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

2010 BPA Rate Case
Wholesale Power Rate Final Proposal

GENERATION INPUTS STUDY

July 2009

WP-10-FS-BPA-08

This page intentionally left blank.

GENERATION INPUTS STUDY

TABLE OF CONTENTS

Page

This page intentionally left blank.

COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
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)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
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
PS	BPA Power Services
PSC	power sales contract
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
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
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
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

This page intentionally left blank.

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 study, FCRPS is used to refer to only generation assets. For rate-setting purposes, these uses of the FCRPS must be evaluated, and the costs associated with these uses allocated to Transmission Services (TS) under the 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 Generation Inputs Study (Study) explains the various cost allocations for generation inputs and forecasts Power Services (PS) revenues associated with provision of these generation inputs. Generation inputs include energy and capacity from the FCRPS that TS uses to provide ancillary services and control area services and to maintain reliability of the transmission system. The generation inputs costs developed in this Study are used by TS to determine transmission, ancillary services, and control area services rates for the rate period, FY 2010-2011.

1.2 Summary of Study

PS provides TS generation inputs of Regulating Reserve, Following Reserve, and Wind Balancing Reserve. To determine the amount of these capacity reserves needed by TS, an analysis is performed of historical operations, the forecast amount of wind generation expected to interconnect to the BPA Balancing Authority Area (BAA) prior to and during the rate period, the expected load on the system, and the amount of capacity needed to provide Regulating Reserve, Following Reserve, and Imbalance Reserve for both wind generation and load. The cost allocation methodology for these capacity reserves includes both embedded and variable costs.

PS also provides generation inputs for Operating Reserve – Spinning Reserve Service and Operating Reserve – Supplemental Reserve Service. Spinning Operating Reserve is provided under Schedule 5 of the Open Access Transmission Tariff (OATT), and supplemental Operating Reserve is provided under Schedule 6 of the OATT. This Study forecasts the quantity of Operating Reserve TS requires for FY 2010 and FY 2011. PS applies an embedded cost pricing methodology to Operating Reserve and adds a variable cost component to price spinning Operating Reserve.

Other generation inputs include Synchronous Condensing, Generation Dropping, Redispatch Service, and Station Service. Synchronous Condensing involves using certain generators as motors to provide voltage control to the power system. Generation Dropping refers to a reliability scheme where TS requests PS to instantaneously disconnect a large generator of at least 600 MW from the grid. TS uses Redispatch Service to manage congestion on the transmission grid. Station Service is the amount of energy PS provides directly to TS for the electrical needs of substations and for the Ross and Big Eddy/Celilo complexes. This Study also contains a segmentation study for COE and Reclamation Network and Delivery facilities in order to allocate the cost of such facilities to TS.

A summary of the PS revenue forecast for supplying these generation inputs is shown in Table 1.1. The table shows the proposed annual average revenue forecast for each generation input for the rate period, including separate lines for embedded cost and variable cost revenues for Regulating Reserve, Wind Balancing Reserve, and Operating Reserves. Table 1.1, lines 1 through 11. The table includes forecast quantities for the various reserves. Also, the table provides a unit cost for Regulating Reserve, Wind Balancing Reserve, spinning Operating Reserve, and supplemental Operating Reserve. Table 1.1 lines 3, 6, 9, and 10.

1.3 Mid-Rate Period Adjustment of Wind Balancing Service Rate

The Wind Balancing Service rate schedule provides for the rate to be adjusted under certain conditions during the rate period to be consistent with providing an amount of reserves associated with a 45-minute persistence scheduling accuracy assumption. The cost allocation for a 45-minute persistence scheduling accuracy assumption is documented. *See* Sections 3.8 and 4.6; Tables 3.12 and 4.23. The combined embedded and variable costs for Wind Balancing Service using a 45-minute persistence scheduling accuracy assumption is documented in Table 1.2. Tables 1.3 and 1.4 show the separation of the three components of the Wind Balancing Service rate for the 30-minute and 45-minute persistence scheduling accuracy assumptions, respectively, for purposes of TS allowing partial self-provision of Wind Balancing Service reserves.

1.4 Organization of Study

The Study contains 10 sections, including this introduction. Sections 2 through 5 have some inter-dependence, as certain outputs from some of these sections are used as inputs for the other sections. Tables and documentation for all sections are at the end of the Study.

This page intentionally left blank.

2. GENERATION RESERVE FORECAST

2.1 Introduction

2.1.1 Purpose of the Generation Reserve Forecast

The Generation Reserve Forecast estimates the amount of generation reserve expected to be required for providing certain ancillary and control area services during the rate period. The forecast described in this section focuses on the reserves associated with Regulating Reserve, Load Following Reserve, and Wind Balancing Reserves.

2.1.2 Overview

As a BAA, BPA must maintain a load-resource balance at all times. All generators within the BPA BAA provide hourly generation schedules to TS with an estimate of the average amount of energy they expect to generate in the coming hour. PS identifies an estimate of the average amount of load to be served in the BPA BAA in the coming hour. Transmission customers submit hourly transmission schedules (via E-tag), identifying all energy to be transmitted across or within the BPA BAA in the coming hour. BPA uses the transmission schedules to match generation inside the BPA BAA and imports of energy from other BAAs with loads served inside the BPA BAA and exports to other BAAs. The transmission schedules identified with each adjacent BAA boundary are netted to determine interchange schedules. The interchange schedules are netted for the BPA BAA to determine controller totals, which 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 generators in the BPA BAA in response to changes in load, system frequency, and other factors to maintain the scheduled system frequency and interchanges with other control areas. Currently, 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 BAA must use its own generation resources to offset differences between scheduled and actual generation and to maintain within-hour load-resource balance in the BAA.

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 (*inc*) generation. If load decreases, or generation increases, the AGC system decreases (*dec*) generation. The cumulative "*inc*" and "*dec*" generation required to maintain load-resource balance within the hour forms the basis for the reserves that TS must have to provide balancing services.

PS designates FCRPS generating resources under AGC control to provide the generation inputs necessary for TS to supply within-hour 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 BAA that generates below its schedule. Conversely, PS 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 resources that generate above their schedule in the BAA.

BPA's reserve requirement consists of three components: regulating reserve, following reserve, and imbalance reserve. Under Schedule 3 of BPA's OATT, regulating reserve "is necessary to provide for the continuous balancing of resources (generation and interchange) with load" and requires committing on-line generation whose output is raised or lowered as necessary to follow the moment-by-moment changes in load.

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 Generation Reserve Forecast estimates the reserve needed to follow these average energy shifts according to a 10-minute clock cycle. BPA currently does not distinguish between regulating reserve and following reserve in its operations.

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, because of 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 Generation Reserve Forecast estimates the incremental amount of following reserve due to imbalance and defines this amount as the imbalance reserve capacity component of the reserve requirement.

The forecast methodology is based primarily on data from a 21-month period from October 1, 2006, to July 1, 2008. The data needed for the forecast was downloaded or developed, including the existing and future wind projects, the total actual wind generation, total wind generation forecast, the actual BAA load, and the BAA load forecast for the period. Sections 2.2 through 2.5 describe in detail how this data was obtained or developed.

Section 2.2 describes the amount of existing and future wind projects assumed in the forecast. This section also describes how the generation associated with wind projects expected to operate during the rate period is estimated by identifying time delays between existing and future projects within the BAA. Using these leads and lags and actual minute-by-minute generation values for existing projects from October 1, 2006, to July 1, 2008, all future wind projects were "scaled in" through the rate period. This results in estimates of the generation levels for each future project over time and the associated generation levels as a whole for any particular level of installed wind capacity.

Section 2.3 details the determination of the actual BAA loads and BAA load forecasts. For the actual BAA load, a base load amount for FY 2008 was determined and adjusted for the rate period to reflect load growth data from the load forecasting group. For the BAA load forecast, system load forecast data for the study period is obtained and adjusted to reflect the impact of transfer schedules, and load growth factors were applied to the yearly amounts. Adjusting the BAA load and load forecast over time provides load information that corresponds to the amount of wind project generation forecast in this Study.

Section 2.4 describes the assumption in the Study that the accuracy of wind schedules during the rate period will be equivalent to a 30-minute persistence model.

Section 2.5 describes the determination of the *inc* and *dec* amounts that contribute to the total reserve requirement and the allocation of that requirement between the wind and load. Using the actual BAA load, BAA load forecast, actual total wind generation, and total wind generation forecast data, the actual load net wind (actual BAA load minus actual total wind generation) is calculated and load net wind forecast (BAA load forecast minus total wind generation forecast) on a minute-by-minute basis. For the actual BAA load, actual total wind generation, and actual load net wind datasets, "perfect" schedules and 10-minute averages are developed, and these form the basis for determining the regulating reserve, following reserve, and imbalance reserve components associated with each time series. The *inc* and *dec* requirements of the three components are determined and the maximum values for each component are used as the basis to allocate the reserves between the load and wind.

Section 2.6 describes the results of the Generation Reserve Forecast.

2.2 "Scaling in" Future Wind Generation

2.2.1 Existing and Future Wind Projects for the Rate Period

Developing the forecast of the reserve required to provide balancing services for wind generation during the rate period requires a forecast of the amount of wind generation that will be on-line during that period. Table 2.1 identifies the existing and future wind projects that are forecast to be on-line during the rate period. The projects are organized by the year that the facility went into service or is expected to be in service. Entries for existing facilities include the project's installed capacity in megawatts and the month and year that the project reached its installed capacity. Entries for the future wind projects include the installed capacity and the completion date (month and year) that the project is expected to reach its installed capacity. Section 2.2.2 discusses the information under the "Time Shift and Scale" column in Table 2.1.

The forecast is based on a review of the pending requests in BPA's interconnection queue, information provided for the requests under BPA's Large Generator Interconnection Procedures (LGIP), and the application of certain criteria. References to "future" or "planned" projects in Table 2.1 and throughout the Study indicate expectations with respect to the interconnection of certain facilities based on Staff's assessment of the circumstances and information at the time but are not intended to convey certainty about interconnection of a particular project.

To forecast which projects will interconnect and the timing of the interconnections, the status of various projects in BPA's interconnection queue as of April 2009 is assessed. In addition to the requested interconnection date in each interconnection request, other factors are also 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, so 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 expected on-line 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) before deciding whether to interconnect a particular generator. NEPA review can take a substantial amount of time, and BPA typically coordinates that review with the timing of the state/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 their plans (project scheduling, financing, turbine ordering commitment). A significant factor that affects the interconnection forecast is 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 acquiring equipment with a long procurement lead time.
5. The execution of an interconnection agreement and commitment by the customer to fund the BPA facilities necessary for the interconnection. A firm construction program schedule can be established once this has happened. Executing an interconnection agreement usually occurs only in the last year before energization of a project.

The forecast of installed wind fleet capacity is an average of 3,053 megawatts for the rate period, FY 2010-2011.

2.2.2 Methodology for Determining Lead and Lag Times

Forecasting the balancing requirements for future wind generation during the rate period requires estimating minute-by-minute generation levels of the wind facilities in the BPA BAA or expected to connect in the BAA. For data on generation of the existing wind facilities, 21 months of one-minute actual average generation data from BPA's Plant Information (PI) system is used. The data covers generation from all existing wind generators in the BPA BAA for the period from October 1, 2006, to July 1, 2008.

To help estimate minute-by-minute generation for future facilities, the time delays between existing wind projects in BPA's BAA and the locations of future wind projects are used. Table 2.2 includes a map that shows the locations of the projects in the generation reserve forecast for the FY 2010-2011 rate period. A west-to-east wind pattern prevails generally in the locations of many future wind projects in BPA's BAA, 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. Data reflecting common delays between existing projects and future project locations was obtained from a wind forecasting company in Seattle (3TIER). This data includes 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 different 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 is adjusted to reflect a 10-20 minute lead or lag based on BPA's observations and knowledge of the area in question. With this adjustment, zero value leads or lags are excluded from 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 is used. More than one existing project is typically used when the existing project sites' output helps to estimate the output of the future project. 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 Plant Information system is reviewed for missing data. Any missing data points are filled in using linear extrapolation from the existing data and by manually filling in certain points (particularly for values that are near zero). This helps ensure that the filled-in data reflects the trends of the PI system data.

The "Time Shift and Scale" (column E) in Table 2.1 includes the lead and/or lag times in minutes from existing facilities to the future wind facilities. For example, for the Klondike III project (Table 2.1, line 10), the generation for any particular minute is assumed to reflect the generation at Klondike I and II 20 minutes earlier. Column E for certain existing projects includes the leads and lags between other existing projects.

2.2.3 Estimating Future Wind Project Generation

Once the lead and lag times for each wind project are determined, the 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.

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. Typically, the forecast assumes that each existing project's output is equally accurate when used to estimate the future project's output and assigns equal weights to each existing project. However, more weight is assigned to a particular existing project if the data indicates that the existing project's output more accurately estimates the future project's output. For existing projects that are assigned unequal weights, Column E in Table 2.1 indicates the weight assigned to each existing project as a proportion of the future project's overall capacity.

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 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, and is multiplied by the conversion factor. 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 (A) has a 1-minute lag after the 126 MW Biglow Canyon project and a 10-minute lead before the 96 MW Goodnoe Hills project. Both Biglow Canyon and Goodnoe Hills are equally indicative of project A's generation, so each project is assigned equal weight. Using these assumptions, A's generation for any particular minute is determined using the following equation:

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

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 fiscal year, the actual total wind generation is calculated by adding the installed wind, both existing and scaled in, over the study period. The resulting total wind generation is used to forecast the reserve requirement for the rate period.

2.3 Load Estimates

To forecast the reserve requirements attributable to wind or load, the requirements that result from variations in load and wind are differentiated. The following sections describe how the actual BAA loads and the BAA load forecasts that correspond to particular levels of installed wind used in the forecast are derived.

2.3.1 Accounting for Pump Load

Load estimates start with the BAA load posted on the BPA external operations Web site. The BAA load posted on the operations page reflects the total generation in the BPA BAA minus the total of all interchanges (transfers to and from adjacent BAAs). BPA's pump load is load associated with operating the pumps at Grand Coulee to fill Banks Lake for irrigation purposes, as determined by 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 (same power draw whether it is 30 degrees or 100 degrees), and Grand Coulee generation serves this load directly, so it does not affect the rest of the controlled hydro system. For these reasons, the pump load is subtracted from the BAA load prior to using the BAA load numbers in the reserve requirements calculations.

2.3.2 Actual BAA Load Amounts that Correspond With Wind Penetration Levels

The goal in developing BAA load data is to determine BAA load amounts for each month of a 21-month study period that corresponded to the applicable wind penetration levels. This is accomplished by using fiscal year load data and making certain assumptions and adjustments to conform that data to a 21-month period. For example, for the 21 months of BAA loads that correspond to FY 2007 loads and wind penetration levels, actual scrubbed PI data from October 2006 through September 2007 are used for the first 12 months of the study period (*e.g.*, October to September). For the remaining nine months of the study period (*e.g.*, October to June), the load data from October 2006 through June 2007 is repeated.

Similar assumptions and adjustments are made to develop 21-month load datasets that correspond to wind penetration levels during the rate period. The datasets are developed by starting with a base FY 2008 load amount and applying load growth factors for future years. The base FY 2008 load amount for the first 14 months of the study period was determined by starting with the actual PI data from October 2006 through November 2007 and adjusting that data upward by 10 percent to reflect two changes. First, Clark Public Utilities' load returned to BPA's BAA in November 2007, and Clark's load represents approximately nine percent of the BAA load. As a result, the October 2006 to November 2007 load data is increased by nine percent to reflect this change. Second, the October 2006 to November 2007 data is increased by another one percent to account for load growth from FY 2007 to FY 2008. For the remaining seven months of the study period, the actual scrubbed PI data from December 2007 through June 2008 are used. The base time series is scrubbed for missing data.

For the 21-month dataset that corresponds to FY 2009 load and wind penetration levels, the FY 2008 dataset is used and a one percent load growth factor is applied. For the remaining years, the load growth factors shown below are applied, which are based on the forecasts for total BAA load from the BPA load forecasting group.

FY 2009 (2041MW wind) Load = FY 2008 Load × -1.4285% Load Growth

FY 2010 (2515MW wind) Load = FY 2009 Load × 2.8030% Load Growth

FY 2011 (3593MW wind) Load = FY 2010 Load × 1.8829% Load Growth

2.3.3 BAA Load Forecasts

To determine the BAA load forecasts, system load from historical storage (*i.e.*, rotary accounts) is used. In order to change the historical system load estimates to a BAA 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 BAAs and are therefore not included in the BAA load. The resulting BAA load forecast for the October 2006 through November 2007 time period is increased by 10 percent to establish the base FY 2008 load forecast. The Study applies the same load growth multipliers shown above 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 10 minutes prior to the hour is used to calculate the estimated load at 10 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 10 minutes prior to the hour and the load forecasts for the current hour and the next two hours.

2.4 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 is consistent with the actual generation of the facility 30 minutes prior to the hour.

The Study also includes a forecast of the reserve requirements using a 45-minute persistence assumption consistent with the Wind Balancing Service rate schedule provision that allows for the rate and the level of reserves to be adjusted under certain conditions during the rate period.

2.5 Wind Balancing Service and Capacity Requirements Methodology

2.5.1 Base Methodology

The methodology for forecasting the Wind Balancing Service and capacity requirements requires the following one-minute datasets: actual BAA load, BAA load forecast, 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 2.4. Using these datasets, the actual load net wind (actual BAA load minus actual total wind generation) and load net wind forecast (BAA load forecast minus total wind generation forecast) is determined on a minute-by-minute basis.

For each of the actual BAA load, actual total wind generation, and actual load net wind 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 10 through 49 of each hour is set to the clock hourly average value. For minute 50 of the current hour through minute nine 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 BAA load estimates.

Ten-minute averages for each of the actual BAA load, actual total wind generation, and actual load net wind datasets are developed. The actual datasets, forecast and ramped-in datasets, 10-minute averages, and ramped-in perfect schedules provide the foundation for the Generation Reserve Forecast. Table 2.3 is a graph depicting the one-minute average, 10-minute average, perfect schedule, and estimated values for the actual load net wind dataset for a sample three-hour period.

Three components make up the total reserve requirement: regulating reserve (*reg*), following reserve (*fol*), and imbalance reserve (*imb*). For purposes of the forecast, the regulating reserve component is defined by the minute-by-minute variations around the 10-minute clock average of the load net wind dataset. The following reserve component is defined by the difference minute-by-minute between the 10-minute clock average of the load net wind dataset and the associated perfect schedule. The imbalance reserve component is defined as the incremental amount of additional following reserve that results from using forecast schedules instead of perfect schedules. Table 2.3 reflects the regulating reserve, following reserve, and imbalance reserve components in terms of the relationships between the one-minute averages, 10-minute averages, perfect schedules, and estimated schedules for a sample three-hour period.

2.5.2 Time Series of Studies

To forecast the overall reserve requirement, an *inc* and *dec* requirement is calculated for the regulating reserve, following reserve, and imbalance reserve components for each of the actual BAA load, actual total wind generation, and actual load net wind datasets. The *inc* and *dec* amounts are calculated for the different amounts of wind penetration and load for FY 2010-2011.

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 BAA. This produces a forecast of the 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 NERC and WECC balancing standards, and therefore it is assumed that an additional 0.2 percent of the movement in the BAA is absorbed from this point forward. This decreases the overall reserve requirement slightly.

Using 99.5 percent of values for each component, the total reserve requirement forecast is determined based on the maximum value for each of the total actual wind generation, total actual BAA load, and actual load net wind datasets. The maximum values for the actual load net wind dataset represent a forecast of the total reserve requirement.

2.5.3 Allocating the Total Reserve Requirement Between Wind and Load

Once the forecast of the total reserve requirement is determined, the total is allocated between the contributions from wind 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.*, wind *reg* up + load *reg* up = total *reg* up). To do this in a statistically accurate manner, incremental standard deviation (ISD) is employed to allocate reserves to load and wind based upon how each contributes to the joint load-wind regulating reserve requirement, following reserve requirement, and imbalance reserve requirement. The ISD measures how much load and wind each contributes to the total load net wind reserve need based on how sensitive the total reserve need is with respect to the individual load and wind components. Stated differently, ISD shows how much the total reserve standard deviation changes given a one MW change in the load and/or wind standard deviation. ISD recognizes the diversification between the load and wind error signals, *i.e.*, the fact that the load and wind error signals do not always move in the same direction. The result of diversification is a joint load-wind reserve requirement that is less than the sum of the individual requirements for load and wind. Through the ISD, the joint load-wind reserve requirement is decomposed into the component contributions of load and wind, resulting in a total, diversified reserve requirement that equals the sum of the individual reserve requirements.

The data used to determine the reserve requirement are not normally distributed. The distribution of the data is not symmetrical, and approximately 68 percent of the values are not contained within +/- one standard deviation from the mean. As a result, using the ISD to allocate between wind and load requires an adjustment to infer the reserve requirement at the desired percentile. The current reserve 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 less 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 the wind and load error signals are standard normal and using a z-value of +/- 2.81 for purposes of the reserve forecast in this case, however, 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 error signal to determine an "actual" *inc* and *dec* z-value. Multiplying the "actual" z-value by the ISD results in a decomposed reserve requirement adjusted for the non-normality in the empirical data.

2.6 Results

The amount of regulating reserve and following reserve that will be required as the wind fleet grows through FY 2011 is forecast. Using the actual data that was obtained, the data created by using the obtained data, and the lead and lag values, the three different components of the reserve requirement are forecast: regulating reserve, following reserve (with perfect schedules), and imbalance reserve (following reserve with actual schedules and estimates). This method of allocating the total reserve requirement between wind and load ensures that the source that causes BPA to hold reserve is the source to which the reserve requirement is allocated.

Tables 2.4 through 2.9 include the results of the reserve forecast. Tables 2.4 through 2.6 include the *inc* and *dec* amounts for each component of the total reserve requirement, the wind reserve requirement, and the load reserve requirement, respectively, under the 30-minute persistence assumption for wind scheduling accuracy. Tables 2.7 through 2.9 provide the same information under the 45-minute persistence assumption for wind scheduling accuracy.

3. EMBEDDED COST PRICING METHODOLOGY

3.1 Introduction

This section of the Study describes the allocation of embedded costs for Regulating Reserve and Wind Balancing Reserve that are assigned to TS. These embedded cost allocations provide a revenue credit to power rates and represent part of the costs that TS will recover through its ancillary services and control area service rates. As described in section 4 of this Study, PS also calculates a variable cost associated with providing these reserves that is assigned to TS.

Regulating Reserve is used to balance loads in the BPA BAA on a moment-to-moment basis. Wind Balancing Reserve is comprised of regulating, following, and imbalance reserves that are used to balance the wind generation in the BPA BAA both on a moment-to-moment basis and through the operating hour. The amount of the Regulating and Wind Balancing reserves and the amount of Following reserves associated with load in the BPA BAA needed to calculate the cost allocation in this Study and the forecast methodology are described in the Generation Reserve Forecast in section 2. Another input to the embedded cost allocation methodology is the amount of Operating Reserve required by TS, which is documented in the Operating Reserve Cost Allocation in section 5.

3.2 General Methodology for Pricing Regulating and Wind Balancing Reserve

The embedded unit cost of Regulating Reserve and Wind Balancing Reserve is calculated by taking the costs associated with the Big 10 hydro projects (described in section 3.4) and dividing these costs by the average annual capacity amount of those same hydro projects (adjusted for other requirements). The capacity amount is determined using the HYDSIM and HOSS (Hourly Operation and Scheduling Simulator) models; both models are discussed in greater detail below.

These models are used to compute the average annual 120-hour peaking capability of the regulated hydro system.

The average annual 120-hour peaking capability represents the capacity of 14 major hydro projects (regulated hydro projects) that are available to serve load after adjusting for operational and reserve uses of the system. The peaking capability of certain independent hydro resources is added to the 120-hour peaking capability of the regulated hydro system to establish the total peaking capability available for providing reserves. The total peaking capability is adjusted to reflect the fact that only the Big 10 projects, a subset of the 14 regulated hydro projects, are used to provide Regulating and Wind Balancing Reserves. Lastly, the Regulating, Following, Operating, and Wind Balancing Reserves that are assumed in both HOSS and HYDSIM are added back in to arrive at the capacity system uses (average annual capacity amount) of the Big 10 projects in megawatts.

3.3 Determining the Amount of Capacity Provided by the FCRPS

To obtain an amount of available peaking capability for planning purposes, the installed capacity of FCRPS resources is adjusted to account for the operational constraints placed on the system (*e.g.*, flood control, fish operations, recreation), the loads that need to be met, reliability requirements (Forced Outage Reserves), and availability of water. The combination of the two hydro simulation models (HOSS and HYDSIM) is used to quantify the magnitude of these adjustments for the 14 Federal regulated hydro resources. The regulated hydro resources, with the Big 10 shown in bold, are listed in Table 3.1 for FY 2010 and Table 3.2 for FY 2011.

The combined output of the HYDSIM and HOSS models is used to determine the amount of capacity available to serve loads, assuming the 120-hour peaking capability under 1958 (representative of average) water conditions. These models are described in detail in sections 3.3.2 through 3.3.4.

In addition to the 14 regulated hydro resources, the embedded cost methodology includes a subset of independent hydro resources. Independent hydro resources are those hydro resources that are operated independently as run-of-river projects; they are listed in Table 3.1 for FY 2010 and Table 3.2 for FY 2011. The subset of independent hydro that is added to the regulated hydro is discussed in more detail in section 3.3.5. The peaking capabilities of BPA's independent hydro resources are calculated using mid-month elevations under 1958 water conditions, provided by COE and Reclamation.

3.3.1 120-Hour Peaking Capability

The Study uses a 120-hour peaking measurement for capacity quantification. The 120-hour period is defined as the highest six hours of generation for each of five weekdays of a four-week period for each of the 12 periods (120 hours for all months except for the split months of April and August, each of which uses two 60-hour periods representing the highest six hours of generation for each of the five weekdays of each two-week period). These 120 hours are averaged for each month, and this average is considered to be the amount of reliable monthly sustained capacity that would be available for operational planning purposes.

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

HYDSIM is a computer model that simulates hydro operations under the physical characteristics and limits placed on the FCRPS, including hard project constraints (*e.g.*, flow limits, elevation limits), project outages (planned/forced outages), reserve requirements, one-percent efficiency restrictions, and non-power constraints (flood control, variable draft limits, fish operations pursuant to the Biological Opinion/Technical Management Team, coordination with Canada). HYDSIM also considers net hydro loads (loads net of miscellaneous resources, thermal resources, and CGS), and the operational characteristics of all coordinated system projects (including non-Federal resources) and load.

The output of a HYDSIM run results in 70 years (1929-1998) of 14-period (April and August are split into halves to reflect the significant differences in hydro conditions that can occur in these two months) hydro project flows with initial and ending forebay elevations for each hydro project. HYDSIM also produces 14 periods of monthly energy generated by the hydro system for each of the 70 water years. HYDSIM does not provide insight into hourly operations or HLH and LLH energy amounts by period. The hourly detail is produced by HOSS, which is described in the following section. HYDSIM is documented in the Loads and Resources Study, WP-10-FS-BPA-01.

3.3.3 Objective and Outputs of the HOSS Model

The HOSS model, using monthly project flows, initial and ending conditions, and constraints supplied by the HYDSIM model, creates an hourly operation of the FCRPS that attempts to maximize HLH generation. The outputs of HOSS are not directly used for ratesetting purposes. Rather, relationships between monthly average energy, monthly HLH energy, monthly LLH energy, and 120-hour sustained capacity are constructed using the output of HOSS (calculation of these relationships is described in greater detail below) and are applied to the flat 14-period average energy amounts produced by HYDSIM. Applying these relationships to the 14-period HYDSIM energy amounts produces the average HLH generation, average LLH generation, and 120-hour sustained peaking capability amounts used in the Study.

3.3.4 Source and Description of Inputs to the HOSS Model

HOSS is a computer model that provides a forecast hourly operation of the Federal hydro system for the 14 reporting periods and 70 water years produced by HYDSIM. HOSS uses the beginning and ending reservoir elevations and project flows from each HYDSIM reporting period for the FCRPS for 70 historical water years and combines that information with hourly load forecasts and market assumptions to optimize the FCRPS.

The majority of the inputs to the HOSS model are either outputs from the HYDSIM model or inputs consisting of the same or more granular versions of the HYDSIM data. HOSS and HYDSIM share many of the same operational constraint inputs.

Both HYDSIM and HOSS require input data for Regulating Reserve, Operating Reserve, Load Following Reserve, and Wind Balancing 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 amount of 120-hour capacity available and are added back into the final quantities to create a complete FCRPS resource measurement for cost allocation purposes.

Operating Reserve amounts input into HYDSIM and HOSS are not based on the forecast need described in the Operating Reserve Cost Allocation in section 5 of this Study. Instead, Operating Reserve requirements for HOSS are calculated based on historical peak BAA generation at the 95th percentile by month. Inputs for the other reserves used in the HOSS model are based on the Regulating Reserve, Load Following Reserve, and Wind Balancing Reserve forecast in the Generation Reserve Forecast in section 2. Table 3.3 documents the total monthly *inc* and *dec* reserve amounts of Regulating Reserve, Load Following Reserve, and Wind Balancing Reserve that were inputs to HOSS.

The HOSS model uses both the *inc* and *dec* reserve amounts. As described in section 2, the Generation Reserve Forecast, *inc* reserve is that capacity available to ramp up generation to meet increasing within-hour load or decreasing within-hour wind generation. *Dec* reserve is that generating capacity available to ramp down to meet increasing within-hour wind generation and decreasing within-hour load. In HOSS, 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.

3.3.5 Detailed Development of 120-Hour Peaking Capability

The output of HOSS is used to develop relationships between monthly average energy during each of the 14 periods of the year and its associated 120-hour peaking capability for each of the 70 historical water years. These relationships are created through curves that define peaking capability 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 Excel is used to generate a peaking capability equation for each month that reflects the 120-hour peaking capability of the system for any given energy content for that period. Therefore, the equation will produce a 120-hour peaking amount (Y) for any input average energy amount (variable X).

These equations (curves), one for each of the 14 periods of the year, are applied to the energy output of HYDSIM to produce the 120-hour peaking capacity for each period. For forecasting the system capacity associated with generation inputs, the 14 period energy amounts associated with 1958 water conditions (average water) are used. The 120-hour peaking amounts are calculated using the curves developed from HOSS data applied to the energy in the Loads and Resources Study for average water.

Table 3.1 for FY 2010 and Table 3.2 for FY 2011 show each year's instantaneous capability by project for the 14 regulated hydro resources and the peaking capabilities of the independent hydro resources using mid-month elevations under 1958 water conditions. Certain independent hydro projects are excluded from the calculation of peaking capability, and thus from the embedded cost calculation, because these particular resources are incapable of providing reserves to BPA, either due to location outside the BAA or due to limitations on resource operation. Peaking capabilities of excluded independent hydro projects are summed at line 41 in Tables 3.1 and 3.2. The list of excluded independent hydro resources is in Table 3.5. Non-hydro resources (miscellaneous small resources, thermal resources, CGS) are omitted from the table, because BPA does not use them to provide reserves. Finally, the total sustained peaking adjustments that are reductions to instantaneous capability are shown at line 42 in Tables 3.1 and 3.2, labeled "Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)."

Because the output of the Loads and Resources Study produces two years of 14-period data, Table 3.4 uses the data from Tables 3.1 and 3.2 to produce a single-month average value for total peaking capability available for providing reserves, which is used for generation input cost allocation. Table 3.4, line 16, column B. Table 3.4, line 16, shows the portion of the total capacity that is associated with the Big 10 projects for purposes of the Regulating and Wind Balancing Reserves cost allocation.

3.4 Capacity and Net Revenue Requirement Associated with the Big 10 Projects

The Big 10 projects are used to quantify BPA's ability to provide capacity for Regulating and Wind Balancing Reserves, because these are the projects on Automatic Generation Control (AGC). 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 BAA to meet NERC Control Performance Criteria. The Big 10 projects include Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville. The Big 10 projects represent 91 percent of the capacity of the BPA hydro system (14 regulated hydro projects plus independent hydro less "excluded" independent hydro). Table 3.4., line 3, column B. The monthly capacity averages of the Big 10 projects (Table 3.4, line 2) are the averages of the two years of instantaneous capacity from line 16 of Tables 3.1 and 3.2. The monthly Big 10 project capacity, as a percent of the system available for providing reserves, is computed and shown on Table 3.4, line 3, columns C-P. The annual average of 91 percent is also shown and calculated on line 3, column B.

The embedded cost net revenue requirement associated with the Big 10 projects is composed of 1) power-related costs of the relevant hydro projects and associated fish mitigation on a project-specific basis; 2) an allocation of administrative and general expense; and 3) three specific revenue credits. *See* Table 3.6. With the exception of the revenue credit for synchronous condensing (Table 3.6, line 18), the inputs for Table 3.6 are described in the Revenue Requirement Study Documentation, Volume 1, WP-10-FS-BPA-02A, section 2. The synchronous condensing costs are allocated to TS in a separate calculation (described in section 6 of this Study), so they are removed (Table 3.6, line 18) to avoid double-counting. The annual average net revenue requirement for the Big 10 projects for the rate period is $768,028,000. Table 3.6, line 19.

3.5 Calculation of the Embedded Unit Cost for Regulating and Wind Balancing Reserves

The annual average capacity uses of the hydro system for the rate period that represent the system for purposes of calculating the embedded cost portion of capacity for Regulating and Wind Balancing Reserves is 11,183 MW. This amount is derived by taking the peaking capability of hydro projects in the BPA BAA capable of providing reserve, line 1 in Table 3.7, and multiplying by 91 percent to determine the total peaking capability for the Big 10 hydro projects. This value is labeled "Hydro Projects Capacity" in Table 3.7, line 6. The sum of capacity system used for Regulating Reserve (83 MW), Operating Reserve less Non-Spinning Operating Reserve provided by resources other than the Big 10 (375 MW), Load Following Reserve (216 MW), and Wind Balancing Reserve (585 MW) is 1,259 MW and is shown on line 7 in Table 3.7, labeled "Total PS Reserve Obligation."

To reflect the Non-Spinning Operating Reserve provided by resources other than the Big 10 projects, the Operating Reserve amount of 393 MW is multiplied by one-half to reflect the amount of Operating Reserve that is Non-Spinning. The Non-Spinning amount of 196.5 MW is reduced by 9 percent (the amount of Non-Spinning Reserve provided by resources other than the Big 10). The result of this adjustment is 375 MW, shown in Table 3.7, line 3 and footnote 1. For all embedded cost allocations, BPA used the *inc* required capacity to represent the capacity withheld from load service. Tables 2.5 and 2.6. These reserves are labeled "Total PS Reserve Obligation" in Table 3.7, line 7. The sum of line 6 and line 7 is 11,183 MW, which is labeled "Hydro Projects Capacity System Uses" and shown in Table 3.7, line 8. The Total PS reserve obligation is added to the hydro projects' capacity, since these reserves are accounted for in HYDSIM and HOSS and are thereby not captured in the 9,924 MW amount found on line 6 in Table 3.7.

The annual average net revenue requirement allocation of $768,028,000 is divided by the Hydro Project Capacity System Uses to calculate the embedded unit cost. The 11,183 MW is converted to an annual total of 134,201,520 kW per month. The result is the embedded unit cost portion of Regulating and Wind Balancing Reserves, $5.72 per kW per month ($768,028,000 / 134,201,520 kW per month = $5.72 per kW per month).

3.6 Forecast of Revenue from Embedded Cost Portion of Regulating Reserve

The embedded cost revenue from providing Regulating Reserve is forecast by applying the unit cost calculated above to the Regulating Reserve quantity forecast in the Generation Reserve Forecast. The forecast need on an annual average basis for the rate period is 83 MW, using the *inc* capacity amount, as it is the capacity withheld from load service. The revenue forecast for the embedded cost portion is an average annual amount of $5,697,120 per year ($5.72 per kW per month × 83 MW × 1,000 kW/MW × 12 months). Table 3.7, line 13.

3.7 Forecast of Revenue from Embedded Cost Portion of Wind Balancing Reserve

The embedded cost revenue from providing Wind Balancing Reserve is forecast by applying the unit cost calculated above to the Wind Balancing Reserve quantity forecast in the Generation Reserve Forecast. The forecast need on an annual average basis for the rate period is 585 MW, using the *inc* capacity amount, as it is the quantity withheld from load service. The revenue forecast for the embedded cost portion is an average annual amount of $40,154,400 per year ($5.72 per kW per month × 585 MW × 1000 kW/MW × 12 months). Table 3.7, line 14.

3.8 Mid-Rate Period Adjustment for Wind Balancing Reserve

BPA may adjust the Wind Balancing Service rate under certain conditions during the rate period. If the rate is adjusted to be based on a 45-minute persistence scheduling accuracy assumption, the embedded unit cost is $5.68, and the embedded cost allocation for Wind Balancing Service is $47,916,480. The same calculation steps from sections 3.5 and 3.7 are applied to the 45-minute scheduling accuracy assumption as to the 30-minute scheduling accuracy assumption. The documentation for the 45-minute scheduling accuracy assumption is shown in Tables 3.8-3.12.

4. VARIABLE COST PRICING METHODOLOGY

4.1 Introduction and Purpose

Having the machine capability to provide reserves and actually delivering reserves have associated variable costs. This section quantifies the variable costs associated with ensuring sufficient machine capability is ready and capable of responding to and delivering the BPA BAA requirements for regulating reserve, following reserve, and imbalance reserve.

The variable costs associated with providing a quantity of reserves are assessed in the Generation and Reserves Dispatch (GARD) Model using inputs from the HYDSIM model, actual system data, and a pre-processing spreadsheet. The GARD model calculates the variable costs incurred as a result of operating the FCRPS with the necessary reserves to maintain reliability and deploying those reserves to maintain load-resource balance within the BPA BAA. Load-resource balance is maintained by automatically increasing or decreasing generation in response to instantaneous changes in demand and/or power production. The need to be ready and capable of automatically increasing generation is referred to as an incremental (*inc*) reserve. Likewise, the need to be ready and capable of automatically decreasing generation is referred to as a decremental (*dec*) reserve.

The GARD model analyzes variable costs in two general categories. The first category is the "stand ready" costs, those costs associated with making a project capable of providing reserves. The other cost category is the "deployment costs," 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, combined with a distribution describing the load-net-wind station control error. The station control error distribution is used to simulate real-time movements of generation to calculate the cost of delivering reserves.

The GARD model specifically reports the following costs associated with standing ready: 1) energy shift, 2) efficiency loss, and 3) base cycling loss. GARD also calculates the following costs associated with deploying reserves: 1) response losses, 2) incremental cycling losses, 3) incremental spill, and 4) incremental efficiency loss. Sections 4.3 through 4.4 detail the definition and calculation of each cost element.

Reserve costs are disaggregated further given the cost types calculated by the GARD model. Costs are categorized as *inc* costs and *dec* costs. Further sub-categorization yields *inc* costs by spinning and non-spinning reserves. *Dec* capability is always spinning, because a unit must be generating (*i.e.*, the turbine is spinning) to provide *dec* capability.

Spinning costs are associated with a portion of the *inc* obligation and all of the *dec* obligation. Spinning costs include part of the energy shift cost, the base cycling cost, efficiency losses, and response losses. Each of these cost categories is associated with on-line units with unloaded capability responsive to AGC.

Non-spinning costs include the incremental cycling losses, incremental spill, and incremental efficiency losses. Each of these costs is realized as units are cycled on from non-spinning status or cycled off to non-spinning status. Section 4.5 describes this analysis in detail.

After being categorized into spinning and non-spinning costs, costs are separated into two general categories: balancing reserves and Operating Reserve. Balancing reserves include regulating reserve, following reserve, and load and wind imbalance reserves. As discussed further in section 4.2.3, *inc* balancing reserves are further subdivided into spinning and non-spinning reserves, where GARD defines a spinning reserve as the unloaded capability of an on-line, generating unit armed for AGC response and a non-spinning reserve as an unloaded turbine capable of fully synchronizing, ramping, and responding to AGC within 10 minutes. The Operating Reserve modeled in GARD is the spinning portion of the total Operating Reserve. Because Operating Reserve is deployed infrequently compared to balancing reserves, which are continuously deployed, GARD does not model Operating Reserve deployments. Consequently, deployment costs, including non-spinning costs, associated with Operating Reserve are not captured. The Operating Reserve is system capability available to respond to system disturbances pursuant to WECC/NERC standards. The post process calculations detailing the final separation of costs are detailed in sections 4.5.1 through 4.5.5.

The GARD model considers two general time periods within a given month: the heavy load hour (HLH) period, consisting of hours 7 through 22 Monday through Saturday; and the light load hour (LLH) period, consisting of hours 23 through 6 Monday through Saturday and all 24 hours on Sunday. Impacts measured over the HLH and LLH periods are average impacts over the respective time periods and do not necessarily reflect any particular hour.

In considering the variable costs, the GARD model seeks to efficiently dispatch the units at projects armed for AGC response, generally referred to in this section as controller projects, such that each project's generation request is met while at the same time meeting the reserve obligation and responding to a simulated reserve need. In the process of making projects capable of responding and then actually providing response, the efficiency of the generators changes. Measuring the net efficiency change associated with providing reserves is the primary concern of the GARD model.

After the GARD model is run, the MWh values for each month and HLH and LLH period of the 70 water year set are passed to RiskMod. These MWh values are associated with efficiency losses, base cycling losses, response losses, incremental cycling losses, incremental spill, and incremental efficiency losses. The energy shift is not passed to RiskMod, because the effect is captured in the HYDSIM generation data already included in RiskMod.

More detailed discussions of the various elements appear in the following sections. Section 4.2 addresses the pre-processes and inputs used in the GARD model. Section 4.3 details the stand ready costs and the component calculations of energy shift, efficiency loss, and base cycling losses. Section 4.4 details the deployment costs and the component calculations of response losses, incremental cycling losses, incremental spill, and incremental efficiency losses. Section 4.5 details the variable cost of carrying reserves and specifically details the total cost, apportioned cost, apportioned spinning cost, apportioned non-spinning cost, and apportioned total cost. Section 4.6 describes supplemental analysis for the 45-minute persistence scheduling assumption for the Wind Balancing Service cost allocation.

4.2 Pre-processes and Inputs

This section describes the preparation of the input data into the GARD model.

4.2.1 The Generation Request

The primary inputs into the GARD model are tables of project-specific generation values calculated by HYDSIM. These generation tables are used to determine the generation request and project dispatch. The generation request is the amount of HLH or LLH generation that a specific project is being asked to produce. The project's dispatch is the number and/or combination of on-line 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). Although all of the Big 10 projects are capable of being, and at various times of the year are, armed for AGC response, 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 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 Supervisory Control and Data Acquisition (SCADA) data from 01/01/02 through 12/31/07. 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 the HLH and LLH generation is 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. The generation quantities appear as a table of 12 months by 70 water years for HLH and LLH (a total of 1680 generation values). These project-specific generation quantities are referred to in the GARD model as the generation requests.

The generation request values are used by the GARD model to determine the unit 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 model will find the dispatch that will maximize plant efficiency. This process is intended to mimic the basepoint setting process, where the hydro duty scheduler submits requested generation amounts to each project and the project dispatches its units in the most efficient manner possible.

An additional secondary input, also derived from the pre-processing spreadsheet, is amounts of pre-existing *dec* capability for each project by month and historical water year. The purpose of this input is to avoid unnecessarily moving energy out of HLH and into LLH when providing *dec* capability. The relevance of pre-existing *dec* and the impacts of providing nighttime *dec* capability are discussed in section 4.3.1. Pre-existing *dec* capability is defined as the difference between the calculated LLH generation and the minimum generation for each of the respective projects. A matrix of pre-existing *dec* capability by month and water year is input into the GARD model.

4.2.2 The Control Error Signal Distribution

The control error signal distribution describes the probability and magnitude of the one-minute control error signal. The control error signal represents the sum of the instantaneous deviations in demand and the instantaneous departures in wind generation from schedule. These instantaneous departures are amounts of generation that the FCRPS must *inc* or *dec* in order to maintain load-resource balance in the BPA BAA during the operating hour. The control error signal distribution influences the calculation of the deployment costs, described in section 4.4, by determining how each of the controller projects responds and deploys spinning and non-spinning capability.

The distribution is input into the GARD model as a cumulative probability distribution. The purpose of the distribution is to model the need for reserves and the corresponding impacts on the controller projects while responding to the need. Given the reserve need calculated in the Generation Reserve Forecast, section 2, the 0.0025th percentile corresponds to the total *dec* reserve requirement. Likewise, the 0.9975th percentile corresponds to the *inc* reserve requirement. Taken together, the *inc* and *dec* reserve cover 99.50 percent of all system variations. Note that the control error signal distribution does not contain instances of Operating Reserve deployments, because it is assumed that Operating Reserve will be deployed very infrequently as compared to other reserve needs. The control error signal distribution is meant to model only the effects of deploying balancing reserves, which include Regulating Reserve, following reserve, and load and wind imbalance reserves.

4.2.3 Carrying the Reserves

Reserves are input into the GARD model in the following three categories: 1) the spinning portion of the Operating Reserve obligation, 2) the total *inc* spinning obligation inclusive of the spinning portion of the Operating Reserve obligation, and 3) the *dec* obligation. The spinning portion of the total reserve obligation is explicitly input into the GARD model to ensure maintenance of sufficient total spinning capability at each of the controller projects. The spinning portion of the reserve obligation is the sum of 100 percent of the regulation requirement, 50 percent of the following requirement, and 50 percent of the total Operating Reserve requirement. The spinning portion of the Operating Reserve obligation is also input standing alone so the GARD model can identify and track the portion of the total spinning obligation attributable to Operating Reserve. In this way, the GARD model maintains at all times a minimum spinning capability equal to the Operating Reserve obligation during the course of within-hour reserves deployment. The total *dec* obligation is identified so the GARD model knows how much minimum generation capability is required to provide the reserve. By definition of how the reserve is met, *dec* obligations are spinning.

The determination of the quantities of spinning versus the quantities of non-spinning is derived from the NERC requirements as well as system operator judgment. NERC requires that at least 50 percent of the BAA Operating Reserve obligation is capable of being met with spinning capability responsive to AGC. NERC requires that 100 percent of the BAA Regulating Reserve must be carried on units with spinning capability responsive to AGC, because Regulating Reserve must respond on a moment-to-moment basis.

In contrast, the reserve categories of following reserve and imbalance reserve do not have NERC-defined criteria. Lacking NERC criteria, at least 50 percent of the *inc* following reserve is assumed to 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 Reserve, following reserve, and imbalance reserve) are spinning, because units must be generating (*i.e.*, the turbine is spinning) in order to deploy *dec* reserves.

The amount of reserve that may be carried non-spinning is not directly input, but rather implied from the three reserve input categories described in the preceding paragraph and the input control error distribution. As noted in section 4.2.2 above, the 0.9975th percentile of the control error signal distribution is equal to the total *inc* balancing reserve obligation (not including Operating Reserve). The total *inc* balancing reserve obligation consists of both a minimum spinning requirement and a non-spinning amount. The difference between the total *inc* balancing reserve obligation and the required *inc* spinning obligation equals the maximum amount of reserve that may be carried as non-spinning. Thus, the difference between the 0.9975th percentile of the control error signal distribution, where the 0.9975th percentile defines the total *inc* balancing reserve obligation, and the total *inc* spinning obligation less Operating Reserve is the amount of *inc* balancing that may be carried as a non-spinning reserve.

The distinction between spinning and non-spinning reserves impacts two aspects of the GARD model by trading stand ready costs for deployment costs for any given level of *inc* obligation. For a given *inc* obligation, a high spinning requirement results in a high stand ready cost and a low deployment cost. Conversely, for the same given *inc* obligation, a lower spinning requirement results in decreased stand ready costs and increased deployment costs. Further discussion on stand ready and deployment costs follows in sections 4.3 and 4.4.

4.3 Stand Ready Costs

In order to meet the potential reserve requirements on any given hour, BPA's system must be set up to respond to these reserve needs going into the operational hour. Stand ready costs are those variable costs associated with ensuring that the FCRPS is capable of providing the required reserve. Stand ready costs are distinct from actually deploying reserves within the hour in response to the reserve need. To ensure that the FCRPS is standing ready to deploy reserves as needed, specific costs arise: energy shift, efficiency loss, and base cycling losses.

4.3.1 Energy Shift

The GARD model's first step in determining the stand ready effects of carrying reserves is to calculate how much energy is shaped out of the HLH period and into the LLH period. This movement of energy is referred to as the "energy shift."

Energy shift impacts may arise from making certain that sufficient *dec* capability exists during the nighttime. In this instance, costs are incurred by taking energy from the HLH period and using it to generate during the LLH period, thereby ensuring nighttime generation is sufficiently above minimum generation requirements to meet *dec* reserve needs. To the extent that the LLH generation is already above system minimum generation, there is no need to pull energy out of the HLH period. In these instances, "pre-existing *dec*" capability is said to exist. If the pre-existing *dec* capability does not fully meet the *dec* requirement, energy is shifted out of the HLH and into the LLH. *See* section 4.2.1 for the definition and calculation of pre-existing *dec* capability.

Relying on pre-existing *dec* capability saves the upfront cost of pulling energy out of the HLH period in exchange for the probability of spilling nighttime energy. Spill may occur if a *dec* need pushes generation into the pre-existing *dec*. In these instances, energy is spilled, because the water must continue to move despite the *dec* need pushing turbine flows below the amount of flow required to pass a given project. *See* section 4.4.3 for a detailed discussion relating pre-existing *dec* to spill potential.

When evaluating the amount of pre-existing *dec* capability, the GARD model also considers the graveyard time period, hours 0100 through 0400. These hours are taken into account because the amount of pre-existing *dec* capability may be substantially different from what is available in hours 2300 through 0000 and hours 0500 through 0600—hydraulic constraints limit how quickly the FCRPS can move to and from minimum generation. Maintaining a cushion of generation above system minimum equal to the *dec* requirement allows the FCRPS to decrease generation for balancing purposes.

The impact of the energy shift calculation is twofold. First, there is an economic cost to shifting generation out of the HLH period and into the LLH period, and there is a change in plant efficiency due to the change in HLH and LLH generation values. As previously discussed, to the extent that energy is moved into the LLH period in order to maintain an adequate LLH generation level above system minimum, costs are realized. The economic impact results from reduced high-value HLH power sales for increased LLH sales of lesser value.

All of the energy that GARD determines is shifted out of the HLH and into the LLH is valued at the monthly HLH-LLH price differential as used in the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. For FY 2010 and 2011, the average energy taken out of the HLH period is 141,771 MWh, worth $1,018,020. Table 4.1. The energy shift cost is calculated as the difference between the HLH and LLH prices multiplied by the megawatthours that are shifted in the GARD model.

In addition to the economic impact from shaping more sales into the LLH period, plant efficiency is changed. Because the resulting generation request after calculating the energy shift changes the HLH period and LLH period generation, the efficiency of the project may change. The impacts of the efficiency changes are described below in section 4.3.2.

4.3.2 Efficiency Loss

For any given generation request, a project has a unit dispatch that maximizes efficiency by minimizing the amount of water per MW generated. For each generation request and reserve requirement, the GARD model seeks to dispatch each of the controller projects most efficiently. The efficient dispatch is a function of the individual project's generation request, the project's response, the project's unit efficiency curves, the minimum amount of spinning reserve required, and the amount of non-spinning reserve. It is worth noting that there is a tradeoff between upfront efficiency losses, the topic of this section, and incremental cycling losses, the topic of section 4.4.2. For a given *inc* reserve obligation, a relatively low proportion of required spinning reserve will save efficiency losses and increase incremental cycling costs. Conversely, a relatively high proportion of required spinning reserve trades an upfront efficiency loss in exchange for lower incremental cycling costs.

As previously discussed, the project's generation request is the project's HLH or LLH generation requirement. The project response is the relative amount AGC would need to move generation at a given project during a reserve deployment. The project response determines the minimum amount of total *inc* and *dec* capability required at a given controller project; *i.e.*, the project response determines what fraction of the total reserve obligation must be met by that project. The responses used in the GARD model are typical response schemes used by the hydro duty schedulers. As mentioned in section 4.2.1, the GARD model considers the four most commonly armed projects for AGC response—GCL, CHJ, JDA, and TDA. The response scheme used in the GARD model is a typical response scheme whereby during the months of July through March GCL is set to respond to 50 percent of the control error signal, CHJ 25 percent, JDA 15 percent, and TDA 10 percent. Given this response setting and a station control error of +100 MW, GCL would *dec* 50 MW, CHJ 25 MW, JDA 15 MW, and TDA 10 MW. Due to limited flexibility and the need to manage spill percentage on the lower river, the response scheme for the months of April through June has GCL meeting 60 percent of the control error signal, CHJ 30 percent, JDA 5 percent, and TDA 5 percent. This alternative response scheme is reflected in the GARD model.

The efficiency curves are polynomial functions relating unit generation for each of the controller projects to unit efficiency. The polynomial functions are derived from actual measured generator unit data obtained from the COE and Reclamation. Polynomial functions relating generation to efficiency are derived for the big units at GCL, the small units at GCL, and units at CHJ, JDA, and TDA. In addition to determining 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.

In calculating the amount of efficiency loss, the GARD model calculates the most efficient unit dispatch for a given generation request without a reserve requirement and compares this efficiency to the efficiency obtained while meeting both the generation request and the input reserve requirement. To the extent that a given generation request results in an efficient dispatch with sufficient capability, no additional losses are incurred. Conversely, to the extent that a given generation request results in an efficient dispatch with insufficient capability, the dispatch must be altered to ensure the required minimum reserve. Changing the project dispatch may result in either an efficiency loss or an efficiency gain; however, on average, altering the unit dispatch results in an efficiency loss.

All efficiency losses and gains are valued at the monthly HLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The HLH price is used because efficiency impacts, losses and gains in energy, are taken out of or put into the HLH period. For FY 2010 and 2011, the average annual efficiency losses for HLH and LLH are 52,821 MWh and 90,421 MWh, respectively, resulting in an annual average cost of $6,234,248. Table 4.1.

4.3.3 Base Cycling Losses

Base cycling losses originate from the additional synchronization and ramping of units. For base cycling, the number of units cycled on-line or off-line is calculated by comparing the on-line units in the base “no reserves” case to the on-line units in the case where the reserve requirement is being met. To the extent that more or fewer units were on-line, a cycling cost is realized. Because the GARD model considers only HLH and LLH periods, 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 on-line during the HLH period relative to a case without a reserve requirement, 18 unit cycles are assumed to occur; that is, one cycle for each of the 18 HLH periods in a month. The change in the number of units on-line is calculated for each of the controller projects. For GCL, the change in the number of small units, as well as the number of big units, is also calculated.

Once the number of unit cycles for each project is calculated, including a separate calculation for each powerhouse in the case of GCL, the losses associated with cycling are calculated. The loss calculations are 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 cycle, synchronization and ramping losses are calculated. During synchronization, water is lost as the unit is spun to synchronize to 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.

All base cycling losses are valued at the monthly HLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The HLH price is used because the base cycling impacts (that is, losses in energy) are taken out of the HLH period. For FY 2010 and 2011, the average annual base cycling losses for HLH and LLH are 563 MWh and 1,152 MWh, respectively, resulting in an annual average cost of $74,699. Table 4.1.

4.4 Deployment Costs

In addition to the cost of having BPA's system set up to respond to reserve 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 resources. The costs of meeting the within-hour variations in loads and resources are referred to as "deployment costs." Deployment costs are those variable costs realized when the FCRPS automatically increases or decreases generation in order to balance the system. These costs are distinct from the standing ready cost. The cost sub-categories for deployment costs are response losses, incremental cycling loss, incremental spill, and incremental efficiency loss.

4.4.1 Response Losses

Response losses are a form of efficiency loss incurred when units on-line and on AGC respond to a signal. Response losses are an additional amount of efficiency loss realized as the unit's efficiency continuously changes over the course of deployment. The losses are a function of the respective controller project's unit dispatch, the project's response, and the amount of the control error signal.

The GARD model calculates the response losses by simulating a control error signal and calculating how each of the controller project's units change generation as a function of the given project's response and size of the control error signal. When generation changes at each of the units as a result of the simulated control error signal, GARD calculates the average efficiency of the unit as it moves in response to the control error signal by integrating over the unit's efficiency curve function from each unit's starting generation value to its ending value. The result of the integration is the average efficiency of the generating units during the course of the reserves deployment. The difference in the efficiency prior to deploying and the integrated efficiency during the course of response is the change in efficiency due to responding. Multiplying the change in efficiency during deployment by the average generation during deployment yields the generation loss in megawatthours.

The deployment simulation samples from the control error signal distribution, as described in section 4.2.2, one in every 10 minutes of each HLH and LLH period of each month. As such, losses and gains calculated for any given minute are expected to be realized for nine other minutes in the period. For example, if a control error signal value of 100 MW for one minute is sampled, GARD assumes that the 100 MW one-minute control error occurs 10 other times over the course of the HLH or LLH period. The current sampling was chosen because it balances the need to capture sub-hourly movements while at the same time is not computationally burdensome.

Response losses are realized by only those units that are currently on-line. Should additional units be cycled on-line, incremental cycling losses are calculated as a function of the unit being brought on-line and the generation level required of the unit while responding to the control error signal. *See* section 4.4.2 for further discussion.

All response losses and gains are valued at the monthly HLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The HLH price is used because response impacts, losses and gains in energy, are taken out of or put into the HLH period. For FY 2010 and 2011, the average annual response losses for HLH and LLH are 5,687 MWh and 4,424 MWh, respectively, resulting in an annual average rate period cost of $450,853. Table 4.2.

4.4.2 Incremental Cycling Losses

During the course of deployment, an *inc* signal may exceed the available spinning capability. In these instances, the GARD model will synchronize and ramp additional units as needed. This process captures the effect of deploying non-spinning reserves. When additional units are brought on-line, cycling costs are realized in the same fashion, as described in section 4.3.3.

Rather than run another simulation for 10-minute movements, GARD uses the same simulated data set from the response loss simulation described in section 4.4.1. Because the process of synchronizing and ramping takes place over 10 minutes, the modeling of incremental cycles occurs on only one in any 10 minutes of the deployment simulation and only when a control error signal exceeds the current spinning capability. As with response losses, the current method and sampling are chosen to balance the need to capture sub-hourly movements while at the same time not being overly burdensome from a computational standpoint.

All incremental cycling losses are valued at the monthly HLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The HLH price is used because energy lost due to incremental cycling is taken out of the HLH period. For FY 2010 and 2011, the annual average incremental cycling losses for HLH and LLH are 3,641 MWh and 37,417 MWh, respectively, resulting in an annual average rate period cost of $1,796,201. Table 4.2.

4.4.3 Incremental Spill

During the course of deployment, incremental spill may occur in the GARD model one of two ways. First, spill may occur if a sufficiently large *dec* signal pushes generation below the amount of generation shifted out of the HLH and into the LLH. This occurs because the water must continue to move past the projects while at the same time the project is being required to reduce generation. The second occurrence of incremental spill is when the *dec* signal exceeds the project's maximum generation drop rate. When this occurs, the project must spill to keep passing water while meeting the request to reduce generation.

GARD watches for and calculates the impact of any incremental spill during the course of the control error signal simulation. For each minute of the control error signal, GARD calculates how much it can decrease generation before needing to spill by comparing the *dec* control error signal to the amount of generation shifted out of HLH and into LLH. To the extent that the control error signal is less than the amount of shifted generation, no incremental spill occurs. If the control error signal exceeds the amount of generation shifted into the LLH, the model relies on the pre-existing *dec* capability to meet the *dec* need. When relying on the pre-existing *dec*, the model spills as generation continues to be decremented. The spill occurs because the water continues to move as the generation is dropping.

As stated above, spill may occur if the generation drop exceeds the drop rate allowed by the project. The drop rate constraint is a particular feature of GCL. GCL's ability to drop generation is limited because of tailwater bank stability concerns. The tailwater constraint is determined by the United States Geological Survey and enforced by Reclamation. The tailwater constraint is represented in GARD as a function of GCL LLH generation.

All incremental spill is valued at the LLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The LLH price is used because energy spilled in the LLH is energy that is required to move during the LLH and is not capable of being shaped into the HLH. For FY 2010 and 2011, the average annual incremental spill for LLH is 104,195 MWh, resulting in an annual average rate period cost of $3,691,312. Table 4.2.

4.4.4 Incremental Efficiency Loss

Incremental efficiency losses occur as a project attempts to efficiently dispatch in response to the control error signal while maintaining the spinning portion of the Operating Reserve. Incremental efficiency losses are calculated by comparing the project efficiency in its stand ready state against the efficiency after having responded to the control error signal, moved spinning units to a new generation level, and potentially cycled units on/off line. This change in efficiency is distinct from response losses, because incremental efficiency losses are the resulting efficiency after responding. In these measurements the efficiency of the project is altered after generation has changed to a new value in reaction to the control error signal, while the response losses are associated with reaching the new generation level.

All incremental efficiency losses and gains are valued at the HLH price from the market price forecast for the risk analysis for each month of the rate period. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The HLH price is used because efficiency impacts—that is, losses and gains in energy—are taken out of or put into the HLH period. For FY 2010 and 2011, the annual average incremental efficiency loss for HLH is 2,043 MWh, with an annual average efficiency gain of 7,400 MWh on LLH, resulting in an annual average rate period benefit of $229,561. Table 4.2.

4.5 Variable Cost of Reserves

The end goal of costing reserves is the ability to assign costs to specific types of reserve. After pricing balancing reserves and Operating Reserve, further decomposition into the spinning *inc*, non-spinning *inc*, Regulating Reserve, and *dec* portions of the total reserve cost is needed to align the costs of the various types of reserves with the impact these uses have on the hydrosystem.

To achieve the decomposition of reserve cost, the GARD model is run in two modes to determine the total cost of reserves, the cost of the spinning portion of the Operating Reserves obligation, and the spinning and non-spinning component cost of balancing reserves. A single model run is used to calculate the total variable cost of reserves. Determining the allocation of cost among *inc*, *dec*, spinning, and non-spinning components requires a batch model run where many different combinations of *inc* and *dec* reserve requirement are run. From this output, the costs associated with spinning reserves and non-spinning reserves as a function of *inc* and *dec* combination are calculated. The purpose of identifying the component cost of the reserves is to identify which cost components will be assigned to the various services for which the reserves are held.

4.5.1 Variable Cost of Reserves: Total Cost

For FY 2010 and 2011, the average annual variable cost of providing reserve is $13,035,771. Table 4.3. This forecast is for providing the average amount of reserve described in the Generation Reserve Forecast and the spinning portion of the operating reserve described in the Operating Reserve Cost Allocation. Generation Reserve Forecast section 2 and Tables 2.5 and 2.6; Operating Reserve Cost Allocation section 5 and Table 5.6. *See also* Tables 4.1-4.3. The total cost is then apportioned into the cost of Regulating Reserve, Load Following Reserve, Wind Balancing Reserve, and Operating Reserve.

The resulting allocation of cost between generation input costs is summarized in Tables 4.4 and 4.5. A more detailed discussion regarding the separation of the cost components follows in sections 4.5.2 through 4.5.5 below.

4.5.2 Variable Cost of Reserves: Apportioned Cost

Assigning cost begins by running the GARD model in a batch process where the costs of 25 different combinations of *inc* and *dec* reserve obligations are calculated to account for the cost diversity that exists when carrying different combinations of *inc* and *dec* reserves. The result of cost diversity is a lower cost for a given combination of *inc* and *dec* than the sum of the individual costs for *inc* alone and *dec* alone. The batch model run is the first step in determining a diversified cost separation.

The costs obtained from the batch model run are broken into spinning and non-spinning costs. Spinning costs are assigned the energy shift cost associated with the *dec* obligation, the base cycling cost, efficiency losses, and response losses. Each of these cost categories is associated with units on-line and generating. Non-spinning costs are assigned the incremental cycling losses, incremental spill, and incremental efficiency losses. Each of these costs is realized as units are cycled on from non-spinning status or cycled off to non-spinning status. Tables 4.6, 4.7, and 4.8.

The resulting tables of spinning and non-spinning costs are used to fit a multivariate regression describing spinning cost and non-spinning costs as a function of *inc* and *dec* obligation. The total cost is the sum of the spinning and non-spinning costs for a given *inc* and *dec* combination. Given the total cost, the relative spinning and non-spinning costs for a given *inc* and *dec* obligation are calculated, thus describing the total cost in a percentage due to spinning and non-spinning *inc* and *dec*. These relative costs for the specific *inc* and *dec* obligation are applied to the total cost of $13,035,771, yielding the specific dollar costs associated with the type of reserve. This process is detailed in sections 4.5.3 through 4.5.5 below.

4.5.3 Variable Cost of Reserves: Apportioned Spinning Cost

Using the results of the batch model run contained in Table 4.6, a multivariate regression model is fit to the data with the following functional form, where spinning cost is a direct function of the amount of the total spinning obligation, inclusive of Operating Reserve, and the *dec* obligation:

$$\text{Spin Cost} = (b_1\ \text{Inc} + b_2\ \text{Inc}^2 + b_3\ \text{Inc}^3) + (b_4\ \text{Dec} + b_5\ \text{Dec}^2 + b_6\ \text{Dec}^3)$$

(*See* Table 4.9 for the regression coefficients.)

From the above function, the spinning reserve cost is broken into *inc* costs and *dec* costs. The spinning cost is further broken into the costs of spinning for balancing and spinning for Operating Reserve. The average rate period Operating Reserve obligation is 197 MW, which is detailed in section 5 and Table 5.6. Because Operating Reserve must be maintained at all times, even as balancing reserves are being deployed during the course of an hour, Operating Reserve is assigned the cost of the first 197 MW of reserve. Given the above function and regression coefficients from Table 4.9, the Operating Reserve cost becomes:

$$\text{OR Cost} = (b_1\ 197 + b_2\ 197^2 + b_3\ 197^3)$$

Given the OR cost function, the function for the *inc* spinning cost for balancing becomes:

$$\text{BalIncSpin Cost} = b_1\ \text{BalInc} + b_2\ \text{BalInc}^2 + b_3\ \text{BalInc}^3,$$

Where BalInc = Inc - 197; that is, the total spinning *inc* obligation less the spinning portion of operating reserve.

The total spinning cost then becomes:

Spin Cost = OR Cost + BalIncSpin Cost + Dec Cost,

Where Dec Cost = (b_4 Dec+b_5 Dec^2+b_6 Dec^3).

The relative costs of Operating Reserve, balancing spinning, and *dec* are found by dividing the component costs by the total cost of the total reserve obligation:

Relative OR = OR Cost / Total Cost^

Relative BalIncSpin = BalIncSpin / Total Cost^

Relative Dec = (b_4 Dec+b_5 Dec^2+b_6 Dec^3) / Total Cost^

Where Total Cost^ is the total forecast spinning and non-spinning cost for the *inc* and *dec* combination pursuant to the fitted regression equations. Total Cost^ = Spin Cost + NonSpin Cost. NonSpin Cost is described in section 4.5.4.

The relative cost as a function of various combinations of spinning *inc* and *dec* reserve levels appears in Table 4.10. From Table 4.10, one may determine for a given *inc* and *dec* combination what fraction of the total cost is attributable to spinning *inc*, the spinning portion of operating reserve, and the *dec* reserve.

4.5.4 Variable Cost of Reserves: Apportioned Non-Spinning Cost

The decomposition of the non-spinning costs is a repeat of the process used in section 4.5.3 using the non-spinning data contained in Table 4.7. Using the data contained in Table 4.7, a multivariate regression model is fit to the data with the following functional form:

$$\text{NonSpin Cost} = (b_1\ \text{NSInc} + b_2\ \text{NSInc}^2 + b_3\ \text{NSInc}^3) + (b_4\ \text{Dec} + b_5\ \text{Dec}^2 + b_6\ \text{Dec}^3),$$

Where variable NSInc is the non-spinning portion of the *inc* obligation and Dec is the total *dec* obligation. The *dec* obligation is used as an explanatory variable for non-spinning costs because cycling units offline and/or spilling while deploying to meet a *dec*, and the resulting plant efficiency changes, are all rolled into non-spinning costs. The logic is that putting a unit into non-spinning status during a *dec* deployment is the opposite of bringing up a unit from non-spinning during an *inc* deployment. *See* Table 4.11 for the regression coefficients.

Given the above function, the relative costs of non-spinning *inc* and *dec* are found by dividing the component costs by the total cost of the total reserve obligation:

$$\text{Relative NSInc} = (b_1\ \text{NSInc} + b_2\ \text{NSInc}^2 + b_3\ \text{NSInc}^3)\ /\ \text{Total Cost}\wedge$$

$$\text{Relative Dec} = (b_4\ \text{Dec} + b_5\ \text{Dec}^2 + b_6\ \text{Dec}^3)\ /\ \text{Total Cost}\wedge$$

For the relative cost as a function of non-spinning reserve level, *see* Table 4.12.

4.5.5 Variable Cost of Reserves: Apportioned Total Cost

The next step is to consider the specific case of the FY 2010 and 2011 reserve requirement. The total average reserve obligation for the rate period comes from the Generation Reserve Forecast and the spinning portion of the Operating Reserve described in the Operating Reserve Cost Allocation and is outlined in Table 4.13. Section 2 and Table 2.5 and 2.6; section 5 and Table 5.6.

Given the rate period reserve requirement and the relative costs by reserve category shown in Tables 4.10 and 4.12, the relative cost for the specific types of reserve obligations can be defined. Interpolating the relative costs of the reserves outlined in Table 4.13 using the results contained in Table 4.10 and Table 4.12 yields the allocation appearing in Table 4.14.

Costs allocated to the reserve categories of balancing reserve spinning *inc*, balancing reserve non-spinning *inc*, Operating Reserve, and balancing *dec* are obtained by multiplying the annual total cost of reserves for the rate period, $13,035,771, from Table 4.3 by the percentages appearing in Table 4.14, as shown in Table 4.15.

Table 4.16 contains the reserve requirement separated by load and wind. The reserve is further separated into the spinning and non-spinning components by load and wind, as shown in Table 4.17. For determining the spinning requirement, 100 percent of the Regulating Reserve obligation and 50 percent of the following reserve obligation are spinning. Based on the Generation Reserve Forecast, section 2, over the rate period, on average, 19 percent of the total *inc* obligation is spinning based on the previously stated requirement. Table 4.17 calculates the spinning obligation by multiplying the load and wind total *inc* obligation by 19.5 and 8.6 percent, respectively, such that the weighted average of load and wind is 19 percent.

Using the quantities in Table 4.17 and the costs by reserve category in Table 4.15, Table 4.18 is generated. Table 4.18 is calculated by taking the proportion of the reserve type for load and wind and allocating the total cost of the given reserve type by the proportion. For example, from Table 4.17, load accounts for 70 percent (176MW / 253MW) of the total spinning *inc* obligation. Thus, load is allocated 70 percent of the spinning *inc* obligation from Table 4.15: 70 percent × $4,797,630 = $3,334,869.

The values in Table 4.18 are further separated into those costs billed as generation inputs and those that are incorporated into the power rates. This calculation requires separating out the costs of load regulation. The total generation input charge allocated to transmission rates consists of Regulating Reserve, Wind Balancing Reserve, and Operating Reserve. Regulating Reserve costs are calculated by taking the Regulating Reserve's proportion of the *inc* and *dec* obligation and multiplying by the spinning *inc* and *dec* costs. Wind Balancing Reserve is the sum of all reserve types associated with wind, and Operating Reserve is calculated in its totality in Table 4.19. These amounts are added to the embedded cost components of these various cost allocations in Table 1.1, and these combined allocations are discussed in the Introduction, section 1.

4.6 Supplemental Analysis

In addition to calculating the cost of a quantity of reserves based on a wind scheduling accuracy assumption equivalent to 30-minute persistence scheduling, reserves cost calculations based on a wind scheduling accuracy assumption equivalent to 45-minute persistence scheduling are included. Tables 4.20 through 4.38 detail the costs associated with this alternate quantity of reserves.

This page intentionally left blank.

5. OPERATING RESERVE COST ALLOCATION

5.1 Introduction

Operating Reserve is the reserve that TS provides under Schedule 5 and 6 of the OATT. The reserves that TS uses for Schedule 5 and 6 of the OATT are sometimes referred to as Contingency Reserves, but for purposes of allocating costs, they are referred to as Operating Reserve. Operating Reserve is an amount of spinning reserve and non-spinning (Supplemental) reserve. TS is obligated to offer to provide both spinning and supplemental Operating Reserve under the OATT. At least half of the Operating Reserve must be spinning reserve.

The current WECC standard requires that for each BAA, 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 five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation.

The current Operating Reserve standard may be replaced during the FY 2010-2011 rate period by the proposed new WECC Standard BAL-002-WECC-1. Under that new standard, the reserve obligation amount shall be the greater of:

(a) The loss of the most severe single contingency; or

(b) 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).

This Operating Reserve Cost Allocation Study first describes the amount of Operating Reserve TS is forecasting for FY 2010 and FY 2011 using the current standard. Second, the Operating Reserve forecast methodology to forecast the Operating Reserve under the proposed new Operating Reserve standard is described. Third, the Operating Reserve forecast is calculated based on the assumption that the current standard is in effect for the first six months of the rate period and the new standard is in effect for the last 18 months of the rate period. Fourth, the general methodology for allocating costs for Operating Reserve capacity is described. Fifth, the portion of BPA's system resources used to provide Operating Reserve and the revenue requirement associated with those projects are identified. Sixth, the embedded unit cost for Operating Reserve capacity to be allocated to TS by PS is established. Seventh, the embedded unit cost is multiplied by the Operating Reserve forecast to determine the total allocation of embedded costs forecast for Operating Reserve. Finally, an estimate of the total Operating Reserve cost allocation that includes both embedded and variable costs using the reserve forecast assumptions for the final rate proposal is provided.

5.2 Calculating the Quantity of Operating Reserve Using BAL-002-0

The current WECC and NWPP standards require the BPA BAA to maintain operating reserve for five percent of hydro, five percent of wind, and seven percent of thermal on-line generation. The weighted average of Federal generation resources (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 Federal resources.

Under the current standard, TS forecasts the quantity of Operating Reserve obligation to be provided by PS using the following methodology. The total BPA BAA Operating Reserve obligation forecast is based on regression analysis of historical total BPA BAA Operating Reserve obligation. Hourly historical total BPA BAA Operating Reserve obligations from October 2001 through July 2008 are summed 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 5.1. Next, the annual average total BPA BAA Operating Reserve obligation is calculated by dividing the sum of the average hourly total obligation amounts in the fiscal year by the number of hours in the fiscal year. A linear regression is then generated based on the annual average total BPA BAA Operating Reserve obligation. Table 5.2. The total BPA BAA obligation forecast calculated from the regression formula is 754 MW in FY 2010 and 772 MW in FY 2011 (763 MW average for FY 2010-2011). Table 5.3.

The amount of Operating Reserve obligation provided through self-supply and third-party supply is forecast based on the status as of December 2008, 252 MW, which is assumed constant through FY 2010 and FY 2011. The difference of the total BPA BAA Operating Reserve obligation and the amount provided by self-supply and third-party supply yields the Operating Reserve obligation to be provided by PS to TS. The total BPA BAA Operating Reserve obligation provided by PS is 502 MW in FY 2010 and 520 MW in FY 2011 (511 MW average for FY 2010-2011). Table 5.3.

5.3 Calculating the Quantity of Operating Reserve Using the Proposed New BAL-002-WECC-1

The proposed new WECC standard 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 BAA Operating Reserve obligation under the proposed new BAL-002-WECC-1 standard is determined as follows. First, the BPA BAA load is forecast using BPA BAA load in FY 2008 as a base year. The forecast of the loads through FY 2011 is based on the forecast BPA BAA load growth of -1.4 percent in FY 2009, 2.8 percent in FY 2010, and 1.9 percent in FY 2011. Second, BPA BAA generation is forecast based on a ratio of generation to load of approximately two-to-one observed historically from FY 2005 through FY 2008. Next, the total BPA BAA 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 BAA Operating Reserve obligation under BAL-002-WECC-1 is forecast to be 575 MW in FY 2010 and 586 MW in FY 2011 (581 MW average in FY 2010-2011). Table 5.4.

Reserve obligation provided by self-supply and third-party supply is based on the status of self-supply and third-party provision of Operating Reserve as of December 2008. Because the proposed new standard is based on three percent of load and three percent of generation in the BAA, an additional step is needed to adjust the reserve obligation for third-party suppliers and self-suppliers. The adjustment is needed to account for the change from 5.2 percent to six percent and for customers that have only generators or only loads in the BPA BAA, but not both. The obligation will change from 5.2 percent to six percent if the third-party and self-suppliers have load and generation in the BPA BAA, or from 5.2 percent to three percent if load or generation is outside of the BPA BAA. Third-party and self-supply forecast under the proposed new WECC standard is 227 MW in FY 2010 and FY 2011. The total PS Operating Reserve obligation provided to TS is the difference between the total BPA BAA Operating Reserve obligation and the amount of the total Operating Reserve obligation provided by self-supply or third-party supply. Assuming Commission approval of the new standard, BPA's Operating Reserve obligation would be reduced due to self-supply to 348 MW in FY 2010 and 359 MW in FY 2011 (354 MW average in FY 2010-2011), as shown in Table 5.5.

5.4 Calculating the Operating Reserve Forecast for the Final Proposal

NERC approved the proposed new WECC standard BAL-002-WECC-1 in October 2008 and submitted the standard to Federal Energy Regulatory Commission (the Commission) for approval on March 25, 2009. BPA expects the Commission to approve the new standard, but the exact timing of that approval is uncertain. Therefore, the current WECC standard is assumed to be effective for the first six months of the rate period (October 2009 to March 2010) and the proposed new WECC standard is assumed to be effective for the remaining 18 months of the rate period (April 2010 to September 2011). To determine the Operating Reserve obligation for FY 2010 and FY 2011 under that assumption, the monthly shaping is calculated using the following steps.

First, the average monthly shaping of BPA BAA load is calculated based on historical loads from FY 2005 through FY 2008. Second, the average monthly shaping of BPA BAA generation is calculated based on historical generation from FY 2005 through FY 2008. Third, a weighted-average monthly shaping percentage for each month is calculated using the monthly load shape times one-third plus the monthly generation shape times two-thirds, consistent with the ratio of generation to load.

The Operating Reserve obligation for the first six months of FY 2010 (October through March) is calculated by multiplying the total annual obligation in FY 2010 under the current standard by the weighted-average monthly shaping percentage. The Operating Reserve obligation for the last six months of FY 2010 (April through September) is calculated by multiplying the total annual amount in FY 2010 under the new standard by the weighted-average monthly shaping percentage. The Operating Reserve obligation for FY 2011 is calculated by multiplying the total annual obligation in FY 2011 under the new standard by the weighted-average monthly shaping. The Operating Reserve obligation under these assumptions yields 428 MW in FY 2010 and 359 MW in FY 2011 (an annual average of 393 MW for FY 2010-2011) as shown in Table 5.6. BPA uses the FY 2010-2011 average forecast amounts in the calculation of the unit cost of Operating Reserve cost allocation forecast.

5.5 Embedded Cost of Operating Reserve

This section describes the method used to allocate embedded costs for the capacity uses of the system for the development of the inter-business line provision of generation inputs for Operating Reserve. In addition to the embedded costs, variable costs are allocated to TS for the spinning component of Operating Reserve. These variable costs are described in section 5.10 and documented in the Variable Cost Pricing Methodology in section 4.

5.6 General Methodology for Pricing Operating Reserve

The unit cost of Operating Reserve is calculated by dividing the costs associated with all the hydro projects capable of providing Operating Reserve by the average annual capacity amount of those same hydro projects (adjusted for other requirements). As described in detail in the Embedded Cost Pricing Methodology, section 3, the capacity amount used to allocate Operating

Reserve cost is calculated by adding the average water 120-hour peaking capability of the regulated hydro projects to the average water peaking capability of the independent hydro projects that are used to provide reserves. Section 3.3. The Operating Reserve, Regulating Reserve, Wind Balancing Reserve, and Load Following Reserve that are removed in both HOSS and HYDSIM are added back in to establish total system capacity uses. The revenue requirement for the system that provides Operating Reserve is then divided by the total system capacity uses to determine a unit cost. The unit cost is multiplied by the forecast obligation described in section 5.4 (393 MW for FY 2010-2011) to determine the embedded cost allocation forecast for Operating Reserve.

5.7 Identify the System that Provides Operating Reserve

In the embedded cost for Operating Reserve calculation, the method used for determining the amount of capacity provided by the FCRPS is consistent with the Embedded Cost Pricing Methodology, section 3.3. The calculation is the same in both studies, except that the 120-hour peaking capacity quantities in the Embedded Cost Pricing Methodology are multiplied by 91 percent to quantify the Big 10 hydro projects that are used for providing Regulating Reserve and Wind Balancing Reserve. The 91 percent adjustment is not made for calculation of the Operating Reserve system.

As discussed in section 3, some independent hydro projects are not used to provide reserves. The remaining hydro resources of the FCRPS are used to provide BPA’s Operating Reserve requirement. The embedded cost net revenue requirement for Operating Reserve is composed of 1) power-related costs of the relevant hydro projects and associated fish mitigation on a project-specific basis, 2) allocation of the administrative and general expense, and 3) three revenue credits, all detailed in Table 5.7. The inputs for Table 5.7 are described in the Revenue

Requirement Study Documentation, Volume 1, WP-10-FS-BPA-02A, section 2. The synchronous condensing costs are allocated to TS in a separate calculation (described in section 6 of this Study), so they are removed (Table 5.7, line 18) to avoid double-counting. The rate period annual average revenue requirement allocation to the projects capable of providing Operating Reserve is $879,486,000, shown in Table 5.7, line 19.

5.8 Calculation of the Embedded Unit Cost of Operating Reserve Capacity

The annual average capacity uses of the hydro system for the rate period for purposes of calculating the embedded cost portion of capacity for Operating Reserve is 10,906 MW. This figure is the total peaking capability available for providing reserves (120-hour peaking capability of the regulated hydro projects plus certain independent hydro projects), described in the Embedded Cost Pricing Methodology, section 3.3, without the 91 percent adjustment. This is labeled Regulated + Independent Hydro Projects Capacity in Table 5.8, line 6. The sum of capacity system use for Regulating Reserve, Operating Reserve, Load Following Reserve, and Wind Balancing Reserve is 1,277 MW. This total is labeled Total Power Services Reserve Obligation in Table 5.8, line 7. The sum of these two amounts is 12,183 MW, which is Regulated + Independent Hydro Projects Capacity System Uses, shown on Table 5.8, line 8.

The annual average revenue requirement allocation of $879,486,000 is divided by the Regulated + Independent Hydro Capacity System Uses to calculate the embedded unit cost. The 12,183 MW is converted to an annual total of 146,196,000 of kW per month (12,183 MW × 1000 kW/MW × 12 months). The embedded unit cost of Operating Reserve is $6.02 per kW per month ($879,486.000 / 146,196,000 annual total of kW per month). Table 5.8, lines 9 through 12. Half of this Operating Reserve is spinning and is allocated to TS for establishing its rate for Schedule 5 of the OATT. The variable cost for spinning Operating Reserve described in the

Variable Cost Pricing Methodology is added to this allocation, for a total unit cost of spinning Operating Reserve described in section 5.10. The other half of Operating Reserve allocation is for non-spinning reserve provide by TS under Schedule 6 of the OATT, and there is no variable cost added to the embedded cost allocation or unit price for non-spinning Operating Reserve.

5.9 Forecast of Revenue from Embedded Cost Portion of Operating Reserve

The revenue forecast applies the rate calculated above to the forecast Operating Reserve quantity needed by TS. The forecast need on an annual average basis for the rate period is 393 MW. The revenue forecast for the embedded cost portion is $28,390,320 per year ($6.02 per kW per month × 393 MW × 1000 kW/MW × 12 months). Table 5.8, line 13.

5.10 Total Cost Allocation and Unit Prices for Spinning Operating Reserve

As discussed above, half of this Operating Reserve is spinning and is allocated to TS for establishing the rate for Schedule 5 of the OATT. In addition to the embedded cost for Operating Reserve, there is a variable cost for spinning Operating Reserve. The calculation of this variable cost component is documented in the Variable Cost Pricing Methodology, section 4. The total cost allocation for the variable cost of spinning Operating Reserve is $493,672, as shown on Table 4.4. The total forecast cost allocation for Operating Reserve, including both the embedded cost and the variable cost, is $28,883,992. Table 1.1, line 11.

The variable unit cost for spinning Operating Reserve is $0.21, which is derived by taking the total dollars allocated to spinning Operating Reserve and dividing by the forecast amount of spinning Operating Reserve converted to kW per month ($493,672 / (196.5 MW× 1000 kW/MW × 12 months)). The variable unit cost for spinning Operating Reserve is added to the embedded unit cost to calculate a total cost for spinning operating reserve of $6.23. Table 1.1, line 9.

This page intentionally left blank.

6. SYNCHRONOUS CONDENSING

6.1 Synchronous Condensing

This section describes the method used to determine the amount of energy consumed by those FCRPS hydro generators that operate as synchronous condensers. It also describes the costs for investment in plant modifications necessary to provide synchronous condensing at the John Day and The Dalles projects.

6.2 Description of Synchronous Condensers

A synchronous condenser is essentially a motor with an excitation system that enables it to provide voltage control to the transmission system. Some FCRPS generators operate in synchronous condenser or "condense" mode for voltage control and for other purposes (*e.g.*, 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. In the case of FCRPS generators operating in condense mode, the energy consumed is supplied by other units in the FCRPS.

6.3 Synchronous Condenser Costs

Synchronous condensing costs are: 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. These costs are allocated to TS.

The investments in plant modifications at the John Day and The Dalles projects result in costs allocated to TS of $329,000 for FY 2010 and $319,000 for FY 2011, for an average of $324,000 per year. Table 6.2. and Revenue Requirement Study Documentation Volume 1, WP-10-FS-BPA-02A, section 2. These costs are the annual capital cost 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.

The cost of the energy forecast to be consumed by FCRPS generators operating in condense mode is allocated to TS; 40,301 MWh of energy is forecast to be consumed by synchronous condensers for voltage control. Table 6.1. The methodology to determine the amount of energy consumption is described below. The energy consumed for condensing operation is priced at the market price forecast for the risk analysis. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. Applying the market price forecast for the risk analysis of $40.58 per MWh to the energy consumed results in a total cost of $1,635,419 per year, shown on Table 6.1.

6.4 General Methodology to Determine Energy Consumption

For the rate period, FY 2010 and 2011, 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 is FYs 2005, 2006, and 2007. 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. Table 6.1, column C. Finally, the market price forecast for the risk analysis is applied to the amount of energy consumed. 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.

6.4.1 Grand Coulee Project

Six generators (Units 19-24) at the Grand Coulee project are capable of operating as synchronous condensers. BPA uses primarily units 19-21 for synchronous condensing. The Study forecasts the number of hours that the Grand Coulee units operated in condense mode based on historical condenser operations in FYs 2005, 2006, and 2007 during night-time hours (generally 10.p.m. to 6.a.m.). The transmission system typically needs additional voltage control from the Grand Coulee project during night-time hours 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 archived reactive meter readings for FYs 2005, 2006, and 2007. The total measured reactive demand represents the total reactive support (*i.e.*, MVAr) 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 are 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 FYs 2005, 2006, and 2007 is averaged, and energy consumption is determined by multiplying the average annual condensing hours by the fixed hourly energy consumption of the generators. For total energy consumed by the Grand Coulee generators operating in synchronous condense mode for voltage control, the Study forecasts 26,253 MWh of energy per year. Table 6.1, line 1, column I.

6.4.2 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 archived meter data for FYs 2005, 2006, and 2007 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. For total energy consumed by the generators operating in condense mode for voltage control, the Study forecasts 8,072 MWh of energy per year for the John Day projects, 2,723 MWh of energy per year for The Dalles project, and 96 MWh (Units 1-2) and 1,628 MWh (Unit 3) of energy per year for the Dworshak project. Table 6.1, lines 2-5, column I.

6.4.3 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 archived meter data for FYs 2006 and 2007 are averaged. FY 2006 and 2007 data are used for the forecast because this period correlates with current operating practices. Energy consumption is determined by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the project. For energy consumption by the Palisades generators operating in condense mode for voltage control, the Study forecasts 1,529 MWh of energy. Table 6.1, line 6, column I.

6.4.4 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.. Table 6.1, lines 7-9, column I.

6.4.5 Hungry Horse Project

The Hungry Horse project has four generators (Units 1-4) capable of condensing. Although capable of condensing, Hungry Horse did not operate in condense mode during the three-year period examined. Therefore, the energy consumption for the Hungry Horse generators is forecast to be zero. Table 6.1, line 10, column I.

6.5 Summary – Costs Assigned to Transmission Services

The total cost for synchronous condensing is $1,959,419 for each year in the rate period. Costs are based on the market price forecast for the risk analysis of $40.58/MWh. *See* Market Price Forecast, WP-10-FS-BPA-03A, Table 17. The costs allocated to Transmission Services are calculated as shown below:

- The investment in plant modifications at John Day & The Dalles: average $324,000 per year
- Energy consumption: 40,301 MWh/yr × $40.58/MWh = $1,635,419/year

7. GENERATION DROPPING

7.1 Introduction

This section describes the method for allocating costs of Generation Dropping. The following sections describe the methodology, identify the assumptions used in the methodology, and establish the generation input cost allocation that is applied to determine the annual revenue forecast.

7.2 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, PS is requested by 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).

7.3 Forecast Amount of Generation Dropping

Historically, six large units have been dropped over the last four years. In past rate periods, the forecast has been 1.5 drops per year. The estimate of "large generating units dropped" remains at 1.5 drops per year for this Study.

7.4 General Methodology

The overall valuation approach considers two factors. First, the desired Generation Dropping Service or "forced outage duty" causes additional wear and tear component on equipment that will incrementally decrease the life and increase the maintenance of the unit. For each major component that is affected by this service, Table 7.1 shows the cost associated with incremental equipment deterioration, replacement, and overhaul in columns B-D and the cost associated with incremental routine operation and maintenance cost in columns E-G.

PS previously contracted with an engineering company to work with Reclamation and the COE (owners of 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 by Harza Engineering Company are updated using the Handy-Whitman Index to reflect price escalation of equipment and labor costs.

Second, the incremental impact is evaluated by computing lost revenues during the outages required during replacement or overhaul of the equipment. The market price forecast for the risk analysis is applied to the energy costs. Market Price Forecast Study, WP-10-FS-BPA-03A, Table 17. Table 7.1 shows the calculation of this incremental lost revenue in columns H-K.

7.5 Determining Costs to Allocate to Generation Dropping

Historical data for the Grand Coulee Third Powerhouse generating units, as well as statistical data for other hydroelectric units, provides capital cost, O&M costs, and frequency of operation information for the generation dropping analysis. Stresses during "forced outage duty" on the equipment versus stresses during "normal operation" are compared. Through the application of this data, the incremental capital and O&M costs for the generation drop service are developed. The incremental impacts of these factors that result from generation drop service are converted into a percentage change in the 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. Table 7.1, columns B, E, and H, shows the percentage reductions in life expectancies per generation drop.

In addition to capital and O&M 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, a cost is calculated for the outages that cannot be scheduled to avoid lost revenues. This lost revenue analysis is based on the forecast price of HLH and LLH energy averaged over the rate period. It is assumed that these outages are longer than scheduled and are unpredictable, and therefore cannot be scheduled to avoid a loss in total project generation. Table 7.1, columns H-K, shows the calculation of the lost revenue.

7.6 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. Table 7.1, column B.

7.7 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 $407,965. Table 7.1.

This amount is comprised of $132,404 in incremental equipment deterioration, replacement, or overhaul costs; $4,440 in incremental routine operation and maintenance costs; and $271,121 in incremental lost revenue in the event of replacement or overhaul. The sum, $407,965, is multiplied by the estimate of 1.5 generation drops per year for a total annual cost of $611,948 per year. Table 7.2.

8. REDISPATCH

8.1 Introduction

Under OATT, Attachment M, TS initiates redispatch of Federal and non-Federal resources as part of congestion management efforts. Generally, redispatch results in decrementing resources that can effectively relieve flowgates that are at or near Operating Transfer Capability (OTC) limits and incrementing 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 or decrementing resource whole financially. In the case of a decrementing resource, the resource 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 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 for the value of that generation.

There are three levels of redispatch under Attachment M of the OATT that TS can request from PS to relieve flowgate congestion: Discretionary Redispatch; Network (NT) Redispatch; and Emergency Redispatch. The FY 2010-2011 revenues PS expects to recover for redispatch services is forecast by quantifying the amount of redispatch service provided by PS in FY 2008 and adjusting this amount by excluding unusual events that are not expected to reoccur. This process is described below.

8.2 Discretionary Redispatch

TS may request discretionary bids for redispatch from either Federal (Discretionary Redispatch from PS under Attachment M of the OATT) or non-Federal resources to *inc* and *dec* generation (collectively, Reliability Redispatch). Reliability Redispatch is the preferred method for managing congestion, as it provides immediate relief on affected paths and keeps transactions whole. Reliability Redispatch is the primary redispatch cost for TS.

Actual costs of Reliability Redispatch incurred by TS for FY 2008 totaled $492,970 for both Federal and non-Federal generators. A total of $499,693 was attributable to Discretionary Redispatch requested from PS under Attachment M. Table 8.2. The amount of Discretionary Redispatch requested from PS is higher than the total amount of Reliability Redispatch costs because the majority of redispatch provided by non-Federal generators involved the decrementing of resources for which TS was paid. These costs were included as revenues for PS in FY 2008.

Table 8.2 shows each time Discretionary Redispatch was requested by TS from PS in FY 2008, including the MWh of redispatch requested, the amount delivered, the total cost, the cost per MWh, the generation that was requested to either *inc* or *dec*, and the cause of the redispatch request. TS experienced one large discretionary redispatch event in July 2008 that cost $325,624; this event is assumed to be an anomaly resulting from a transition in congestion management tools and is therefore excluded from the revenues. Table 8.2, line 12. New dispatch procedures and training should reduce the likelihood of a similar event in the future. The FY 2008 revenue recovered by PS for Discretionary Redispatch, excluding the July anomaly, was $174,069. Based on this amount, the revenue that TS will pay PS for Discretionary Redispatch in FY 2010 and FY 2011 is forecast to be $175,000 per year.

8.3 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 PTP and secondary NT schedules are curtailed in a sequence consistent with NERC curtailment priority. NT Redispatch can include transmission purchases and/or power purchases or sales to maintain firm NT schedules. PS must provide NT Redispatch when requested by TS to the extent that it can do so without violating non-power constraints.

Actual TS NT Redispatch costs and PS revenues for FY 2008 were $542,678. Table 8.1 lists all dates that NT Redispatch was requested by TS from PS for FY 2008, including the MWh of redispatch requested, the total cost, and the cost per MWh. These NT Redispatch requests represent only transmission purchases and/or power purchases or sales to maintain firm NT schedules. TS did not request any NT Redispatch from PS that required PS to redispatch the Federal hydro system in FY 2008. TS requested one large NT Redispatch event in September that cost $310,559, resulting from the need to replace transmission poles. Table 8.1, line 12. The replacement of the transmission poles is a one-time occurrence; thus, the redispatch costs incurred during the replacement are not included in the forecast. Excluding this anomaly, FY 2008 revenue recovered by PS was $232,119. Accordingly, the revenue that TS will pay PS during the rate period for NT redispatch is forecast to be $225,000 per year.

8.4 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 must violate non-power constraints.

TS did not request Emergency Redispatch in FY 2008 and has never requested Emergency Redispatch from PS. Therefore, no revenue for Emergency Redispatch is forecast for FY 2010 and FY 2011.

8.5 Revenue Forecast for Redispatch Service

Based on FY 2008 adjusted revenues, a total of $400,000 per year in revenues is forecast for FY 2010 and FY 2011 for Discretionary and NT Redispatch services provided to TS under Attachment M of the OATT.

9. SEGMENTATION OF COE AND RECLAMATION TRANSMISSION FACILITIES

9.1 Introduction

The COE and Reclamation own transmission facilities associated with their respective generating projects. All COE and Reclamation costs are functionalized to the generation function in the Revenue Requirement Study. Therefore, the COE and Reclamation transmission-related investment are identified so that the proper portion of the annual cost of these transmission facilities may be assigned to 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 generation revenue requirement. The relevant segment definitions and proposed treatment are described below.

9.2 Generation Integration

GI facilities are those facilities that 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 Commission practice.

9.3 Integrated Network

Integrated Network facilities are those transmission facilities that provide the bulk of transmission of electric power within the Pacific Northwest and operate at voltages of

34.5 kilovolts (kV) and above. The COE and Reclamation tranmission costs that are associated with Network facilities are allocated to TS.

9.4 Utility Delivery

Utility Delivery facilities are those facilities that deliver power to BPA public utility customers at voltages below 34.5 kV. The COE and Reclamation tranmission costs that are associated with Utility Delivery facilities are allocated to TS. The segmentation of these facilities is consistent with the definitions used in TS's most recent segmentation study. 2002 Final Transmission Proposal Segmentation Study, TR-02-FS-BPA-02.

9.5 COE Facilities

The transmission facilities owned by the COE are primarily GSU and associated equipment at the projects. These facilities 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. Therefore, this switching equipment is segmented between Network and GI. Table 9.1.

9.6 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 either Network or Utility Delivery functions. The Study shows the information used to assign the lines and substation investment at each Reclamation project into the appropriate segment. Tables 9.2 and 9.3 describe the Columbia Basin project (Grand Coulee), and Table 9.5 describes the other Reclamation projects. The available Reclamation investment data does not disaggregate costs to the equipment level. Therefore, to develop investment by segment(s), typical costs shown on Table 9.4, column E, are used as a proxy for major pieces of equipment. 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. Table 9.4, column B. The segment percentage is multiplied by the total transmission investment for each station to determine the segment investment. Table 9.3, line 25.

9.6.1 Columbia Basin Transmission Costs

Tables 9.2 and 9.3 show the assignment of Reclamation Columbia Basin project transmission costs to the appropriate segments. The GI segment includes transmission facilities between the generator and the Network station, including step-up transformers, powerhouse lines or cables, and switching equipment at the Network station for the powerhouse lines. The GI segment comprises 71.95 percent of the transmission investment in the Columbia Basin project; 27.64 percent of the transmission investment in the Columbia Basin project is assigned to the Network segment; and less than one-half percent of the transmission investment is assigned to the Utility Delivery segment. Table 9.2, lines 4-6.

Reclamation does not have investment data to the level of major pieces of equipment. Table 9.3. Accordingly, these costs are assigned to the GI, Network, and Delivery segments based on BPA typical facility costs for the major equipment. Table 9.4, lines 23-25. The typical costs are developed for each piece of equipment in major divisions, such as the 500 kV switchyard. The ratio for Network is developed based on the cost of the equipment that is Network as a ratio of the total cost.

9.6.2 Assumptions/Method for Developing Columbia Basin Transmission Costs

The Columbia Basin project includes generation equipment and associated switchyard equipment. 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 11.83 percent, using FY 2007 data. Table 9.3, line 7.

The investment in the Columbia Basin project does not include construction work in progress. As previously explained in section 9.6.1, typical costs are used for each piece of equipment, as specified in Table 9.4, column E. The Reclamation transmission facilities start at the high side of the generator breaker (low side of a step-up transformer). This includes 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 and Nespelem Valley Electric Coop at Lonepine. Table 9.4, lines 18 and 19. Because these facilities serve both station service and Delivery functions, the costs of these facilities are segmented accordingly. The 500 kV additions for the Coulee-Bell line are not included in the investment.

9.7 Revenue Requirement for Investment in COE and Reclamation Facilities

The investment for COE and Reclamation transmission facilities is: 1) GI, $149.2 million; 2) Network, $57.3 million; and 3) Utility Delivery, $1.2 million. Table 9.6. The investment associated with Network and Utility Delivery facilities results in a revenue requirement of $6.044 million for FY 2010 and $6.362 million for FY 2011. Table 9.7 and Revenue Requirement Study Documentation Volume 1, WP-10-FS-BPA-02A, section 2. These annual revenue requirements are averaged to obtain the $6.203 million rate case average shown on line

15 of Table 1.1. This amount is allocated to TS and the revenue is credited to the generation revenue requirement.

10. STATION SERVICE

10.1 Introduction

Station Service refers to real power that TS takes directly off the BPA power system for use at substations and other non-electric plant, such as facilities located on the Ross Complex and Big Eddy/Celilo Complex. Station Service does not include station service that TS purchases from another utility or that is supplied by another utility through contractual arrangements. 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 non-electric plant is estimated . The Study describes the station service energy usage and determines the costs that are allocated to TS for station service energy usage.

10.1.1 Overview of Methodology

The Station Service costing methodology consists of four steps. First, the amount of installed transformation (measured in kVa units) at all BPA substations is assessed. Second, the historical monthly average energy usage at all substations and other non-electric plant at the Ross Complex and the Big Eddy/Celilo Complex is compiled. Third, an average load factor from the installed transformation and historical monthly average of energy usage is derived. Fourth, the total quantity of station service energy usage for the BPA system is determined. Table 10.1.

10.2 Assessment of Installed Transformation

The Study identifies the amount of installed transformation for all BPA substations at locations listed in Table 10.1, lines 8 through 47, column C. The total amount of installed transformation at BPA substations is 15,456 kVa.

10.3 Assessment of Station Service Energy Usage

The metered usage of station service received from the BPA power system at the other non-electric plant facilities at Ross Complex and Big Eddy/Celilo Complex is included in the 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. Table 10.1, line 65, column D.

The historical average monthly energy usage at BPA substations is taken from meter data, when such data was available. The total historical average monthly usage for BPA substations is 1,066,446 kWh. Table 10.1, line 49, column D. Because not all usage is metered, the total average monthly usage for BPA substations is estimated based on the historical average monthly usage times an average load factor described in section 10.4.

10.4 Calculation of Average Load Factor

The average monthly load factor is calculated by dividing the total historical monthly usage for all BPA substations by the total installed transformation for these BPA substations, then dividing by 730 hours in a month. This yields an average 9.45 percent load factor, as shown on Table 10.1, line 49, column E.

10.5 Calculating the Total Quantity of Station Service

To derive the total amount of station service energy usage for the BPA system, the historical station service energy usage for the Ross Complex and the Big Eddy/Celilo Complex is added to the calculated amount of energy usage at all the BPA substations. Multiplying the installed transformation by the average calculated load factor yields the calculated historical average monthly usage for substations to be 3,058,373 kWh (44,325 kVa × 730 × 9.45 percent).

Table 10.1, line 56. The total quantity of station service average usage that PS supplies directly to BPA substations and other non-electric plant is estimated to be 6,630,610 kWh per month and 79,567,320 kWh per year. Table 10.1, lines 65 and 68, column E.

10.6 Determining Costs to Allocate to Station Service

The market price forecast for the risk analysis applied to the estimated total quantity of station service yields the costs to be allocated to Station Service. The rate period average market price forecast is $40.58 per MWh. Market Price Forecast, WP-10-FS-BPA-03A, Table 17. Multiplying the average price by the average usage of 79,567 MWh per year yields an annual cost of $3,228,829. Table 10.2.

This page intentionally left blank.

Tables 1.1 through 10.2 for

Generation Inputs Study

WP-10-FS-BPA-08

This page intentionally left blank.

Table 1.1				
Generation Inputs Revenue Forecast				
	A	**B**	**C**	**D**
	Generation Inputs Total	**Quantity**	**Per Unit Cost ($/kW/month)**	**Annual Average Revenue for FY 2010-FY 2011**
1	Regulating Reserve - Embedded Cost Portion	83 MW		$ 5,697,120
2	Regulating Reserve - Variable Cost Portion	83 MW inc 89 MW dec		$ 2,001,664
3	**Regulating Reserve Total**	**83 MW**	**$ 7.73**	**$ 7,698,784**
4	Wind Balancing Reserve - Embedded Cost Portion	585 MW		$ 40,154,400
5	Wind Balancing Reserve - Variable Cost Portion	585 MW inc 838 MW dec		$ 7,255,487
6	**Wind Balancing Reserve Total**	**585 MW**	**$ 6.75**	**$ 47,409,887**
7	Operating Reserve - Spinning (Embedded Cost Portion)	196.5 MW	**$ 6.02**	$ 14,195,160
8	Operating Reserve - Spinning (Variable Cost Portion)	196.5 MW	**$ 0.21**	$ 493,672
9	**Operating Reserve - Spinning Total**	196.5 MW	**$ 6.23**	**$ 14,688,832**
10	**Operating Reserve - Supplemental Total**	196.5 MW	**$ 6.02**	**$ 14,195,160**
11	**Operating Reserve Total**	393 MW		**$ 28,883,992**
12	**Synchronous Condensing**	40,301 MWh		**$ 1,959,419**
13	**Generation Dropping**	1.5 drops/year		**$ 611,948**
14	**Redispatch**			**$ 400,000**
15	**Segmentation of COE/Reclamation Network and Delivery Facilities**			**$ 6,203,000**
16	**Station Service**	79,567 MWh		**$ 3,228,829**
17	**Generation Inputs Total**			**$ 96,395,859**

	Table 1.2			
	Generation Inputs Unit Cost for Wind Balancing Reserve Under 45-Minute Persistence Scheduling Accuracy Assumption			
	A	B	C	D
	Generation Inputs Total	Quantity	Per Unit Cost ($/kW/month)	Annual Average Cost Allocation for FY 2010-FY 2011
1	Wind Balancing Reserve - Embedded Cost Portion	703 MW		$ 47,916,480
2	Wind Balancing Reserve - Variable Cost Portion	703 MW inc 1029 MW dec		$ 9,889,216
3	**Wind Balancing Reserve Total**	**703 MW**	**$ 8.23**	**$ 57,805,696**

	Table 1.3				
	Breakout of Components of Wind Balancing Service Rate Under 30-Minute Persistence Scheduling Accuracy for Self-Supply				
	A	B	C	D	E
	Service Component	Wind Balancing Service Rate ($/kW/month)	Embedded Cost	Variable Cost	Total Cost
1	Regulating Reserve	$ 0.05	$ 1,441,440	$ 488,728	$ 1,930,168
2	Following Reserve	$ 0.26	$ 7,756,320	$ 1,838,707	$ 9,595,027
3	Imbalance Capacity	$ 0.98	$ 30,956,640	$ 4,928,052	$ 35,884,692
4	Total	$ 1.29	$ 40,154,400	$ 7,255,487	$ 47,409,887
5	Wind Balancing Service Rate Component (B) is calculated by dividing the Total Cost for the Component (E) by (3053 MW of installed wind capacity * 12 months * 1000 kW/MW).				

	Table 1.4				
	Breakout of Components of Wind Balancing Service Rate Under 45-Minute Persistence Scheduling Accuracy for Self-Supply				
	A	B	C	D	E
	Service Component	Wind Balancing Service Rate ($/kW/month)	Embedded Cost	Variable Cost	Total Cost
1	Regulating Reserve	$ 0.05	$ 1,431,360	$ 512,909	$ 1,944,269
2	Following Reserve	$ 0.27	$ 7,702,080	$ 1,996,688	$ 9,698,768
3	Imbalance Capacity	$ 1.26	$ 38,783,040	$ 7,379,620	$ 46,162,660
4	Total	$ 1.58	$ 47,916,480	$ 9,889,217	$ 57,805,697
5	Wind Balancing Service Rate Component (B) is calculated by dividing the Total Cost for the Component (E) by (3053 MW of installed wind capacity * 12 months * 1000 kW/MW).				

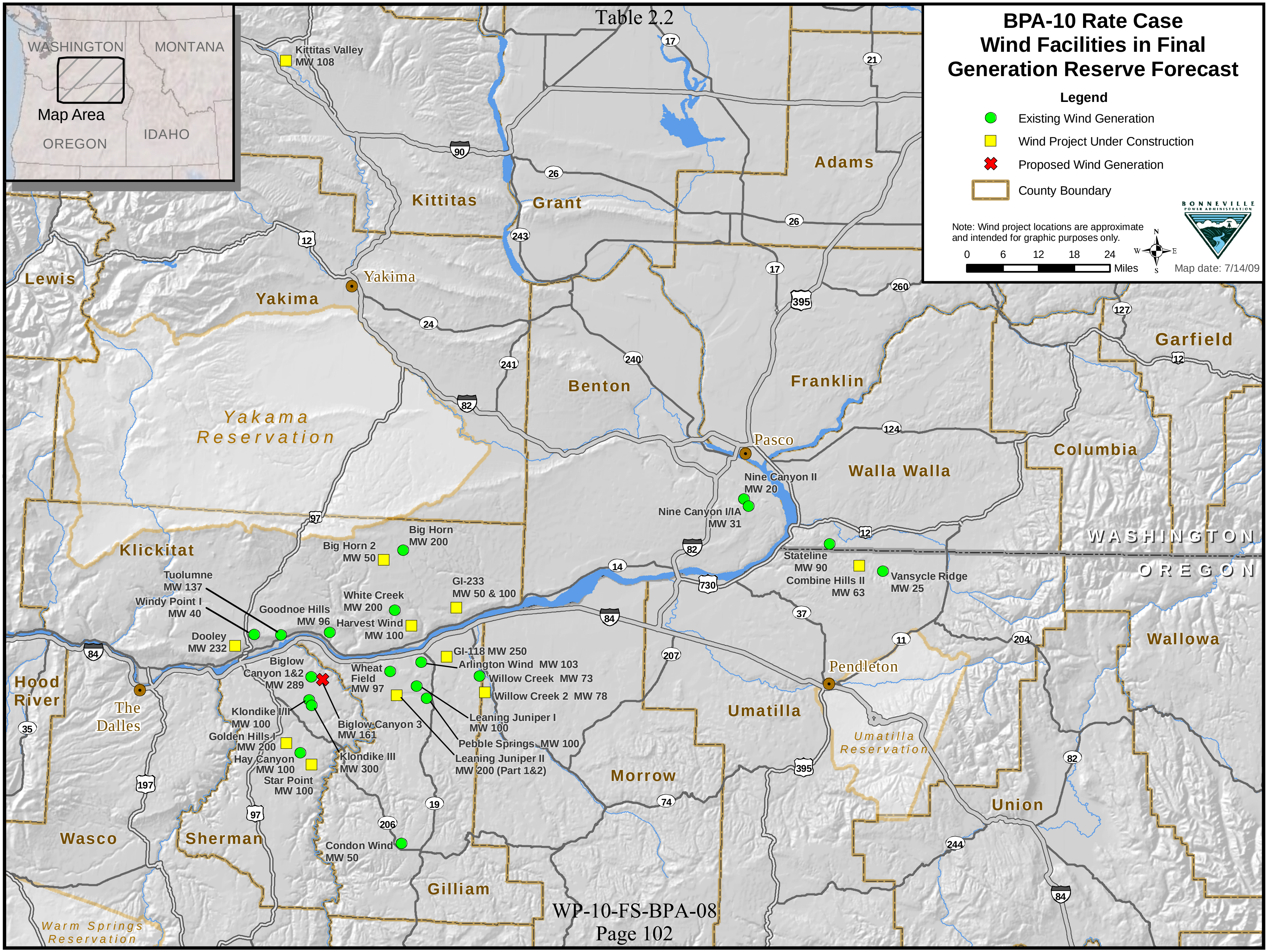
Table 2.1				
Existing Projects - 1998 to June 2009				
	Project	**Installed Capacity (MW)**	**Full Service Date**	**Time Shift and Scale**
A	**B**	**C**	**D**	**E**
1	Vansycle Wind Project	25	1998	
2	Stateline Wind Project	90	2000	
3	Condon Wind Project	50	2000	
4	Klondike I	24	2000	
5	Nine Canyon I	18	2001	
6	Klondike II	76	2005	
7	Big Horn	200	Aug-06	
8	Leaning Juniper I	100	Oct-06	
9	White Creek Wind	200	Oct-07	10 min. before Big Horn (100MW), 20 min. before Big Horn (100MW)
10	Klondike III part 1 and 2	225	Oct-07	20 min. after Klondike I and II
11	Biglow Canyon I	126	Oct-07	10 min. before LJ1 (50.4MW), 5 min. before Klondike I and II (75.6MW)
12	Nine Canyon IA	13	Dec-07	Same as Nine Canyon I (13MW of 45 MW total in BPA BAA)
13	Goodnoe Hills	96	Feb-08	prior to 11/07: 30 min. before Big Horn following 11/07: 15 min. before White Creek
14	Nine Canyon II Addition	20	May-08	5 min. after Nine Canyon (only 20MW of 32MW total in BPA BAA)
15	Klondike III part 3	75	Jun-08	10 min. after Klondike III
16	Arlington Wind	103	Jan-09	30 min. after Klondike III (100MW) 5 min. before LJ1 (100MW)
17	Willow Creek 1	73	Feb-09	50 min. after Klondike I (24.3MW) and II (24.3MW), 40 min. after Biglow (24.4MW)
18	Hay Canyon	100	Mar-09	30 min. before LJ1
19	Pebble Springs	100	Mar-09	5 min. after LJ1 (50MW), 30 min. before Biglow Canyon (50MW)
20	Wheat Field	97	Apr-09	30 min. after Klondike III (100MW) 5 min. before LJ1 (100MW)
21	Windy Point 1 (Tuolumne) Part 1	80	Jun-09	40 min. before LJ1 (40MW), 10 min. before Goodnoe Hills (40MW)
22	**Total - June 2009**	**1891**		

Table 2.1				
Future Projects: August 2009 - April 2010				
	Project	**Installed Capacity (MW)**	**Full Service Date**	**Time Shift and Scale**
A	**B**	**C**	**D**	**E**
23	Biglow Canyon Phase 2	163	Aug-09	1 min. after Biglow (81.5 MW),
				10 min. before Goodnoe Hills (81.5MW)
24	Windy Point 1 (Tuolumne) Part 2	57	Oct-09	40 min. before LJ1 (28.5MW),
				10 min. before Goodnoe Hills (28.5MW)
25	Star Point (Hay Canyon 2)	100	Jan-10	40 min. before LJ1
26	Leaning Juniper 2 part 1	91	Feb-10	30 min. after Klondike I (22.75MW) and II (22.75MW),
				40 min. after Klondike III (22.75MW),
				5 min. before LJ1 (22.75MW)
27	Harvest Wind	100	Feb-10	10 min. after Goodnoe Hills (25MW),
				5 min. after White Creek (50MW),
				90 min. before Nine Canyon (25MW)
28	Combine Hills II	63	Apr-10	20 min. before Hopkins Ridge (31.5MW),
				45 min. after Nine Canyon (31.5MW)
29	#233 Part 1	50	Apr-10	10 min. after White Creek (25 MW),
				40 min. after Klondike I (12MW) and II (13MW)
30	**Estimated Total - April 2010**	**2515**		

Table 2.1				
Future Projects: August 2010 - December 2010				
	Project	**Installed Capacity (MW)**	**Full Service Date**	**Time Shift and Scale**
A	**B**	**C**	**D**	**E**
31	Windy Point 1	40	Aug-10	10 min. before Goodnoe Hills (20MW), 20 min. before White Creek (20MW)
32	Golden Hills I	200	Aug-10	30 min. before LJ1 (68MW), 10 min. before Klondike I (66MW) and II (66MW)
33	Dooley (Windy Flats 1&2)	232	Aug-10	30 min. before LJ1 (116MW), 10 min. before Biglow (116MW)
34	Biglow Canyon Phase 3	161	Aug-10	10 min. before Biglow (96.6MW), 30 min. before LJ1 (64.4MW)
35	Big Horn 2	50	Aug-10	5 min. before Big Horn
36	#233 Part 2	100	Oct-10	10 min. after White Creek, 40 min. after Klondike I and II
37	Kittitas Valley	108	Oct-10	50 min. before Wild Horse
38	Leaning Juniper 2 part 2	109	Oct-10	30 min. after Klondike I (27.25MW) and II (27.25MW), 40 min. after Klondike III (27.25MW), 5 min. before LJ1 (27.25MW)
39	Willow Creek 2	78	Dec-10	60 min. after Klondike I (10MW) and II (10MW), 20 min. after LJ1 (27MW), 40 min. after Biglow (31MW)
40	**Estimated Total - December 2010**	**3593**		

Future Projects: December 2010 - August 2011				
	Project	**Installed Capacity (MW)**	**Full Service Date**	**Time Shift and Scale**
41	GI #118 Part 1	250	Aug-11	40 min. after Klondike I and II (125MW) and Klondike III (93.75MW), 40 min. before Vansycle (31.25MW)
42	**Estimated Total - August 2011**	**3843**		

Table 2.2



BPA-10 Rate Case
Wind Facilities in Final Generation Reserve Forecast
Legend
Existing Wind Generation
Wind Project Under Construction
Proposed Wind Generation
County Boundary
Note: Wind project locations are approximate and intended for graphic purposes only.
0 6 12 18 24 Miles
Map date: 7/14/09
WASHINGTON
MONTANA
Map Area
IDAHO
OREGON
Kittitas Valley MW 108
Kittitas
Grant
Adams
Lewis
Yakima
Yakama Reservation
Benton
Franklin
Pasco
Garfield
Columbia
Walla Walla
Nine Canyon II MW 20
Nine Canyon I/IA MW 31
Klickitat
Big Horn MW 200
Big Horn 2 MW 50
GI-233 MW 50 & 100
White Creek MW 200
Harvest Wind MW 100
Goodnoe Hills MW 96
Tuolumne MW 137
Windy Point I MW 40
Dooley MW 232
Stateline MW 90
Combine Hills II MW 63
Vansycle Ridge MW 25
WASHINGTON
OREGON
Wallowa
Hood River
The Dalles
Biglow Canyon 1&2 MW 289
Wheat Field MW 97
GI-118 MW 250
Arlington Wind MW 103
Willow Creek MW 73
Willow Creek 2 MW 78
Leaning Juniper I MW 100
Pebble Springs MW 100
Leaning Juniper II MW 200 (Part 1&2)
Biglow Canyon 3 MW 161
Klondike I/II MW 100
Golden Hills I MW 200
Hay Canyon MW 100
Star Point MW 100
Klondike III MW 300
Pendleton
Umatilla
Umatilla Reservation
Morrow
Union
Wasco
Sherman
Condon Wind MW 50
Gilliam
Warm Springs Reservation

Table 2.3
Wind Regulation Requirements Methodology
LOAD plus NEGATIVE WIND

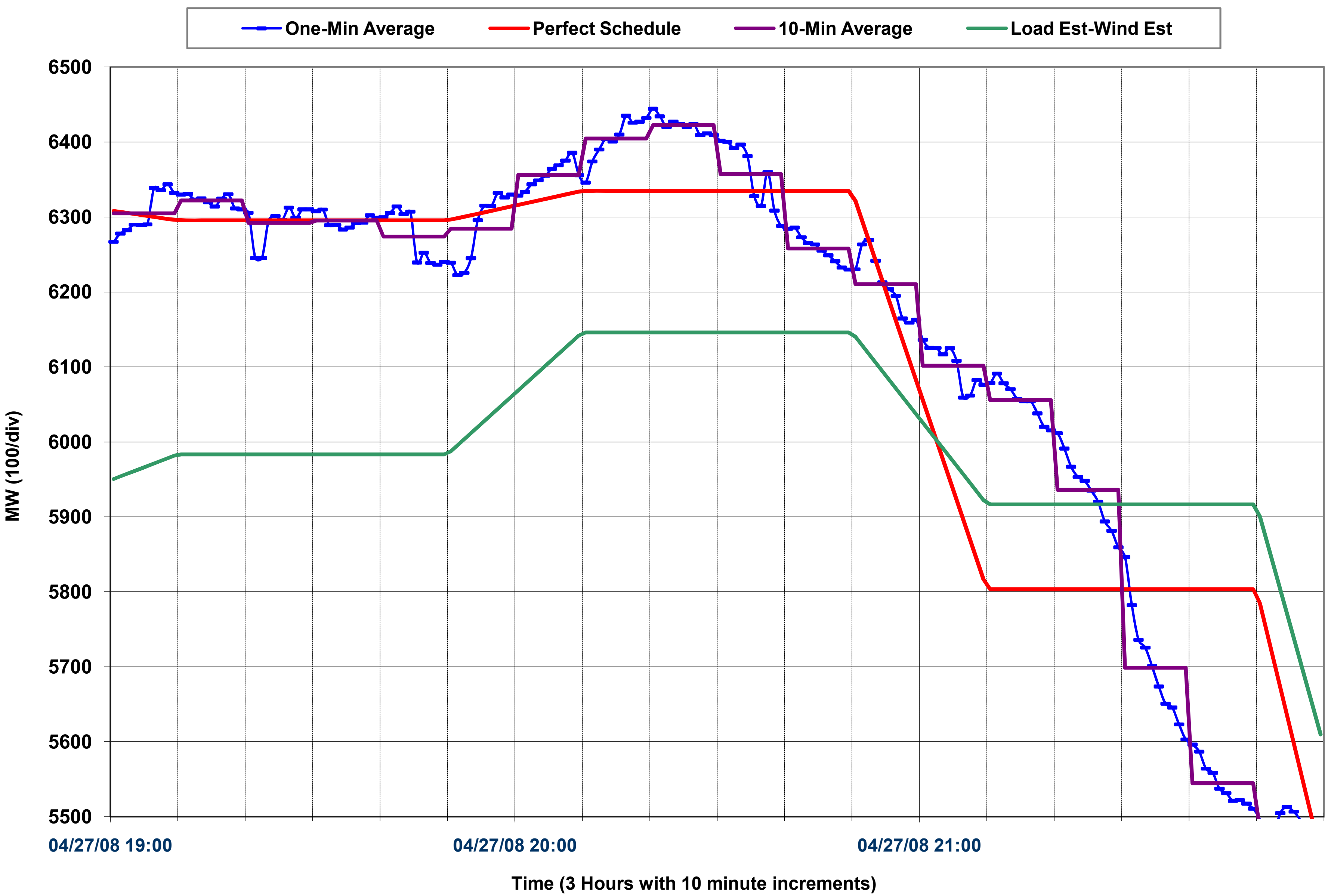


Table 2.4												
Total Reserve Requirement (Load Net Wind) 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY												
	A	B	C	D	E	F	G	H	I	J	K	L
1			Regulation		Following (PS)		Following (ES)		Following (Imb)		Total (Reg + ES)	
2	Date	Installed Capacity	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec
3	Oct-09	2111 MW	94.2	-98.8	251.0	-268.2	571.6	-703.2	320.6	-435.0	665.9	-802.1
4	Nov-09	2111 MW	94.2	-98.8	251.0	-268.2	571.6	-703.2	320.6	-435.0	665.9	-802.1
5	Dec-09	2111 MW	94.2	-98.8	251.0	-268.2	571.6	-703.2	320.6	-435.0	665.9	-802.1
6	Jan-10	2211 MW	95.5	-100.0	256.3	-273.7	598.5	-740.2	342.1	-466.5	693.9	-840.2
7	Feb-10	2402 MW	97.8	-102.1	266.5	-284.3	649.7	-810.9	383.2	-526.7	747.5	-913.1
8	Mar-10	2402 MW	97.8	-102.1	266.5	-284.3	649.7	-810.9	383.2	-526.7	747.5	-913.1
9	Apr-10	2515 MW	99.2	-103.4	272.5	-290.5	680.1	-852.7	407.6	-562.3	779.2	-956.2
10	May-10	2515 MW	99.2	-103.4	272.5	-290.5	680.1	-852.7	407.6	-562.3	779.2	-956.2
11	Jun-10	2515 MW	99.2	-103.4	272.5	-290.5	680.1	-852.7	407.6	-562.3	779.2	-956.2
12	Jul-10	2515 MW	99.2	-103.4	272.5	-290.5	680.1	-852.7	407.6	-562.3	779.2	-956.2
13	Aug-10	3198 MW	105.7	-110.1	305.5	-326.7	833.2	-1,086.3	527.7	-759.7	938.9	-1,196.4
14	Sep-10	3198 MW	105.7	-110.1	305.5	-326.7	833.2	-1,086.3	527.7	-759.7	938.9	-1,196.4
15	Oct-10	3515 MW	108.8	-113.1	320.8	-343.5	904.2	-1,194.8	583.4	-851.3	1,013.0	-1,307.9
16	Nov-10	3515 MW	108.8	-113.1	320.8	-343.5	904.2	-1,194.8	583.4	-851.3	1,013.0	-1,307.9
17	Dec-10	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
18	Jan-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
19	Feb-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
20	Mar-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
21	Apr-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
22	May-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
23	Jun-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
24	Jul-11	3593 MW	109.5	-113.9	324.6	-347.6	921.7	-1,221.5	597.1	-873.8	1,031.2	-1,335.4
25	Aug-11	3843 MW	112.1	-116.5	341.2	-360.5	977.1	-1,297.6	635.9	-937.1	1,089.2	-1,414.0
26	Sep-11	3843 MW	112.1	-116.5	341.2	-360.5	977.1	-1,297.6	635.9	-937.1	1,089.2	-1,414.0
27	Rate Period Average	3053 MW	104.2	-108.5	298.5	-318.8	797.3	-1,033.8	498.8	-715.0	901.5	-1,142.4

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (30 minute persistence forecast for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 2.5												
Wind Reserve 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY												
	A	B	C	D	E	F	G	H	I	J	K	L
1			Regulation		Following (PS)		Following (ES)		Following (Imb)		Total (Reg + ES)	
2	Date	Installed Capacity	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec
3	Oct-09	2111 MW	11.0	-10.4	67.6	-66.5	319.0	-467.9	251.4	-401.5	330.0	-478.3
4	Nov-09	2111 MW	11.0	-10.4	67.6	-66.5	319.0	-467.9	251.4	-401.5	330.0	-478.3
5	Dec-09	2111 MW	11.0	-10.4	67.6	-66.5	319.0	-467.9	251.4	-401.5	330.0	-478.3
6	Jan-10	2211 MW	11.9	-11.3	72.7	-72.3	348.6	-507.7	275.9	-435.4	360.6	-518.9
7	Feb-10	2402 MW	13.7	-13.0	82.4	-83.4	405.2	-583.5	322.8	-500.1	419.0	-596.5
8	Mar-10	2402 MW	13.7	-13.0	82.4	-83.4	405.2	-583.5	322.8	-500.1	419.0	-596.5
9	Apr-10	2515 MW	14.8	-14.0	88.1	-89.9	438.7	-628.4	350.6	-538.4	453.5	-642.4
10	May-10	2515 MW	14.8	-14.0	88.1	-89.9	438.7	-628.4	350.6	-538.4	453.5	-642.4
11	Jun-10	2515 MW	14.8	-14.0	88.1	-89.9	438.7	-628.4	350.6	-538.4	453.5	-642.4
12	Jul-10	2515 MW	14.8	-14.0	88.1	-89.9	438.7	-628.4	350.6	-538.4	453.5	-642.4
13	Aug-10	3198 MW	22.2	-21.3	119.9	-128.0	602.7	-872.4	482.9	-744.4	624.9	-893.7
14	Sep-10	3198 MW	22.2	-21.3	119.9	-128.0	602.7	-872.4	482.9	-744.4	624.9	-893.7
15	Oct-10	3515 MW	25.6	-24.7	134.6	-145.6	678.9	-985.7	544.3	-840.0	704.4	-1,010.4
16	Nov-10	3515 MW	25.6	-24.7	134.6	-145.6	678.9	-985.7	544.3	-840.0	704.4	-1,010.4
17	Dec-10	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
18	Jan-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
19	Feb-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
20	Mar-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
21	Apr-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
22	May-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
23	Jun-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
24	Jul-11	3593 MW	26.4	-25.6	138.2	-150.0	697.6	-1,013.5	559.4	-863.6	724.0	-1,039.1
25	Aug-11	3843 MW	30.0	-28.7	151.5	-160.0	760.8	-1,102.5	609.3	-942.5	790.8	-1,131.2
26	Sep-11	3843 MW	30.0	-28.7	151.5	-160.0	760.8	-1,102.5	609.3	-942.5	790.8	-1,131.2
27	Rate Period Average	3053 MW	20.8	-19.9	112.9	-119.4	564.0	-817.6	451.1	-698.2	584.8	-837.5

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (30 minute persistence forecast for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 2.6												
Load Reserve 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY												
	A	B	C	D	E	F	G	H	I	J	K	L
1			Regulation		Following (PS)		Following (ES)		Following (Imb)		Total (Reg + ES)	
2	Date	Installed Capacity	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec	Inc	Dec
3	Oct-09	2111 MW	83.3	-88.5	183.4	-201.8	252.6	-235.3	69.2	-33.5	335.9	-323.7
4	Nov-09	2111 MW	83.3	-88.5	183.4	-201.8	252.6	-235.3	69.2	-33.5	335.9	-323.7
5	Dec-09	2111 MW	83.3	-88.5	183.4	-201.8	252.6	-235.3	69.2	-33.5	335.9	-323.7
6	Jan-10	2211 MW	83.5	-88.7	183.7	-201.5	249.8	-232.6	66.2	-31.1	333.4	-321.3
7	Feb-10	2402 MW	84.0	-89.1	184.1	-200.9	244.5	-227.4	60.4	-26.5	328.6	-316.5
8	Mar-10	2402 MW	84.0	-89.1	184.1	-200.9	244.5	-227.4	60.4	-26.5	328.6	-316.5
9	Apr-10	2515 MW	84.3	-89.4	184.4	-200.5	241.4	-224.4	57.0	-23.8	325.7	-313.8
10	May-10	2515 MW	84.3	-89.4	184.4	-200.5	241.4	-224.4	57.0	-23.8	325.7	-313.8
11	Jun-10	2515 MW	84.3	-89.4	184.4	-200.5	241.4	-224.4	57.0	-23.8	325.7	-313.8
12	Jul-10	2515 MW	84.3	-89.4	184.4	-200.5	241.4	-224.4	57.0	-23.8	325.7	-313.8
13	Aug-10	3198 MW	83.6	-88.7	185.6	-198.7	230.4	-213.9	44.8	-15.2	314.0	-302.7
14	Sep-10	3198 MW	83.6	-88.7	185.6	-198.7	230.4	-213.9	44.8	-15.2	314.0	-302.7
15	Oct-10	3515 MW	83.2	-88.4	186.2	-197.9	225.3	-209.1	39.2	-11.2	308.6	-297.5
16	Nov-10	3515 MW	83.2	-88.4	186.2	-197.9	225.3	-209.1	39.2	-11.2	308.6	-297.5
17	Dec-10	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
18	Jan-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
19	Feb-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
20	Mar-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
21	Apr-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
22	May-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
23	Jun-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
24	Jul-11	3593 MW	83.1	-88.3	186.3	-197.7	224.1	-207.9	37.8	-10.3	307.2	-296.3
25	Aug-11	3843 MW	82.1	-87.8	189.7	-200.6	216.3	-195.1	26.6	5.5	298.4	-282.8
26	Sep-11	3843 MW	82.1	-87.8	189.7	-200.6	216.3	-195.1	26.6	5.5	298.4	-282.8
27	Rate Period Average	3053 MW	83.4	-88.6	185.5	-199.4	233.3	-216.3	47.7	-16.8	316.7	-304.9

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (30 minute persistence forecast for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 2.7												
Total Reserve Requirement (Load Net Wind) 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY												
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**
1			**Regulation**		**Following (PS)**		**Following (ES)**		**Following (Imb)**		**Total (Reg + ES)**	
2	**Date**	**Installed Capacity**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
3	Oct-09	2111 MW	94.2	-98.8	251.0	-268.2	635.7	-808.5	384.6	-540.3	729.9	-907.3
4	Nov-09	2111 MW	94.2	-98.8	251.0	-268.2	635.7	-808.5	384.6	-540.3	729.9	-907.3
5	Dec-09	2111 MW	94.2	-98.8	251.0	-268.2	635.7	-808.5	384.6	-540.3	729.9	-907.3
6	Jan-10	2211 MW	95.5	-100.0	256.3	-273.7	665.6	-855.3	409.2	-581.5	761.0	-955.2
7	Feb-10	2402 MW	97.8	-102.1	266.5	-284.3	722.7	-944.6	456.2	-660.4	820.4	-1,046.8
8	Mar-10	2402 MW	97.8	-102.1	266.5	-284.3	722.7	-944.6	456.2	-660.4	820.4	-1,046.8
9	Apr-10	2515 MW	99.2	-103.4	272.5	-290.5	756.4	-997.5	483.9	-707.0	855.6	-1,100.9
10	May-10	2515 MW	99.2	-103.4	272.5	-290.5	756.4	-997.5	483.9	-707.0	855.6	-1,100.9
11	Jun-10	2515 MW	99.2	-103.4	272.5	-290.5	756.4	-997.5	483.9	-707.0	855.6	-1,100.9
12	Jul-10	2515 MW	99.2	-103.4	272.5	-290.5	756.4	-997.5	483.9	-707.0	855.6	-1,100.9
13	Aug-10	3198 MW	105.7	-110.1	305.5	-326.7	938.8	-1,263.5	633.3	-936.9	1,044.5	-1,373.6
14	Sep-10	3198 MW	105.7	-110.1	305.5	-326.7	938.8	-1,263.5	633.3	-936.9	1,044.5	-1,373.6
15	Oct-10	3515 MW	108.8	-113.1	320.8	-343.5	1,023.4	-1,387.0	702.6	-1,043.5	1,132.2	-1,500.2
16	Nov-10	3515 MW	108.8	-113.1	320.8	-343.5	1,023.4	-1,387.0	702.6	-1,043.5	1,132.2	-1,500.2
17	Dec-10	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
18	Jan-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
19	Feb-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
20	Mar-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
21	Apr-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
22	May-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
23	Jun-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
24	Jul-11	3593 MW	109.5	-113.9	324.6	-347.6	1,044.3	-1,417.4	719.7	-1,069.8	1,153.8	-1,531.3
25	Aug-11	3843 MW	112.1	-116.5	341.2	-360.5	1,113.6	-1,515.5	772.5	-1,155.0	1,225.7	-1,631.9
26	Sep-11	3843 MW	112.1	-116.5	341.2	-360.5	1,113.6	-1,515.5	772.5	-1,155.0	1,225.7	-1,631.9
27	Rate Period Average	3053 MW	104.2	-108.5	298.5	-318.8	897.9	-1,201.3	599.4	-882.5	1,002.1	-1,309.8

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (45 minute persistence for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 2.8

Wind Reserve
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L
1			**Regulation**		**Following (PS)**		**Following (ES)**		**Following (Imb)**		**Total (Reg + ES)**	
2	**Date**	**Installed Capacity**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
3	Oct-09	2111 MW	11.0	-10.4	67.6	-66.5	397.2	-589.2	329.6	-522.7	408.2	-599.6
4	Nov-09	2111 MW	11.0	-10.4	67.6	-66.5	397.2	-589.2	329.6	-522.7	408.2	-599.6
5	Dec-09	2111 MW	11.0	-10.4	67.6	-66.5	397.2	-589.2	329.6	-522.7	408.2	-599.6
6	Jan-10	2211 MW	11.9	-11.3	72.7	-72.3	429.8	-639.6	357.1	-567.3	441.7	-650.8
7	Feb-10	2402 MW	13.7	-13.0	82.4	-83.4	492.0	-735.8	409.6	-652.4	505.7	-748.8
8	Mar-10	2402 MW	13.7	-13.0	82.4	-83.4	492.0	-735.8	409.6	-652.4	505.7	-748.8
9	Apr-10	2515 MW	14.8	-14.0	88.1	-89.9	528.8	-792.7	440.7	-702.8	543.6	-806.7
10	May-10	2515 MW	14.8	-14.0	88.1	-89.9	528.8	-792.7	440.7	-702.8	543.6	-806.7
11	Jun-10	2515 MW	14.8	-14.0	88.1	-89.9	528.8	-792.7	440.7	-702.8	543.6	-806.7
12	Jul-10	2515 MW	14.8	-14.0	88.1	-89.9	528.8	-792.7	440.7	-702.8	543.6	-806.7
13	Aug-10	3198 MW	22.2	-21.3	119.9	-128.0	726.1	-1,075.2	606.3	-947.3	748.3	-1,096.6
14	Sep-10	3198 MW	22.2	-21.3	119.9	-128.0	726.1	-1,075.2	606.3	-947.3	748.3	-1,096.6
15	Oct-10	3515 MW	25.6	-24.7	134.6	-145.6	817.7	-1,206.4	683.1	-1,060.7	843.3	-1,231.1
16	Nov-10	3515 MW	25.6	-24.7	134.6	-145.6	817.7	-1,206.4	683.1	-1,060.7	843.3	-1,231.1
17	Dec-10	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
18	Jan-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
19	Feb-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
20	Mar-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
21	Apr-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
22	May-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
23	Jun-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
24	Jul-11	3593 MW	26.4	-25.6	138.2	-150.0	840.3	-1,238.6	702.0	-1,088.7	866.7	-1,264.2
25	Aug-11	3843 MW	30.0	-28.7	151.5	-160.0	915.6	-1,346.8	764.1	-1,186.9	945.6	-1,375.5
26	Sep-11	3843 MW	30.0	-28.7	151.5	-160.0	915.6	-1,346.8	764.1	-1,186.9	945.6	-1,375.5
27	Rate Period Average	3053 MW	20.8	-19.9	112.9	-119.4	681.7	-1,009.0	568.8	-889.6	702.5	-1,028.9

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (45 minute persistence for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 2.9

Load Reserve
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L
1			**Regulation**		**Following (PS)**		**Following (ES)**		**Following (Imb)**		**Total (Reg + ES)**	
2	**Date**	**Installed Capacity**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**
3	Oct-09	2111 MW	83.3	-88.5	183.4	-201.8	238.4	-219.3	55.0	-17.5	321.7	-307.8
4	Nov-09	2111 MW	83.3	-88.5	183.4	-201.8	238.4	-219.3	55.0	-17.5	321.7	-307.8
5	Dec-09	2111 MW	83.3	-88.5	183.4	-201.8	238.4	-219.3	55.0	-17.5	321.7	-307.8
6	Jan-10	2211 MW	83.5	-88.7	183.7	-201.5	235.8	-215.7	52.1	-14.2	319.3	-304.4
7	Feb-10	2402 MW	84.0	-89.1	184.1	-200.9	230.7	-208.8	46.6	-7.9	314.7	-298.0
8	Mar-10	2402 MW	84.0	-89.1	184.1	-200.9	230.7	-208.8	46.6	-7.9	314.7	-298.0
9	Apr-10	2515 MW	84.3	-89.4	184.4	-200.5	227.6	-204.7	43.3	-4.2	312.0	-294.1
10	May-10	2515 MW	84.3	-89.4	184.4	-200.5	227.6	-204.7	43.3	-4.2	312.0	-294.1
11	Jun-10	2515 MW	84.3	-89.4	184.4	-200.5	227.6	-204.7	43.3	-4.2	312.0	-294.1
12	Jul-10	2515 MW	84.3	-89.4	184.4	-200.5	227.6	-204.7	43.3	-4.2	312.0	-294.1
13	Aug-10	3198 MW	83.6	-88.7	185.6	-198.7	212.7	-188.3	27.1	10.4	296.2	-277.0
14	Sep-10	3198 MW	83.6	-88.7	185.6	-198.7	212.7	-188.3	27.1	10.4	296.2	-277.0
15	Oct-10	3515 MW	83.2	-88.4	186.2	-197.9	205.7	-180.7	19.5	17.2	288.9	-269.1
16	Nov-10	3515 MW	83.2	-88.4	186.2	-197.9	205.7	-180.7	19.5	17.2	288.9	-269.1
17	Dec-10	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
18	Jan-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
19	Feb-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
20	Mar-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
21	Apr-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
22	May-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
23	Jun-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
24	Jul-11	3593 MW	83.1	-88.3	186.3	-197.7	204.0	-178.8	17.7	18.9	287.1	-267.1
25	Aug-11	3843 MW	82.1	-87.8	189.7	-200.6	198.1	-168.6	8.4	31.9	280.2	-256.4
26	Sep-11	3843 MW	82.1	-87.8	189.7	-200.6	198.1	-168.6	8.4	31.9	280.2	-256.4
27	Rate Period Average	3053 MW	83.4	-88.6	185.5	-199.4	216.2	-192.3	30.6	7.1	299.6	-280.9

- PS – based on a perfect schedule (hourly average ramped in over 20 minutes)
- ES – based on an estimated schedule (45 minute persistence for wind; scaled historical estimates for load)
- Imb – the delta, i.e. the increase in following due to imbalance (ES – PS)

Table 3.1

Adjustment for 1958 Capacity for FY 2010
30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Adjustment for 1958 Capacity 120 (MW)	Oct	Nov	Dec	Jan	Feb	Mar	1-Apr	16-Apr	May	Jun	Jul	1-Aug	16-Aug	Sep
	Hydro Resources														
1	Regulated Hydro	20,567.8	20,825.3	20,744.7	20,562.8	20,055.4	19,810.6	19,274.8	18,925.9	19,605.1	20,458.2	20,536.3	20,437.1	20,354.6	20,487.5
2	Albeni Falls	42.3	31.3	28.0	27.1	27.5	27.3	26.7	20.3	25.2	47.9	50.0	50.0	50.0	50.0
3	**Bonneville Hydro**	1,048.5	1,048.6	1,051.4	1,052.0	1,052.1	1,048.3	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.9	1,048.8
4	**Chief Joseph Hydro**	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0
5	Dworshak Hydro	445.3	445.3	445.4	445.5	445.8	445.7	445.8	445.8	446.5	449.1	449.3	447.7	446.5	445.8
6	**Grand Coulee Hydro**	6,359.3	6,630.4	6,553.9	6,400.7	5,919.0	5,690.2	5,265.8	4,965.7	5,501.7	6,295.2	6,365.7	6,271.5	6,192.6	6,277.9
7	Hungry Horse	405.4	400.0	394.2	387.3	380.6	375.5	298.9	301.0	397.9	417.6	419.1	416.1	414.0	410.9
8	**Ice Harbor Hydro**	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.7	692.8	692.8	692.8
9	**John Day Hydro**	2,484.0	2,484.0	2,484.0	2,483.9	2,483.9	2,483.9	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0
10	Libby	592.0	588.9	578.4	556.9	537.1	530.3	528.8	535.8	576.4	591.1	595.1	594.6	594.1	592.7
11	**Little Goose Hydro**	927.8	927.8	927.8	927.8	927.8	927.8	921.7	883.7	883.8	883.7	883.7	883.7	883.7	921.7
12	**Lower Granite Hydro**	912.0	917.7	930.3	930.3	930.3	930.3	917.7	912.0	912.0	912.0	912.0	912.0	912.0	912.0
13	**Lower Monumental Hydro**	922.4	922.5	922.5	922.5	922.5	922.5	914.9	907.1	907.1	907.1	907.0	907.0	907.0	914.9
14	**Mc Nary Hydro**	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0
15	**The Dalles Hydro**	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0
16	**BIG 10 (Sum of Bold)**	19,082.8	19,359.8	19,298.7	19,146.0	18,664.4	18,431.8	17,974.6	17,623.0	18,159.1	18,952.5	19,022.8	18,928.7	18,850.0	18,988.1
17	Independent Hydro	632.3	697.6	682.9	710.1	745.8	542.8	681.9	655.3	803.8	799.5	681.8	683.8	681.8	679.3
18	***Anderson Ranch***	39.6	39.8	39.4	38.7	37.8	36.4	34.9	34.9	40.0	40.0	40.0	40.0	40.0	40.0
19	Big Cliff	15.0	22.0	23.0	23.0	22.0	10.0	12.0	16.0	18.0	13.0	10.0	8.0	8.0	12.0
20	***Black Canyon***	9.7	5.9	7.1	8.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
21	***Boise River Diversion***	3.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
22	Bonneville Fishway	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
23	Chandler	8.3	12.6	13.0	13.0	13.0	13.0	10.0	10.0	8.4	8.1	4.6	5.2	5.2	4.1
24	Cougar	28.5	28.8	24.0	25.0	29.0	8.2	30.0	26.3	30.0	20.9	10.6	20.0	21.0	27.7
25	***Cowlitz Falls***	14.2	15.7	34.5	39.4	48.0	24.4	38.4	57.0	60.1	35.9	14.9	10.2	10.2	13.4
26	Detroit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
27	Dexter	16.0	18.0	18.0	19.0	19.0	8.0	17.0	10.8	11.5	14.0	6.0	9.7	10.8	8.0
28	Foster	10.1	14.0	18.0	19.0	21.0	9.0	19.3	23.0	15.0	9.1	7.0	7.0	7.0	12.5
29	Green Peter	62.0	79.0	93.0	88.0	89.0	48.0	69.0	92.0	60.0	40.0	60.0	71.0	76.0	86.0
30	***Green Springs - USBR***	17.1	18.0	18.3	18.9	18.7	18.5	18.3	18.3	17.6	17.2	16.4	16.2	16.2	15.1
31	Hills Creek	29.0	36.0	31.0	32.0	33.0	9.0	9.0	28.0	33.0	31.2	13.0	10.0	10.0	28.0
32	***Idaho Falls - City Plant***	2.6	4.1	4.4	4.5	5.0	4.9	6.1	6.1	6.7	7.1	7.1	5.9	5.9	4.7
33	***Idaho Falls - Lower Plant***	2.7	4.3	4.6	4.7	5.3	5.2	6.4	6.4	7.4	7.7	7.5	6.1	6.1	4.9
34	***Idaho Falls - Upper Plant***	2.8	4.5	4.7	4.9	5.4	5.3	6.4	6.4	7.3	7.4	7.3	6.2	6.2	5.0
35	Lookout Point	124.0	131.0	99.0	132.0	137.0	82.0	143.0	58.0	84.0	143.0	74.0	89.0	92.0	73.0
36	***Lost Creek***	52.0	51.0	50.0	50.0	53.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	55.0
37	***Minidoka***	13.5	20.8	18.1	18.3	23.2	23.4	30.3	30.3	30.5	30.5	30.5	30.5	30.5	28.7
38	***Packwood***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	***Palisades***	52.9	63.4	52.3	37.2	36.0	31.1	25.4	25.4	168.0	168.0	166.4	142.4	130.3	123.7
40	Roza	4.8	4.3	6.0	6.2	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	0.0
41	**Excluded Independent Hydro Projects for Reserve Calc. (Sum of Bold Italic)**	210.1	227.4	233.4	228.4	245.4	218.2	235.2	253.8	406.5	382.8	359.2	326.5	314.4	303.5
42	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)	-12,494.6	-11,538.4	-10,739.7	-9,363.3	-6,653.5	-8,026.8	-8,667.1	-6,201.0	-5,440.6	-6,715.2	-8,852.1	-11,403.0	-13,159.9	-12,920.5

1/ Source of information is the Loads and Resources Study under 1958 Water [59] for the WP-10 Final Study

Table 3.2

Adjustment for 1958 Capacity for FY 2011

30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Line	**Adjustment for 1958 Capacity 120 (MW)**	Oct	Nov	Dec	Jan	Feb	Mar	1-Apr	16-Apr	May	Jun	Jul	1-Aug	16-Aug	Sep
	Hydro Resources														
1	Regulated Hydro	20,567.8	20,825.3	20,744.7	20,562.8	20,055.4	19,810.6	19,274.8	18,925.9	19,605.1	20,458.2	20,536.3	20,437.1	20,354.6	20,487.5
2	Albeni Falls	42.3	31.3	28.0	27.1	27.5	27.3	26.7	20.3	25.2	47.9	50.0	50.0	50.0	50.0
3	**Bonneville Hydro**	1,048.5	1,048.6	1,051.4	1,052.0	1,052.1	1,048.3	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.9	1,048.8
4	**Chief Joseph Hydro**	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0
5	Dworshak Hydro	445.3	445.3	445.4	445.5	445.8	445.7	445.8	445.8	446.5	449.1	449.3	447.7	446.5	445.8
6	**Grand Coulee Hydro**	6,359.3	6,630.4	6,553.9	6,400.7	5,919.0	5,690.2	5,265.8	4,965.7	5,501.7	6,295.2	6,365.7	6,271.5	6,192.6	6,277.9
7	Hungry Horse	405.4	400.0	394.2	387.3	380.6	375.5	298.9	301.0	397.9	417.6	419.1	416.1	414.0	410.9
8	**Ice Harbor Hydro**	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.7	692.8	692.8	692.8
9	**John Day Hydro**	2,484.0	2,484.0	2,484.0	2,483.9	2,483.9	2,483.9	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0
10	Libby	592.0	588.9	578.4	556.9	537.1	530.3	528.8	535.8	576.4	591.1	595.1	594.6	594.1	592.7
11	**Little Goose Hydro**	927.8	927.8	927.8	927.8	927.8	927.8	921.7	883.7	883.8	883.7	883.7	883.7	883.7	921.7
12	**Lower Granite Hydro**	912.0	917.7	930.3	930.3	930.3	930.3	917.7	912.0	912.0	912.0	912.0	912.0	912.0	912.0
13	**Lower Monumental Hydro**	922.4	922.5	922.5	922.5	922.5	922.5	914.9	907.1	907.1	907.1	907.0	907.0	907.0	914.9
14	**Mc Nary Hydro**	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0
15	**The Dalles Hydro**	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0
16	**BIG 10 (Sum of Bold)**	19,082.8	19,359.8	19,298.7	19,146.0	18,664.4	18,431.8	17,974.6	17,623.0	18,159.1	18,952.5	19,022.8	18,928.7	18,850.0	18,988.1
17	Independent Hydro	632.3	697.6	682.9	710.1	745.8	542.8	681.9	655.3	803.8	799.5	681.8	683.8	681.8	679.3
18	***Anderson Ranch***	39.6	39.8	39.4	38.7	37.8	36.4	34.9	34.9	40.0	40.0	40.0	40.0	40.0	40.0
19	Big Cliff	15.0	22.0	23.0	23.0	22.0	10.0	12.0	16.0	18.0	13.0	10.0	8.0	8.0	12.0
20	***Black Canyon***	9.7	5.9	7.1	8.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
21	***Boise River Diversion***	3.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
22	Bonneville Fishway	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
23	Chandler	8.3	12.6	13.0	13.0	13.0	13.0	10.0	10.0	8.4	8.1	4.6	5.2	5.2	4.1
24	Cougar	28.5	28.8	24.0	25.0	29.0	8.2	30.0	26.3	30.0	20.9	10.6	20.0	21.0	27.7
25	***Cowlitz Falls***	14.2	15.7	34.5	39.4	48.0	24.4	38.4	57.0	60.1	35.9	14.9	10.2	10.2	13.4
26	Detroit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
27	Dexter	16.0	18.0	18.0	19.0	19.0	8.0	17.0	10.8	11.5	14.0	6.0	9.7	10.8	8.0
28	Foster	10.1	14.0	18.0	19.0	21.0	9.0	19.3	23.0	15.0	9.1	7.0	7.0	7.0	12.5
29	Green Peter	62.0	79.0	93.0	88.0	89.0	48.0	69.0	92.0	60.0	40.0	60.0	71.0	76.0	86.0
30	***Green Springs - USBR***	17.1	18.0	18.3	18.9	18.7	18.5	18.3	18.3	17.6	17.2	16.4	16.2	16.2	15.1
31	Hills Creek	29.0	36.0	31.0	32.0	33.0	9.0	9.0	28.0	33.0	31.2	13.0	10.0	10.0	28.0
32	***Idaho Falls - City Plant***	2.6	4.1	4.4	4.5	5.0	4.9	6.1	6.1	6.7	7.1	7.1	5.9	5.9	4.7
33	***Idaho Falls - Lower Plant***	2.7	4.3	4.6	4.7	5.3	5.2	6.4	6.4	7.4	7.7	7.5	6.1	6.1	4.9
34	***Idaho Falls - Upper Plant***	2.8	4.5	4.7	4.9	5.4	5.3	6.4	6.4	7.3	7.4	7.3	6.2	6.2	5.0
35	Lookout Point	124.0	131.0	99.0	132.0	137.0	82.0	143.0	58.0	84.0	143.0	74.0	89.0	92.0	73.0
36	***Lost Creek***	52.0	51.0	50.0	50.0	53.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	55.0
37	***Minidoka***	13.5	20.8	18.1	18.3	23.2	23.4	30.3	30.3	30.5	30.5	30.5	30.5	30.5	28.7
38	***Packwood***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	***Palisades***	52.9	63.4	52.3	37.2	36.0	31.1	25.4	25.4	168.0	168.0	166.4	142.4	130.3	123.7
40	Roza	4.8	4.3	6.0	6.2	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	0.0
41	**Excluded Independent Hydro Projects for Reserve Calc. (Sum of Bold Italic)**	210.1	227.4	233.4	228.4	245.4	218.2	235.2	253.8	406.5	382.8	359.2	326.5	314.4	303.5
42	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)	-12,675.0	-11,662.5	-10,842.3	-9,387.8	-6,776.3	-7,975.5	-8,739.6	-6,205.2	-5,459.2	-6,313.3	-8,994.2	-11,393.8	-13,220.4	-13,043.1

1/ Source of information is the Loads and Resources Study under 1958 Water [59] for the WP-10 Final Study

Table 3.3				
Load and Wind Reserve Amounts Used as Inputs to HOSS 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY				
Load + -Wind				
	A	**B**	**C**	**D**
1	**Date**	**Installed Capacity (MW)**	**Total Inc**	**Total Dec**
2	10/1/2009	2111	665.9	-802.1
3	11/1/2009	2111	665.9	-802.1
4	12/1/2009	2111	665.9	-802.1
5	1/1/2010	2111	693.9	-840.2
6	2/1/2010	2402	747.5	-913.1
7	3/1/2010	2402	747.5	-913.1
8	4/1/2010	2515	779.2	-956.2
9	5/1/2010	2515	779.2	-956.2
10	6/1/2010	2515	779.2	-956.2
11	7/1/2010	2515	779.2	-956.2
12	8/1/2010	3198	938.9	-1196.4
13	9/1/2010	3198	938.9	-1196.4
14	10/1/2010	3515	1013	-1307.9
15	11/1/2010	3515	1013	-1307.9
16	12/1/2010	3593	1031.2	-1335.4
17	1/1/2011	3593	1031.2	-1335.4
18	2/1/2011	3593	1031.2	-1335.4
19	3/1/2011	3593	1031.2	-1335.4
20	4/1/2011	3593	1031.2	-1335.4
21	5/1/2011	3593	1031.2	-1335.4
22	6/1/2011	3593	1031.2	-1335.4
23	7/1/2011	3593	1031.2	-1335.4
24	8/1/2011	3843	1089.2	-1414
25	9/1/2011	3843	1089.2	-1414

Table 3.4																
Calculation of System Available for Reserves - Average of FY 2010 and FY 2011 **30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY**																
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**	**P**
Line		**Annual Average**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
1	Total Capacity prior to Deductions to Determine Big 10 as % of Total (Line 4 + Line 5 + Line 6)		20,990	21,296	21,195	21,045	20,556	20,136	19,722	19,327	20,002	20,875	20,859	20,794	20,723	20,862
2	BIG 10 Capacity		19,083	19,360	19,299	19,146	18,664	18,432	17,975	17,623	18,159	18,953	19,023	18,929	18,850	18,988
3	BIG 10 as percent of total (Line 1 / Line 2)	**91%**	91%	91%	91%	91%	91%	92%	91%	91%	91%	91%	91%	91%	91%	91%
	Hydro Resources		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
4	Regulated Hydro		20,568	20,825	20,745	20,563	20,055	19,811	19,275	18,926	19,605	20,458	20,536	20,437	20,355	20,487
5	Independent Hydro		632	698	683	710	746	543	682	655	804	800	682	684	682	679
6	Independent Excluded		-210	-227	-233	-228	-245	-218	-235	-254	-407	-383	-359	-327	-314	-304
	Reserves & Maintenance		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
7	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)		-12,585	-11,600	-10,791	-9,376	-6,715	-8,001	-8,703	-6,203	-5,450	-6,514	-8,923	-11,398	-13,190	-12,982
8	Total System Available for Reserves (Line 4 + Line 5 + Line 6 + Line 7)		8,405	9,696	10,404	11,669	13,841	12,135	11,019	13,124	14,552	14,361	11,936	9,396	7,533	7,880
9	Federal Trans. Losses @ 3.35% (Line 8 * 3.35%)	3.35%	-282	-325	-349	-391	-464	-407	-369	-440	-487	-481	-400	-315	-252	-264
10	Total System Available for Reserves net Losses (line 8 + Line 9)		8,123	9,371	10,055	11,278	13,377	11,728	10,650	12,684	14,065	13,880	11,536	9,081	7,281	7,616
	Total 12 Months	**Annual Average**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr (ave of 1-Apr and 16-Apr)**	**May**	**Jun**	**Jul**	**Aug (ave of 1-Aug and 16-Aug)**	**Sep**		
11	Regulated Hydro (Line 4)		20,568	20,825	20,745	20,563	20,055	19,811	19,101	19,605	20,458	20,536	20,396	20,487		
12	Independent Hydro (Line 5)		632	698	683	710	746	543	669	804	800	682	683	679		
13	Independent Excluded (Line 6)	-282	-210	-227	-233	-228	-245	-218	-245	-407	-383	-359	-321	-304		
14	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj) (Line 7)		-12,585	-11,600	-10,791	-9,376	-6,715	-8,001	-7,453	-5,450	-6,514	-8,923	-12,294	-12,982		
15	Federal Trans. Losses (Line 9)		-282	-325	-349	-391	-464	-407	-405	-487	-481	-400	-284	-264		
16	Total 12 Month Period (Line 11 + Line 12 + Line 13 + Line 14 + Line 15)	**10,906**	8,123	9,371	10,055	11,278	13,377	11,728	11,667	14,065	13,880	11,536	8,180	7,616		

Table 3.5		
Independent Hydro Projects Excluded from Generation Inputs for Reserve Cost Allocation		
	A	**B**
1	**Independent Hydro:**	**Excluded Projects:**
2	Anderson Ranch	Anderson Ranch
3	Big Cliff	
4	Black Canyon	Black Canyon
5	Boise River Diversion	Boise River Diversion
6	Bonneville Fishway	
7	Chandler	
8	Cougar	
9	Cowlitz Falls	Cowlitz Falls
10	Detroit	
11	Dexter	
12	Foster	
13	Green Peter	
14	Green Springs - USBR	Green Springs - USBR
15	Hills Creek	
16	Idaho Falls - City Plant	Idaho Falls - City Plant
17	Idaho Falls - Lower Plant	Idaho Falls - Lower Plant
18	Idaho Falls - Upper Plant	Idaho Falls - Upper Plant
19	Lookout Point	
20	Lost Creek	Lost Creek
21	Minidoka	Minidoka
22	Packwood	Packwood
23	Palisades	Palisades
24	Roza	

Table 3.6

Regulating Reserve
Power Revenue Requirement Associated with
Big Ten Hydroelectric Projects and Fish and Wildlife

($ thousands)

	A	B	C	D
		FY 2010	**FY 2011**	**Annual Average of FY 2010 - FY 2011**
1	**Big 10 Dams**			
2	O&M	190,624	198,930	194,777
3	Depreciation	70,178	71,478	70,828
4	Net Interest	80,529	81,738	81,134
5	Minimum Required Net Revenues	26,074	21,935	24,005
6	Subtotal	367,405	374,081	370,743
7	**Fish & Wildlife**			
8	O&M	265,892	286,181	276,037
9	Amortization/Depreciation	37,331	40,910	39,121
10	Net Interest	43,253	48,896	46,075
11	Minimum Required Net Revenues	14,005	13,121	13,563
12	Subtotal	360,481	389,109	374,795
13	**A&G Expense 1/**	85,464	87,265	86,365
14	**Total Revenue Requirement**	813,350	850,455	831,903
15	**Revenue Credits:**			
16	4h10C (non-operations)	57,835	60,067	58,951
17	Colville Payment Treasury Credit	4,600	4,600	4,600
18	Synchronous Condensing	329	319	324
19	**Net Revenue Requirement**	750,586	785,469	768,028

1/ Power Marketing Sales & Support, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

Table 3.7		
Embedded Cost Calculation for Regulating Reserve and Wind Balancing Reserve **30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY**		
	A	**B**
		Annual Average of FY 2010-FY 2011
	Reserve Assumptions	
1	Regulated + Independent Hydro (MW)	10,906
2	Regulating Reserve (MW)	83
3	Operating Reserve less Operating Reserve on rest of System (MW) 1/	375
4	Following Capacity (MW)	216
5	Wind Balancing Reserve (MW)	585
	Forecast of Hydro Capacity System Uses	
	Big 10 is 91% of Total	
6	Hydro Projects Capacity (Line 1 * 91%)	9,924
7	Total PS Reserve Obligation (Line 2+3+4+5)	1,259
8	Hydro Project Capacity System Uses (Line 6+7)	11,183
	Adjusted Revenue Requirement	
9	Power Revenue Requirement for Hydro Projects	$ 768,028,000
10	Hydro Project Capacity System Uses (Line 8)	11,183
11	Total kW/month/year Hydro Project Capacity (Line 10 * 12 months * 1000kW/MW)	134,201,520
12	Per Unit Allocation $/kW/month (Line 9 / Line 11)	$ 5.72
	Revenue Forecast by Product	
13	Regulating Reserve (Line 2 * 12 months * 1000 kW/MW * Line 12)	$ 5,697,120
14	Wind Balancing Reserve (Line 5 * 12 months * 1000 kW/MW * Line 12)	$ 40,154,400

1/ The 393 MW for Operating Reserve is adjusted to account for 9% of the Non-Spinning portion (half of the total Operating Reserve) being supplied by the rest of the system.

Table 3.8

Adjustment for 1958 Capacity for FY 2010
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Adjustment for 1958 Capacity 120 (MW)	Oct	Nov	Dec	Jan	Feb	Mar	1-Apr	16-Apr	May	Jun	Jul	1-Aug	16-Aug	Sep
	Hydro Resources														
1	Regulated Hydro	20,567.8	20,825.3	20,744.7	20,562.8	20,055.4	19,810.6	19,274.8	18,925.9	19,605.1	20,458.2	20,536.3	20,437.1	20,354.6	20,487.5
2	Albeni Falls	42.3	31.3	28.0	27.1	27.5	27.3	26.7	20.3	25.2	47.9	50.0	50.0	50.0	50.0
3	**Bonneville Hydro**	1,048.5	1,048.6	1,051.4	1,052.0	1,052.1	1,048.3	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.9	1,048.8
4	**Chief Joseph Hydro**	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0
5	Dworshak Hydro	445.3	445.3	445.4	445.5	445.8	445.7	445.8	445.8	446.5	449.1	449.3	447.7	446.5	445.8
6	**Grand Coulee Hydro**	6,359.3	6,630.4	6,553.9	6,400.7	5,919.0	5,690.2	5,265.8	4,965.7	5,501.7	6,295.2	6,365.7	6,271.5	6,192.6	6,277.9
7	Hungry Horse	405.4	400.0	394.2	387.3	380.6	375.5	298.9	301.0	397.9	417.6	419.1	416.1	414.0	410.9
8	**Ice Harbor Hydro**	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.7	692.8	692.8	692.8
9	**John Day Hydro**	2,484.0	2,484.0	2,484.0	2,483.9	2,483.9	2,483.9	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0
10	Libby	592.0	588.9	578.4	556.9	537.1	530.3	528.8	535.8	576.4	591.1	595.1	594.6	594.1	592.7
11	**Little Goose Hydro**	927.8	927.8	927.8	927.8	927.8	927.8	921.7	883.7	883.8	883.7	883.7	883.7	883.7	921.7
12	**Lower Granite Hydro**	912.0	917.7	930.3	930.3	930.3	930.3	917.7	912.0	912.0	912.0	912.0	912.0	912.0	912.0
13	**Lower Monumental Hydro**	922.4	922.5	922.5	922.5	922.5	922.5	914.9	907.1	907.1	907.1	907.0	907.0	907.0	914.9
14	**Mc Nary Hydro**	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0
15	**The Dalles Hydro**	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0
16	**BIG 10 (Sum of Bold)**	19,082.8	19,359.8	19,298.7	19,146.0	18,664.4	18,431.8	17,974.6	17,623.0	18,159.1	18,952.5	19,022.8	18,928.7	18,850.0	18,988.1
17	Independent Hydro	632.3	697.6	682.9	710.1	745.8	542.8	681.9	655.3	803.8	799.5	681.8	683.8	681.8	679.3
18	***Anderson Ranch***	39.6	39.8	39.4	38.7	37.8	36.4	34.9	34.9	40.0	40.0	40.0	40.0	40.0	40.0
19	Big Cliff	15.0	22.0	23.0	23.0	22.0	10.0	12.0	16.0	18.0	13.0	10.0	8.0	8.0	12.0
20	***Black Canyon***	9.7	5.9	7.1	8.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
21	***Boise River Diversion***	3.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
22	Bonneville Fishway	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
23	Chandler	8.3	12.6	13.0	13.0	13.0	13.0	10.0	10.0	8.4	8.1	4.6	5.2	5.2	4.1
24	Cougar	28.5	28.8	24.0	25.0	29.0	8.2	30.0	26.3	30.0	20.9	10.6	20.0	21.0	27.7
25	***Cowlitz Falls***	14.2	15.7	34.5	39.4	48.0	24.4	38.4	57.0	60.1	35.9	14.9	10.2	10.2	13.4
26	Detroit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
27	Dexter	16.0	18.0	18.0	19.0	19.0	8.0	17.0	10.8	11.5	14.0	6.0	9.7	10.8	8.0
28	Foster	10.1	14.0	18.0	19.0	21.0	9.0	19.3	23.0	15.0	9.1	7.0	7.0	7.0	12.5
29	Green Peter	62.0	79.0	93.0	88.0	89.0	48.0	69.0	92.0	60.0	40.0	60.0	71.0	76.0	86.0
30	***Green Springs - USBR***	17.1	18.0	18.3	18.9	18.7	18.5	18.3	18.3	17.6	17.2	16.4	16.2	16.2	15.1
31	Hills Creek	29.0	36.0	31.0	32.0	33.0	9.0	9.0	28.0	33.0	31.2	13.0	10.0	10.0	28.0
32	***Idaho Falls - City Plant***	2.6	4.1	4.4	4.5	5.0	4.9	6.1	6.1	6.7	7.1	7.1	5.9	5.9	4.7
33	***Idaho Falls - Lower Plant***	2.7	4.3	4.6	4.7	5.3	5.2	6.4	6.4	7.4	7.7	7.5	6.1	6.1	4.9
34	***Idaho Falls - Upper Plant***	2.8	4.5	4.7	4.9	5.4	5.3	6.4	6.4	7.3	7.4	7.3	6.2	6.2	5.0
35	Lookout Point	124.0	131.0	99.0	132.0	137.0	82.0	143.0	58.0	84.0	143.0	74.0	89.0	92.0	73.0
36	***Lost Creek***	52.0	51.0	50.0	50.0	53.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	55.0
37	***Minidoka***	13.5	20.8	18.1	18.3	23.2	23.4	30.3	30.3	30.5	30.5	30.5	30.5	30.5	28.7
38	***Packwood***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	***Palisades***	52.9	63.4	52.3	37.2	36.0	31.1	25.4	25.4	168.0	168.0	166.4	142.4	130.3	123.7
40	Roza	4.8	4.3	6.0	6.2	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	0.0
41	**Excluded Independent Hydro Projects for Reserve Calc. (Sum of Bold Italic)**	210.1	227.4	233.4	228.4	245.4	218.2	235.2	253.8	406.5	382.8	359.2	326.5	314.4	303.5
42	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)	-12,528.9	-11,559.3	-10,751.7	-9,377.3	-6,656.4	-8,033.3	-8,691.5	-6,221.2	-5,495.8	-6,752.7	-8,911.6	-11,451.5	-13,238.6	-13,006.3

1/ Source of information is the Loads and Resources Study under 1958 Water [59] for the WP-10 Final Study

	Table 3.9													
	Adjustment for 1958 Capacity for FY 2011													
	45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY													
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**	**N**	**O**
Line	**Adjustment for 1958 Capacity 120 (MW)**	Oct	Nov	Dec	Jan	Feb	Mar	1-Apr	16-Apr	May	Jun	Jul	1-Aug	16-Aug	Sep
	Hydro Resources														
1	Regulated Hydro	20,567.8	20,825.3	20,744.7	20,562.8	20,055.4	19,810.6	19,274.8	18,925.9	19,605.1	20,458.2	20,536.3	20,437.1	20,354.6	20,487.5
2	Albeni Falls	42.3	31.3	28.0	27.1	27.5	27.3	26.7	20.3	25.2	47.9	50.0	50.0	50.0	50.0
3	**Bonneville Hydro**	1,048.5	1,048.6	1,051.4	1,052.0	1,052.1	1,048.3	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.7	1,041.9	1,048.8
4	**Chief Joseph Hydro**	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0	2,535.0
5	Dworshak Hydro	445.3	445.3	445.4	445.5	445.8	445.7	445.8	445.8	446.5	449.1	449.3	447.7	446.5	445.8
6	**Grand Coulee Hydro**	6,359.3	6,630.4	6,553.9	6,400.7	5,919.0	5,690.2	5,265.8	4,965.7	5,501.7	6,295.2	6,365.7	6,271.5	6,192.6	6,277.9
7	Hungry Horse	405.4	400.0	394.2	387.3	380.6	375.5	298.9	301.0	397.9	417.6	419.1	416.1	414.0	410.9
8	**Ice Harbor Hydro**	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.8	692.7	692.8	692.8	692.8
9	**John Day Hydro**	2,484.0	2,484.0	2,484.0	2,483.9	2,483.9	2,483.9	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0	2,484.0
10	Libby	592.0	588.9	578.4	556.9	537.1	530.3	528.8	535.8	576.4	591.1	595.1	594.6	594.1	592.7
11	**Little Goose Hydro**	927.8	927.8	927.8	927.8	927.8	927.8	921.7	883.7	883.8	883.7	883.7	883.7	883.7	921.7
12	**Lower Granite Hydro**	912.0	917.7	930.3	930.3	930.3	930.3	917.7	912.0	912.0	912.0	912.0	912.0	912.0	912.0
13	**Lower Monumental Hydro**	922.4	922.5	922.5	922.5	922.5	922.5	914.9	907.1	907.1	907.1	907.0	907.0	907.0	914.9
14	**Mc Nary Hydro**	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0	1,127.0
15	**The Dalles Hydro**	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0	2,074.0
16	**BIG 10 (Sum of Bold)**	19,082.8	19,359.8	19,298.7	19,146.0	18,664.4	18,431.8	17,974.6	17,623.0	18,159.1	18,952.5	19,022.8	18,928.7	18,850.0	18,988.1
17	Independent Hydro	632.3	697.6	682.9	710.1	745.8	542.8	681.9	655.3	803.8	799.5	681.8	683.8	681.8	679.3
18	***Anderson Ranch***	39.6	39.8	39.4	38.7	37.8	36.4	34.9	34.9	40.0	40.0	40.0	40.0	40.0	40.0
19	Big Cliff	15.0	22.0	23.0	23.0	22.0	10.0	12.0	16.0	18.0	13.0	10.0	8.0	8.0	12.0
20	***Black Canyon***	9.7	5.9	7.1	8.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
21	***Boise River Diversion***	3.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
22	Bonneville Fishway	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
23	Chandler	8.3	12.6	13.0	13.0	13.0	13.0	10.0	10.0	8.4	8.1	4.6	5.2	5.2	4.1
24	Cougar	28.5	28.8	24.0	25.0	29.0	8.2	30.0	26.3	30.0	20.9	10.6	20.0	21.0	27.7
25	***Cowlitz Falls***	14.2	15.7	34.5	39.4	48.0	24.4	38.4	57.0	60.1	35.9	14.9	10.2	10.2	13.4
26	Detroit	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
27	Dexter	16.0	18.0	18.0	19.0	19.0	8.0	17.0	10.8	11.5	14.0	6.0	9.7	10.8	8.0
28	Foster	10.1	14.0	18.0	19.0	21.0	9.0	19.3	23.0	15.0	9.1	7.0	7.0	7.0	12.5
29	Green Peter	62.0	79.0	93.0	88.0	89.0	48.0	69.0	92.0	60.0	40.0	60.0	71.0	76.0	86.0
30	***Green Springs - USBR***	17.1	18.0	18.3	18.9	18.7	18.5	18.3	18.3	17.6	17.2	16.4	16.2	16.2	15.1
31	Hills Creek	29.0	36.0	31.0	32.0	33.0	9.0	9.0	28.0	33.0	31.2	13.0	10.0	10.0	28.0
32	***Idaho Falls - City Plant***	2.6	4.1	4.4	4.5	5.0	4.9	6.1	6.1	6.7	7.1	7.1	5.9	5.9	4.7
33	***Idaho Falls - Lower Plant***	2.7	4.3	4.6	4.7	5.3	5.2	6.4	6.4	7.4	7.7	7.5	6.1	6.1	4.9
34	***Idaho Falls - Upper Plant***	2.8	4.5	4.7	4.9	5.4	5.3	6.4	6.4	7.3	7.4	7.3	6.2	6.2	5.0
35	Lookout Point	124.0	131.0	99.0	132.0	137.0	82.0	143.0	58.0	84.0	143.0	74.0	89.0	92.0	73.0
36	***Lost Creek***	52.0	51.0	50.0	50.0	53.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	56.0	55.0
37	***Minidoka***	13.5	20.8	18.1	18.3	23.2	23.4	30.3	30.3	30.5	30.5	30.5	30.5	30.5	28.7
38	***Packwood***	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	***Palisades***	52.9	63.4	52.3	37.2	36.0	31.1	25.4	25.4	168.0	168.0	166.4	142.4	130.3	123.7
40	Roza	4.8	4.3	6.0	6.2	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	0.0
41	**Excluded Independent Hydro Projects for Reserve Calc. (Sum of Bold Italic)**	210.1	227.4	233.4	228.4	245.4	218.2	235.2	253.8	406.5	382.8	359.2	326.5	314.4	303.5
42	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)	-12,764.8	-11,721.4	-10,869.9	-9,427.9	-6,790.7	-7,992.0	-8,769.4	-6,231.0	-5,542.6	-6,392.1	-9,092.7	-11,463.3	-13,334.2	-13,132.6

1/ Source of information is the Loads and Resources Study under 1958 Water [59] for the WP-10 Final Study

Table 3.10

Load and Wind Reserve Amounts Used as Inputs to HOSS 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

Load + -Wind

	A	B	C	D
1	Date	Installed Capacity (MW)	Total Inc	Total Dec
2	10/1/2009	2111	729.9	-907.3
3	11/1/2009	2111	729.9	-907.3
4	12/1/2009	2111	729.9	-907.3
5	1/1/2010	2211	761	-955.2
6	2/1/2010	2402	820.4	-1046.8
7	3/1/2010	2402	820.4	-1046.8
8	4/1/2010	2515	855.6	-1100.9
9	5/1/2010	2515	855.6	-1100.9
10	6/1/2010	2515	855.6	-1100.9
11	7/1/2010	2515	855.6	-1100.9
12	8/1/2010	3198	1044.5	-1373.6
13	9/1/2010	3198	1044.5	-1373.6
14	10/1/2010	3515	1132.2	-1500.2
15	11/1/2010	3515	1132.2	-1500.2
16	12/1/2010	3593	1153.8	-1531.3
17	1/1/2011	3593	1153.8	-1531.3
18	2/1/2011	3593	1153.8	-1531.3
19	3/1/2011	3593	1153.8	-1531.3
20	4/1/2011	3593	1153.8	-1531.3
21	5/1/2011	3593	1153.8	-1531.3
22	6/1/2011	3593	1153.8	-1531.3
23	7/1/2011	3593	1153.8	-1531.3
24	8/1/2011	3843	1225.7	-1631.9
25	9/1/2011	3843	1225.7	-1631.9

Table 3.11

Calculation of System Available for Reserves - Average of FY 2010 and FY 2011
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Line		**Annual Average**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
1	Total Capacity prior to Deductions to Determine Big 10 as % of Total (Line 4 + Line 5 + Line 6)		20,990	21,296	21,195	21,045	20,556	20,136	19,722	19,327	20,002	20,875	20,859	20,794	20,723	20,862
2	BIG 10 Capacity		19,083	19,360	19,299	19,146	18,664	18,432	17,975	17,623	18,159	18,953	19,023	18,929	18,850	18,988
3	BIG 10 as percent of total (Line 2 / Line 3)	**91%**	91%	91%	91%	91%	91%	92%	91%	91%	91%	91%	91%	91%	91%	91%
	Hydro Resources		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
4	Regulated Hydro		20,568	20,825	20,745	20,563	20,055	19,811	19,275	18,926	19,605	20,458	20,536	20,437	20,355	20,487
5	Independent Hydro		632	698	683	710	746	543	682	655	804	800	682	684	682	679
6	Independent Excluded		-210	-227	-233	-228	-245	-218	-235	-254	-407	-383	-359	-327	-314	-304
	Reserves & Maintenance		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
7	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj)		-12,647	-11,640	-10,811	-9,403	-6,724	-8,013	-8,730	-6,226	-5,519	-6,572	-9,002	-11,457	-13,286	-13,069
8	Total System Available for Reserves (Line 4 + Line 5 + Line 6 + Line 7)		8,343	9,656	10,384	11,642	13,832	12,123	10,992	13,101	14,483	14,303	11,857	9,337	7,437	7,793
9	Federal Trans. Losses @ 3.35% (Line 8 * 3.35%)		-279	-323	-348	-390	-463	-406	-368	-439	-485	-479	-397	-313	-249	-261
10	Total System Available for Reserves net Losses (line 8 + Line 9)		8,064	9,333	10,036	11,252	13,369	11,717	10,624	12,662	13,998	13,824	11,460	9,024	7,188	7,532
	Total 12 Months	**Annual Average**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr (ave of 1-Apr and 16-Apr)**	**May**	**Jun**	**Jul**	**Aug (ave of 1-Aug and 16-Aug)**	**Sep**		
11	Regulated Hydro (Line 4)		20,568	20,825	20,745	20,563	20,055	19,811	19,101	19,605	20,458	20,536	20,396	20,487		
12	Independent Hydro (Line 5)		632	698	683	710	746	543	669	804	800	682	683	679		
13	Independent Excluded (Line 6)	-282	-210	-227	-233	-228	-245	-218	-245	-407	-383	-359	-321	-304		
14	Operational Adjustments (Reserves, Hydro Maint., Operational Peaking Adj) (Line 7)		-12,647	-11,640	-10,811	-9,403	-6,724	-8,013	-7,478	-5,519	-6,572	-9,002	-12,372	-13,069		
15	Federal Trans. Losses (Line 9)		-279	-323	-348	-390	-463	-406	-404	-485	-479	-397	-281	-261		
16	Total 12 Month Period (Line 11 + Line 12 + Line 13 + Line 14 + Line 15)	**10,861**	8,064	9,333	10,036	11,252	13,369	11,717	11,643	13,998	13,824	11,460	8,105	7,532		

Table 3.12		
Embedded Cost Calculation for Wind Balancing Reserve Under a 45-Minute Persistence Scheduling Accuracy Assumption		
	A	**B**
		Annual Average of FY 2010-FY 2011 (MW)
	Reserve Assumptions	
1	Regulated + Independent Hydro	10,861
2	Regulating Reserve	83
3	Operating Reserve less Operating Reserve on rest of System 1/	375
4	Following Capacity	216
5	Wind Balancing Reserve	703
	Forecast of Hydro Capacity System Uses	
	Big 10 is 91% of Total	
6	Hydro Projects Capacity (Line 1 * 91%)	9,884
7	Total PS Reserve Obligation (Line 2+3+4+5)	1,377
8	Hydro Project Capacity System Uses (Line 6+7)	11,261
	Adjusted Revenue Requirement	
9	Power Revenue Requirement for Hydro Projects	$ 768,028,000
10	Hydro Project Capacity System Uses (Line 8)	11,261
11	Total kW/month/year Hydro Project Capacity (Line 10 * 12 months * 1000kW/MW)	135,129,900
12	Per Unit Allocation $/kW/month (Line 9 / Line 11)	$ 5.68
	Revenue Forecast by Product	
13	Wind Balancing Reserve (Line 5 * 12 months * 1000 kW/MW * Line 12)	$ 47,916,480

1/ The 393 MW for Operating Reserve is adjusted to account for 9% of the Non-Spinning portion (half of the total Operating Reserve) being supplied by the rest of the system.

Table 4.1		
STAND READY COMPONENTS AND COSTS 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	B
1	ENERGY SHIFT ($)	-1,018,020
2	EFFICIENCY LOSS ($)	-6,234,248
3	BASE CYCLE LOSS ($)	-74,699
4	**TOTAL STAND READY ($)**	**-7,326,967**

Table 4.2		
DEPLOYMENT COMPONENTS AND COSTS 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	B
1	RESPONSE LOSS ($)	-450,853
2	INC CYCLING LOSS ($)	-1,796,201
3	INCREMENTAL SPILL ($)	-3,691,312
4	INC EFFICIENCY LOSS ($)	229,561
5	**TOTAL DEPLOYMENT ($)**	**-5,708,805**

Table 4.3		
TOTAL STAND READY AND DEPLOYMENTS COSTS 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	B
1	TOTAL STAND READY ($)	-7,326,967
2	TOTAL DEPLOYMENT ($)	-5,708,805
3	**TOTAL STAND READY & DEPLOYMENT ($)**	**-13,035,771**

Table 4.4		
TOTAL GENERATION INPUT VARIABLE COST 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	B
1	REG 83.4 MW INC ($)	-1,578,703
2	REG 88.6 MW DEC ($)	-422,960
3	**TOTAL**	**-2,001,664**
4	WIND BAL 585 MW INC ($)	-3,257,413
5	WIND BAL 838 MW DEC ($)	-3,998,075
6	**TOTAL**	**-7,255,487**
7	**OPERATING RESERVE 196.5 MW INC ($)**	**-493,672**
8	**VARIABLE GEN INPUT COST TO TX ($)**	**-9,750,823**

Table 4.5		
VARIABLE COST ALLOCATION TO TS AND PS 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	B
1	VARIABLE GEN INPUT COST TO TS ($)	-9,750,823
2	LOAD FOLLOWING COST TO POWER RATES ($)	-3,284,948
3	TOTAL VARIABLE COSTS ($)	-13,035,771

Table 4.6							
SPINNING OBLIGATION (values in MW) 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY							
	A	B	C	D	E	F	G
1	TOT BAL DEC		0	358	519	680	842
2		0	$ -	$ (5,020,811)	$ (9,967,563)	$ (18,929,176)	$ (27,180,495)
3		(575)	$ (2,244,711)	$ (5,232,892)	$ (10,408,378)	$ (19,510,424)	$ (27,836,797)
4		(1,150)	$ (4,105,025)	$ (7,157,820)	$ (12,450,082)	$ (21,465,093)	$ (29,975,865)
5		(1,725)	$ (9,435,889)	$ (12,699,389)	$ (19,602,238)	$ (28,329,846)	$ (37,349,143)
6		(2,300)	$ (21,103,393)	$ (24,840,784)	$ (30,573,808)	$ (39,206,346)	$ (45,992,860)

Table 4.7							
NON-SPIN BAL INC (values in MW) 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY							
	A	B	C	D	E	F	G
1	TOT BAL DEC		0	217	631	1,045	1,458
2		0	$ -	$ (385,369)	$ (3,419,643)	$ (9,456,389)	$ (18,786,805)
3		(575)	$ (1,866,317)	$ (2,120,974)	$ (4,845,485)	$ (10,786,647)	$ (20,010,044)
4		(1,150)	$ (5,279,042)	$ (5,584,524)	$ (8,020,975)	$ (13,921,389)	$ (22,983,593)
5		(1,725)	$ (8,711,721)	$ (9,234,936)	$ (11,246,168)	$ (16,934,482)	$ (25,501,541)
6		(2,300)	$ (10,884,140)	$ (11,160,625)	$ (12,943,879)	$ (18,299,965)	$ (26,866,162)

Table 4.8							
TOT BAL INC (values in MW) 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY							
	A	B	C	D	E	F	G
1	TOT BAL DEC		0	575	1,150	1,725	2,300
2		0	$ -	$ (5,406,180)	$ (13,387,207)	$ (28,385,566)	$ (45,967,300)
3		(575)	$ (4,111,027)	$ (7,353,866)	$ (15,253,863)	$ (30,297,071)	$ (47,846,841)
4		(1,150)	$ (9,384,067)	$ (12,742,345)	$ (20,471,057)	$ (35,386,482)	$ (52,959,458)
5		(1,725)	$ (18,147,610)	$ (21,934,325)	$ (30,848,407)	$ (45,264,329)	$ (62,850,684)
6		(2,300)	$ (31,987,533)	$ (36,001,409)	$ (43,517,687)	$ (57,506,311)	$ (72,859,022)

Note: These batch tables include *inc* energy shift costs not included in the final cost allocation.

Table 4.9						
REGRESSION COEFFICIENT FOR SPINNING 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	B	C	D	E	F
1	/INC			/DEC		
2	/b1	/b2	/b3	/b4	/b5	/b6
3	8849.18381	-68.28281	0.02280	188.25192	-0.48909	0.00140

Table 4.10						
RELATIVE COST OF SPINNING RESERVE 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	B	C	D	E	F
1	INC (MW)	INC$%	CRO (MW)	CRO$%	DEC (MW)	DEC$%
2	0	0.0000	0	0.0000	0	0.0000
3	161	0.7564	196.5	0.1440	0	0.0000
4	323	0.7162	196.5	0.0525	0	0.0000
5	484	0.6514	196.5	0.0267	0	0.0000
6	645	0.5895	196.5	0.0161	0	0.0000
7	0	0.0000	196.5	0.2307	-575	0.1708
8	161	0.5110	196.5	0.0973	-575	0.0720
9	323	0.6095	196.5	0.0447	-575	0.0331
10	484	0.5981	196.5	0.0245	-575	0.0181
11	645	0.5595	196.5	0.0152	-575	0.0113
12	0	0.0000	196.5	0.0821	-1,150	0.3392
13	161	0.2897	196.5	0.0552	-1,150	0.2280
14	323	0.4513	196.5	0.0331	-1,150	0.1366
15	484	0.5016	196.5	0.0206	-1,150	0.0850
16	645	0.4997	196.5	0.0136	-1,150	0.0563
17	0	0.0000	196.5	0.0403	-1,725	0.4991
18	161	0.1708	196.5	0.0325	-1,725	0.4027
19	323	0.3184	196.5	0.0233	-1,725	0.2889
20	484	0.3982	196.5	0.0163	-1,725	0.2021
21	645	0.4265	196.5	0.0116	-1,725	0.1438
22	0	0.0000	196.5	0.0235	-2,300	0.6521
23	161	0.1085	196.5	0.0207	-2,300	0.5720
24	323	0.2255	196.5	0.0165	-2,300	0.4575
25	484	0.3091	196.5	0.0127	-2,300	0.3509
26	645	0.3538	196.5	0.0096	-2,300	0.2670

Table 4.11						
REGRESSION COEFFICIENT FOR NON-SPINNING 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	B	C	D	E	F
1	/INC			/DEC		
2	/b1	/b2	/b3	/b4	/b5	/b6
3	-1073.94665	-5.32755	-0.00158	1279.70197	-4.17010	-0.00123

Table 4.12				
RELATIVE COST OF NON-SPINNING RESERVE 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY				
	A	B	C	D
1	INC (MW)	INC$%	DEC (MW)	DEC$%
2	0	0.0000	0	0.0000
3	217	0.0995	0	0.0000
4	631	0.2314	0	0.0000
5	1,045	0.3219	0	0.0000
6	1,458	0.3945	0	0.0000
7	0	0.0000	-575	0.5985
8	217	0.0673	-575	0.2524
9	631	0.1969	-575	0.1158
10	1,045	0.2956	-575	0.0636
11	1,458	0.3744	-575	0.0395
12	0	0.0000	-1150	0.5787
13	217	0.0381	-1150	0.3890
14	631	0.1458	-1150	0.2331
15	1,045	0.2479	-1150	0.1450
16	1,458	0.3344	-1150	0.0960
17	0	0.0000	-1725	0.4606
18	217	0.0225	-1725	0.3716
19	631	0.1029	-1725	0.2665
20	1,045	0.1968	-1725	0.1865
21	1,458	0.2854	-1725	0.1327
22	0	0.0000	-2300	0.3244
23	217	0.0143	-2300	0.2846
24	631	0.0728	-2300	0.2276
25	1,045	0.1528	-2300	0.1745
26	1,458	0.2368	-2300	0.1328

Table 4.13		
RESERVE QUANTITIES 30-MINUTE PERSISTENCE WIND SCHEDULING		
	A	B
1	TOTAL BAL SPINNING INC (MW)	253
2	TOTAL BAL NON-SPINNING INC (MW)	648
3	OPERATING RESERVE (MW)	197
4	TOTAL BAL DEC (MW)	-1,142

Table 4.14		
RELATIVE COMPONENT COST 30-MINUTE PERSISTENCE WIND SCHEDULING		
	A	B
1	TOTAL BAL SPINNING INC (%)	0.368
2	TOTAL BAL NON-SPINNING INC (%)	0.176
3	OPERATING RESERVE (%)	0.038
4	TOTAL BAL DEC (%)	0.418
5	TOTAL COST (%)	1.000

Table 4.15		
DOLLAR COST 30-MINUTE PERSISTENCE WIND SCHEDULING		
	A	B
1	TOTAL COST ($)	-13,035,771
2	TOTAL BAL SPINNING INC ($)	-4,797,630
3	TOTAL BAL NON-SPINNING INC ($)	-2,291,334
4	OPERATING RESERVE ($)	-493,672
5	TOTAL BAL DEC ($)	-5,453,135
6	TOTAL COST ($)	-13,035,771

Table 4.16		
TOTAL RESERVE QUANTITY BY LOAD & WIND 30-MINUTE PERSISTENCE WIND SCHEDULING		
	A	B
1	LOAD INC (MW)	317
2	WIND INC (MW)	585
3	LOAD DEC (MW)	-305
4	WIND DEC (MW)	-838
5	OPERATING RESERVE (MW)	197

Table 4.17			
TOTAL RESERVE QUANTITY BY LOAD & WIND 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	**B**	**C**
1	LOAD INC SPINNING (MW)		176
2	WIND INC SPINNING (MW)		77
3		TOTAL BAL SPINNING (MW)	253
4	LOAD INC NON-SPINNING (MW)		140
5	WIND INC NON-SPINNING (MW)		508
6		TOTAL BAL NON-SPINNING (MW)	648
7	LOAD DEC (MW)		-305
8	WIND DEC (MW)		-838
9		TOTAL BAL DEC (MW)	-1,142
10	OR SPINNING (MW)		197
11		TOTAL OR SPINNING (MW)	197

Table 4.18			
TOTAL VARIABLE RESERVE COST BY LOAD & WIND 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	**B**	**C**
1	LOAD INC SPINNING ($)		-3,334,869
2	WIND INC SPINNING ($)		-1,462,761
3		TOTAL BAL SPINNING ($)	-4,797,630
4	LOAD INC NON-SPINNING ($)		-496,683
5	WIND INC NON-SPINNING ($)		-1,794,651
6		TOTAL BAL NON-SPINNING ($)	-2,291,334
7	LOAD DEC ($)		-1,455,060
8	WIND DEC ($)		-3,998,075
9		TOTAL BAL DEC ($)	-5,453,135
10	OPERATING RESERVE SPINNING ($)		-493,672
11		TOTAL OR SPINNING ($)	-493,672
12	TOTAL VARIABLE COST		-13,035,771

Table 4.19			
TOTAL GEN INPUT VARIABLE COST 30-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	**B**	**C**
1	REG 83.4 MW INC ($)		-1,578,703
2	REG 88.6 MW DEC ($)		-422,960
3		TOTAL REG ($)	-2,001,664
4	WIND BAL 585 MW INC ($)		-3,257,413
5	WIND BAL 838 MW DEC ($)		-3,998,075
6		TOTAL WIND BAL ($)	-7,255,487
7	OPERATING RESERVE 197 MW INC ($)		-493,672
8		TOTAL OR SPINNING ($)	-493,672
9	VARIABLE GEN INPUT COST TO TS ($)		-9,750,823
10	LOAD FOLLOWING COST TO POWER RATES ($)		-3,284,948
11		TOTAL VARIABLE COST ($)	-13,035,771

Table 4.20		
STAND READY COMPONENTS AND COSTS 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	**B**
1	ENERGY SHIFT ($)	-3,093,502
2	EFFICIENCY LOSS ($)	-6,012,578
3	BASE CYCLE LOSS ($)	-80,146
4	**TOTAL STAND READY ($)**	**-9,186,226**

Table 4.21		
DEPLOYMENT COMPONENTS AND COSTS 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	**B**
1	RESPONSE LOSS ($)	-578,476
2	INC CYCLING LOSS ($)	-2,243,404
3	INCREMENTAL SPILL ($)	-4,383,453
4	INC EFFICIENCY LOSS ($)	173,358
5	**TOTAL DEPLOYMENT ($)**	**-7,031,975**

Table 4.22		
TOTAL STAND READY AND DEPLOYMENTS COSTS 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	**B**
1	TOTAL STAND READY ($)	-9,344,309
2	TOTAL DEPLOYMENT ($)	-7,031,975
3	**TOTAL STAND READY & DEPLOYMENT ($)**	**-16,376,283**

Table 4.23		
TOTAL GENERATION INPUT VARIABLE COST 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	**B**
1	REG 83.4 MW INC ($)	-1,609,474
2	REG 88.6 MW DEC ($)	-496,448
3	**TOTAL**	**-2,105,922**
4	WIND BAL 703 MW INC ($)	-4,124,030
5	WIND BAL 1029 MW DEC ($)	-5,765,186
6	**TOTAL**	**-9,889,216**
7	**OPERATING RESERVE 256.5 MW INC ($)**	**-835,684**
8	**VARIABLE GEN INPUT COST TO TX ($)**	**-12,830,823**

Table 4.24		
VARIABLE COST ALLOCATION TO TS AND PS 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY		
	A	**B**
1	VARIABLE GEN INPUT COST TO TS ($)	-12,830,823
2	LOAD FOLLOWING COST TO POWER RATES (	-3,387,378
3	TOTAL VARIABLE COSTS ($)	-16,218,201

Table 4.25
SPINNING OBLIGATION (values in MW)
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G
1	TOT BAL DEC		0	340	484	628	772
2		0	$ -	$ (4,678,141)	$ (8,861,649)	$ (15,914,336)	$ (23,907,669)
3		(575)	$ (2,244,711)	$ (4,902,349)	$ (9,262,235)	$ (16,455,585)	$ (24,525,044)
4		(1,150)	$ (4,105,025)	$ (6,759,671)	$ (11,347,130)	$ (18,530,460)	$ (26,539,721)
5		(1,725)	$ (9,435,889)	$ (12,399,545)	$ (18,771,271)	$ (25,189,662)	$ (33,824,813)
6		(2,300)	$ (21,103,393)	$ (24,485,573)	$ (29,068,579)	$ (35,928,298)	$ (43,535,066)

Table 4.26
NON-SPIN BAL INC (values in MW)
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G
1	TOT BAL DEC		0	235	666	1,097	1,529
2		0	$ -	$ (441,546)	$ (3,657,878)	$ (10,080,248)	$ (19,742,209)
3		(575)	$ (1,866,317)	$ (2,176,376)	$ (5,097,906)	$ (11,429,558)	$ (20,977,319)
4		(1,150)	$ (5,279,042)	$ (5,615,949)	$ (8,265,583)	$ (14,543,996)	$ (23,970,107)
5		(1,725)	$ (8,711,721)	$ (9,275,543)	$ (11,462,059)	$ (17,534,305)	$ (26,552,228)
6		(2,300)	$ (10,884,140)	$ (11,214,576)	$ (13,227,611)	$ (18,977,944)	$ (27,790,197)

Table 4.27
TOT BAL INC (values in MW)
45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY

	A	B	C	D	E	F	G
1	TOT BAL DEC		0	575	1,150	1,725	2,300
2		0	$ -	$ (5,119,687)	$ (12,519,526)	$ (25,994,584)	$ (43,649,878)
3		(575)	$ (4,111,027)	$ (7,078,725)	$ (14,360,141)	$ (27,885,144)	$ (45,502,362)
4		(1,150)	$ (9,384,067)	$ (12,375,621)	$ (19,612,713)	$ (33,074,456)	$ (50,509,829)
5		(1,725)	$ (18,147,610)	$ (21,675,088)	$ (30,233,330)	$ (42,723,966)	$ (60,377,041)
6		(2,300)	$ (31,987,533)	$ (35,700,150)	$ (42,296,190)	$ (54,906,243)	$ (71,325,264)

Note: These batch tables include *inc* energy shift costs not included in the final cost allocation.

Table 4.28						
REGRESSION COEFFICIENT FOR SPINNING 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	**B**	**C**	**D**	**E**	**F**
1	**/INC**			**/DEC**		
2	**/b1**	**/b2**	**/b3**	**/b4**	**/b5**	**/b6**
3	3695.82184	-49.74658	0.00573	-264.79680	-0.81040	0.00134

Table 4.29						
RELATIVE COST OF SPINNING RESERVE 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	**B**	**C**	**D**	**E**	**F**
1	**INC (MW)**	**INC$%**	**CRO (MW)**	**CRO$%**	**DEC (MW)**	**DEC$%**
2	0	0.0000	0	0.0000	0	0.0000
3	144	0.6500	196.5	0.2395	0	0.0000
4	288	0.6365	196.5	0.0909	0	0.0000
5	431	0.5834	196.5	0.0456	0	0.0000
6	575	0.5355	196.5	0.0268	0	0.0000
7	0	0.0000	196.5	0.3380	-575	0.1086
8	144	0.4425	196.5	0.1630	-575	0.0524
9	288	0.5403	196.5	0.0771	-575	0.0248
10	431	0.5355	196.5	0.0419	-575	0.0135
11	575	0.5088	196.5	0.0255	-575	0.0082
12	0	0.0000	196.5	0.1270	-1,150	0.3089
13	144	0.2457	196.5	0.0905	-1,150	0.2201
14	288	0.3918	196.5	0.0559	-1,150	0.1360
15	431	0.4441	196.5	0.0347	-1,150	0.0845
16	575	0.4522	196.5	0.0227	-1,150	0.0551
17	0	0.0000	196.5	0.0631	-1,725	0.4831
18	144	0.1426	196.5	0.0525	-1,725	0.4024
19	288	0.2709	196.5	0.0387	-1,725	0.2962
20	431	0.3477	196.5	0.0272	-1,725	0.2083
21	575	0.3829	196.5	0.0192	-1,725	0.1469
22	0	0.0000	196.5	0.0370	-2,300	0.6415
23	144	0.0899	196.5	0.0331	-2,300	0.5740
24	288	0.1893	196.5	0.0270	-2,300	0.4680
25	431	0.2668	196.5	0.0209	-2,300	0.3615
26	575	0.3154	196.5	0.0158	-2,300	0.2738

Table 4.30						
REGRESSION COEFFICIENT FOR NON-SPINNING 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY						
	A	B	C	D	E	F
1	/INC			/DEC		
2	/b1	/b2	/b3	/b4	/b5	/b6
3	-845.81583	-5.77257	-0.00112	1299.84204	-4.14701	-0.00123

Table 4.31				
RELATIVE COST OF NON-SPINNING RESERVE 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY				
	A	B	C	D
1	INC (MW)	INC$%	DEC (MW)	DEC$%
2	0	0.0000	0	0.0000
3	235	0.1105	0	0.0000
4	666	0.2726	0	0.0000
5	1,097	0.3709	0	0.0000
6	1,529	0.4376	0	0.0000
7	0	0.0000	-575	0.5535
8	235	0.0752	-575	0.2669
9	666	0.2315	-575	0.1263
10	1,097	0.3405	-575	0.0686
11	1,529	0.4158	-575	0.0417
12	0	0.0000	-1150	0.5641
13	235	0.0418	-1150	0.4019
14	666	0.1678	-1150	0.2484
15	1,097	0.2824	-1150	0.1543
16	1,529	0.3695	-1150	0.1006
17	0	0.0000	-1725	0.4539
18	235	0.0242	-1725	0.3781
19	666	0.1160	-1725	0.2782
20	1,097	0.2211	-1725	0.1957
21	1,529	0.3129	-1725	0.1380
22	0	0.0000	-2300	0.3215
23	235	0.0153	-2300	0.2877
24	666	0.0811	-2300	0.2346
25	1,097	0.1696	-2300	0.1812
26	1,529	0.2578	-2300	0.1372

Table 4.32		
RESERVE QUANTITIES 45-MINUTE PERSISTENCE WIND SCHEDULING		
	A	**B**
1	TOTAL BAL SPINNING INC (MW)	253
2	TOTAL BAL NON-SPINNING INC (MW)	749
3	OPERATING RESERVE (MW)	197
4	TOTAL BAL DEC (MW)	-1,310

Table 4.33		
RELATIVE COMPONENT COST 45-MINUTE PERSISTENCE WIND SCHEDULING		
	A	**B**
1	TOTAL BAL SPINNING INC (%)	0.302
2	TOTAL BAL NON-SPINNING INC (%)	0.194
3	OPERATING RESERVE (%)	0.052
4	TOTAL BAL DEC (%)	0.453
5	TOTAL COST (%)	1.000

Table 4.34		
DOLLAR COST 45-MINUTE PERSISTENCE WIND SCHEDULING		
	A	**B**
1	TOTAL COST ($)	-16,218,201
2	TOTAL BAL SPINNING INC ($)	-4,891,141
3	TOTAL BAL NON-SPINNING INC ($)	-3,152,236
4	OPERATING RESERVE ($)	-835,684
5	TOTAL BAL DEC ($)	-7,339,139
6	TOTAL COST ($)	-16,218,201

Table 4.35		
TOTAL RESERVE QUANTITY BY LOAD & WIND 45-MINUTE PERSISTENCE WIND SCHEDULING		
	A	**B**
1	LOAD INC (MW)	300
2	WIND INC (MW)	703
3	LOAD DEC (MW)	-281
4	WIND DEC (MW)	-1,029
5	OPERATING RESERVE (MW)	197

Table 4.36			
TOTAL RESERVE QUANTITY BY LOAD & WIND 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	B	C
1	LOAD INC SPINNING (MW)		176
2	WIND INC SPINNING (MW)		77
3		TOTAL BAL SPINNING (MW)	253
4	LOAD INC NON-SPINNING (MW)		123
5	WIND INC NON-SPINNING (MW)		625
6		TOTAL BAL NON-SPINNING (MW)	749
7	LOAD DEC (MW)		-281
8	WIND DEC (MW)		-1,029
9		TOTAL BAL DEC (MW)	-1,310
10	OR SPINNING (MW)		197
11		TOTAL OR SPINNING (MW)	197

Table 4.37			
TOTAL VARIABLE RESERVE COST BY LOAD & WIND 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	B	C
1	LOAD INC SPINNING ($)		-3,399,869
2	WIND INC SPINNING ($)		-1,491,272
3		TOTAL BAL SPINNING ($)	-4,891,141
4	LOAD INC NON-SPINNING ($)		-519,478
5	WIND INC NON-SPINNING ($)		-2,632,758
6		TOTAL BAL NON-SPINNING ($)	-3,152,236
7	LOAD DEC ($)		-1,573,953
8	WIND DEC ($)		-5,765,186
9		TOTAL BAL DEC ($)	-7,339,139
10	OPERATING RESERVE SPINNING ($)		-835,684
11		TOTAL OR SPINNING ($)	-835,684
12	TOTAL VARIABLE COST		-16,218,201

Table 4.38			
TOTAL GEN INPUT VARIABLE COST 45-MINUTE PERSISTENCE WIND SCHEDULING ACCURACY			
	A	B	C
1	REG 83.4 MW INC ($)		-1,609,474
2	REG 88.6 MW DEC ($)		-496,448
3		TOTAL REG ($)	-2,105,922
4	WIND BAL 703 ME INC ($)		-4,124,030
5	WIND BAL 1029 MW DEC ($)		-5,765,186
6		TOTAL WIND BAL ($)	-9,889,216
7	OPERATING RESERVE 197 MW INC ($)		-835,684
8		TOTAL OR SPINNING ($)	-835,684
9	VARIABLE GEN INPUT COST TO TX ($)		-12,830,823
10	LOAD FOLLOWING COST TO POWER RATES ($)		-3,387,378
11		TOTAL VARIABLE COST ($)	-16,218,201

Table 5.1

Total Balancing Authority Reserve Obligation
Current WECC OR Standard BAL-STD-002-0

Balancing Authority Operating Reserve Obligations (RODS Acct 498899) Average By Month

	A	B	C	D	E	F	G	H
1	(MW)	**FY02**	**FY03**	**FY04**	**FY05**	**FY06**	**FY07**	**FY08**
2	**OCT**	423.9	559.9	590.3	618.3	587.6	641.2	595.1
3	**NOV**	535.1	610.2	649.6	686.6	663.0	613.4	650.2
4	**DEC**	592.0	672.6	674.7	728.8	710.2	711.2	746.4
5	**JAN**	640.6	622.8	688.6	719.0	656.5	756.2	792.2
6	**FEB**	608.6	608.0	675.1	686.4	703.5	659.3	745.2
7	**MAR**	576.6	629.8	628.3	662.5	644.2	680.6	731.8
8	**APR**	633.8	644.1	622.4	618.3	747.7	698.2	720.9
9	**MAY**	651.5	619.7	654.4	600.3	758.8	686.0	756.4
10	**JUN**	752.9	665.3	724.8	617.5	806.7	649.3	866.3
11	**JUL**	707.2	699.3	694.2	723.7	744.7	719.3	838.3
12	**AUG**	650.7	691.6	642.1	681.8	702.2	674.9	700.3
13	**SEP**	573.3	607.1	611.4	600.6	645.1	598.7	673.5
14	**FY AVG**	**612.1**	**636.1**	**654.6**	**662.1**	**697.3**	**674.5**	**734.7**

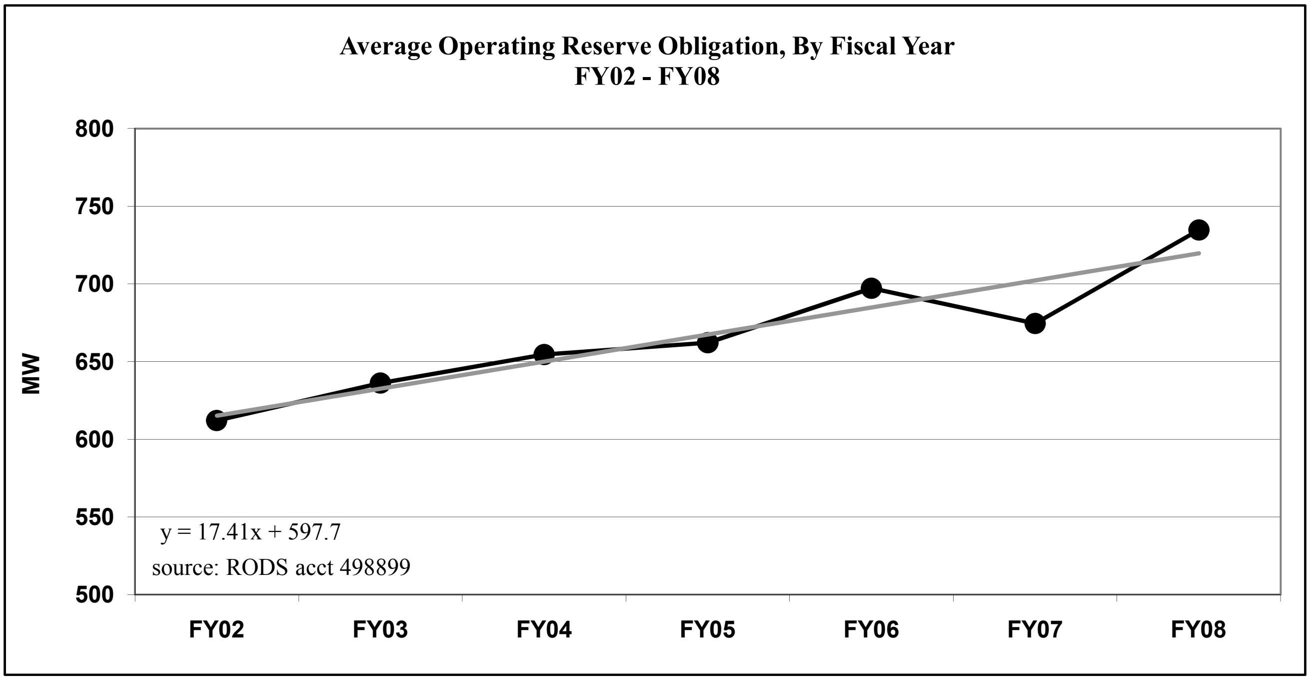
Table 5.2
Total Balancing Authority Reserve Obligation **Current WECC OR Standard BAL-STD-002-0**


Table 5.3				
Calculation of Balancing Authority Reserve Obligation Current WECC OR Standard BAL-STD-002-0				
	A	**B**	**C**	**D**
1	(MW)	**Total BAA Reserve Obligation**	**Total Third Party/Self-Supply Reserve Obligation**	**Total BAA Reserve Obligation Provided by BPA PS**
2	FY 2010	754	252	502
3	FY 2011	772	252	520
4	**FY10-11 Average**	**763**	**252**	**511**

Column C: Total Third Party and Self-Supply is based on historical amounts for current suppliers.
Column D: BPA Power Services share of the Reserve Obligation is Column B minus Column C.

Table 5.4						
Calculation of Total Balancing Authority Reserve Obligation Proposed WECC OR Standard BAL-002-WECC-1						
(MW)	**A**	**B**	**C**	**D**	**E**	**F**
1	**Fiscal Year**	**242200 Balancing Area Load**	**202100 Balancing Area Generation**	**3% BA LOAD**	**3% BA GEN**	**Total BAA Reserve Obligation**
2	2005	5,289	11,523			
3	2006	5,441	12,200			
4	2007	5,752	11,869			
5	2008	6,010	12,628			
6	2009 forecast	5,924	12,715	178	381	559
7	**2010 forecast**	**6,090**	**13,071**	**183**	**392**	**575**
8	**2011 forecast**	**6,205**	**13,318**	**186**	**400**	**586**
9	**FY10-11 Average**					**581**

BAA load growth rate is based on the Agency Load Forecast as of March 2009.

Percent change over prior year: -1.4% for FY09, 2.8% for FY10, and 1.9% for FY11.

BPA BAA generation to load ratio 2.11:1 is based on the historical average.

Table 5.5				
Calculation of Balancing Authority Reserve Obligation Proposed WECC OR Standard BAL-002-WECC-1				
	A	**B**	**C**	**D**
1	(MW)	**Total BAA Reserve Obligation**	**Third Party/Self-Supply Reserve Obligation**	**Total BAA Reserve Obligation Provided by BPA PS**
2	FY 2010	575	227	348
3	FY 2011	586	227	359
4	**FY10-11 Average**	**581**	**227**	**354**

Column C: Total Third Party and Self-Supply is based on historical amounts for current suppliers.

Column D: BPA Power Services share of the Reserve Obligation is Column B minus Column C.

Table 5.6

Calculation of Balancing Authority Reserve Obligation Provided by BPA PS

Current WECC OR Standard BAL-STD-002-0 Effective for FY 2010 (October through March) and
Proposed WECC OR Standard BAL-002-WECC-1 Effective for FY 2010 (April through September) and FY 2011

	A	B	C	D
	(MW)	**FY10**	**FY11**	**FY10-11 Average**
1	**Oct**	564	403	484
2	**Nov**	488	349	419
3	**Dec**	517	369	443
4	**Jan**	503	359	431
5	**Feb**	529	378	454
6	**Mar**	528	377	452
7	**Apr**	365	376	370
8	**May**	336	347	342
9	**Jun**	295	304	300
10	**Jul**	306	315	311
11	**Aug**	325	335	330
12	**Sep**	381	393	387
13	***FY Average***	***428***	***359***	***393***

The Balancing Authority reserve obligation provided by BPA PS is shaped monthly based on a weighted average of historical (FY05-FY08) shaping of BPA BAA load and generation.

Table 5.7				
Operating Reserve Power Revenue Requirement for All Hydroelectric Projects in BPA Balancing Authority ($ in thousands)				
	A	**B**	**C**	**D**
		FY 2010	**FY 2011**	**Annual Average for FY 2010-FY 2011**
1	**All Hydro Projects 1/**			
2	O&M	229,563	238,981	234,272
3	Depreciation	86,739	88,286	87,513
4	Net Interest	102,591	104,060	103,326
5	Minimum Required Net Revenues	33,218	27,925	30,572
6	**Total Revenue Requirement**	452,111	459,252	455,682
7	**Fish & Wildlife**			
8	O&M	283,424	305,050	294,237
9	Amortization/Depreciation	39,792	43,607	41,700
10	Net Interest	46,105	52,120	49,113
11	Minimum Required Net Revenues	14,928	13,986	14,457
12	**Subtotal**	384,249	414,764	399,507
13	**A&G Expense 2/**	91,099	93,019	92,059
14	**Total Revenue Requirement**	927,460	967,036	947,248
15	**Revenue Credits**			
16	4h10C (non-operations)	61,648	64,028	62,838
17	Colville payment Treas. Credit	4,600	4,600	4,600
18	Synchronous Condensing	329	319	324
19	**Net Revenue Requirement**	**860,883**	**898,089**	**879,486**

1/ Excludes Boise, Minidoka-Palisades, Green Springs (USBR) and Lost Creek (COE).

2/ Power Marketing Sales & Support, Power Scheduling, Generation Oversight, Corporate Expense and 1/2 Planning Council

Table 5.8		
Cost Allocation for Embedded Cost Portion of Operating Reserve		
	A	**B**
		Annual Average of FY2010-FY2011
	Reserve Assumptions	
1	Regulated + Independent Hydro Projects Capacity (MW)	10,906
2	Regulating Reserve (MW)	83
3	Operating Reserve (MW)	393
4	Following Reserve (MW)	216
5	Wind Balancing Reserves (MW)	585
	Forecast of Hydro Capacity System Uses	
6	Regulated + Independent Hydro Projects Capacity (Line 1)	10,906
7	Total Power Services Reserve Obligation (Line 2+3+4+5)	1,277
8	Regulated + Independent Hydro Projects Capacity System Uses (Line 6+7)	12,183
	Adjusted Revenue Requirement	
9	Power Services' Revenue Requirement for Regulated + Independent Hydro Projects	$ 879,486,000
10	Regulated + Independent Hydro Projects Capacity System Uses (Line 8)	12,183
11	Total kW/month/year Hydro Project Capacity (Line 10 * 12 months * 1000 kW/MW)	146,196,000
12	**Per Unit Allocation $/kW/month (Line 9 / Line 11)**	$ 6.02
	Revenue Forecast by Product	
13	Operating Reserve Embedded Cost (Line 3 *12 months * 1000 kW/MW * Line 12)	$ 28,390,320

Table 6.1										
Synchronous Condenser Projected Motoring Hours, Hourly Energy Consumption and Energy Costs										
	A	B	C	D	E	F	G	H	I	J
	Generating Project	**Nameplate rating (MW/unit)**	**Motoring power consumption (MW/unit)**	**Projected Units to be used**	**Condensing Hours FY 2005**	**Condensing Hours FY 2006**	**Condensing Hours FY 2007**	**Average Annual Condensing hours/year [(E+F+G)/3]**	**Energy Consumption MWhrs/year [H * C]**	**Total Cost of Energy [I * energy value]**
1	**Grand Coulee, units 19-24**	690 (units 19-21) 805 (units 22-24)	11.0	units 19-21	2,385	1,526	2,240	2,050	26,253	$1,065,347
2	**John Day, units 11-14**	155	3.0	units 11-14	3,046	2,329	2,697	2,691	8,072	$327,562
3	**The Dalles, units 15-20**	99	1.5	units 15-20	1,597	843	3,006	1,815	2,723	$110,499
4	**Dworshak (small units)**	103	4.0	units 1-2	NA	23	25	24	96	$3,896
5	**Dworshak (big unit)**	259	8.0	unit 3	NA	253	154	204	1,628	$66,064
6	**Palisades, units 1-4**	44	0.6	units 1-4	NA	2,777	2,320	2,549	1,529	$62,051
7	**Detroit, units 1-2**	58	2.0	units 1-2	NA	NA	NA	0	0	$0
8	**Green Peter, units 1-2**	46	1.2	units 1-2	NA	NA	NA	0	0	$0
9	**Lookout Point, units 1-3**	46	1.1	units 1-3	NA	NA	NA	0	0	$0
10	**Hungry Horse, units 1-4**	107	2.5	units 1-4	0	0	0	0	0	$0
11								**TOTAL ENERGY COST**	**40,301**	**$1,635,419**
12	**Value of energy ($/MWh)**	**40.58**								

Table 6.2				
Determination of Synchronous Condenser Annual Costs ($ thousands)				
	A	**B**	**C**	**D**
		FY 2010	**FY 2011**	**Annual Average of FY 2010 - FY2011**
1	**Synchronous Condensers Net Plant**	6,576	6,473	6,525
2	Total Corps/Bureau Average Net Plant	5,179,606	5,290,646	5,235,126
3	**percent**	0.13%	0.12%	0
4	Corps/Bureau Net Interest	134,911	138,674	136,793
5	**Sync Cond Net Interest**	171	170	171
6	Corps/Bureau MRNR	43,682	37,213	40,448
7	**Sync Cond MRNR**	55	46	51
8	**Sync Cond Depreciation**	103	103	103
9	**Total Sync Cond Costs**	**329**	**319**	**324**

Table 7.1

ESTIMATED COSTS OF "GENERATION DROP" OF UNIT 22, 23, OR 24 AT THE GRAND COULEE THIRD POWERHOUSE

	A	B	C	D	E	F	G	H	I	J	K	L
1	Equipment	Incremental Equipment Deterioration, Replacement or Overhaul Costs			Incremental Routine Operation and Maintenance Costs			Incremental Lost Revenue In The Event of Replacement or Overhaul				Total Cost Per Drop
2		% Life Reduction Per Drop	Cost of Major Overhaul (1)	Cost/Drop	% Increase O&M Per Drop	Annual O&M Cost	Cost/Drop	Probability of Failure	Months of Downtime	Downtime Cost (2)	Cost/Drop	
3	550kV Circuit Breaker (50% of replacement)	0.04%	$ 696,034	$ 278	0.04%	$ 4,941	$ 2	0.04%	1	$ 1,980,000	$ 792	**$ 1,072**
4	Main Power Transformer (equal to replacement)	0.015%	$ 7,944,393	$ 1,192	0.015%	$ 57,069	$ 9	0.018%	1	$ 1,980,000	$ 356	**$ 1,557**
5	Generator (rewinding)	0.71%	$ 17,679,263	$ 125,523	0.71%	$ 450,000	$ 3,195	0.71%	18	$ 35,640,000	$ 253,044	**$ 381,762**
6	Turbine (refurbished)	0.24%	$ 1,392,068	$ 3,341	0.24%	$ 450,000	$ 1,080	0.05%	16	$ 31,680,000	$ 15,840	**$ 20,261**
7	500 kV Cable (replacement)	0.055%	$ 3,762,000	$ 2,069	0.055%	$ 281,779	$ 155	0.055%	1	$ 1,980,000	$ 1,089	**$ 3,313**
8	**Total Cost Per Drop**			**$ 132,404**			**$ 4,440**				**$ 271,121**	**$ 407,965**

(1) Updated to FY2010-FY2011 from original Harza Engineering Company study using the Handy-Whittman Index to calculate cost multiplier

1.39

(2) The downtime cost from last unit out at Coulee analysis, assumes normal unit availability at Coulee and then the loss of an additional big unit. The current Value of Availability 080709 prices is adjusted to forecasted cost of energy during the rate period.

Table 7.2			
Revenue Forecast for Generation Dropping			
	A	B	C
1	Average Number of Drops Per Year	Cost Per Drop	Revenue Forecast
2	1.5	$ 407,965	$ 611,948

Table 8.1					
NT Redispatch Resulting from the Purchase of Energy or Transmission on an Alternate Path					
	A	B	C	D	E
		MWH	Total Cost	$/MWH	Notes
1	October-2007	13,146	$ 88,054.00	$ 6.70	
2	November-2007	31,666	$ 99,277.00	$ 3.14	
3	December-2007	1,440	$ 17,682.00	$ 12.28	
4	January-2008	0	$ -	$ -	
5	February-2008	0	$ -	$ -	
6	March-2008	110	$ -	$ -	(PSANI Test)
7	April-2008	1,217	$ 4,621.00	$ 3.80	
8	May-2008	1,317	$ 11,017.00	$ 8.37	
9	June-2008	0	$ -	$ -	
10	July-2008	0	$ -	$ -	
11	August-2008	4,271	$ 11,468.00	$ 2.69	
12	September-2008	30,173	$ 310,559.00	$ 10.29	1/
13		Total:	$ 542,678.00		

1/ The problem was that poles needed to be replaced which is a one-time occurrence so this excessive cost is an anomaly.

Table 8.2									
Discretionary Redispatch Including the Pilot Redispatch									
	A	B	C	D	E	F	G	H	I
		MWH Requested	MW Delivered	Total Cost	$/MWH	Duration of Redispatch Event	INC	DEC	Cause
1	**North of Hanford Flow gate**								
2	12/30/2007	200	150	$3,750	$25.00	(1 hour)	GCL, CHJ	JDA, TDA	Flows exceeded OTC
3	3/21/2008	200	145	$5,075	$35.00	(1-hour)	GCL	JDA	Load control, North of Hanford relief
4	9/17/2008	200	166	$11,655	$35.11	(2-hours)	GCL	MCN, JDA, TDA	
5	9/18/2008	385	342	$35,910	$35.00	(3-hours)	GCL	JDA, TDA	
6	**Cross Cascades North**								
7	2/6/2008	38	38	$1,128	$29.69	(1-hour)	JDA, Carmen Smith 1/	Hermiston 1/	Test
8	2/6/2008	55	55	$1,633	$29.69	(1-hour)	JDA	Hermiston 1/	Test
9	2/6/2008	66	66	$1,960	$29.69	(1-hour)	JDA	Hermiston 1/	Test
10	**Columbia Injection**								
11	7/10/2008	100	63	$10,000	$79.37	(2-hours)	JDA	TDA	Columbia Injection exceeded level 2
12	7/12/2008	450	408	$325,624	$99.76	(8-hours)	JDA, TDA, Lower Snake Plants	GCL	Columbia Injection exceeded level 3
13	7/17/2008	200	142	$2,900	$20.42	(1-hour)	JDA, TDA	CHJ	Columbia Injection exceeded level 4
14	**South of Allston**								
15	7/12/08	Included in Columbia Injection problem above				(2-hours)	JDA, TDA	GCL	South of Allston OTC exceeded
16	9/4/2008	200	170	$37,455	$55.08	(4-hours)	CHJ, JDA, TDA	GCL	
17	9/30/2008	198	176	$54,980	$52.06	(6-hours)	MCN, JDA, TDA	GCL, CNT 1/	
18	**MISC**								
19	8/17/08	20	20	$900	$45.00	(1-hour)			Transformer issue
20	**Discretionary Redispatch Total**			$499,693					

1/ Non-Federal generators shown for accuracy. These costs are not included in the total cost shown in line 20 above.

Table 9.1
COE Transmission Segmentation

BONNEVILLE DAM

A major rehab was done to the Bonneville Dam switchyard in 1999.
The current plant in service costs provided by the COE are:

	A	B	C
1	**Prop ID**	**Plant Item**	**Book Cost**
2	BONNE-13361	Power transformers	$ 27,997,022
3	BONNE-13358	Switchyard circuit breaker	1,499,685
4	BONNE-13559	Switchyard circuit breaker	1,499,960
5	BONNE-13360	Switchyard circuit breaker	1,500,514
6		**Total:**	**$ 32,497,181**
7			
8	The power transformers are assigned to generation.		
9	Circuit breakers are allocated to Network & Generation Integration based on use.		
10	There are six 115 kV circuit breakers; two Generation Integration and four Network.		
11	BONNE-13358	Switchyard circuit breaker	$ 1,499,685
12	BONNE-13559	Switchyard circuit breaker	1,499,960
13	BONNE-13360	Switchyard circuit breaker	1,500,514
14		**Total Circuit Breakers:**	**$ 4,500,159**
15	Since four of the six circuit breakers at the switchyard serve the Network function and two serve the Generation Integration function, 4/6 of the total cost of the breakers will be allocated to the Network function and 2/6 of the costs will be assigned to		
16	**Network Allocation (4/6 of the Total Circuit Breakers)**		**$ 3,000,106**
17	**Generation Integration Allocation (2/6 of the Total Circuit Breakers)**		**$ 1,500,053**

	A	B	C
	Table 9.2 COLUMBIA BASIN COSTS (Grand Coulee) SUMMARY		
1		**As of 9/30/2007**	
2	**TOTAL TRANSMISSION**		
3	**Segment**	**Investment**	**Percent**
4	Network	50,920,144.43	27.64%
5	Generation Integration	132,563,179.00	71.95%
6	Utility Delivery	763,461.40	0.41%
7	**Total**	**184,246,784.84**	**100.00%**
8			
9	**THIRD POWERHOUSE (500 kV Facilities)**		
10	Network	19,709,060.40	17.77%
11	Generation Integration	91,182,789.27	82.23%
12	**Total**	**110,891,849.67**	**100.00%**
13			
14	**FIRST & SECOND POWERHOUSE & OTHERS**		
15	Network	31,211,084.03	42.55%
16	Generation Integration	41,380,389.73	56.41%
17	Utility Delivery	763,461.40	1.04%
18	**Total**	**73,354,935.16**	**100.00%**
19			
20	Investment includes IDC.		

Table 9.3
COLUMBIA BASIN COSTS (Grand Coulee)
Reclamation data for investment as of 9/30/2007

	A	B	C	D	E	F
1			**Network**	**Segment Generation Integration**	**Utility Delivery**	**Source**
2						
3	13.031 Pump Generator Switchyard		4,742,053	4,742,053	4,742,053	3/ From Reclamation Schedule 1
4	Times: Percentage Allocated to Segment		0.00%	100.00%	0.00%	
5	**Subtotal**		**0**	**4,742,053**	**0**	
6	Add: Interest During Construction (@ 11.83%)		0	561,175	0	
7	Equals: Amount Allocated		0	5,303,228	0	
8						
9						
10	13.034 500kV & Other Switchyard	99,157,544				3/ From Reclamation Schedule 1
11	Less: 500kV cables 6/	(22,789,063)				From detailed Reclamation records on 500kV
12	Equals: Amount to be Segmented		76,368,481	76,368,481	76,368,481	
13	Times: Percentage Allocated to Segment		23.08%	76.92%	0.00%	Based on typical costs
14	**Subtotal**		**17,623,496**	**58,744,985**	**0**	
15	Add back: 500 kV cables (all GI)		0	22,789,063	0	
16	**Subtotal**		**17,623,496**	**81,534,048**	**0**	
17	Add: Interest During Construction (@ 11.83%)		2,085,565	9,648,741	0	
18	Equals: Amount Allocated		19,709,060	91,182,789	0	
19						
20						
21	13.035 Modified Left Switchyard	60,850,641				4/ From Reclamation Schedule 1
22	Less: Lines 7/	(4,309,008)				From detailed Reclamation records on 500kV
23	Equals: Amount to be Segmented		56,541,633	56,541,633	56,541,633	
24	Times: Percentage Allocated to Segment		49.36%	49.43%	1.21%	Based on typical costs; Left Yard only 115/12 kV
25	**Subtotal**		**27,908,403**	**27,950,556**	**682,674**	
26	Add back: Lines (all GI)		0	4,309,008	0	
27			27,908,403	32,259,564	682,674	
28	Add: Interest During Construction (@ 11.83%)		3,302,681	3,817,597	80,788	
29	Equals: Amount Allocated		31,211,084	36,077,162	763,461	
30						
31	**TOTAL For Segment**		**50,920,144**	**132,563,179**	**763,461**	
32						
33	NOTES:					
34	1/ Assume all transmission costs to be segmented are included in the Reclamation Schedule 1 for the Columbia Basin (Grand Coulee) project.					
35	2/ Assume this is in pump gen switchyard and power plant.					
36	3/ Assume this includes all 500 kV line and substation costs; IDC not included.					
37	4/ Assume this includes all 230 kV and other transmission costs; IDC not included.					
38	5/ IDC is allocated based on ratio of investment to total investment.					
39	6/ Assumes that (a) cables are all in 500 kV yard and can be removed as a group and (b) these cables are part of generation integration.					
40	7/ Assumes that (a) all lines are part of left yard and can be removed as a group and (b) these cables are part of generation integration..					

Table 9.4
NETWORK INVESTMENT RATIO-ASSIGNMENT BASED ON TYPICAL SUB COSTS
BPA typical cost of facilities - 12/11/1998

	A	B	C	D	E	F	G	H	I	J
1		No. Units			**Unit Cost**					
2	**Items**	**Total**	**Network**	**Gen Int**	**$000**	**Total**	**Network**	**Gen Int**	**Utility Delivery**	**Note**
3	**500 kV Switchyard**									
4	500 kV terminal (1&1/2)	11	5	6	4,500	49,500	22,500	27,000		
5	Step-ups 7-800 MVA	6		6	8,000	48,000	0	48,000		3/
6	Total					97,500	22,500	75,000	0	
7	500kV - Network % =	23.08%		% w/o step-ups		45.5%				
8	500kV - GI % =	76.92%								
9	**Total**	**100.00%**								
10										
11										
12	**Left Switchyard (includes 230 & 115 yards)**									
13	230 kV PCB 1/	22	17	5	560	12,320	9,520	2,800		
14	500/230 tx 1200MVA	1	1		9,800	9,800	9,800	0		
15	230/287kV tx	1	1		2,600	2,600	2,600	0		
16	230/115 tx 230MVA	1	1		2,600	2,600	2,600	0		
17	115kV PCB	7	7		375	2,625	2,625	0		
18	115/12.5 kV - 20 MVA tx	2			1,010	2,020		1,616	404	2/
19	12.5 kV feeder terminals	11			130	1,430		1,170	260	2/
20	Step-ups 1-125MVA	18		18	1,200	21,600	0	21,600		4/
21	**Total**					**54,995**	**27,145**	**27,186**	**664**	
22										
23	Left Yard -- % Network	49.36%		Network % w/o step-ups		81.3%		% Delivery	1.2%	
24	Left Yard -- % GI	49.43%					%Del w/o step-up		2.0%	
25	Left Yard -- % Utility Delivery	1.21%								
26	**Total**	**100.00%**								
27										
28	NOTES:									
29	1/ Some breakers are for bus tie, etc.; these are Network.									
30	2/ Low voltage transformer split 20% to Utility Delivery; based on estimate of 25 MVA with low and high side PCB.									
31	Low voltage terminals based on 12.5kV feeder cost; split based on 2 for Utility Delivery and rest for station service.									
32	3/ Cost of 500 kV step-ups are similar to 500/230, so cost of 700MVA without breakers is used.									
33	4/ Cost of 230 kV step-ups are similar to 230/69, so cost of 75MVA without breakers is used.									
34	5/ Coulee-Bell additions not in plant for FY 2004 so not included in allocation.									

Table 9.5
RECLAMATION SEGMENTATION - OTHER PRODUCTS
As of 9/30/2007 - Based on data from Reclamation

	A	B	C	D	E
1	**PROJECT**	**TRANSMISSION INVESTMENT 2/**	**NETWORK**	**GENERATION INTEGRATION**	**UTILITY DELIVERY**
2	Hungry Horse	9,802,259	2,048,233	7,754,025	0
3	Boise 1/	1,826,683	0	1,826,683	0
4	Yakima (Rosa) 3/	3,209,856	0	3,209,856	0
5	Green Springs	178,988	0	178,988	0
6	Minidoka	1,706,746	901,450	805,296	0
7	Palisades	2,220,063	413,505	1,408,980	397,577
8	***Total***	**18,944,593**	**3,363,188**	**15,183,827**	**397,577**
9					
10	Segment investment is total investment times segment % determined below.				
11	Segment percent is estimated using 1998 typical BPA facility costs as proxy.				
12	1/ Includes Anderson Ranch and Black Canyon.				
13	2/ Total from Reclamation Transmission Plant In Service, subaccount 13, with IDC allocation.				
14	3/ Does not include the Chandler project. 100% of the costs of Electrical Plant In Service at this project are for Generation Integration and thus no costs are to be allocated to BPA/TS for segmentation and recovery				
15					
16	**SEGMENT PERCENTAGES FOR MULTI-SEGMENT PLANTS**				
17	Hungry Horse				
18	**Item**	**Cost**	**Network**	**Gen Int**	
19	2-230kV terminals	1,120,000	1,120,000	0	
20	2-230kV terminals	1,120,000	0	1,120,000	
21	2-180MVA step-ups	3,120,000	0	3,120,000	
22		5,360,000	1,120,000	4,240,000	
23	*Percent of total*	100.0%	20.9%	79.1%	
24	Step-up transformer cost based on 230/69kV 75 MVA w disconnects.				
25					
26	**Minidoka-Palisades**				
27	**Minidoka sub**	**Cost**	**Network**	**Gen Int**	**Utility Delivery**
28	5-138kV terminal	2,250,000	1,500,000	750,000	
29	1 Step-up to 138kV	590,000		590,000	
30	***Total***	**2,840,000**	**1,500,000**	**1,340,000**	**0**
31	*Percent of total*		52.8%	47.2%	0.0%
32	Palisades				
33	9-115kV terminals	3,375,000	1,265,625	1,687,500	421,875
34	4-35MVA step-ups	2,360,000		2,360,000	
35	10MVA 115/12.5kV	1,060,000		265,000	795,000
36	***Total***	**6,795,000**	**1,265,625**	**4,312,500**	**1,216,875**
37	*Percent of total*		18.6%	63.5%	17.9%
38					
39	NOTES:				
40	Minidoka terminals - use 115kV terminal cost of $375,000;				
41	Minidoka terminals - 4 Network, 2 Generation Integration, 1 bus tie				
42	Minidoka step-up - use 115/34.5kV 25 MVA transformer cost				
43	Palisades - 9 PCB/8 terminals - 4 GI, 3 Net, 1 Del				
44	Palisades step-ups - use 115/34.5kV 25 MVA transformer cost				
45	Palisades - utility delivery is for Lower Valley and station service				
46	Base utility delivery tx on cost of 115/12.5 sub 25MVA				
47	Split station service facilities 25% to utility delivery & 75% to station service/GI				

Table 9.6 Segmentation Summary -- All COE and Reclamation Projects				
	A	**B**	**C**	**D**
		Generation Integration	**Network**	**Utility Delivery**
1	**Reclamation Projects:**			
2	Columbia Basin (Grand Coulee) Project	132,563,179	50,920,144	763,461
3	Other Projects	15,183,827	3,363,188	397,577
4	**Total Reclamation Projects**	**147,747,006**	**54,283,333**	**1,161,039**
5	**COE Projects:**			
6	**Total Bonneville Project**	**1,500,053**	**3,000,106**	**0**
7	**TOTAL ALL PROJECTS:**	**149,247,059**	**57,283,439**	**1,161,039**

Table 9.7 COE/Reclamation Transmission Costs ($ in thousands)										
	A	B	C	D	E	F	G	H	I	J
		FY 2010 Total	FY 2010 Network	FY 2010 Utility Delivery	FY 2011 Total	FY 2011 Network	FY 2011 Utility Delivery	Annual Average for FY2010-FY 2011 Total	Annual Average for FY2010-FY 2011 Network	Annual Average for FY2010-FY 2011 Utility Delivery
1	O&M	3,906	3,184	722	4,299	3,501	798	4,103	3,343	760
2	Depreciation	777	751	26	777	751	26	777	751	26
3	Interest Expense	1,028	991	37	1,014	978	36	1,021	985	37
4	MRNR	333	321	12	272	262	10	303	292	11
5	**Total COE/Reclamation Trans Costs**	**6,044**	**5,247**	**797**	**6,362**	**5,492**	**870**	**6,203**	**5,370**	**834**

Table 10.1 Station Service Quality Analysis					
	A	**B**	**C**	**D**	**E**
1	**Measured Historical Average Monthly Usage**				
2	**Facility Name**			**Historical Average Monthly Usage (kWh)**	
3	Big Eddy / Celilo Complex			1,822,937	
4	Ross Complex			1,749,300	
5	**Load Factor Calculation (Average Monthly Usage divided by Transformation divided by 730 average hours in the month)**				
6	**Substation Name**		**Installed Transformation (kVa)**	**Historical Average Monthly Usage (kWh)**	**Calculated Load Factor**
7	**Large**				
8	Alvey		2,267	96,923	
9	Bell		2,250	149,000	
10	Snohomish		1,250	78,000	
11	Olympia		1,100	132,738	
12	Covington		946	108,333	
13	Pearl		875	28,067	
14	Longview		825	38,317	
15	McNary		800	108,717	
16	Chemawa		725	18,140	
17	Anaconda		600	42,910	
18	Columbia		600	18,292	
19	John Day		500	65,896	
20	Santiam		400	25,740	
21	St. Johns		310	15,858	
22	Port Angeles		300	49,920	
23	Valhalla		300	17,592	
24	Fairview		300	12,560	
25	**Subtotal**		14,348	1,007,003	
26					
27	**Medium**				
28	Oregon City		225	13,663	
29	Walla Walla		150	6,919	
30	LaGrande		150	5,663	
31	Ellensburg		100	3,897	
32	Roundup		75	5,708	
33	Boardman		75	1,595	
34	Drain		65	1,654	
35	Reedsport		55	3,922	
36	**Subtotal**		895	43,021	

Table 10.1 Station Service Quality Analysis					
	A	**B**	**C**	**D**	**E**
37					
38	**Small**				
39	Sappho		45	2,363	
40	Lookout Point		40	3,387	
41	The Dalles		38	2,657	
42	Bandon		25	1,746	
43	Gardiner		25	1,402	
44	Creston		15	1,122	
45	Hauser		10	1,525	
46	Duckabush		10	1,192	
47	Ione		5	1,028	
48	**Subtotal**		213	16,422	
49	**TOTAL**		**15,456**	**1,066,446**	**9.45%**
50	**Calculated Monthly Usage** **(Transformation times Load Factor)**				
51	**Facility Name**		**Installed Transformation (kVa)**	**Average Calculated Load Factor (Overall)**	**Calculated Average Monthly Usage (kWh)**
52					
53	Large		37,636	9.45%	**2,596,840**
54	Medium		5,223	9.45%	**360,381**
55	Small		1,466	9.45%	**101,152**
56			44,325		**3,058,373**
57					
58	**Total Monthly Usage** **(Historical + Calculated)**				
59	**Facility Name**		**Calculated Average Monthly Usage (kWh)**	**Historical Average Monthly Usage (kWh)**	**Total Average Monthly Usage (kWh)**
60	Big Eddy / Celilo			1,822,937	
61	Ross Complex			1,749,300	
62	Large		2,596,840		
63	Medium		360,381		
64	Small		101,152		
65	**Total Month Usage (kWh):**		**3,058,373**	**3,572,237**	**6,630,610**
66	**Total Annual Usage** **(Total Monthly Usage times 12)**				
67			**Total Monthly Usage (kWh)**	**Months in a Year**	**Total Annual Usage (kWh)**
68	**Total Annual Usage (kWh)**		**6,630,610**	**12**	**79,567,320**

Table 10.2 Cost Allocation for Station Service				
	A	B	C	D
	Amount of Station Service Energy Forecasted by TS per Year (kWh)	Amount of Station Service Energy Forecasted by TS per Year (MWh)	Annual Average Market Price Forecast ($/MWh)	Cost Allocation for Station Service ($)
1	**79,567,320**	**79,567**	**$ 40.58**	**$ 3,228,829**