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

BP-16 Initial Rate Proceeding

Power Loads and Resources Study

BP-16-E-BPA-03

December 2014

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER step	Actual Energy Regulation study
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPA-P	Bonneville Power Administration – Power
BPA-T	Bonneville Power Administration – Transmission
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DOP	Detailed Operating Plan
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power

ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GMS	Generation Management Service
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid C	Mid Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour

NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NRFS	New Resource Flattening Service
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OPER step	operational study
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people’s utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation

REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

1. INTRODUCTION AND OVERVIEW

1.1 Introduction

The Power Loads and Resources Study (Study) contains the load and resource data used to develop Bonneville Power Administration's (BPA's) wholesale power rates. This Study illustrates how each component of the loads and resources analysis is completed, how the components relate to each other, and how they fit into the rate development process. The Power Loads and Resources Study Documentation (Documentation), BP-16-E-BPA-03A, contains details and results supporting this Study.

This Study has two primary purposes: (1) to determine BPA's load and resource balance (load-resource balance); and (2) to calculate various inputs that are used in other studies and calculations within the rate case. The purpose of BPA's load-resource balance analysis is to determine whether BPA's resources meet, are less than, or are greater than BPA's load for the rate period, fiscal years (FY) 2016–2017. If BPA's resources are less than the amount of load forecast for the rate period, some amount of system augmentation is required to achieve load-resource balance.

This Study provides inputs into various other studies and calculations in the ratemaking process. The results of this Study provide data to (1) the Power Rates Study, BP-16-E-BPA-01; (2) the Power Revenue Requirement Study, BP-16-E-BPA-02; and (3) the Power Risk and Market Price Study, BP-16-E-BPA-04.

1.2 Overview of Methodology

This Study includes three main components: (1) load data, including a forecast of the Federal system load and contract obligations; (2) resource data, including Federal system resource and contract purchase estimates, total Pacific Northwest (PNW) regional hydro resource estimates, and the estimated amount of power purchases that are eligible for section 4(h)(10)(C) credits under the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. §§ 839–839h; and (3) the Federal system load-resource balance, which compares Federal system sales, loads, and contract obligations to the Federal system generating resources and contract purchases.

The first component of the Study, the Federal system load obligation forecast, estimates the firm energy that BPA expects to serve during FY 2016–2017 under firm requirements contract obligations and other BPA contract obligations. The load estimates are discussed in section 2 of this Study and are detailed in the Documentation.

The second component of the Study is the resource component, which includes the forecast of (1) Federal system resources; (2) PNW regional hydro resources; and (3) power purchases eligible for 4(h)(10)(C) credits. The Federal system resource forecast includes hydro and non-hydro generation estimates plus power deliveries from BPA contract purchases. The Federal system resource estimates are discussed in section 3.1 of this Study and are detailed in the Documentation. The PNW regional hydro resources include all hydro resources in the Pacific Northwest, whether Federally or non-Federally owned. Energy generation estimates of the PNW regional hydro resources are used in the forecast of electricity market prices in the Power Risk and Market Price Study, BP-16-E-BPA-04. The regional hydro estimates are discussed in section 3.2 of this Study and are detailed in the Documentation. The resource estimates used to calculate the 4(h)(10)(C) credits are discussed in section 3.3 of this Study, and the estimated power purchases eligible for 4(h)(10)(C) credits are detailed in the Documentation.

These 4(h)(10)(C) credits are taken by BPA to offset the non-power share of fish and wildlife costs incurred as mitigation for the impact of the Federal hydro system. *See* § 3.3.1.

The third component of this Study is the Federal system load-resource balance, which completes BPA's load and resource picture by comparing total Federal system load obligations to Federal system resource output for FY 2016–2017. Federal system resources under critical water conditions minus loads yields BPA's estimated Federal system monthly and annual firm energy surplus or deficit. If there is a forecast annual average firm energy deficit, system augmentation is added to Federal system resources to balance loads and resources. The load-resource balance is discussed in section 4 of this Study and is detailed in the Documentation.

Throughout the Study and Documentation, the load and resource forecasts are shown using three different measurements. The first, energy in average megawatts (aMW), is the average amount of energy produced or consumed over a given time period, in most cases a month. The second measurement, heavy load hour energy in megawatthours (MWh), is the total MWh generated or consumed over heavy load hours. Heavy load hours (referred to as either Heavy or HLH) can vary by contract but generally are hours 6 a.m. to 10 p.m. (or Hour Ending (HE) 0007 to HE 2200), Monday through Saturday, excluding North American Electric Reliability Corporation (NERC) holidays. The third measurement, light load hour energy in MWh, is the total MWh generated or consumed over light load hours. Light load hours (referred to as either Light or LLH) can vary by contract but generally are hours 10 p.m. to 6 a.m. (or HE 2300 to HE 0006), Monday through Saturday, all day Sunday, and holidays defined by NERC. These measurements are used to ensure that BPA will have adequate resources to meet the variability of loads.

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2. FEDERAL SYSTEM LOAD OBLIGATION FORECAST

2.1 Overview

The Federal System Load Obligation forecast includes: (1) BPA's projected firm requirements power sales contract (PSC) obligations to consumer-owned utilities (COUs) and Federal agencies (together, for purposes of this Study, called Public Agencies or Public Agency Customers); (2) PSC obligations to investor-owned utilities (IOUs); (3) PSC obligations to direct-service industries (DSIs); (4) contract obligations to the U.S. Bureau of Reclamation (USBR); and (5) other BPA contract obligations, including contract obligations outside the Pacific Northwest region (Exports) and contract obligations within the Pacific Northwest region (Intra-Regional Transfers (Out)). Summaries of BPA's forecasts of these obligations follow in this section.

2.2 Public Agencies' Total Retail Load and Firm Requirement PSC Obligation Forecasts

In December 2008, BPA executed power sales contracts with Public Agencies under which BPA is obligated to provide power deliveries from October 1, 2011, through September 30, 2028. They are referred to as Contract High Water Mark (CHWM) contracts. Three types of CHWM contracts were offered to customers: Load-Following, Slice/Block, and Block (with or without Shaping Capacity). Of the 135 BPA Public Agency CHWM customers, 118 signed Load Following contracts, 16 signed Slice/Block contracts, and one signed a Block contract.

Under these CHWM contracts, customers must make elections to serve some of their load by (1) adding new non-Federal resources; (2) buying power from sources other than BPA; and/or (3) requesting BPA to supply power. The quantities of these elections factor into the forecasting process to determine the total amount of energy BPA will be obligated to serve under each customer's PSC.

2.2.1 Load Following PSC Obligation Forecasts

The Load Following product provides firm power to meet the customer's total retail load, less the firm power from the customer's non-Federal resource generation amounts and purchases from other suppliers used to serve the customer's total retail load.

The total monthly firm energy requirements PSC obligation forecast for Public Agency customers that purchase the Load Following product is based on the sum of the utility-specific firm requirements PSC obligation forecasts, which are customarily produced by BPA analysts. The method used for preparing the firm requirements PSC obligation forecasts is as follows.

First, utility-specific forecasts of total retail load are produced using least-squares regression-based models on historical monthly energy loads. These models may include several independent variables, such as a time trend, heating degree days, cooling degree days, and monthly indicator variables. Heating and cooling degree days are measures of temperature effects to account for changes in electricity usage related to temperature changes. Heating degree days are calculated when the temperature is below a base temperature, such as 65 degrees; similarly, cooling degree days are calculated when the temperature is above the base temperature. The results from these computations are utility-specific monthly forecasts of total retail energy load. The total retail energy load is split into HLH and LLH time periods using recent historical relationships.

The monthly peak loads are forecast similarly, including the use of historical data for the customers' peaks.

Second, estimates of customer-owned and consumer-owned dedicated resource generation and contract purchases dedicated to serve retail loads are subtracted from the utility-specific total retail load forecasts to produce a firm requirement PSC obligation forecast for each utility. These firm requirement PSC obligation forecasts provide the basis for the Load Following product sales projections incorporated in BPA ratemaking.

A list of the 118 Public Agency customers that have purchased the Load Following product is shown in Documentation Table 1.1.1. BPA's forecast of the total Public Agency PSC obligation including Federal Agencies is summarized in Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH, on line 3 *(Load Following)*. The components of this forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 2 *(Federal Agencies)* and line 6 *(Load Following)*.

2.2.2 Block PSC Obligation Forecasts

The Block product provides a planned amount of firm requirements power to serve the customer's total retail load up to its planned net requirement. The customer is responsible for using its own non-Federal resources or unspecified resources dedicated to its total retail load to meet any load in excess of the planned monthly BPA purchase.

The single Block customer is identified in Documentation Table 1.1.2. BPA's forecast of the total Block PSC Obligation is summarized in Documentation Table 1.2.1 for energy, Table 1.2.2

for HLH, and Table 1.2.3 for LLH, on line 14 *(Tier 1 Block)*. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 7 *(Tier 1 Block)*.

2.2.3 Slice/Block PSC Obligation Forecasts

The Slice/Block product provides firm requirements power to serve the customer's total retail load up to its planned net requirement. For each fiscal year, the planned annual Slice/Block amounts are adjusted based on BPA's calculation of the customer's planned net requirement under the contract. The Block portion of the Slice/Block product (Slice Block) provides a planned amount of firm requirements power in a fixed monthly shape, while the Slice Output from the Tier 1 System (Slice Output) portion provides planned amounts of firm requirements power in the shape of BPA's generation from the Tier 1 System.

The annual Slice Block forecast and monthly shape of the Slice Block product for FY 2016–2017 is calculated by multiplying: (i) the Tier 1 Block Monthly Shaping Factors in the customer's CHWM contract; by (ii) the customer's planned annual net requirement in aMW less its annual forecast Critical Slice Amounts, as defined in the CHWM Contract. Critical Slice Amounts are forecast to equal the customer's Slice Percentage multiplied by the applicable annual forecasts used in the RHWM Tier 1 System Capability forecasts. Slice Block obligation forecasts may change in the Final Proposal due to updated planned net requirement forecasts. The Critical Slice Amounts used to calculate the Slice Block amounts are not expected to change in the Final Proposal.

BPA's Slice Output obligations for the Slice/Block customers is forecast by multiplying the monthly forecast of Tier 1 System output by the sum of the individual customers' Slice

Percentages as listed in the Slice/Block CHWM Contracts. The Tier 1 System output is comprised of Federal system resources and the net of contracts specified in the TRM. The Tier 1 System forecasts will be updated, incorporating any changes in hydro and non-hydro resource forecasts and specified Tier 1 contracts for the Final Study. *See* § 3.4.

A list of the 16 Slice/Block customers is shown in Documentation Table 1.1.3. BPA's forecast of the total Slice/Block PSC Obligation is summarized in Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH, on line 8 *(Slice Block)* and line 11 *(Slice Output from Tier 1 System)*. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 8 *(Slice Block)* and line 9 *(Slice Output from Tier 1 System).*

2.2.4 Sum of Load Following, Slice/Block, and Block PSC Obligation Forecasts

The sum of the projected firm requirements PSC obligations for customers with CHWM contracts comprises the Public Agencies Preference Customers' portion of the Priority Firm Public (PFp) load obligation forecast. Each customer's load obligation forecast accounts for the reported amount of conservation that the customer plans to achieve during the FY 2016–2017 rate period. These forecasts do not include additional BPA-funded conservation beyond what the customers have reported they plan to achieve. Due to the structure of Tiered Rates it is important to attribute conservation achieved to individual customers. As individual customers achieve conservation measures in addition to what they already committed to, the customers will receive credits on their power bills reflecting lower loads due to these conservation measures. The annual average energy PF load obligations by product for FY 2016–2017 are presented in Table 3.

2.3 Investor-Owned Utilities Sales Forecast and Other Load Served at the NR Rate

The six IOUs in the PNW region are Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation (formerly Montana Power Company), PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Most of the IOUs have signed BPA power sales contracts for FY 2011 through 2028; however, no IOUs have chosen to take service under these contracts. If requested, BPA would serve any net requirements of an IOU at the New Resource Firm Power (NR-16) rate. No net requirements power sales to regional IOUs are forecast for FY 2016–2017 based on BPA's current contracts with the regional IOUs.

In addition, BPA makes power available at the NR-16 rate to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act, 16 U.S.C. §§ 839–839h. BPA also offers products at the NR-16 rate for customers electing to serve its NLSL(s) with its own dedicated resources. However, no sales at the NR-16 rate are forecast in the FY 2016–2017 rate period.

2.4 Direct Service Industry Sales Forecast

Currently BPA is making power sales deliveries to Alcoa, Inc. (Alcoa) and Port Townsend Paper Corporation (Port Townsend). Port Townsend's current contract with BPA runs through September 30, 2022. Under the current contract, BPA will provide a maximum contract demand of 15.75 MW to Port Townsend through September 30, 2022. In addition to BPA's current contract with Port Townsend, Jefferson County PUD serves Port Townsend's wheel turning load (load not integral to the industrial process) and Port Townsend's Old Corrugated Containers (OCC) recycling plant load, totaling 8.5 aMW. Jefferson County PUD's load forecast reflects this service arrangement. BPA assumes in this Study that it will continue to serve the remainder of Port Townsend's load, approximately 15.5 aMW. BPA and Alcoa signed a new 10-year power sales contract on December 7, 2012, for 300 aMW. Thus, this Study assumes power sales to the DSIs totaling 315.5 aMW for each year of the rate period, comprised of 300 aMW for Alcoa and 15.5 aMW for Port Townsend, all sold at the IP-16 rate.

The DSI forecast is summarized in Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH, on line 1 *(DSI Obligation)*. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 4 *(DSI Obligation)*.

2.5 USBR Irrigation District Obligations

BPA is obligated to provide power from the Federal system to several irrigation districts associated with USBR projects in the Pacific Northwest. These irrigation districts have been congressionally authorized to receive power from specified Federal Columbia River Power System (FCRPS) projects as part of the USBR project authorization. BPA does not contract directly with these irrigation districts; instead, there are several agreements between BPA and USBR that provide details on the power deliveries.

A list of USBR irrigation district obligation customers is shown in Documentation Table 1.1.4. BPA's forecast of the total USBR customer load is summarized in Documentation Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH, on line 18 *(U.S. Bureau of Reclamation Obligation)*. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 3 *(USBR Obligation)*.

2.6 Other Federal System Contract Obligations

BPA provides Federal power to customers under a variety of contract arrangements not included in the Public Agencies, IOU, DSI, or USBR forecasts. These contract obligations are categorized as: (1) power sales; (2) power or energy exchanges; (3) capacity sales or capacity-for-energy exchanges; (4) power payments for services; and (5) power commitments under the Columbia River Treaty. These arrangements, collectively called "Other Contract Obligations," are specified by individual contract provisions and can have various delivery arrangements and rate structures. BPA's Other Contract Obligations are assumed to be served by Federal system firm resources regardless of weather, water, or economic conditions. These contracts include obligations delivered to entities outside the Pacific Northwest region (Exports) and obligations delivered to entities within the Pacific Northwest region (Intra-Regional Transfers (Out)). These contract obligations are modeled individually and are specified or estimated for monthly energy in aMW, HLH, and LLH.

BPA's Export contract obligations are detailed in Documentation Table 1.3.1 for energy, Table 1.3.2 for HLH, and Table 1.3.3 for LLH. BPA's Intra-Regional Transfers (Out) contract obligations are detailed in Documentation Table 2.9.1 for energy, Table 2.9.2 for HLH, and Table 2.9.3 for LLH, on line 12 *(Intra-Regional Transfers (Out))*. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 10 *(Exports)* and line 11 *(Intra-Regional Transfers (Out))*.

Estimates of trading floor sales during the rate period are not included in BPA's load-resource balance used in ratemaking. Revenue impacts of these contract obligations are reflected as presales of secondary energy and are included as secondary revenues credited to non-Slice customers' rates. These contracts are accounted for as committed sales in the Power Risk and Market Price Study Documentation, BP-16-E-BPA-04A.

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3. RESOURCE FORECAST

3.1 Federal System Resource Forecast

3.1.1 Overview

In the Pacific Northwest, BPA is the Federal power marketing agency charged with marketing power and transmission to serve the firm electric load needs of its customers. BPA does not own generating resources; rather, BPA markets power from Federal and non-Federal generating resources to meet Federal load obligations. In addition, BPA purchases power through contracts that add to the Federal system generating capability. These resources and contract purchases are collectively called “Federal system resources” in this Study. Federal system resources are classified as Federal regulated and independent hydro projects, non-Federal independent hydro projects, other non-Federal resources (renewable, cogeneration, large thermal, wind, and small non-utility generation [NUG] projects), and Federal contract purchases.

3.1.2 Federal System Hydro Generation

Federal system hydro resources are comprised of the generation from regulated and independent hydro projects. Regulated projects and the process used for estimating the generation of regulated hydro projects are detailed in section 3.1.2.1. Independent hydro projects and the methodology for forecasting generation of independent hydro projects are described in section 3.1.2.2. BPA also purchases the output from two small NUG hydro projects. Generation estimates for these small hydro projects were provided by each individual project owner and are assumed not to vary by water year. Small hydro projects are described in section 3.1.3.

3.1.2.1 Regulated Hydro Generation Forecast

BPA markets the generation from the Federal system hydro projects, listed in Documentation Table 2.1.1, lines 2–15. These projects are owned and operated by either the U.S. Army Corps of Engineers (USACE) or USBR.

This Study uses BPA's hydrosystem simulator model, HYDSIM, to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the PNW Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for 80 water years (October 1928 through September 2008). The hydro projects modeled in HYDSIM are called regulated hydro projects. The hydro regulation study uses individual project operating characteristics and conditions to determine energy production expected from each specific project. Physical characteristics of each project come from annual Pacific Northwest Coordination Agreement (PNCA) data submittals from regional utilities and government agencies involved in the coordination and operation of regional hydro projects. The HYDSIM model provides project-by-project monthly energy generation estimates for the Federal system regulated hydro projects that vary by water year. HYDSIM incorporates and produces data for 14 periods per year, including 10 calendar months and two periods each for April and August. This 14-period data is referred to as monthly data for simplicity.

There are three main steps of the hydro regulation studies that estimate regulated hydro generation production. First, the Canadian operation is set based on the best available information from the Columbia River Treaty (Treaty) planning and coordination process. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and a Detailed Operating Plan (DOP) to be completed if necessary the year prior to the operating year. The DOP reflects modifications to the AOP if agreed to by the U.S. and Canada and is usually completed a few months prior to the operating year. These official DOP studies from the Columbia River Treaty process are not available in time for use in BPA's ratesetting process. As a surrogate for the official 2016 and 2017 DOP studies, the official 2016 and 2017 AOP studies are used with a few modifications to reflect updates expected in the official DOP studies. These are referred to as "surrogate DOP" studies and reflect the best estimate available for Canadian operations before the official DOP studies are available. The surrogate DOP studies include the official AOP study assumptions plus the following updates: (1) 80-year historical water conditions instead of 70; (2) most recent flood control data provided by the USACE; and (3) most recent plant data available from project owners through the PNCA planning and coordination process.

Second, an Actual Energy Regulation study (AER step) is run in HYDSIM to determine the operation of the hydro system under each of the 80 years of historical water conditions while meeting the Firm Energy Load Carrying Capability (FELCC) produced in the PNCA final hydro regulation. In this step, the Canadian operation is fixed to the surrogate DOP studies. Also in this step, the U.S. Federal, U.S. non-Federal, and Canadian reservoirs draft water to meet the Coordinated System FELCC while continuing to meet individual reservoir non-power operating requirements.

Third, an 80-year operational study (OPER step) is run in HYDSIM with the estimated regional firm loads developed for each year of the Study and with any deviations from the PNCA data submittals necessary to reflect expected operations during the rate period. In the OPER step the non-Federal projects are fixed to their operations from the AER step, and the Federal projects operate differently based on the deviations from PNCA data and the estimated regional firm load.

In summary, a surrogate DOP is used to determine the Canadian operations, an AER step is run based on PNCA data to determine the operation of the non-Federal projects, and an OPER step is run to determine the operation of the Federal projects based on PNCA data plus additional assumptions needed to reflect expected operations. The end result of these three steps is generally referred to as the hydro regulation study.

For this Study, separate hydro regulation studies are incorporated for each year of the rate period. By modeling hydro regulation studies for individual years, the hydro generation estimates capture changes in variables that characterize yearly variations in the hydro operations due to firm loads, firm resources, markets for hydro energy products in better than critical water conditions, and project operating limitations and requirements. These variables affect the amount and timing of energy available from the hydro system and are changed as necessary to reflect current expectations. Sections 3.1.2.1.1 through 3.1.2.1.4 contain additional details on the process of producing the regulated hydro generation estimates used in this Study.

Documentation Tables 2.1.1, 2.1.2, and 2.1.3, lines 2–15, list the hydro projects included in BPA's Regulated Hydro Generation forecast. An aggregate of the Federal system regulated hydro generation is summarized for energy in Documentation Table 2.1.1, HLH in Table 2.1.2, and LLH in Table 2.1.3, on line 17 *(Total Regulated Hydro).* The regulated hydro HLH and LLH split is based on the aggregated Federal system regulated hydro generation estimates produced by BPA's Hourly Operating and Scheduling Simulator (HOSS) analyses, which utilize the HYDSIM hydro regulation studies as their base input. *See* section 3.1.2.1.4. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 15 *(Regulated Hydro – Net).*

The energy for the net regulated hydro generation is provided to the Power Risk and Market Price Study, BP-16-E-BPA-04. The HLH and LLH Federal system regulated hydro generation estimates are later combined with the Federal system independent hydro HLH-LLH split in the Power Risk and Market Price Study, BP-16-E-BPA-04.

3.1.2.1.1 Assumptions in the HYDSIM Hydro Regulation Study

The HYDSIM studies incorporate the power and non-power operating requirements expected to be in effect during the rate period, including those described in the National Oceanic and Atmospheric Administration (NOAA) Fisheries FCRPS Biological Opinion (BiOp) regarding salmon and steelhead, published May 5, 2008; the NOAA Fisheries FCRPS Supplemental BiOp, published May 20, 2010; the NOAA Fisheries FCRPS Supplemental BiOp, published January 17, 2014; the U.S. Fish and Wildlife Service (USFWS) FCRPS BiOp regarding bull trout, published December 20, 2000; the USFWS Libby BiOp regarding bull trout and Kootenai River white sturgeon, published February 18, 2006; relevant operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program; and other fish mitigation measures. Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation efficiency requirements.

Additionally, HYDSIM uses hydro plant operating characteristics in combination with power and non-power requirements to simulate the coordinated operation of the hydro system. These operating requirements include but are not limited to storage content limits determined by rule curves, maximum project draft rates determined by each project owner, and flow and spill objectives described in the NOAA Fisheries and USFWS BiOps listed above and as provided by the 2014 PNCA data submittals. Some deviations from the 2014 PNCA data submittals are necessary to more accurately model anticipated operations for the rate period, such as fine-tuning the study to reflect typical in-season management decisions that are not reflected in the 2014 PNCA data submittals.

The hydro regulation studies include sets of power and non-power requirements for each year of the rate period. Specific assumptions for the HYDSIM hydro regulation study are detailed in the Documentation, section 3.

Several changes have been made to the hydro modeling since the BP-14 Loads and Resources Study. These changes have been made as part of BPA's continuous efforts to incorporate the most recent available data in the model and to improve hydro regulation modeling to more accurately reflect operations. The following are the more significant updates to the HYDSIM hydro regulation studies included in this Study:

- All projects have been updated according to 2014 PNCA data. These updates are too numerous to list in their entirety and tend to be minor. The following are some of the more noteworthy PNCA data updates:
  - Albeni Falls' operation was updated based on data submitted by the USACE.
  - Duncan and Libby operations are no longer constrained by the Kootenay Lake elevation in January through April.
- Flood Control rule curves have been updated to the most recent data provided by the USACE.
- Canadian project operations have been updated based on the surrogate 2016 DOP and 2017 DOP described earlier. Because the 2016 AOP and 2017 AOP studies include identical Canadian operations, the surrogate DOP studies are the same for the FY 2016 and FY 2017 HYDSIM studies.

- The operation under the Libby Coordination Agreement is not included in the BP-16 HYDSIM study because it is price-dependent and impractical to forecast.
- Loads and independent hydro projects have been updated based on the numbers presented in this Study. HYDSIM uses the residual hydro load for the region, which is calculated by subtracting the regional firm non-hydro resources from the total regional firm load. As a result, assumptions for other resources affect the residual hydro loads used in HYDSIM. Since the BP-14 HYDSIM study, the capacity factor assumption for combustion turbine resources has been changed to 90 percent. The residual hydro load in the BP-16 HYDSIM study is lower than in the BP-14 HYDSIM study primarily due to this change in assumption for combustion turbine resources.
- Miscellaneous updates have been made to better reflect expected actual operations:
  - The assumed start date of Libby's sturgeon pulse operation has been updated based on the most recent information available.
  - Updated modeling has been incorporated to remove forced drafts for drum gate maintenance at Grand Coulee during FY 2016. This is because enough maintenance has been performed during the past few years to ensure that maintenance requirement can be met without forcing the draft specifically for maintenance purposes in FY 2016.
  - Brownlee's operation has been updated based on the most-recent information available.
  - Kerr's operation has been updated based on the project owner's best estimate.

- There have been several spill updates since the BP-14 Power Loads and Resources Study based on the 2014 NOAA Fisheries BiOp and the most recent information available:
  - The spring maximum transport operation in two weeks of all years at Lower Granite, Little Goose, and Lower Monumental assumed in the BP-14 HYDSIM study is not included in the BP-16 HYDSIM study.
  - The spring maximum transport operation in dry years at Lower Granite, Little Goose, and Lower Monumental assumed in the BP-14 HYDSIM study is not included in FY 2016. In FY 2017, a spring maximum transport operation is assumed in years when the average spring flow (April through June) at Lower Granite is less than 55 thousand cubic feet per second (kcfs). In the eight water years that meet this criteria, Lower Granite, Little Goose, and Lower Monumental do not spill for fish passage April – June 4 and start summer spill on June 5.
  - Lower Granite is assumed to spill 20 kcfs during the spring April 3–June 20 (previously April 3–June 4) and 18 kcfs during the summer June 21–August 9 (previously June 5–August 7).
  - Little Goose is assumed to spill 30 percent of the total river discharge during the spring and summer April 3–August 17 (previously April 5–August 12).
  - Lower Monumental is assumed to spill equal to its dissolved gas cap during the spring April 3–June 20 (previously April 7–June 4) and 17 kcfs during the summer June 21–August 19 (previously June 5–August 15).
  - Ice Harbor is assumed to spill 45 kcfs day and dissolved gas cap night April 3–April 28; alternate between 30 percent of the total river discharge and 45 kcfs day and dissolved gas cap night April 29–July 13; and 45 kcfs

day and dissolved gas cap night July 14–August 21 (previously 35 percent of the total river discharge April 7–June 15 and 30 percent of the total river discharge June 16–August 16).

  – John Day is assumed to spill 30 percent of the total river discharge April 10–April 27; alternate between 30 percent of the total river discharge and 40 percent of the total river discharge April 28–July 20; and 30 percent of the total river discharge July 21–August 31 (previously 30 percent of the total river discharge April 10–August 31).
  – Spill priorities and dissolved gas caps have been updated based on the most recent data available.

- Federal powerhouse availability factors have been updated using a combination of planned outages, forced outages that are based on historical data with additional input from the project owners, and more recent balancing and operating reserve requirement assumptions. *See* § 3.1.2.1.4. These balancing and operating reserve requirement updates are incorporated into the availability factors in HYDSIM and reduce the powerhouse generating capability.
- The lack of market spill has been updated based on estimates from the AURORAxmp® model.

These HYDSIM study changes generally decrease firm generation (annual average during 1937 critical water conditions) and slightly decrease average generation (80-year annual average). The study decreases the BP-16 rate period annual average Federal generation about 160 aMW in 1937 critical water conditions compared to the BP-14 rate period annual average. The study decreases the BP-16 rate period 80-year average Federal generation about 10 aMW compared to the BP-14 rate period 80-year average. The separate effects of each modeling change have not been analyzed. However, the changes are largely attributable to a couple of the more significant changes, which include the updates to the Canadian Treaty operations and the spill assumptions for Lower Granite, Little Goose, Lower Monumental, Ice Harbor, and John Day.

The assumptions in the hydro regulation studies are the same for FY 2016 and FY 2017 except for the following:

- The hydro availability factors used to model anticipated unit outages and the standard reserve requirements are estimated for each study year. The unit outages reflect estimates for each year and are different in the FY 2016 and FY 2017 studies. The availability factors are adjusted to reflect the estimated amount of reserve requirements, including operating reserves and balancing reserve capacity. The reserve requirements were the same for FY 2016 and FY 2017. *See* § 3.1.2.1.4.
- The residual hydro loads assumed in HYDSIM are different in the two hydro regulation studies. The loads incorporated in the FY 2017 hydro regulation study are slightly higher than the loads projected for the FY 2016 hydro regulation study on an annual average basis, mainly due to load growth, but also due to changes in regional thermal resources.
- The amounts of spill due to lack of market are different in the two hydro regulation studies. These differences come from the AURORAxmp® model, which simulated the different anticipated market conditions in each of the two years.
- The Grand Coulee drum gate maintenance operation is not included in FY 2016 but is included in FY 2017, as described above.

- The spring maximum transport operation in dry years is not included in FY 2016 but is included in FY 2017 in years when the average spring flow (April through June) at Lower Granite is less than 55 kcfs, as described above.

3.1.2.1.2 80-Year Modified Streamflows

The HYDSIM model uses streamflows from historical years as the basis for estimating power production of the hydroelectric system. The HYDSIM studies are developed using the 2010 level of modified historical streamflows. Historical streamflows are modified to reflect the changes over time due to the effects of irrigation and consumptive diversion demand, return flow, and changes in contents of upstream reservoirs and lakes. These modified streamflows were developed under a BPA contract funded by the PNCA parties. The modified streamflows are also adjusted in this Study to include updated estimates of Grand Coulee irrigation pumping and resulting downstream return flows, using data provided by USBR in its 2014 PNCA data submittal.

Eighty years of streamflow data are used because hydro is a resource with a high degree of variability in generation from year to year. The Study uses an 80-year hydro regulation study to forecast the expected operations of the regulated hydro projects for varying hydro conditions. Approximately 80 percent of BPA’s Federal system resource stack is comprised of hydro generation, which can vary annually by about 5,000 aMW depending on water conditions. HYDSIM estimates regulated hydro project generation for varying water conditions and takes into account specific flows, volumes of water, elevations at dams, biological opinions, and many other aspects of the hydro system. Given the variability of hydro generation, as many years as possible are modeled; 80 years is the largest number of years for which all the historical data are available as needed by HYDSIM.

Additionally, BPA has generation estimates for other hydro projects that are based on 80 historical water conditions, October 1928 through September 2008. These projects are called "independent hydro" projects because their operations are not regulated in this HYDSIM study, primarily because they have much less storage capability than the hydro projects in the Columbia River Basin regulated in the HYDSIM study. The independent hydro projects usually have generation estimates for each of the 80 water years of record. Most of these hydro projects are not Federally owned, and their generation estimates are updated with the cooperation of each project owner. For those independent hydro projects that did not have data for all 80 water years, generation estimates were expanded using the project's median generation to estimate generation for the additional water years.

3.1.2.1.3 1937 Critical Water for Firm Planning

To ensure that it has sufficient generation to meet load, BPA bases its resource planning on critical water conditions. Critical water conditions are when the PNW hydro system would produce the least amount of power while taking into account the historical streamflow record, power and non-power operating constraints, the planned operation of non-hydro resources, and system load requirements. For operational purposes, BPA considers critical water conditions to be the eight-month critical period of September 1936 through April 1937. For planning purposes and to align with the fiscal years used in this Study, however, the Study uses the historical streamflows from October 1936 through September 1937 water conditions as the critical period. This is designated "1937 critical water conditions." The hydro generation estimates under 1937 critical water conditions determine the critical period firm energy for the regulated and independent hydro projects. This is called the FELCC, or firm energy load carrying capability.

3.1.2.1.4 Regulated Hydro HLH/LLH Split Calculation Using HOSS

The monthly energy produced by HYDSIM for each regulated hydro project is split between heavy and light load hours for input to the market price forecast in the Power Risk and Market Price Study, BP-16-E-BPA-04, section 2.5.2.1. To calculate the HLH/LLH regulated hydro splits, BPA forecasts an hourly simulation of the regulated hydro projects' operation using HOSS. The hourly outputs of HOSS are not directly used for ratesetting purposes. Rather, the hourly HOSS outputs are used to derive monthly Federal system regulated hydro generation energy relationships. These monthly relationships provide monthly HLH energy and LLH energy shapes used in ratemaking.

To simulate hourly Federal regulated hydro generation, the HOSS model uses HYDSIM monthly project flows, initial and ending conditions, reserve requirements, and other power and non-power constraints that are discussed in section 3.1.2.1. The HOSS studies incorporate the same monthly versions of input data for Regulating Reserve, Operating Reserve, Load Following Reserve, Dispatchable Energy Resource Balancing Service (DERBS) Reserve, and Variable Energy Resource Balancing Service (VERBS) Reserve as are used in HYDSIM. For purposes of this Study, the amount of balancing reserve capacity available from the FCRPS was capped at 900 MW of *inc* reserves in August through March, 400 MW of *inc* reserves in April through July and *dec* reserves of 900 MW for all months**.**

The resulting HOSS model generation study shapes the monthly energy from HYDSIM into HLH and LLH Federal hydro generation, by period, for each of the 80 water conditions of the study period. These projections provide the basis for the Federal system hydro energy relationships that provide HLH and LLH energy splits that are shown in the Documentation, BP-16-E-BPA-03A, Tables 2.1.2 and 2.1.3, and inputs to the Power Risk and Market Price Study, BP-16-E-BPA-04, section 2.4.

3.1.2.2 Independent Hydro Generation Forecast

Federal system independent hydro includes hydro projects whose generation output typically varies by water conditions; however, the generation forecasts for these projects are not modeled or regulated in the HYDSIM model. BPA markets the power from independent hydro projects that are owned and operated by USBR, USACE, and other project owners. Federal system independent hydro generation estimates are provided by individual project owners for 80 water years (October 1928 through September 2008). These include power purchased from hydro projects owned by Lewis County Public Utility District (Cowlitz Falls), Mission Valley (Big Creek), and Idaho Falls Power (Bulb Turbine project). Documentation Tables 2.2.1, 2.2.2, and 2.2.3, lines 1–22, list the hydro projects included in BPA's Independent Hydro Generation forecast.

The energy estimates for Federal system independent hydro generation used in this Study are summarized in Documentation section 2.2, Table 2.2.1 for energy, Table 2.2.2 for HLH, and Table 2.2.3 for LLH, line 24. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 16 *(Independent Hydro – Net)*.

The HLH-LLH split for the independent hydro generation estimates is developed based on actual historical data. This Study provides the HLH and LLH Federal system independent hydro generation to the Power Risk and Market Price Study, BP-16-E-BPA-04.

3.1.3 Other Federal System Generation

Other Federal system generation includes the purchased output from non-Federally owned projects and project generation that is directly assigned to BPA. Other Federal system generation estimates are detailed for monthly energy in aMW and HLH and LLH megawatthours as follows.

(1) Cogeneration resources include the Georgia-Pacific (Wauna) project, from which BPA has acquired the power output through March 31, 2016. This project is detailed in Documentation Table 2.3.1 for energy, Table 2.3.2 for HLH, and Table 2.3.3 for LLH. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 18 *(Cogeneration Resources)*.

(2) Large thermal resources include the Columbia Generating Station project, whose forecast features a two-year refueling cycle. The generation forecast incorporates facility improvements that were not included in the BP-14 Final Study. The generation forecast for Columbia Generating Station is shown in Documentation Table 2.4.1 for energy, Table 2.4.2 for HLH, and Table 2.4.3 for LLH. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 20 *(Large Thermal Resources)*.

(3) Renewable resources, which include wind resources (Federal purchases of shares of the Condon Wind Project; Foote Creek 1 and 4 Wind Projects; Klondike I Wind Project; Klondike III Wind Project; Stateline Wind project; Ashland Solar; and White Bluffs Solar). These projects are detailed in Documentation section 2.5, Table 2.5.1 for energy, Table 2.5.2 for HLH, and Table 2.5.3 for LLH. This forecast is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 21 *(Renewable Resources)*.

(4) Small hydro resources include the Dworshak/Clearwater Small Hydro project and Rocky Brook hydro project. Small hydro resources are detailed in Documentation Table 2.6.1 for energy, Table 2.6.2 for HLH, and Table 2.6.3 for LLH. This forecast is also included in the calculation of the load-resource balance, Documentation

Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 22 *(Small Hydro Resources)*.

3.1.4 Federal System Contract Purchases

BPA purchases or receives power under a variety of contractual arrangements to help meet Federal load obligations. The contracts are categorized as (1) power purchases; (2) power or energy exchange purchases; (3) capacity sales or capacity-for-energy exchange contracts; (4) power purchased or assigned to BPA under the Columbia River Treaty; and (5) transmission loss returns under Slice/Block contracts. These arrangements are collectively called "Contract Purchases." BPA's Contract Purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. The transmission loss returns category captures the return of Slice transmission losses to the Federal system as part of the Slice/Block contracts, which acts as a Federal system resource.

BPA's expected Contract Purchases are detailed in the Documentation as follows. Power purchases from delivery points outside the Pacific Northwest Region are termed Imports, which are found in Documentation Table 2.7.1 for energy, Table 2.7.2 for HLH, and Table 2.7.3 for LLH. Non-Federal Canadian Entitlement Return deliveries are found in Documentation Table 2.8.1 for energy, Table 2.8.2 for HLH, and Table 2.8.3 for LLH. Power purchases from delivery points within the Pacific Northwest Region are called Intra-Regional Transfers (In) and are found in Documentation Table 2.9.1 for energy, Table 2.9.2 for HLH, and Table 2.9.3 for LLH. Federal Transmission Loss Returns does not have its own table but is included in the Federal system load-resource balance calculation described below.

The forecast for Contract Purchases is also included in the calculation of the load-resource balance, Documentation Table 4.1.1 for energy, Table 4.1.2 for HLH, and Table 4.1.3 for LLH, on line 25 *(Imports)*, line 26 *(Intra-Regional Transfers (In))*, line 27 *(Non-Fed CER)*, and line 28 *(Slice Transmission Loss Returns)*.

Contract Purchases do not include purchases under BPA power contracts made to meet monthly within-year energy deficits or trading floor purchases (including purchases that have been made to meet Tier 2 load obligations served by BPA). BPA has made trading floor purchases that continue into FY 2016 and FY 2017, such as to meet anticipated Tier 2 obligations and purchases made to meet the Southern Idaho Load Service (SILS). These contracts are not included in the calculation of BPA's firm annual load-resource balance in this Study.

For Tier 2 load service, the load and contract purchase amounts match, and therefore would not impact load-resource balance. Purchases to meet SILS are for the purpose of providing transfer service and are not used to offset the need for system augmentation. Therefore, these purchases are excluded from the computation of system augmentation necessary to achieve load-resource balance. Any additional Federal system surplus over the 80-year water conditions due to these purchases would be sold as secondary energy or used to reduced balancing purchases. These contracts are reflected in the Power Risk and Market Price Study, BP-16-E-BPA-04.

Contract Purchases do include estimates of system augmentation purchases to meet any annual deficits of the Federal system load-resource balance. Calculation of system augmentation purchases is discussed in section 4.2.

3.1.5 Federal System Transmission Losses

3.1.5.1 Overview

Federal system transmission loss estimates are treated as generation reductions in the Study. These losses are calculated monthly and vary by water conditions. This Study includes expected Federal system transmission loss factors for energy and peak load conditions. The loss factors have several components that combine to give the estimate of losses typically associated with Federal system generation: (1) step-up transformers from generation to the high-voltage transmission network; (2) high-voltage network transmission; (3) transfers to Federal loads over non-Federal transmission systems; and (4) step-down transformers from high-voltage transmission to low-voltage delivery.

Of these four loss factor components, only component (3), transfer service to Federal loads over non-Federal transmission systems, has changed from the BP-14 Final Study. The other three transmission loss factor components used in this Study were developed in 1992 and reaffirmed by BPA's Transmission business unit in 1994, 2000, and 2011. BPA is not planning to change transmission loss components (1), (2), and (4) for BP-16.

Power Services updated the loss factor component that estimates transfer service losses to Federal loads over non-Federal transmission systems, using actual BPA transfer data, as described below in section 3.1.5.2. This update will make the transfer service loss factor component more accurately reflect the actual losses the FCRPS incurs for transfer service over third-party transmission systems. This update increased the loss factor estimate for Federal loads over non-Federal transmission systems from 0.34 percent to 0.49 percent for energy, HLH and LLH, and from 0.40 percent to 0.43 percent for peak deliveries when averaged over the year. This update increased the total Federal system loss factor for BPA's transmission system from

2.82 percent to 2.97 percent for energy, HLH and LLH, and from 3.35 percent to 3.38 percent for peak deliveries when averaged over the year. *See* section 3.1.5.2.

The estimated magnitude of each loss factor component for energy is as follows:

(1) Step-up transformers between the Federal generation and the transmission network: average losses of 0.31 percent.

(2) High-voltage network: average losses of 1.90 percent.

(3) Transfer service to Federal system loads over non-Federal transmission systems: average losses of 0.49 percent.

(4) Step-down transformer: average losses of 0.27 percent.

The Power Risk and Market Price Study, BP-16-E-BPA-04, uses the same transmission loss factors as this Study. The Power Rates Study, BP-16-E-BPA-01, uses the same transmission loss factors, but they are mathematically converted to be applied to loads.

3.1.5.2 Transfer Service Loss Factor Component Update

The third component of the Federal system transmission loss factor, transfer service to Federal loads over non-Federal transmission systems (Transfer Service Loss Factor), was updated for BP-16 based on best available actual transfer service loss data.

The Transfer Service Loss Factor represents the losses associated with BPA's transfer customer load service, which incurs losses crossing third-party transmission networks. Each third-party transmission provider assesses a system loss factor for deliveries on its system. Some third-party transmission providers also charge a distribution loss factor for transmitting power at lower voltages. For eight of these third-party transmission providers, BPA returns losses in kind from the FCRPS. These losses contribute to the loss factor for the Study.

The eight third-party transmission providers all have different system loss factors, and some have additional distribution loss factors that must be accounted for. Loss factor calculations were performed for energy and peak load conditions. Calculations provided in this section are shown in kWH to be consistent with BPA metering data and billing procedures.

BPA used actual transfer metered data from FY 2013 to calculate the Transfer Service Loss Factor. The Transfer Service Loss Factor for energy is presented in Table 1. To calculate the energy loss factor, first the total monthly energy for each transmission provider for each month of FY 2013 was determined. Next, the FY 2013 monthly average energy for each transmission provider was computed and compared against the FY 2013 monthly average energy for all transmission providers (10,264,438,280 kWH) to determine the percentage weights of energy for each transmission provider.

Several transmission providers also assess a distribution loss factor by individual point of delivery (POD). For those transmission providers with multiple distribution loss factors, the weighted average distribution loss factor was computed. The first step was to compare metered energy at each POD against total transmission provider energy to determine percentage weights. The percentage weights were then applied against the POD distribution loss factors. The sum of the weighted distribution loss factors was then computed, which equals the weighted distribution loss factor for that transmission provider. The total loss factor for each transmission provider was then computed by adding the transmission provider's system loss factor to its weighted average distribution loss factor.

Weighted average loss factors for each transmission provider were then calculated by applying the percentage weights of energy for each transmission provider to the total loss factors for each transmission provider. The sum of those weighted average loss factors is the weighted average transmission provider loss factor, which for FY 2013 was 3.38 percent when compared to the magnitude of the Federal system transfer loads. Table 1, line 11. To be directly comparable to the total Federal system load obligations, the weighted average transmission provider loss factor must be scaled to the total Federal system load obligations. The FY 2013 monthly average energy for all transmission providers (10,264,438,280 kWH) was divided by the monthly average energy of the FY 2014 total Federal system load obligations (70,948,981,435 kWH) from the BP-14 Final Rate Case *(8,099 MWh * 8760 hours/year * 1,000 kWH/MWh = 70,948,981,435 kWH).* FY 2014 was used because this data is the most recent published total Federal system load obligations used for ratesetting purposes. *See* BP-14 Final Loads and Resources Documentation, BP-14-FS-BPA-03A, Table 4.1.1, Loads and Resources – Federal System, Total Federal Firm Obligations, line 13, page 134, for FY 2014. Therefore, the percentage of Federal system transfer energy compared to Federal system total firm obligations represents 14.47 percent *(10,264,438,280 kWH / 70,948,981,435 kWH = 14.47 percent)* of total BPA firm obligations.

The final step to computing the transfer service energy loss factor was completed by multiplying the transfer energy percentage of total Federal system firm obligations (14.47 percent) by the weighted average transmission provider loss factor (3.38 percent), which is 0.49 percent *(14.47 percent * 3.38 percent = 0.49 percent).* Table 1 shows the transmission provider components used in updating the energy Transfer Service Loss Factor.

BPA updated the Transfer Service Loss Factor for both the energy and peak for this Study. Usually the peak number is needed for the Generation Inputs portion of the rate case. However, because the Generation Inputs portion of the rate case settled for BP-16, the Transfer Service Loss Factor for peak was not used. BPA is including the peak information in this Study for use in future studies.

BPA's calculation of the Transfer Service Loss Factor for peak used actual transfer metered data from FY 2013 actual transfer meter data. The Transfer Service Loss Factor for peak is presented in Table 2. The same calculation was completed as described above for average energy, except here BPA used the monthly peak amounts at the time of BPA's Transmission System Peak during each month of FY 2013. The FY 2013 monthly average peak load for each transmission provider was computed and compared against the FY 2013 monthly average peak load for all transmission providers (1,371,175 kW) to determine percentage weights of peak load for each transmission provider. The sum of the weighted average loss factors for peak was 3.36 percent. Table 2, line 11. To be directly comparable to the total Federal system peak load obligation, the weighted average transmission provider loss factor must be scaled to the total Federal system peak load obligations. The FY 2013 monthly average peak load for all transmission providers (1,371,175 kW) was divided by the average of the monthly 1-hour peak for FY 2014 Federal system load obligations (10,749,036 kW) corresponding to the BP-14 Final Rate Case *(10,749 MW * 1,000 kW/MWh = 10,749,036 kW)*. The 1-hour peak Federal system load obligations were not published in the BP-14 Final Loads and Resources Documentation; however, the 1-hour data corresponds directly to the energy data presented in BP-14-FS-BPA-03A, Table 4.1.1, Loads and Resources – Federal System, Total Federal Firm Obligations, line 13, page 134, for FY 2014. Therefore, the percentage of Federal system transfer peak load compared to peak Federal system total firm obligations represents 12.76 percent *(1,371,175 kW / 10,749,036 kW = 12.76 percent)* of total BPA firm peak load obligations.

The final step to computing the Transfer Service Loss Factor for peak was completed by multiplying the transfer load percentage of total BPA obligations (12.76 percent) by the weighted average transmission provider loss factor (3.36 percent) which is 0.43 percent *(12.76 percent **

3.36 percent = 0.43 percent). Table 2 shows the transmission provider components used in updating the peak Transfer Service Loss Factor.

3.2 Regional Hydro Resources

3.2.1 Overview

This Study produces total PNW regional hydro resource estimates for FY 2016–2017 to provide input into the AURORAxmp® model for the Power Risk and Market Price Study, BP-16-E-BPA-04.

3.2.2 PNW Regional 80 Water Year Hydro Generation

PNW regional hydro resource estimates are one of the inputs to the AURORAxmp® model and are comprised of regulated and independent hydro, plus small hydro for FY 2016–2017 for all PNW hydro resources, Federal and non-Federal. Regulated hydro project generation estimates for this Study are developed, by month, for each of the 80 water years (October 1928 through September 2008) using the HYDSIM study described in section 3.1.2.1. Independent hydro generation estimates are provided by the project owners for the same 80 water years. Generation estimates for the small hydro projects are provided by the individual project owners and are assumed not to vary by water year.

The regional regulated, independent, and small hydro totals are summarized for energy for each of the 80 water years for FY 2016–2017 and are shown in Documentation section 2.10, Tables 2.10.1 and 2.10.2.

3.3 4(h)(10)(C) Credits

3.3.1 Overview

The Northwest Power Act directs BPA to make expenditures to protect, mitigate, and enhance fish and wildlife affected by the development and operation of Federal hydroelectric projects in the Columbia River Basin and its tributaries. These expenditures are to be made in a manner consistent with the Power Plan and Fish and Wildlife Program developed by the Northwest Power and Conservation Planning Council (Council) and consistent with other purposes of the Northwest Power Act. 16 U.S.C. §§ 839–839h. Section 4(h)(10)(C) of the Northwest Power Act requires that the costs of mitigating these impacts be properly accounted for among the various purposes of the hydroelectric projects by making sure that when BPA funds mitigation on behalf of both power and non-power project purposes, ratepayers can recoup the non-power share. The non-power purposes include flood control, irrigation, recreation, and navigation; the percentage of costs attributable to non-power purposes is 22.3 percent. This percentage is the systemwide average of cost allocations for non-power purposes of the FCRPS provided by the USBR and USACE for their hydropower projects.

Following the Northwest Power Act's requirement for appropriate cost allocation, BPA annually recoups the non-power portion of costs associated with fish measures through "4(h)(10)(C) credits" against BPA's payments to the U.S. Treasury. This Study estimates the replacement power purchases resulting from changes in hydro system operations to benefit fish and wildlife. These power purchases are part of the calculation of 4(h)(10)(C) credits in Power Risk and Market Price Study, BP-16-E-BPA-04, section 2.6.1. The operations to benefit fish and wildlife are described in section 3.1.2.1.1.

3.3.2 Forecast of Power Purchases Eligible for 4(h)(10)(C) Credits

The power purchases eligible for 4(h)(10)(C) credits are estimated by comparing power purchase estimates between two HYDSIM hydro regulation studies. The first hydro regulation study, termed the "with-fish" study, models hydro system operations using current requirements for fish mitigation and wildlife enhancement under 80 historical water year conditions (October 1928 through September 2008). The BP-16 Initial Proposal HYDSIM study serves as the "with-fish" study for the power purchase estimates. The second hydro regulation study, called the "no-fish" study, models the hydro system operation assuming no operational changes were made to benefit fish and wildlife, using the same 80 historical water year conditions.

BPA estimates the power purchases that would be required to meet a specific firm load (described below) under the with-fish study and the power purchases that would be required to meet the same specific firm load under the no-fish study. The 4(h)(10)(C) credits do not pertain to the entire generation difference between the with-fish study and the no-fish study; instead, the credits pertain to only a portion of the additional power purchases in the with-fish study compared to the power purchases in the no-fish study. BPA receives section 4(h)(10)(C) credits for the non-power portion (22.3 percent) of the additional power purchases it must make in the with-fish study relative to the no-fish study.

The specific firm load used in the calculation of 4(h)(10)(C) credits was a part of the original negotiated arrangement between the U.S. Department of Energy and U.S. Department of Treasury allowing BPA to claim the credits. A fundamental principle of this arrangement for claiming section 4(h)(10)(C) credits is that the calculation is not to be affected by BPA's marketing decisions. In order to separate the credit calculation from BPA marketing decisions, 4(h)(10)(C) credits are calculated using the load that could have been served with certainty while drafting the system from full to empty without fish operations and under the worst energy-producing water conditions in the 80-year record (referred to as the critical period, which is 1929–1932 in the no-fish study). This FELCC is the amount of firm load that BPA would have been entitled to sell without fish operations and is used as the firm load in the section 4(h)(10)(C) power purchases analysis. The differences between the Federal FELCC and the Federal generation in the with-fish study determine the power purchases under the with-fish study. Similarly, the differences between the Federal FELCC and the Federal generation in the no-fish study determine the power purchases under the no-fish study. The instances where power purchases are greater in the with-fish study compared to the no-fish study result in power purchases eligible for section 4(h)(10)(C) credits. Alternatively, when power purchases are less in the with-fish study than in the no-fish study, the difference constitutes a negative section 4(h)(10)(C) credit.

The differences in energy purchase amounts between the with-fish and no-fish hydro studies are calculated for each period and water condition of the 80 water year studies. The differences are shown for the rate period in Documentation section 2.11, Tables 2.11.1 and 2.11.2. These power purchases are used as inputs to the Power Risk and Market Price Study, BP-16-E-BPA-04, where, combined with AURORAxmp® market price estimates, they are used to calculate the 4(h)(10)(C) credits for power purchases. The non-power portion (22.3 percent) of the average expense for these purchases is used as the forecast of section 4(h)(10)(C) credits for Federal hydro system fish operations.

3.4 Use of Tier 1 System Firm Critical Output Calculation

A forecast of Tier 1 System Firm Critical Output (T1SFCO) for use in the ratesetting process was calculated in the 2016 Rate Period High Water Mark (RHWM) Process. The T1SFCO is part of the calculation of the Tier 1 System Capability used for this Study. The Tier 1 System Capability is the sum of the T1SFCO plus RHWM Augmentation. Tiered Rate Methodology, BP-12-A-03, at xxi. For the rate period, FY 2016–2017, the RHWM Tier 1 System Capability was determined in the RHWM Process, which ended October 28, 2014. The 2016 RHWM Process rescaled the CHWMs to an augmented Tier 1 System (RHWM Tier 1 System Capability). These rescaled CHWMs are the RHWMs for the rate period FY 2016–2017.

Resource and contract forecasts for this Study have been updated since BP-14. These updates changed the Tier 1 System output. The BP-16 RHWM Process assumes a Slice Output of 26.61866 percent of the Tier 1 System.

Supporting tables for the T1SFCO used in this Study for the calculation of the updated Tier 1 System output are provided in Documentation section 2.12. Table 2.12.1 contains the summary of the T1SFCO for FY 2016–2017. Table 2.12.2 contains the Federal System Hydro Generation. Table 2.12.3 contains the Designated Non-Federally Owned Resources. Table 2.12.4 contains the Designated BPA Contract Purchases. Table 2.12.5 contains the Designated BPA System Obligations. The Tier 1 System output is estimated to be about 6,924 aMW when averaged over the two-year rate period FY 2106-2017.

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4. FEDERAL SYSTEM LOAD-RESOURCE BALANCE

4.1 Overview

For BPA to do operational planning and set power rates, the Federal system must be in load and resource balance; that is, BPA must forecast that it has enough resources available to serve its forecast loads during critical water conditions. The load-resource balance is composed of the monthly energy amounts of BPA's resources, which include hydro, non-hydro, and contract purchases, less BPA's load obligations, which are comprised of BPA's PSC obligations and Other Contract Obligations.

To determine whether the Federal system is in load-resource balance, the amount of BPA's annual forecast firm energy resources under 1937 critical water conditions is estimated. If BPA's expected firm energy resources under critical water conditions are sufficient to serve BPA's expected load obligations, then BPA is considered to be in load-resource balance. If BPA's resources under critical water conditions are less than its load obligations, BPA is assumed to purchase power or otherwise secure resources to avoid Federal system annual energy deficits. Purchases to meet these annual firm energy deficits are called system augmentation purchases. Annual system augmentation purchases may not fully meet monthly Federal system HLH or LLH energy deficits. Additional purchases made to meet these monthly HLH or LLH energy deficits are called balancing purchases.

4.2 Federal System Energy Load-Resource Balance

Table 4 shows a summary of the Federal system annual energy load-resource balance for FY 2016–2017. Under 1937 critical water conditions, the Federal system is expected to be in firm annual energy load-resource balance for the rate period. This result assumes 198 aMW of system augmentation purchases for FY 2016 and 318 aMW of augmentation purchases for FY 2017. The individual components that make up the Federal system annual energy load-resource balance for FY 2016–2017 are shown in Table 5, and presented monthly in Documentation section 4, Table 4.1.1 for energy, Table 4.2.1 for HLH, and Table 4.3.1 for LLH.

SUMMARY TABLES

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Table 1
Transfer Service Loss Factor
For Energy
(Percent %)

A	B	C	D
Transmission Provider	**Percentage of Transfer Energy**	**Total Transmission Provider Loss Factor**	**Weighted Average Loss Factor**
1. Avista Energy	17.13%	4.37%	0.75%
2. Idaho Power	18.38%	5.60%	1.03%
3. NorthWestern Energy	7.80%	4.00%	0.31%
4. NV Energy	7.60%	4.00%	0.30%
5. PacifiCorp - East	12.79%	2.06%	0.26%
6. PacifiCorp - West	8.72%	2.10%	0.18%
7. Portland General Electric - GTA	3.95%	1.32%	0.05%
8. Portland General Electric - OATT	0.88%	2.00%	0.02%
9. Puget Sound Energy	5.64%	2.70%	0.15%
10. Tacoma Power	17.11%	1.87%	0.32%
11. Weighted Average Transmission Provider Loss Factor *(Sum Lines 1-10)*			**3.38%**
12. Transfer Energy Portion of Total BPA Tirm Obligations			14.47%
13. Transfer Service Loss Factor (Energy) *(Line 11 / Line 12)*			**0.49%**

Table 2
Transfer Service Loss Factor
For Peak
(Percent %)

A	B	C	D
Transmission Provider	**Percentage of Transfer Peak Load**	**Total Transmission Provider Loss Factor**	**Weighted Average Loss Factor**
1. Avista Energy	17.94%	4.37%	0.78%
2. Idaho Power	17.81%	5.60%	1.00%
3. NorthWestern Energy	7.85%	4.00%	0.31%
4. NV Energy	6.65%	4.00%	0.27%
5. PacifiCorp - East	11.61%	2.06%	0.24%
6. PacifiCorp - West	9.26%	2.10%	0.19%
7. Portland General Electric - GTA	4.11%	1.32%	0.05%
8. Portland General Electric - OATT	1.01%	2.00%	0.02%
9. Puget Sound Energy	5.64%	2.70%	0.15%
10. Tacoma Power	18.13%	1.87%	0.34%
11. Weighted Average Transmission Provider Loss Factor *(Sum Lines 1-10)*			**3.36%**
12. Transfer Energy Portion of Total BPA Tirm Obligations			12.76%
13. Transfer Service Loss Factor (Energy) *(Line 11 / Line 12)*			**0.43%**

Table 3
Regional Dialogue Preference Load Obligations
Forecast By Product
Annual Energy in aMW
(Sums may not be exact due to rounding)

A	B	C
Fiscal Year	**2016**	**2017**
Preference Customer Load Obligations		
1. Load-Following Customers *(Including Federal Agencies and does not include AHWM loads not served by BPA)*	3,198	3,208
2. Block	25	25
3. Slice Block	1,774	1,812
4. Slice Output from Tier 1 System	1,872	1,843
5. Total Preference Load Obligations *(Sum of lines 1 through 4)*	**6,869**	**6,888**

Table 4
Loads and Resources – Federal System Summary
Annual Energy in aMW
(Sums may not be exact due to rounding)

A	B	C
Fiscal Year	**2016**	**2017**
Firm Obligations		
1. Non-Utility Obligations	613	615
2. Transfers Out	7,372	7,380
3. Total Net Obligations	**7,985**	**7,995**
Net Resources		
4. Net Hydro Resources	6,663	6,741
5. Other Resources	1,148	979
6. Contract Purchases *(Not including System Augmentation)*	220	202
7. System Augmentation Purchases	198	318
8. Federal System Transmission Losses	-244	-245
9. Net Total Resources *(Sum lines 4 through 8)*	**7,985**	**7,995**
Surplus/Deficit		
10. Firm Surplus/Deficit *(Line 9 - line 3)*	**0**	**0**

Table 5
Loads and Resources – Federal System Components
Annual Energy in aMW
(Sums may not be exact due to rounding)

A	B	C
Energy (aMW)	**2016**	**2017**
Firm Obligations		
1. Non-Utility Obligations *Total*	**613**	**615**
2. Fed. Agencies	119	120
3. USBR Obligation	179	179
4. DSI Obligation	316	316
5. Transfers Out *Total*	**7,372**	**7,380**
6. Load-Following	3,079	3,088
7. Tier 1 Block	25	25
8. Slice Block	1,774	1,812
9. Slice Output from Tier 1 System	1,872	1,843
10. Exports	517	506
11. Intra-Regional Transfers (Out)	105	105
12. Federal Diversity	0	0
13. Total Firm Obligations *(Line 1 + line 5)*	**7,985**	**7,995**
Net Resources		
14. Net Hydro Resources *Total*	**6,663**	**6,741**
15. Regulated Hydro – Net	6,310	6,387
16. Independent Hydro – Net	353	353
17. Other Resources *Total*	**1,148**	**979**
18. Cogeneration Resources	11	0
19. Combustion Turbines	0	0
20. Large Thermal Resources	1,075	916
21. Renewable Resources	60	60
22. Small Hydro Resources	2.9	2.9
23. Small Thermal & Misc. Resources	0	
24. Contract Purchases *Total*	**417**	**521**
25. Imports	17	1
26. Intra-Regional Transfers (In)	30	30
27. Non-Federal CER	137	137
28. Slice Transmission Loss Return	35	35
29. Augmentation Purchases	198	318
30. Reserves & Losses	**-244**	**-245**
31. Contingency Reserves (Non-Spinning)	0	0
32. Contingency Reserves (Spinning)	0	0
33. Generation Imbalance Reserves	0	0
34. Load-Following Reserves	0	0
35. Federal Transmission Losses	-244	-245
36. Total Net Resources *(Sum of lines 14+17+2+30)*	**7,985**	**7,995**
37. Total Firm Surplus/Deficit *(Line 36 – line 13)*	**0**	**0**

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