-12-FS-BPA-04, section 2.4, is applied to the estimated annual energy usage adjusted for transmission losses to yield the annual costs that are allocated to TS for station service energy usage.

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 46,249 kVA. Documentation, Table 9.2, line 4. Substations for which load data exists are listed in Table 9.1 and are used as the basis for calculating the average load factor described in section 9.5. *Id.*, Table 9.1, line 41. The total amount of installed transformation at BPA substations for which load data exists is 15,456 kVA. *Id.*

9.4 Assessment of Station Service Energy Usage

The historical average monthly usage 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. *Id.*, Table 9.3, line 6.

The total historical average monthly usage for other BPA locations for which load data exists is 1,066,446 kWh. *Id.*, Table 9.1, line 41. Because not all usage is metered, the total average monthly usage for BPA substations is estimated based on the historical average monthly usage multiplied by the average load factor. *Id.*, 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 usage for BPA substations for which load data is available by the total installed station service transformation for these BPA substations. This yields an average 9.45 percent load factor. *Id.*, Table 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 usage for all facilities other than the Ross and Big Eddy/Celilo complexes. *Id.*, Table 9.2, line 4. The historical station service energy usage for the Ross Complex and the Big Eddy/Celilo Complex is then added to the calculated amount of energy usage at all other BPA substations. *Id.*, Table 9.3, line 6. The total quantity of station service average usage that Power Services supplies directly to BPA substations and other facilities is estimated to be 81,160,370 kWh per year. *Id.*, Table 9.4, line 1. This quantity is then adjusted for transmission losses by multiplying the average usage by the BPA Transmission Network loss factor. Currently the Network loss factor is 1.9 percent. BPA Open Access Transmission Tariff, Schedule 9. The adjusted quantity of station service average usage supplied to BPA substations and other facilities after adding in the network losses is estimated to be 82,702,417 kWh per year. *Id.*, Table 9.5, line 1.

9.7 Determining Costs to Allocate to Station Service

The annual average forecast market price (Power Risk and Market Price Study, BP-12-FS-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 $2,949,980. *Id.*, Table 9.6, line 1.

9.8 Impact on Power Rates and Transmission Rates

The rate period annual average cost for Station Service is a revenue credit to the composite cost pool under the Tiered Rate Methodology. Power Rate Study, BP-12-FS-BPA-01, section 4.3.

These costs are assigned across the transmission segments that include Network, Southern Intertie, Eastern Intertie, Utility Delivery, DSI Delivery, and Generation Integration based on the allocation of three-year average Operations & Maintenance segmentation.

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 Scheduling, System Control and Dispatch and Reactive Supply and Voltage Control from Generation Sources. BPA addresses those rates in the Transmission Partial Settlement Agreement.

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 (ACS-12) rate schedule, 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C.

The calculations for the Ancillary and Control Area Service rates are shown in this Study, Table 3. Table 1 in this Study contains the forecast of Ancillary and Control Area Service 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 Partial Settlement Agreement.

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); and

(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 Schedules

The ACS-12 rate schedules include rates for six Ancillary Services and six Control Area Services. All rates in the ACS-12 rate schedules are subject to the *Rate Adjustment Due to FERC Order under Federal Power Act Section 212*. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, 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 Federal Columbia River Power System (FCRPS) Biological Opinion (NFB) Mechanisms: RFR, Spinning Reserve Service, Supplemental Reserve Service, VERBS, Provisional VERBS, and DERBS. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, 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 Balancing Authority Area load. 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 3, line 25. The forecast of annual average load for RFR in the BPA Balancing Authority Area for the FY 2012–2013 rate period is 5,682 aMW. *Id.*

10.3.2 RFR Rate Calculation

The generation input cost for PS to provide regulation is $6.601 million, as calculated in Study, section 3.2.8.2, 3.2.8.3, 3.4 and 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 input costs for regulation by the average load results in an RFR rate of 0.13 mills per kilowatthour. Study, Table 3, line 26.

10.4 Operating Reserve Service Rates

The current WECC standard requires that for each Balancing Authority Area, the amount of Operating Reserve must be sufficient to meet the NERC Disturbance Control Standard BAL-002-0. The amount must be equal to the greater of:

(a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or

(b) the sum of 5 percent of the load responsibility served by hydro generation and 7 percent of load responsibility served by thermal generation.

Northwest Power Pool (NWPP) members, including BPA, must also carry Operating Reserves of 5 percent of their load responsibility served by wind generation.

Under the current 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 (at least half of the reserve must be spinning) 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 make an election to self-supply or acquire Operating Reserve service from a third party. For the FY 2012–2013 rate period, the customer's election to acquire Operating Reserve from a third party must have occurred no later than May 1, 2011. 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 below.

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. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 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 3, line 33. 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 current Spinning Reserve Requirement, based on current WECC and NWPP standards, is 2.5 percent of the hydroelectric generation and wind generation and 3.5 percent of the non-hydroelectric generation located in the BPA Balancing Authority Area used to serve the transmission customer's firm load. 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. Customers may supply Supplemental 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 Supplemental Reserve Service obligation. BPA determines the transmission customer's obligation in accordance with 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. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 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 3, line 35. 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 current Supplemental Reserve Requirement, based on current WECC and NWPP standards, is 2.5 percent of the hydroelectric generation and wind generation, and 3.5 percent of the non-hydroelectric generation located in the BPA Balancing Authority Area used to serve the transmission customer's firm load. 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 2012–2013 period are described in section 4 of this Study. The annual revenue requirement for

Operating Reserve – Spinning is $27.277 million. *Id*. at line 28. The Operating Reserve – Spinning rate of 11.20 mills per kilowatthour is calculated by dividing the Operating Reserve – Spinning revenue requirement by the spinning reserve billing factor. The annual average billing factor forecast is 278 MW for the spinning requirement. 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 12.88 mills per kilowatthour. *Id*. at line 34. The default rate is calculated by increasing the normal rate by 15 percent.

The annual revenue requirement for Operating Reserve – Supplemental is $23.177 million. *Id.* at line 29. The Operating Reserve - Supplemental rate of 9.52 mills per kilowatthour is calculated by dividing the Operating Reserve - Supplemental revenue requirement by the supplemental reserve billing factor. The annual average billing factor forecast is 278 MW for the Supplemental requirement. 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 10.95 mills per kilowatthour. *Id.* at line 36. The default rate is calculated by increasing the normal rate by 15 percent.

10.5 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 within-hour differences between actual generation from wind and solar generation and their hourly 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 generator must either purchase this service from TS or make alternative comparable arrangements to satisfy its VERBS obligation.

The VERBS rate in section III.E.2 of the ACS-12 rate schedule is a capacity charge to be applied to the generator's installed wind or solar generating capacity in the BPA Balancing Authority Area. 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 hourly scheduled amount and hourly average generation). The VERBS rates for each of these three balancing reserve capacity components are listed separately in the rate schedule to allow for self-supply of the components.

VERBS for solar resources is in section III.E.4 composed of only the regulation and following balancing reserve capacity components.

10.5.1 VERBS Rate Calculation

The VERBS rates for wind generators are as follows:

Regulation Reserves: $0.08 per kilowatt-month;

Following Reserves: $0.37 per kilowatt-month; and

Imbalance Reserves: $0.78 per kilowatt-month.

This corresponds to a total VERBS rate of $1.23 per kilowatt-month. *Id*. at line 12.

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 balancing reserve capacity requirement for solar resources is equivalent to one-half the balancing reserve capacity for the regulation and following components requirement for an equivalent amount of wind nameplate generating capacity. Solar within-hour variability was assessed using data obtained from the University of Oregon Solar Radiation Monitoring Laboratory (SRML). The data shows that the within-hour variability of solar resources is likely to be greater than one-half the variability from an equivalent amount of wind by nameplate capacity, but a conservative approach was used until BPA has scheduling data from solar generation facilities in the BPA Balancing Authority Area. Since BPA does not currently have solar resources scheduling on its system to provide data for scheduling accuracy, BPA conservatively assumed perfect schedules for these resources. This assumption results in no imbalance component for the balancing reserve requirement for solar resources.

In section 2 of this Study, the average installed amount of wind generation in the BPA Balancing Authority Area for the FY 2012–2013 rate period is forecast to be 4,693 MW. The imbalance component of the balancing reserve capacity requirement is based on the installed capacity less the amount of self-supply. This amount of self-supply is forecast to be 1,393 MW. Study, section 2.7.4; Documentation, Table 2.15. The annual average revenue requirement for PS to provide balancing reserve capacity for VERBS is $55.748 million. Study, Table 3, line 5. The annual average revenue requirement is comprised of $4.335 million for regulation, $20.610 million for following, and $30.804 million for imbalance. *Id.* at lines 2-4.

Dividing the regulation and following requirement by the 4,703 MW of annual average installed generation capacity (wind of 4,693 MW and one-half of solar installed capacity of 21 MW) results in $0.08 per kilowatt per month for regulation and $0.37 per kilowatt per month for following. Dividing the imbalance requirement by 3,300 MW (4,693 MW less the self-supply of 1,393 MW) results in a rate of $0.78 per kilowatt per month for imbalance. *Id.* at lines 9-11.

In addition to the VERBS base rate, two formula rates will adjust the VERBS rate for wind generators under certain circumstances to recover the costs associated with generation inputs for VERBS. These rate design adjustments are discussed below.

10.5.2 Formula Rate I: Rate Adjustment for Replacement of Federal Generation Inputs for VERBS

The base rate for VERBS is adjusted by applying a formula rate adjustment that recovers the net cost of replacing balancing reserve capacity from Federal generation that becomes unavailable during the rate period. The VERBS rate is based on an assumption that all the *inc* and *dec* balancing reserve capacity used to provide this service is supplied from the FCRPS and the additional *dec* balancing reserve capacity purchases that are forecast as part of the *dec* acquisition pilot program. This formula rate adjustment is designed to approximate what the VERBS rate would have been if the costs for VERBS had been calculated assuming: (1) the loss or over-forecast of a specific amount of FCRPS capability to provide balancing reserve capacity; and (2) purchases of non-Federal generation inputs to replace that balancing reserve capacity for VERBS over the rate period.

Subject to the determination of the Administrator, the potential triggers for this rate adjustment include any significant change in the forecast ability of the FCRPS to provide generation inputs for VERBS, a change in the operation of the FCRPS, or any requirement imposed on BPA that affects BPA's ability to provide generation inputs for VERBS during the rate period. If the Administrator decides to acquire non-Federal generation inputs for VERBS during the rate period for the above reasons, the formula rate adjusts the VERBS rate to account for the following inputs:

(a) Term length of the non-Federal generation input purchase in months,

(b) Quantity in megawatts of the purchase,

(c) Type of purchase, *inc* or *dec* balancing reserve capacity,

(d) Cost of purchase, and

(e) Number of months over which the adjusted rate will apply to VERBS customers.

The net cost of the purchase is calculated based on these inputs, and the VERBS rate is adjusted for the number of billing months over which the rate will be applied.

10.5.2.1 Formula Rate I Calculation: Rate Adjustment to Replace FCRPS Generation Inputs

The Formula Rate I adjustment applies to only the imbalance component of the VERBS rate. To calculate the net cost of replacing generation inputs for the imbalance component of VERBS, Formula Rate I in the ACS-12 Rate Schedule is used. *See* 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 Rate Schedule, section III.E.7.

Determining Average Net Cost first requires establishing the *inc* or *dec* megawatt-months purchased and then multiplying by the unit base cost per megawatt of *inc* or *dec*. Subtracting this result from the total *inc* or *dec* purchase cost results in the net total cost. Dividing the net total cost by the number of months remaining in the rate period results in the Average Net Cost.

The *inc* unit base cost per megawatt is calculated by dividing the total rate period *inc* cost by the number of megawatt-months of forecast *inc* requirement; *i.e.*, the same cost and balancing reserve capacity quantities used in the BP-12 determination of the Imbalance rate shown in the VERBS rate, section III.E.2.(a)(iii). The *dec* unit base cost is calculated in a similar fashion.

The monthly forecasts of the installed capacity of variable energy resources, shown in the Study, section 2, over the remaining months of the rate period are averaged to determine the average sales. For example, if application of the formula rate is to begin in month 12 of the rate period, average sales equals the average of the sales forecast for months 12-24.

A formula rate adjustment may be triggered more than once during the rate period. Under such circumstances, BPA will apply the Formula Rate I adjustment to the last adjusted Imbalance rate for VERBS for the remaining months in the rate period. However, the unit net cost will continue to be based on the original unadjusted Imbalance rate calculated in BP-12.

10.5.3 Formula Rate II: Rate Adjustment to Increase Generation Inputs for VERBS

The Formula Rate II adjustment will recover the cost associated with an increase of balancing reserve capacity supplied for VERBS from any BPA purchases of non-Federal generation inputs made during the rate period. This rate adjustment 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 Formula Rate I above.

The Formula Rate II adjustment is triggered under two scenarios. First, this formula rate adjustment triggers if BPA increases the level of balancing reserve capacity for VERBS to a standard higher than 99.5 percent because: (1) one or more participants in the Pacific Northwest utility industry requests the change; or (2) DSO 216 curtailments are prohibited by any rule or court decision.

In addition, BPA will trigger this formula rate adjustment if BPA provides VERBS at a level of service that is superior to what is assumed in this Study and BPA determines that it must purchase non-Federal sources of balancing reserve capacity to continue to provide VERBS. See sections 2.7.4 and 3.1 for a discussion of the 99.5 percent standard for VERBS and BPA’s assumptions for customer self-supply. If BPA is required to provide a higher standard of service for VERBS during the rate period and must purchase additional balancing reserve capacity from non-Federal sources to continue to provide VERBS during the rate period, the cost for such purchases will be recovered through this formula rate adjustment. Purchase costs incurred for additional balancing reserve capacity due to any of these triggers will be included in any calculation of a Formula Rate II adjustment.

10.5.3.1 Formula Rate II Calculation

The monthly costs for *inc* and *dec* balancing reserve capacity acquisitions for the imbalance rate component are added to the monthly base VERBS costs, or to the previously adjusted VERBS component for imbalance for the remainder of the rate period. The sum of the costs for each component becomes the new adjusted VERBS rate. Formula Rate II in the ACS-12 Rate Schedule is used. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 Rate Schedule, section III.E.7.

The VERBS Formula Rate II will be applied independently or in conjunction with the Formula Rate I, as necessary.

10.5.4 Provisional VERBS (Provisional Balancing Service)

Provisional Balancing Service is a new Control Area Service that provides a balancing service to generating customers with variable energy resources under certain circumstances. This service cannot be requested, but it is offered to generating customers that (1) have elected to self-supply, but are unable to continue self-supplying one or more components of VERBS; or (2) had an expected interconnection date after the FY 2012–2013 rate period (*i.e.*, the facility was not included in BPA’s FY 2012–2013 Balancing Reserve Capacity Quantity Forecast in section 2 of this Study) and the customer accelerates its interconnection date into the FY 2012–2013 rate period.

For FY 2012–2013, generating customers with variable energy resources integrated into or expected to be integrated into the BPA Balancing Authority Area must have elected by May 1, 2011, to take full VERBS or self-supply one or more components. BPA will not maintain balancing reserve capacity to provide VERBS for customers that failed to make an election. In addition, BPA will not increase the maximum *inc* and *dec* balancing reserves when a customer takes Provisional Balancing Service. The maximum amount of balancing reserve capacity for Provisional Balancing Service will be limited by DSO 216 in real time to protect the quality of VERBS for other variable energy resource customers.

10.5.4.1 Rate

For the wind generators that elected to self-supply for the rate period but choose not to continue with self-supply at some point during the rate period and for wind generators that did not elect to take VERBS from BPA during the rate period but interconnect to BPA's Balancing Authority Area during the rate period, the rate and billing factor for Provisional Balancing Service is the same as the VERBS rate.

For a customer that elects to self-supply for the rate period but is unable to continue to self-supply during the rate period because BPA withdraws an award of dynamic transfer capability for its balancing resources for the remainder of the rate period, the rate and billing factor for Provisional Balancing Service is 70 percent of the VERBS rate, as adjusted by the Formula Rates I and II if any. *See* 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 Rate Schedule, section III.E.3. BPA is not forecasting any usage of Provisional Balancing Service and, therefore, no revenue from Provisional Balancing Service.

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 new 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 on-line 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-12 rate schedule, BP-12-A-02C, includes a single charge 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 51 MW, and the forecast *dec* reserve requirement is 81 MW. The forecast annual revenue requirement for PS to provide *inc* capacity for DERBS is $4.576 million and to provide *dec* capacity is $1.177 million, as specified in section 3 of this Study and shown on Table 3, lines 16-17 in this Study.

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 thermal generator 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* reserves that exceed 2 MW as measured on a one-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* reserve use by dispatchable energy resources is based on a historical database of one-minute station control error for each resource for the period October 2007 through September 2009. Several adjustments were applied to this data: (1) ramp schedules were built for the 10-minute period before and after the top of each hour, (2) individual generators that are not anticipated to be in the BPA Balancing Authority Area during the FY 2012–2013 rate period were removed, (3) hours in which contingency events were called by the generator had the station control error set to zero, and (4) recent changes in scheduling practice, based on a comparison of the October 2009 – April 2010 to October 2010 – April 2011 periods, were reflected by reducing *inc* station control error for all these resources by 20.9 percent.

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 to obtain 17,520 hours of DERBS billing factors. A series of 500 simulation games was run in which 8,760 hours (one year) were sampled with replacement and totaled. This created a probability distribution of total annual *inc* and *dec* billing factors for the non-Federal dispatchable energy resource fleet. The 40th percentile of this distribution was forecast to represent a reasonable basis on which to recover the revenue requirement. This forecast, being somewhat below the mean, allows a small amount of additional revenue to cover the risk of BPA collecting DERBS revenue based on variable Dispatchable Energy Resource schedules but compensates BPA Power Services for holding a fixed quantity of reserve resources in Generation Inputs. This forecast is 315,572 MW of hourly deviation annually for *inc*, and 326,998 MW of hourly deviation annually for *dec*.

Based on the forecast use of *inc* and *dec* reserves, the hourly *inc* rate is 14.50 mills per kW for use of *inc* reserves that exceed 2 MW, measured as the hourly maximum of one-minute average data. The hourly *dec* rate is similarly calculated and is 3.60 mills per kW for use of *dec* reserves that exceed 2 MW, measured as the hourly maximum of one minute average data. *Id.* at lines 21-22.

10.7 Energy Imbalance and Generation Imbalance Service

All revenues or credits that TS calculates for imbalance rates are passed on to PS. Because the net amount on average is typically small, BPA does not forecast any revenue or cost associated with these services. The rate schedules include an energy index to 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-12 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 energy index in the Pacific Northwest, or an alternate index will be used if there is no adequate hourly index.

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 an additional penalty. *See* Section 10.8 below.

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-12 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 energy index in the Pacific Northwest, or an alternate index will be used if there is no adequate hourly index.

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

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

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. 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.

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 an additional penalty. *See* Section 10.8 below.

10.8 Persistent Deviation for Imbalance Services

10.8.1 Introduction

This section discusses BPA's observations regarding Persistent Deviations over the FY 2010–2011 rate period, analyzes the effectiveness of the current Persistent Deviation penalty charge criteria, and identifies the need for additional criteria to further encourage scheduling accuracy to reduce large and excessive persistent schedule deviations.

10.8.2 Study Summary

BPA has gained significant experience with the Persistent Deviation penalty charge during the FY 2010–2011 rate period. Although BPA has continued to observe a number of Persistent Deviations, BPA has tracked declines in the overall number of Persistent Deviations and in the percentage of time that schedule errors rise to the level of Persistent Deviations. BPA has also observed certain schedule deviations that a scheduling agent should have taken actions to correct, but allowed to persist, which are not captured under parts A and B of the FY 2010–2011 definition of Persistent Deviation (see section 10.8.3 below). This section describes changes to the Persistent Deviation penalty charge criteria in order to target certain schedule deviations and reduce the amount of accumulated imbalance energy stored on the Federal system.

10.8.3 Definition of Persistent Deviation for the FY 2010–2011 Rate Period

For the FY 2010–2011 rate period, Persistent Deviation was defined in the ACS-10 General Rate Schedule Provisions as one or more of the following:

Part A. For Generation Imbalance Service only:

Negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) in the same direction for four or more consecutive hours, if the deviation exceeds both: (i) 15 percent of the schedule for the hour, and (ii) 20 MW in each hour. All such hours will be considered a Persistent Deviation.

Part B. For Energy Imbalance Service only:

Negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) in the same direction for four or more consecutive hours, if the deviation exceeds both: (i) 15 percent of the schedule for the hour, and (ii) 20 MW in each hour. All such hours will be considered a Persistent Deviation.

Part C. A pattern of under-delivery or over-use of energy occurs generally or at specific times of day.

The charge for Persistent Deviation was as follows:

ACS-10 Energy Imbalance Persistent Deviation Charge

The following penalty charges shall apply to each Persistent Deviation*:*

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of: i) 125 percent of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If TS assesses a persistent deviation penalty charge in any hour for a positive deviation, TS will not also assess a charge pursuant to Section II (D) (1) of this ACS-10 schedule.

ACS-10 Generation Imbalance Persistent Deviation Charge

The following penalty charges shall apply to each Persistent Deviation:

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA-TS). For positive deviations (actual generation less than scheduled) which are determined by BPA-TS to be Persistent Deviations, the charge is the greater of: i) 125 percent of BPA's highest incremental cost that occurs during that day, or ii) 100 mills per kilowatthour. If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA-TS determines to be a Persistent Deviation, the charge is the energy index for that hour. New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days. If BPA-TS assesses a Persistent Deviation Penalty charge in any hour for a positive deviation, BPA-TS will not also assess a charge pursuant to Section III (B) (1) of this ACS-10 schedule.

Reduction or Waiver of the Persistent Deviation Penalty Charge

BPA-TS, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances**.**

10.8.4 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.

10.8.5 Persistent Deviations During FY 2010

In this section, BPA describes implementation of the Persistent Deviation penalty charge in FY 2010, explains how frequently BPA has assessed the Persistent Deviation penalty charge under the FY 2010–2011 Persistent Deviation definition, and discusses BPA's findings with regard to whether the penalty charge is avoidable and whether it is affecting parties with excessive frequency.

10.8.5.1 Frequency of Persistent Deviation Penalty Charges – Wind Generators

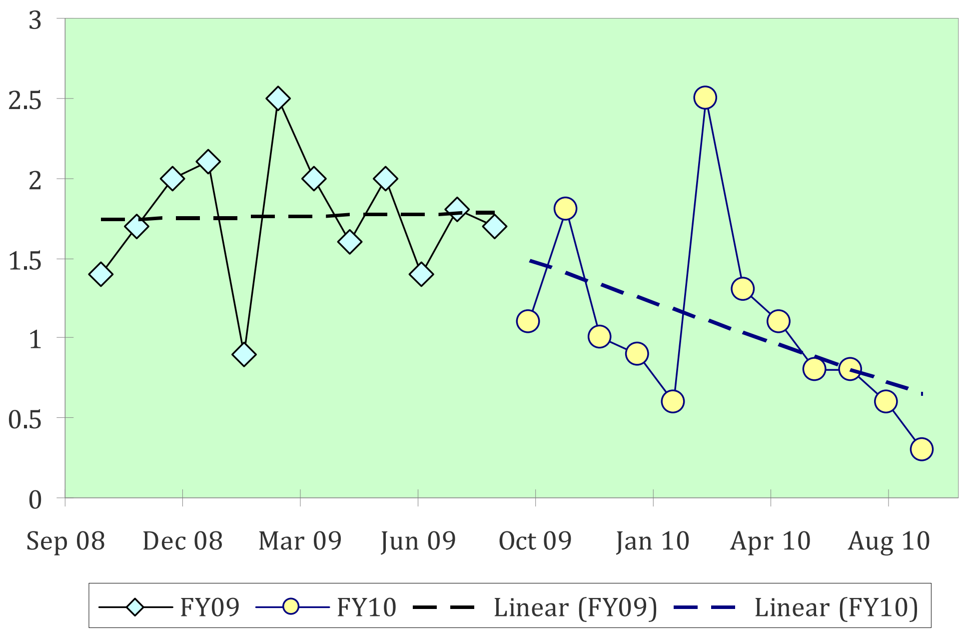
Table 10.1 in the Documentation illustrates the number of Persistent Deviation events that were assessed against wind generators over FY 2010. Table 10.1 indicates that there has been a decline in the number of Persistent Deviation events occurring during FY 2010.

As illustrated in Table 10.1, many wind plants are successfully avoiding Persistent Deviation events under Part A of the Persistent Deviation definition, which focuses on events with hourly deviations greater than both 20 MW and 15 percent of schedule for four hours in the same direction. All except five of the wind plants have averaged less than one Persistent Deviation event per month. Two of the remaining five averaged two or fewer events per month (two events translate to less than 1 percent of the total operating hours). The remaining three plants incurred 71 percent of a total of 417 Persistent Deviation events over 12 months. Although larger plants tend to have more Persistent Deviations and smaller plants tend to have fewer because of the 20 MW band, one of the largest wind plants in the fleet had only four Persistent Deviation events during the year, and medium-sized plants are in both the higher end and lower end of the distribution. Because BPA has a process in which scheduling entities can request waiver of the penalty, not all hours of all Persistent Deviation events included in Table 10.1 were ultimately penalized.

Another way to look at the frequency of Persistent Deviation penalty charges is in terms of percent of time affected by Persistent Deviation. If a generator or load has one 4-hour Persistent Deviation event in a month, it is subject to the Persistent Deviation penalty charge for about 0.5 percent of the hours in the month. Figure 1 illustrates that even in the months with the greatest frequency of Persistent Deviations, Persistent Deviation penalty charges are assessed only about 2.5 percent of the time. In addition, some of those events subsequently have the penalty waived.

Figure 1 also shows a significant difference in the trend of percentage of time that would have been subject to penalty charges in FY 2009, and the percentage of time affected by penalty charges once Persistent Deviation went into effect during FY 2010. Notably, BPA observed a declining trend (as illustrated by the dotted lines) in the percentage of hours affected by Persistent Deviation over a time period during which the overall size of the wind fleet nearly doubled. Although March is similar for both years, most other months show a lower percentage of hours affected by Persistent Deviation in FY 2010 than in FY 2009. Persistent Deviation penalties were initiated in FY 2010. Both February 2009 and February 2010 were months when wind generation output was very low; schedule errors go down when there is no wind generation to schedule. Both March 2009 and March 2010 were periods of higher volatile wind generation.

Figure 1: Trends in Percentage of Hours Meeting 20MW/15 percent/4hr Criteria



With regard to the March 2010 spike in Persistent Deviation events, BPA was informed that some plants were choosing to incur Persistent Deviations as a means of avoiding or minimizing risk from DSO 216 curtailments. Table 10.1 includes a-plant-by plant breakdown of Persistent Deviations in March 2010. After BPA discussions with wind generators in March and April 2010, Persistent Deviations under Part A of the Persistent Deviation criteria were fewer across the wind fleet, including the wind plant that incurred the most Persistent Deviation penalty charges in FY 2010. *See* Documentation, Table 10.1, line 1.

Based on the data regarding Persistent Deviation penalty charge frequency, two conclusions can be drawn. First, with the exception of one wind plant and one month of the Study, there has been a general decline in the assessment of Persistent Deviation penalty charges. Second, the FY 2010–2011 Persistent Deviation penalty charge is affecting most wind plants less than 1 percent of the hours in each month.

10.8.5.2 Frequency of Persistent Deviation Penalty Charges – Load and Thermal Generation Types

With regard to energy imbalance, there have been four instances of the Persistent Deviation penalty charge for load schedules. Since the Persistent Deviation penalty charge went into effect in FY 2010, BPA has not assessed a Persistent Deviation penalty charge on a thermal generator.

10.8.6 Operational Impacts of Persistent Deviations

10.8.6.1 Operational Constraints on the Federal System

The FCRPS is subject to many non-power requirements, including those necessary for flood control, irrigation, navigation, fish and wildlife protection, recreation, and project limitations for physical and human safety. In addition to being the primary source of energy marketed by BPA to its customers, the FCRPS provides balancing services to maintain the balance between load and generation at all times within the BPA Balancing Authority Area. Managing these requirements requires precise, intricate, and coordinated planning. Generating units within the FCRPS must be adjusted to respond to any imbalance between schedules and loads or generation in the BPA Balancing Area at all times. Thus, the scheduling accuracy of BPA's customers is critically important when planning generation operations.

10.8.6.2 Accumulation of Imbalance Energy

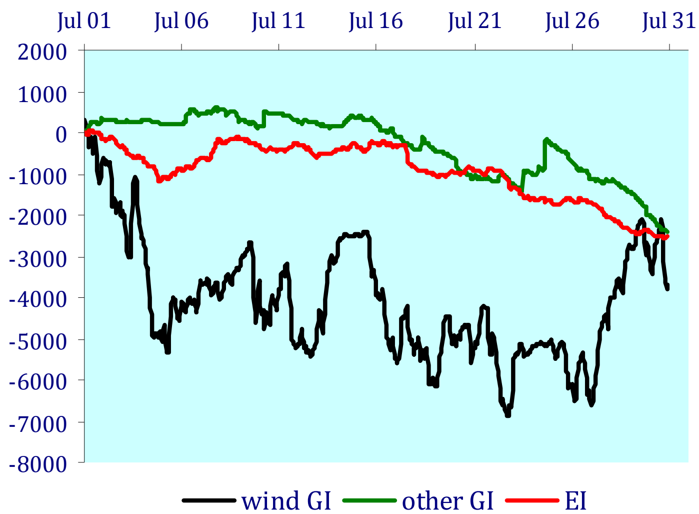
BPA has observed certain time periods with large and persistent schedule errors, as shown on Table 10.1. As noted above, as a Balancing Authority, BPA must maintain load and resource balance at all times. To preserve reliability of the system, BPA stores energy into the hydro system to manage imbalance caused by unscheduled generation or withdraws energy to manage loads in excess of schedules.

During FY 2010, BPA experienced a significant amount of accumulated imbalance energy and biased scheduling by various generators and loads. Table 10.2 illustrates positive, negative, and net accumulations of imbalance energy associated with wind schedules, other generation schedules, and loads for the 12 months of FY 2010. A positive accumulation occurs when BPA must provide energy from the hydro system to manage imbalance; conversely, a negative accumulation occurs when BPA stores energy into the FCRPS to manage imbalance. A net accumulation of imbalance energy means that schedule errors are biased (unevenly distributed) over time in one direction or the other. In Table 10.2, the net difference between total positive accumulation and total negative accumulation over each time period reflects bias. As a percentage of total scheduled energy, wind generators have much greater imbalance in both directions than other generation or loads, roughly six to seven percent of the total in each direction for wind schedules, versus about one percent of the schedule for loads. Also, while the net of imbalance for both load schedules and other generation is small on a percentage basis, the quantity at any given moment can cause marketing or operational changes. Wind generation shows significant difference between negative and positive imbalance, even over the monthly or annual time frame illustrated in this table. If schedule error is unbiased, imbalances would be expected to net to zero over much shorter time periods, because as scheduling agents adjust schedules to be as accurate as possible, their error would vary around zero from hour to hour or every few hours.

When there is sufficient market depth, BPA uses the market (*i.e.*, attempts to 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 when energy market prices are negative or near zero. Based on Intercontinental Exchange data, there were six days in June 2010 during which LLH prices at the Mid-Columbia trading hub averaged below zero. There were over 100 hours in June 2010 during which the weighted average Powerdex price index was negative for the Mid-Columbia trading hub. When energy market prices are negative or near zero, market opportunities to sell accumulated imbalance energy are severely limited. However, even when prices are not negative, 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 2 below 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 MW over very short time periods, even within a day. When the accumulation of imbalance is moving in a positive direction, BPA would need to buy; when it moves in a negative direction, BPA would need to sell. This increase in forced marketing disrupts BPA's marketing and operational planning and potentially reduces the value of short-term sales.

Figure 2: Accumulation of Imbalance Energy (MWh)



10.8.7 Comparison of 30-Minute Persistence Scheduling to Observed Actual Wind Generation Scheduling

As shown above, wind generation in the BPA Balancing Authority Area is the largest source of energy accumulation attributed to schedule error. In studying Persistent Deviation, 30-minute persistence scheduling for hourly schedules was used as a benchmark to compare with historical hourly scheduling data. Thirty-minute persistence scheduling was used as a benchmark because that is the scheduling accuracy assumption used to establish the balancing reserve capacity requirement for wind integration. Further, persistence scheduling is used for a benchmark for studies because it removes any bias associated with marketing decisions, risk management choices, or other factors unrelated to wind behavior, and it standardizes the effect of wind forecast error.

Figures 3 and 4 below illustrate the rolling 24-hour accumulation of imbalance energy that would be associated with wind generation hourly persistence scheduling (Figure 3), as compared to actual historical schedule data (Figure 4). As illustrated in Figure 3, 30-minute persistence scheduling for hourly schedules would yield a relatively even (*i.e.*, unbiased) distribution, with imbalance accumulations only occasionally exceeding 2,000 MW up or down over a 24-hour period. Figure 3 shows the general pattern of imbalance energy BPA would expect to observe from unbiased scheduling practices.

In contrast, Figure 4 shows actual accumulated imbalance energy from the wind fleet for January through August 2010. Figure 4 indicates both a significant bias toward negative imbalance and a distribution of error much wider than expected with 30-minute persistence scheduling, with frequent occurrences of imbalance accumulation much larger than 2,000 MW, particularly for negative imbalances. On several dates in March, negative imbalance accumulations (resulting from generation significantly above schedule for more plants than were underscheduling) over 5,000 MWh occurred. For the persistence scheduling data, the mean is -8 MWh and the standard deviation is 966 MWh. For the actual scheduling data, the mean is 249 MWh and the standard deviation is 1,293 MWh. In other words, the actual schedules are significantly biased (mean is far from 0) and the frequency of large imbalance accumulations is significantly greater for actual schedules than for persistence schedules.

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

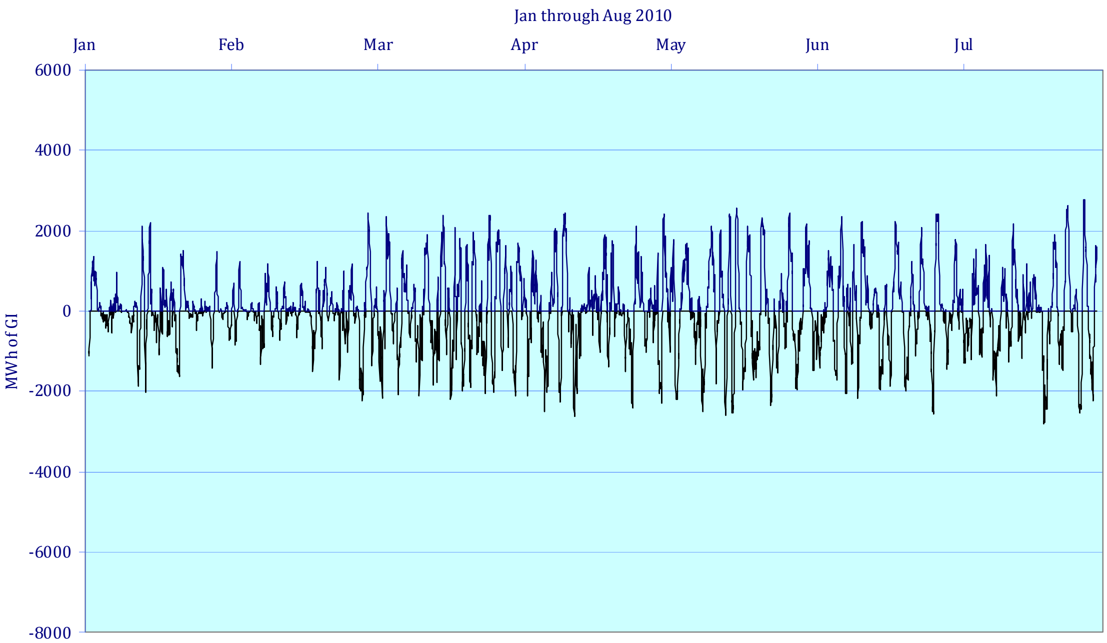
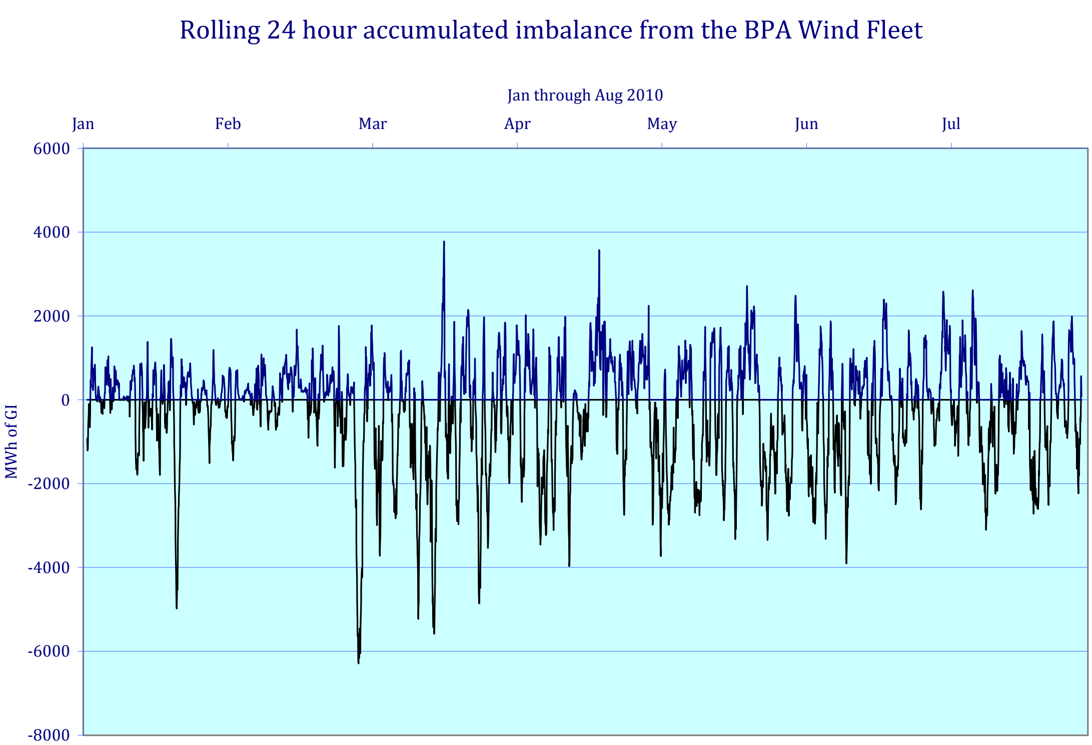


Figure 4: Rolling 24-Hour Accumulated Imbalance From the BPA Wind Fleet

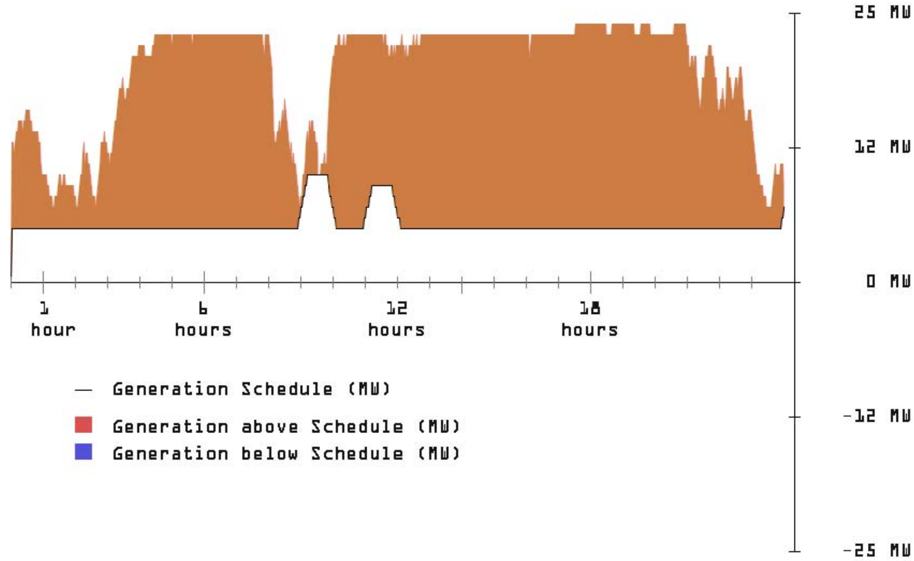


10.8.8 Examples of Schedule Errors That Result in Imbalance Accumulation But Are Not Captured by the FY 2010–2011 Definition of Persistent Deviation

Examining past schedule error patterns, BPA found examples of patterns of schedule error that have not been subject to Persistent Deviation penalty charges based on the FY 2010–2011 Persistent Deviation criteria, but that contribute significantly to imbalance accumulation over time. Figures 5 through 7 below provide examples from actual wind plant schedules showing patterns of over- or undergeneration (*i.e.*, positive or negative deviations) and non-random patterns of schedule error. If the scheduling entity is attempting to schedule accurately, both positive and negative deviations would be observed over fairly short time periods instead of, for example, only negative deviations consistently for long periods of time. Scheduling entities are expected to monitor and adjust schedules even when schedule error is within the 20 MW defined band for Persistent Deviation, particularly when scheduling errors are occurring for longer periods or during periods of stable wind generation or load.

Even without the use of weather forecasts, it is possible with 30-minute persistence scheduling to ensure that schedule errors do not persist for hours at a time. Figure 5 illustrates a plant that did not correct its schedule error over more than 22 hours of relatively stable but low generation output levels. Over this time period, the schedule error is biased in only one direction (*i.e.*, the actual generation output exceeded the scheduled generation output for over 22 hours). Although the plant had the opportunity each hour (as well as the possibility of submitting intra-hour schedules) to modify its schedule to match generation output and avoid schedule error, the plant failed to do so. Because the schedule error was within the 20 MW and 15 percent of the schedule threshold for Persistent Deviation, this situation was not identified as a Persistent Deviation.

Figure 5: Persistent Underscheduling



To avoid this scheduling bias and the accumulation of imbalance energy that results, such schedule errors need to be corrected within the first few hours. The FY 2010–2011 definition of Persistent Deviation does not capture this example as a Persistent Deviation.

Figure 6 illustrates persistent generation output above the scheduled output with periodic schedule adjustments to move within the 20 MW Persistent Deviation band, as defined in the FY 2010–2011 rate schedule, over a time period with relatively stable wind plant output. The schedule error continues in one direction for over 20 hours, without varying around zero. This data illustrates scheduling behavior bias in one direction, with corrective scheduling actions taken only to avoid the Persistent Deviation penalty charge criteria. As a result, this "zig-zag" pattern of schedule error effectively avoided the FY 2010–2011 definition of Persistent Deviation because the schedule came within the 20 MW band once every 3 or 4 hours.

Figure 6: Zig-Zag Scheduling

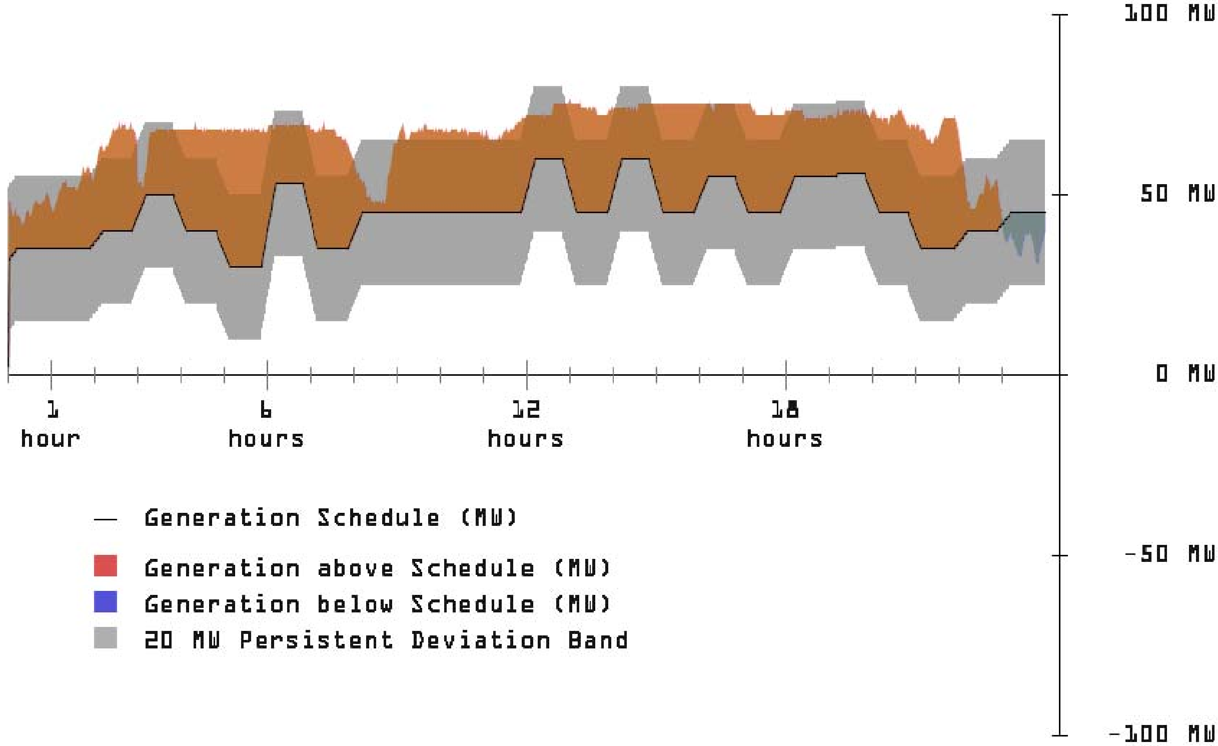
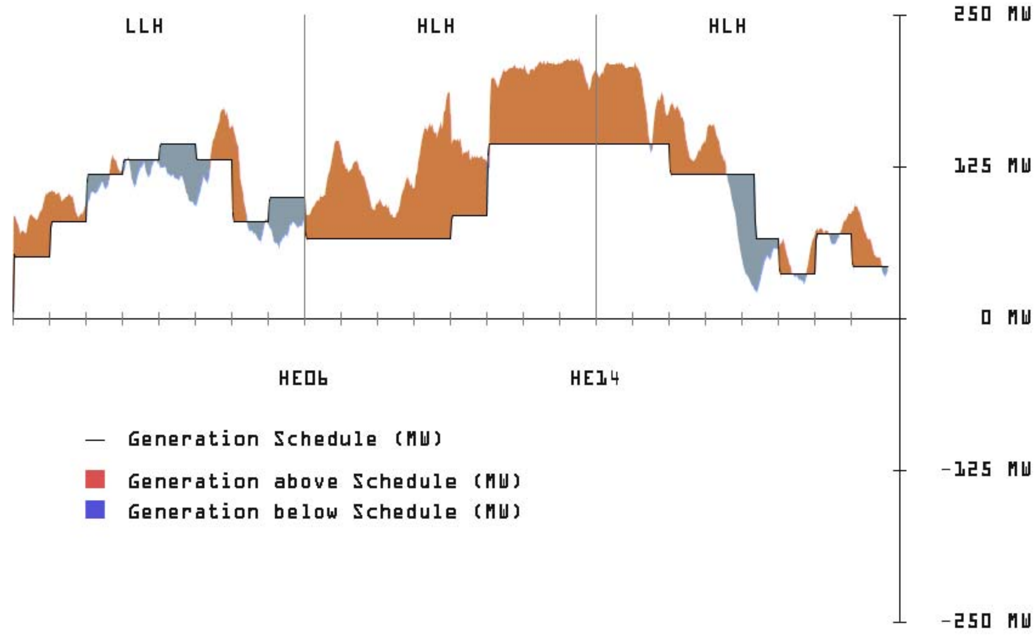


Figure 7 illustrates another pattern of strong diurnal scheduling bias where scheduled generation output for the hour is significantly less than actual generation output for the hour during Heavy Load Hours. This schedule error pattern results in significant accumulation of imbalance energy in the BPA system. As noted above, schedule errors should be more randomly distributed and not continue in one direction for many hours in a row.

Figure 7: Diurnal Pattern



10.8.9 Additional Refinements and Criteria for Persistent Deviation

To further encourage accurate scheduling behavior in all hours, new criteria to measure Persistent Deviations and to deter scheduling errors that result in imbalance energy accumulation were evaluated. These criteria are listed in Documentation, Table 10.4. In addition, a reduced time window from four to three hours under Parts A and B of the definition of FY 2010–2011 ACS-10 Persistent Deviation was evaluated.

Based on the study results discussed below, the Table 10.4 criteria have been added to the definition of Persistent Deviation. In addition, the time window under Parts A and B of the Persistent Deviation definition will be reduced from 4 hours to 3 hours once BPA implements intra-hour scheduling with energy export and import functionality for all customers, and the Persistent Deviation penalty will apply to each scheduled period.

10.8.9.1 Analysis of the Time Windows Used to Identify Persistent Deviation

10.8.9.1.1 Duration of Wind Ramps That Meet Persistent Deviation Criteria

Historical wind generator output data were analyzed to determine the duration of wind ramp events that could cause a Persistent Deviation. Documentation, Table 10.3. BPA defined a ramp affecting a wind plant as a change in average wind output from one hour to the next that is greater than both 20 MW and 15 percent of plant output. Data from October 2009 through August 2010 show that for the wind plants operating in the BPA Balancing Authority Area during that time (23 to 27 wind plants)—about 205,000 total hours of plant operation—wind plant generation met this ramp definition over a single scheduling hour about 7.5 percent of the time. Such ramps occurred for two consecutive hours about 1.7 percent of the time, and for three consecutive hours only 0.24 percent of the time. Finally, for four hours in a row these ramps occurred only 21 times, or 0.04 percent of the total operating hours for the plants. *Id.*

This analysis indicates that a 3-hour window to measure Persistent Deviations would provide sufficient time to correct schedule error associated with an unexpected wind ramp, assuming scheduling entities are scheduling close to real time and are immediately correcting schedule error. However, weather forecasting can be inaccurate, and persistent schedule errors also can occur because scheduling entities are predicting wind ramps several hours ahead of time and are likely to make a marketing decision to sell the increased generation further ahead of time.

10.8.9.1.2 Impact of Time Windows on Scheduled Load

To study Persistent Deviations of scheduled load, the frequency of impact of both the 4-hour and 3-hour time windows were examined, combined with the 20 MW and 15 percent of generation band. Over an 11-month period, for 25 customers, there were 75 total schedule hours subject to the FY 2010–2011 4-hour penalty, an average of 6.8 hours per month or roughly 0.04 percent of total hours. These hours were primarily due to one customer's miscommunication with its scheduling agent. With a 3-hour time window, an average of 7.4 hours per month would be affected. Only three of the 25 customers were affected at all with either the 3- or 4-hour window, and two of those customers had only one Persistent Deviation event under either the 3-hour or 4-hour standard over the 11 months.

10.8.9.1.3 Analysis of Revised Persistent Deviation Criteria

Historical schedule error data showed that, in some cases, smaller biased schedule errors were occurring over longer periods of time, as illustrated in Figures 5 to 7 above. To address this, three categories of longer time windows combined with narrower bands than the 20 MW and 15 percent of schedule band were defined and the impact on Persistent Deviation of longer time windows in combination with narrower megawatt bands was measured. These revised Persistent Deviation criteria that were tested are shown in Documentation, Table 10.4.

BPA also studied a shorter 3-hour window to compare with the 4-hour window criteria to measure Persistent Deviations. The two cases studied were hourly deviations greater than both 20 MW and 15 percent of schedule, in the same direction, for either three or more hours or four or more hours. Staff studied the frequency of errors that met these criteria for wind schedules, using historical wind generation with actual hourly schedules benchmarked with 30-minute persistence scheduling. The results of these studies are summarized in Documentation, Tables 10.5 and 10.6. Frequency of schedule errors meeting the revised Persistent Deviation criteria are shown as a percent of total scheduling hours.

Data in Documentation, Table 10.5 reflect actual schedule errors in FY 2009 before BPA implemented the Persistent Deviation penalty charge. In this table, the percentage hours of persistent deviations are based on hourly deviations greater than both 20 MW and 15 percent of schedule for four or more hours in the same direction.

In Documentation, Table 10.6, the first line shows the percentage of hours affected by the FY 2010–2011 penalty (*i.e.*, status quo) with actual scheduling data. Lines 2 and 3 assess the two cases of additional criteria and indicate the percentage of hours that would have been affected if wind generators scheduled at least as accurately as 30-minute hourly persistence scheduling. Lines 4 and 5 show the percentage of hours that would have been affected under the new criteria with actual historical scheduling accuracy and assuming no scheduling accuracy improvements and no corrective behavior to avoid the revised Persistent Deviation criteria in Documentation, Table 10.4. Lower occurrences of Persistent Deviation penalty charges would be expected after implementation of any revised Persistent Deviation criteria. Additionally, the frequency of Persistent Deviations would be expected to be lower with intra-hour scheduling adjustments, hourly schedule adjustments close to the delivery hour, or improved forecasting accuracy.

The percentages of time listed in Documentation, Table 10.6 do not indicate the frequency that would actually occur, because the analysis assumes no avoidance behavior, since it is based only on historical data. For example, for March, if 9.2 percent of hours would have been in Persistent Deviation events, and half the Persistent Deviation hours (4.6 percent of the time) are from 3-hour events and half are from 6-hour events, then the Persistent Deviation events could all be avoided by doing about 18 schedule corrections in the month (744 hours * .046/3) plus (744 * .046/6). After the first hour with a greater than 20 MW or 15 percent schedule error, the scheduling entity would have two hourly scheduling periods to correct its schedule error and avoid a Persistent Deviation penalty charge.

Wind generators currently have the capability to make intra-hour scheduling corrections (addition of another schedule at the half hour mark) if they are generating above schedule and exporting the wind generation out of the BPA Balancing Authority Area. Expanded availability of intra-hour scheduling is anticipated by the beginning of the FY 2012–2013 rate period. With intra-hour scheduling, under a 3-hour window to measure Persistent Deviation, scheduling entities will have four intra-hour scheduling periods to submit a more accurate schedule. For example, assuming the large error occurring during the hour 12-1 is recognized before 12:40, four half-hour schedule opportunities (scheduling for 1:00, 1:30, 2:00, or 2:30) remain before three hours are completed at 3:00. Each scheduling period would be subject to Persistent Deviation.

BPA also studied the frequency of meeting these criteria for scheduled load. Using past scheduling data, 11 out of 25 customers would have been affected by the revised Persistent Deviation criteria in Table 10.4. Five of the 11 either have fixed the cause of the issues or are not expected to be impacted for other reasons. The other six customers had a total of 1,080 hours, or roughly 2 percent of the hours, as part of Persistent Deviation events over the 11 months. This is an average of 16 hours per month per customer. Two of the six appear to be scheduling flat blocks of energy and not adjusting schedules to the correct amount. The other four are adjusting schedules but have not been following load closely enough to avoid the criteria for longer durations of small persistent errors.

BPA also assessed whether, based on past schedule error, the additional criteria would target and potentially prevent a larger percentage of imbalance accumulation than the FY 2010–2011 criteria. Documentation, Tables 10.7 and 10.8 illustrate the results of that study and confirm that additional criteria would effectively target imbalance accumulation. Documentation, Tables 10.7 and 10.8. Because the tables are based on past schedule errors, they are not indicative of the time that imbalance would actually occur under new Persistent Deviation criteria, because the new criteria are intended to encourage better scheduling accuracy and commensurate avoidance of Persistent Deviations.

10.8.10 Persistent Deviation Penalty and Definition

To accomplish the goals of Persistent Deviation, and to address the risk of longer-term but smaller schedule errors having hydro operations impacts, refinements of the FY 2010–2011 definition of Persistent Deviation and additional criteria to the definition of Persistent Deviation are adopted. 2012 Transmission, Ancillary and Control Area Service Rate Schedules,, BP-12-A-02C, GRSP III.40.

Based on this study, BPA has added the criteria listed in Documentation, Table 10.4 to the definition of Persistent Deviation. *Id*. BPA will change the duration of the existing 15%/20MW criterion from four to three hours after providing 90 days written notice on BPA's OASIS, and each scheduled period will be subject to Persistent Deviation. *Id.* In addition, to recognize good scheduling practices for variable energy resources BPA will exempt from the penalty charge any scheduled period during a Persistent Deviation event that meets the Persistent Deviation criteria but that BPA determines to meet or beat 30-minute persistence scheduling accuracy. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 Rate Schedule, section III.B.2.c. BPA will still apply the penalty charge to any adjacent scheduled period that would otherwise qualify as a Persistent Deviation. Because patterns of schedule error may take other less predictable forms, retention of the general criteria for patterns of Persistent Deviations provides mitigation for risk of unforeseen schedule patterns. Since some scheduling agents may make good faith attempts to mitigate the magnitude and duration of a Persistent Deviation, or experience extraordinary circumstances that are beyond their control, BPA will retain the FY 2010–2011 waiver criteria for Persistent Deviation penalty charges. 2012 Transmission, Ancillary and Control Area Service Rate Schedules, BP-12-A-02C, ACS-12 Rate Schedule, sections II.D.2.c and III.B.2.c.

Table 1
Power Services' Generation Inputs Revenue Forecast for FY 2012–2013
99.5% Level of Service with Customer-Supplied Generation Imbalance

	A	B	C	D	E
	Generation Inputs	**Quantity**	**Per Unit Cost ($/kW/month)**	**Annual Average Revenue for FY 2012-FY 2013**	***Inc* and *Dec* ($)**
1	Regulating Reserve - Embedded Cost Portion	60 MW	$ 6.69	$ 4,816,800	
2	Regulating Reserve - Variable Cost Portion	60 MW *inc* 61 MW *dec*		$ 1,784,250	
3	**Regulating Reserve Total**			**$ 6,601,050**	
4	Variable Energy Resource Balancing Service Reserve - Embedded Cost Portion	470 MW	$ 6.69	$ 37,731,600	
5	Variable Energy Resource Balancing Service Reserve - Direct Assignment Portion	470 MW *inc* 623 MW *dec*		$ 8,214,701	
6	Variable Energy Resource Balancing Service Reserve - Variable Cost Portion	470 MW *inc* 623 MW *dec*		$ 9,801,896	
7	**Variable Energy Resource Balancing Service Reserve Total**			**$ 55,748,197**	
8	**Adjustment for Committed Intra-Hour Scheduling** (34% * VERBS Rate *12 * 1000 *525)	525 MW 1/		$ (2,634,660)	
9	Dispatchable Energy Resource Balancing Service Reserve - Embedded Cost Portion	51 MW	$ 6.69	$ 4,094,280	
10	Dispatchable Energy Resource Balancing Service Reserve - Variable Cost Portion	51 MW *inc* 80 MW *dec*		$ 1,659,163	
11	**Dispatchable Energy Resource Balancing Service Reserve Total**			**$ 5,753,443**	
12	Dispatchable Energy Resource Balancing Service Reserve *Inc*				$ 4,576,249
13	Dispatchable Energy Resource Balancing Service Reserve *Dec*				$ 1,177,194
14	Operating Reserve - Spinning (Embedded Cost Portion)	277.55 MW	$ 6.96	$ 23,176,800	
15	Operating Reserve - Spinning (Variable Cost Portion)	277.55 MW	$ 1.23	$ 4,100,264	
16	**Operating Reserve - Spinning Total**	**277.55 MW**	**$ 8.19**	**$ 27,277,064**	
17	**Operating Reserve - Supplemental Total**	**277.55 MW**	**$ 6.96**	**$ 23,176,800**	
18	**Operating Reserve Total**	**555.1 MW**		**$ 50,453,864**	
19	**Synchronous Condensing**	44,397 MWh		$ 1,890,641	
20	**Generation Dropping**	1 drop/year		$ 376,503	
21	**Redispatch**			$ 400,000	
22	**Segmentation of COE/Reclamation Network and Delivery Facilities**			$ 7,183,000	
23	**Station Service**	82,702 MWh		$ 2,949,980	
24	**Generation Inputs Total**			**$ 128,722,018**	
25	**1/ 525 MW represents the annual average of 600 MW of installed wind capacity participating in Committed Intra-Hour Scheduling Pilot beginning 1 January 2012.**				

Table 2
Cost Allocation of VERBS Components for 99.5% Level of Service with Customer-Supplied Generation Imbalance

	A	B	C	D	E	F	G
	Component	Rate $/kW/month of Installed Capacity	Embedded Cost	Direct Assignment Cost	Variable Cost (12,801,896 - 3,000,000)	*Inc* and *Dec* Reserve Quantity	Total Cost
			$ 37,731,600	**$ 8,214,701**	**$ 9,801,896**		**$ 55,748,197**
1	Regulating Reserve *inc*	0.06	$ 2,729,520	$ 197,401	$ 502,968	34	**$ 3,429,889**
2	Regulating Reserve *dec*	0.02		$ 564,394	$ 340,527	34	**$ 904,921**
3	Regulating Reserve Component	0.08					
4	Following Reserve *inc*	0.29	$ 13,406,760	$ 969,588	$ 1,797,729	167	**$ 16,174,077**
5	Following Reserve *dec*	0.08		$ 2,757,468	$ 1,678,200	171	**$ 4,435,668**
6	Following Reserve Component	0.37					
7	Imbalance Capacity *inc*	0.60	$ 21,595,320	$ 726,101	$ 1,392,353	269	**$ 23,713,774**
8	Imbalance Capacity *dec*	0.18		$ 2,999,749	$ 4,090,119	417	**$ 7,089,868**
9	Imbalance Capacity Component	0.78					
10	**Total**	**1.23**	**$ 37,731,600**	**$ 8,214,701**	**$ 9,801,896**		**$ 55,748,197**

Table 3
Calculation of Ancillary and Control Area Service Rates
Variable Energy Resource Balancing Service, Dispatchable Energy Resource Balancing Service, Regulation and Frequency Response, and Operating Reserve

	A	B	C	D	E	F	G
	Rates	FY 2012-2013 Costs ($000)	FY 2012 Sales (MW)	FY2013 Sales (MW)	FY 2012-2013 Sales (MW)	Rate	Units
1	**Variable Energy Resource Balancing Service (VERBS)**						
2	Regulating component annual average costs	4,335					
3	Following component annual average costs	20,610					
4	Imbalance component annual average costs	30,804					
5	**Total VERBS annual average costs**	**55,748**					
6	Average forecast of installed wind resources		4,147	5,238	**4,693**		
7	Average forecast of customer-supplied generation imbalance (CSGI)		1,301	1,484	**1,393**		
8	Average forecast of installed solar resources		13	29	**21**		
9	Regulating component rate (costs / installed wind and solar resources)					**0.08**	$/kW/month
10	Following component rate (costs / installed wind and solar resources)					**0.37**	$/kW/month
11	Imbalance component rate (costs / installed wind resources less CSGI)					**0.78**	$/kW/month
12	VERBS rate (sum of the three component rates)					1.23	$/kW/month
13	**Dispatchable Energy Resource Balancing Service (DERBS)**						
14	Balancing reserve capacity reserve requirement *inc*		51	51	**51**		
15	Balancing reserve capacity reserve requirement *dec*		81	80	**81**		
16	Annual average costs for *inc*	4,576					
17	Annual average costs for *dec*	1,177					
18	**Total DERBS annual average costs**	**5,753**					
19	Annual sum of Hourly MW deviation beyond 2 MW deadband *inc*		316,004	315,140	**315,572**		
20	Annual sum of Hourly MW deviation beyond 2 MW deadband *dec*		327,445	326,551	**326,998**		
21	Hourly rate *inc* (costs / Annual deviation)					**14.50**	mills/kW/hour
22	Hourly rate *dec* (costs / Annual deviation)					**3.60**	mills/kW/hour
23	**Regulation & Frequency Response (RFR)**						
24	Annual average costs	**6,601**					
25	Balancing Authority Area load forecast (annual average)		5,642	5,722	**5,682**		
26	Rate (costs / load forecast)					**0.13**	mills/kWh
27	**Operating Reserves (OR)** also known as contingency reserves						
28	Annual average costs - OR spinning reserves	**27,277**					
29	Annual average costs - OR supplemental reserves	**23,177**					
30	Balancing Authority Area OR reserve obligation provided by PS		**610**	**500**	555		
31	Balancing Authority Area spinning reserve obligation provided by PS (1/2 total)		305	250	278		
32	Balancing Authority Area supplemental reserve obligation provided by PS (1/2 total)		305	250	278		
33	OR spinning rate (costs / reserve obligation)					**11.20**	mills/kWh
34	Default Rate (normal rate * 1.15)					**12.88**	mills/kWh
35	OR supplemental rate (costs / reserve obligation)					**9.52**	mills/kWh
36	Default Rate (normal rate * 1.15)					**10.95**	mills/kWh

BONNEVILLE POWER ADMINISTRATION

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