FY 2016–2017

FINAL
AVERAGE SYSTEM COST REPORT

Idaho Power Company

July 2015

FY 2016–2017

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Idaho Power Company

Docket Number: ASC-16-IP-01

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 2015

This page intentionally left blank.

TABLE OF CONTENTS

Section **Page**

List of Tables

1 FILING DATA

Utility: **Idaho Power Company**
1221 W. Idaho St.
Boise, Idaho 83702
http://www.idahopower.com/default.cfm

Parties to the Filing:

Investor-Owned Utilities ("IOUs"):
Avista Corporation ("Avista")
PacifiCorp
Portland General Electric ("Portland General")
Puget Sound Energy ("Puget")

Consumer-Owned Utilities ("COUs"):
Public Utility District No. 1 of Clark County ("Clark")
Public Utility District No. 1 of Snohomish County ("Snohomish")

Other Participants to the Filing:
Public Utility Commission of Oregon ("OPUC")

Average System Cost Base Period: Calendar Year ("CY") 2013

Effective Exchange Period: Fiscal Years 2016–2017, October 1, 2015 – September 30, 2017

Statement of Purpose:

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "Act"), 16 U.S.C. § 839c(c), established the Residential Exchange Program ("REP"). Under the REP, any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration ("BPA") at the average system cost of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at a rate established pursuant to sections 5(b)(l) and 5(b)(3) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and farm consumers. 16 U.S.C. § 839c(c)(3). A utility participating in the REP will hereinafter be referred to as a "Utility" or "Exchanging Utility."

The Northwest Power Act grants BPA's Administrator the authority to determine Utilities' average system cost(s) ("ASC") based on a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The Act specifically requires the Administrator to exclude from ASC three categories of costs:

(A) the cost of additional resources in an amount sufficient to serve any new large single load of the Utility;

(B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and

(C) any costs of any generating facility which is terminated prior to initial commercial operation.

Id.

The Act limits eligibility for the REP to Utilities and load located within the geographical area defined as the "Pacific Northwest" or "region." *See* 16 U.S.C. § 839a(14)(A)-(B). Specifically, "region" is defined as follows:

> the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and
>
> any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A), which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region.

Id.

BPA conducted an ASC review to determine Idaho Power's ASC for fiscal years ("FY") 2016-2017 based on BPA's 2008 ASC Methodology ("2008 ASCM"). *See* 18 C.F.R. Part 301, *Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology*, 74 Fed. Reg. 47,052 (2009).

This FY 2016–2017 Final Average System Cost Report ("Final ASC Report") describes BPA's ASC review process and evaluation used to implement the 2008 ASCM and the results of BPA's ASC Filing review.

For more information regarding the 2008 ASCM, please refer to the Federal Energy Regulatory Commission's final ruling and the *2008 ASCM*, available at Federal Energy Regulatory Commission's Final Ruling and the 2008 ASCM, and the *Average System Cost Methodology Final Record of Decision ("2008 ASCM ROD")*, June 30, 2008, available at BPA's Residential Exchange Program website.

General information regarding the ASC Review Process can be found at BPA's Residential Exchange Program website.

NOTE: If a filing Utility or an intervenor wished to preserve any issue related to an ASC Filing for subsequent administrative or judicial appeal, it must have raised such issue in its comments on the Draft ASC Report. If a party failed to do so, the issue is waived for subsequent appeal. *See* Rules of Procedure for BPA's ASC Review Processes ("Rules of Procedure"), § 3.6.1.

This page intentionally left blank.

2 AVERAGE SYSTEM COST SUMMARY

2.1 Idaho Power Company Background[1]

Idaho Power Company ("Idaho Power") is an investor-owned utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and is subject to both state and Federal regulations. The company, based in Boise, Idaho, has an electric generation capacity of more than 3,500 megawatts ("MW"). Idaho Power operates 17 hydroelectric generating plants on the Snake River and its tributaries; three natural gas-fired plants (Bennett Mountain, Danskin and Langley Gulch); and a share of three jointly owned coal-fired plants (Boardman, Jim Bridger, and Valmy). Generation statistics for 2013 are shown in the table below.

Idaho Power Company 2013 Electric Generation and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Hydro	1,707	48%	5,656,364	32%
Coal	1,118	31%	6,326,861	36%
Natural Gas	762	21%	1,576,463	9%
Other	5	0%	38	0%
Purchases			3,881,443	22%
Misc Adj.			18,948	0%
Total	**3,592**	**100%**	**17,460,117**	**100%**

Idaho Power, 2013 FERC Form 1, April 15, 2014.

Idaho Power provides electric service to approximately 508,000 customers in Southern Idaho (95 percent of customer base) and Eastern Oregon. Idaho Power's 24,000-square-mile electric system includes approximately 4,856 miles of transmission lines and 26,817 miles of distribution lines.

2.2 Base Period ASC

The 2008 ASCM requires Utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent Federal Energy Regulatory Commission ("FERC") Form 1 data for IOUs, or the most recent audited financial statements (Annual Reports) for COUs. The Base Period data are derived from the Base Period FERC Form 1s (for IOUs) or the Annual Reports (for COUs), and underlying accounting system data for all Utilities. For purposes of the FY 2016−2017 filing period, the Base Period is CY 2013. The submitted information includes the "Appendix 1," an Excel-based workbook populated with financial and load data used to calculate the Base Period ASC.

[1] Information stated in this section was sourced from Idaho Power's website and FERC Form 1.

Table 2.2-1 summarizes the CY 2013 Base Period ASC based on (1) the information contained in Idaho Power's June 2, 2014, ASC Filing ("As-Filed"), and (2) as adjusted by BPA in this Final ASC Report. This table does not reflect the Exchange Period (defined below) ASC, which is noted in subsequent tables.

Table 2.2-1: CY 2013 Base Period ASC
(Results of Appendix 1 calculations)

	June 2, 2014 As-Filed	**July 23, 2015 Final ASC Report**
Production Cost	$776,046,506	$777,084,089
Transmission Cost	$128,803,900	$128,673,243
(Less) NLSL Costs	$18,474,602	$18,470,631
Contract System Cost ("CSC")	**$886,375,804**	**$887,286,702**
Total Retail Load (MWh)	14,619,354	14,619,354
(Less) NLSL	219,753	219,753
Total Retail Load (Net of NLSL)	14,399,601	14,399,601
Distribution Losses	717,810	717,810
Contract System Load ("CSL")	**15,117,412**	**15,117,412**
CY 2013 Base Period ASC (CSC/CSL)	**$58.63/MWh**	**$58.69/MWh**

2.3 FY 2016–2017 Distribution Loss Factor

The 2008 ASCM requires a Utility to include with its ASC Filing a current distribution loss analysis as described in Endnote e. *See* 18 C.F.R. § 301, End. e.

Losses are the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. *Id.* The distribution loss can be measured using one of the three methods outlined in Endnote e of the 2008 ASCM: (1) a loss study, (2) revenue grade meter readings, or (3) calculating a five-year average total system loss factor using data from the FERC Form 1 or a comparable data source. *Id.*

BPA reviewed and accepted Idaho Power's Distribution Loss Factor and supporting calculation. For purposes of this Final ASC Report, BPA used the Distribution Loss Factor of 4.91 percent included in Idaho Power's As-Filed Appendix 1.

2.4 FY 2016–2017 Exchange Period ASC

BPA and intervenors had the opportunity to review, evaluate, and comment on a Utility's Appendix 1 historical costs and forecast loads submitted in the ASC Review Process. Once the Base Period ASC was determined, the cost data were escalated forward using the "ASC Forecast Model," an Excel-based macro model, to the midpoint of the Exchange Period, which in this instance is October 1, 2016. For purposes of the FY 2016–2017 ASC Review Period, the Exchange Period is October 1, 2015, to September 30, 2017 ("Exchange Period").

A Utility's As-Filed Exchange Period ASC may increase or decrease by the time of the Final ASC Report because of adjustments made during the ASC Review Process, such as updates to BPA's natural gas and market price forecasts, errata corrections, or other changes made by BPA. For all Utilities, BPA updated natural gas and market price forecasts to match natural gas and market price forecasts in the BP-16 Rate Case Final Proposal. See the "Input" tab of the ASC Forecast Model for the Utility's (1) As-Filed and (2) BPA-Adjusted models for additional details. All other adjustments, if any, made during the review are explained in Section 4 of this Final ASC Report.

For the COUs only, BPA updated Rate Period High Water Marks ("RHWMs") and the associated Tiered Rates to match what is being used in the BP-16 Final Proposal. See the "Tiered Rates" tab of the ASC Forecast Model for the Utility's (1) As-Filed and (2) BPA-Adjusted models for additional details.

Table 2.4-1 identifies the Exchange Period ASC the Utility filed on June 2, 2014, and as adjusted by BPA for this Final ASC Report. The ASC shown will be the Utility's ASC for the entire Exchange Period unless the Utility acquires (or loses) a major resource as defined by the 2008 ASCM and discussed in Section 2.5 of this Final ASC Report; or the Utility is subject to a New Large Single Load ("NLSL") adjustment as discussed in Section 2.6.

Table 2.4-1: Exchange Period FY 2016–2017 ASC ($/MWh)
With No Major Resource Additions or Removals

Date	June 2, 2014 As-Filed	July 23, 2015 Final ASC Report
FY 2016–2017	59.69	59.02

2.5 ASC Major Resource Additions or Removals

Under the 2008 ASCM, a Utility's ASC may be adjusted to reflect the addition or loss of a major resource if such resource commences commercial operation (or ceases production) at any point between the end of the Base Period and the end of the Exchange Period. Such new or existing resource must be used to meet a Utility's retail load during the Exchange Period.

Before a Utility's ASC is adjusted to reflect the addition or loss of a major resource, the Utility must demonstrate that the proposed resource will meet the materiality requirements set forth in the 2008 ASCM. Section 301.4(c) of the 2008 ASCM provides that only a resource that affects a

Utility's Base Period ASC by two and one-half percent (2.5%) or more will be considered a major resource. 18 C.F.R. § 301.4(c)(4). This is the materiality threshold. The 2008 ASCM also allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. *Id.* However, each individual resource in the stack must result in a change in Base Period ASC of one-half percent (0.5%) or more. *Id.* See also Section 3.2.14 of this Final ASC Report.

For ASC calculation purposes, a major resource adjustment may be included in a Utility's ASC at the commencement of the Exchange Period if such resource becomes commercially operational (or ceases production) after the Base Period, but before the Exchange Period begins. In order for major resource additions to be included in a Utility's Exchange Period ASC at the beginning of the Exchange Period, a Major Resource Attestation must be received by BPA no later than the tenth (10th) business day after the Exchange Period begins.

Although the 2008 ASCM permits a Utility's ASC to be adjusted to reflect the inclusion of a major new resources that comes on-line during the Exchange Period, as part of the 2012 Residential Exchange Program Settlement Agreement, BPA Contract No. 11PB-12322 ("2012 REP Settlement"), all six regional IOUs agreed to waive this right: "Each IOU waives . . . the right to include in its ASC, . . . the cost of any major resource addition forecasted to occur during the Exchange Period as allowed by the ASC Methodology." 2012 REP Settlement, § 6.4. The exchanging COUs did not make such a waiver and will continue to include major new resource additions during the Exchange Period under the rules of the 2008 ASCM.

For informational purposes, BPA retained Table 2.5-2 in the Draft ASC Report, which identified all Exchanging Utilities' major resource additions *during* the Exchange Period because the 2012 REP Settlement was still subject to a challenge in the U.S. Court of Appeals for the Ninth Circuit (Court). However, on May 22, 2015, the Court issued a memorandum opinion in *Public Power Council v. U.S Dept. of Energy*, 2015 WL 2448336, which dismissed as moot the Western Public Agency Group's (WPAG) challenge to BPA's WP-07S ROD. This dismissal effectively ended all current challenges related to the REP. The dismissal will not change the manner in which BPA reviews or determines ASCs for the IOUs and COUs. However, it confirms that during the term of the 2012 REP Settlement, IOUs will not include major resource additions that come on line during the Exchange Period. Thus, BPA removed Table 2.5-2 from the IOUs' Final ASC Reports, and will not include it in the IOUs' future Draft and Final ASC Reports through the term of the Settlement Agreement.

Table 2.5-1 summarizes the major resource additions, prior to any NLSL adjustments, that are projected to become commercially operational and major resources that will cease to be commercially operational, *prior* to the beginning of the Exchange Period (*i.e.*, January 1, 2014 − September 30, 2015).

Idaho Power has no major resources coming on line or being removed prior to the FY 2016−2017 Exchange Period.

Table 2.5-1: Major Resources Coming On Line or Being Removed *Prior to* the Exchange Period ($/MWh)

As-Filed FY 2016–2017 Exchange Period ASC (MWh)				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line or Removal Date				
Delta*				

Final ASC Report FY 2016–2017 Exchange Period ASC (MWh)				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line or Removal Date				
Delta*				

*The Delta is the incremental change in the ASC as major resources come on line or are removed.

2.6 NLSL Adjustment

An NLSL is any load associated with a new facility, an existing facility or an expansion of an existing facility that was not contracted for or committed to (“CF/CT”) prior to September 1, 1979, and which will result in an increase in power requirements of ten average megawatts (“aMW”) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

By law, NLSLs and associated resource costs in an amount sufficient to serve them are not included in Utilities’ ASCs. *See* 16 U.S.C. § 839c(c)(7)(A). BPA determines the cost of resources in an amount sufficient to serve NLSLs through the methodology provided in Endnote d of the 2008 ASCM and Section 2.7 of this Final ASC Report.

NLSLs are not determined in the ASC Review Process. Instead, NLSLs are identified through a separate process conducted by BPA’s NLSL Staff, which is tasked with implementing BPA’s NLSL policy. The ASC Review Process determines the cost of resources in an amount sufficient to serve the Utility’s NLSL and then excludes these costs from the Utility’s ASC.

Idaho Power currently has no potential new NLSLs on record or under review, and no NLSL resource costs will be removed from its ASC.

Table 2.6-1: New Large Single Loads Under Review

As-Filed FY 2016–2017 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Final ASC Report FY 2016–2017 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Table 2.6-2: New Large Single Loads that Begin Taking Power *Prior to* the Exchange Period

As-Filed FY 2016–2017 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2016–2017 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Table 2.6-3: New Large Single Loads that Begin Taking Power *During* the Exchange Period

As-Filed FY 2016–2017 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2016–2017 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

2.7 NLSL Formula Rate

During customer workshops conducted in 2012, BPA and Utilities agreed to use a formula rate calculation to remove resource costs from a Utility's ASC when an NLSL occurs after the Base Period. The formula rate was first implemented for the FY 2014–2015 Exchange Period and is described in the FY 2014–2015 Final ASC Reports, Section 2.7.

Prior to the FY 2014–2015 Exchange Period, BPA calculated the costs of serving a prospective NLSL in the ASC Review Process based on forecasts of the projected NLSL's megawatt hours ("MWh") and start date as provided by the filing Utility. BPA would then calculate two ASCs for the Utility: an ASC with the NLSL coming on line as scheduled (with an associated reduction in ASC) and an ASC with the NLSL not coming on line (and no associated reduction in ASC). This approach for determining the costs of service to an NLSL, however, led to additional administrative and calculation issues. For one, new NLSL start dates might differ from the forecast; and second, the actual MWh amounts of the NLSL might differ substantially from forecast amounts contained in the Final ASC Report.

For purposes of this Final ASC Report, no Utility identified potential NLSLs taking power prior to or during the FY 2016–2017 Exchange Period. However, in the event a Utility learns it will begin to serve an NLSL during this period, even though the NLSL is not identified herein, BPA will review and evaluate the NLSL and, as necessary, calculate a new ASC using the inputs and formula method as defined below:

$$\text{ASC} = \frac{\text{Contract System Cost} - (\text{Cost of Serving New NLSL} * \text{Actual New NLSL MWh})}{\text{Contract System Load MWh} - \text{Actual New NLSL MWh}}$$

Tables 2.7-1 and 2.7-2 show the inputs necessary to calculate a Utility's Exchange Period ASC using the above NLSL Formula Rate. The tables include the inputs Contract System Cost ($), Cost of Serving NLSL ($/MWh), and Contract System Load (MWh). A Utility's Contract System Cost and Cost of Serving NLSL will change with each new resource addition. Therefore, Table 2.7-1 provides the various combinations of new resource additions possible and the corresponding Contract System Cost and Cost of Serving NLSLs. Table 2.7-2 contains the Utility's Contract System Load, which remains unchanged with the addition of new resources.

Table 2.7-1: NLSL Formula Rate Inputs:
Contract System Cost and Cost of Serving NLSL

Inputs for both *Prior to* and *During* the Exchange Period			
	New Resource	**Contract System Cost ($)**	**Cost of Serving NLSL ($/MWh)**
None	No new resources coming on line	$904,478,160	$83.20/MWh
Prior to	N/A	N/A	N/A
During	N/A	N/A	N/A

Table 2.7-2: Formula Rate Input:
Contract System Load

FY 2016–2017 Contract System Load (MWh)
15,325,421

3 FILING REQUIREMENTS

3.1 ASC Review Process – FY 2016–2017

Utilities' ASCs are established in BPA's ASC Review Processes. The ASC Review Processes for FY 2016–2017 began on June 2, 2014, with the submittal of ASC Filings by the following eight Utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, Portland General, Puget, and Snohomish. An "ASC Filing" consists of two Excel-based models developed by BPA (the Appendix 1 workbook and the ASC Forecast Model), which are populated with supporting data and documentation provided by the Utility.

Notice of the ASC Review Processes was provided on BPA's REP public website, BPA's Secure REP website and via email. The Utilities posted ASC Filings on BPA's Secure REP website by the June 2, 2014, filing deadline. Parties interested in reviewing a Utility's ASC had the opportunity to request access to the Utility's ASC Filing by contacting BPA. Parties wishing to formally intervene in a Utility's ASC proceeding could file an intervention by the date identified in BPA's ASC Review Process schedule. Intervenors were afforded the opportunity to request data, submit comments, and raise issues with the Utilities' ASCs throughout a three-month period; the filing Utilities, in turn, were afforded the opportunity to respond to requests for data, raise and respond to issues, and answer any questions relative to the ASC Filings. BPA engaged in this discovery throughout the entire ASC Review Processes.

Draft ASC Reports were issued December 10, 2014, for reach of the eight Utilities. The schedule afforded Parties with an approximately 4-month period (through April 13, 2015) in which to submit comments to the Draft ASC Report. Additionally, BPA offered to hold both a clarification workshop and oral argument if requested by any Party. BPA did not receive any such requests and as a result, neither event was held. See Sections 4 and 5 to review comments, if any, submitted by the Utilities and intervenors.

This Final ASC Report reflects BPA's findings following its review of Idaho Power's ASC Filing and addresses the issues and questions raised by the Utility, intervenors, and BPA, if any, during the ASC Review Process.

For details of the ASC Review Period and guidelines, please see the Rules of Procedures, available at [BPA's Residential Exchange Program website.]()

Final ASC Reports for each Utility are available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/FY-16-17-ASC-Utility-Filings.aspx.

3.2 Explanation of Appendix 1 Schedules

The Appendix 1 consists of a series of seven schedules and other supporting information that presents the data necessary to calculate a Utility's ASC. The schedules and supporting data include the following:

1. Schedule 1 – Plant Investment/Rate Base ("Rate Base")
2. Schedule 1A – Cash Working Capital Calculation ("Cash Working Capital")
3. Schedule 2 – Capital Structure and Rate of Return ("Rate of Return")
4. Schedule 3 – Expenses
5. Schedule 3A – Taxes
6. Schedule 3B – Other Included Items ("Other Items")
7. Schedule 4 – Average System Cost
8. Purchased Power and Sales for Resale ("3-Year PP & OSS Worksheet")
9. Load Forecast
10. Distribution Loss Calculation ("Distribution Loss Calc")
11. Distribution of Salaries and Wages ("Salaries")
12. Ratios
13. New Resources – Individual and Grouped
14. Materiality for New Resource Additions
15. New Large Single Loads ("NLSL Base New-Calc")
16. Tiered Rates
17. Above-RHWM Base Calculation

3.2.1 Schedule 1 – Plant Investment/Rate Base

Schedule 1 of the Appendix 1 establishes the Utility's Rate Base, which is the value of property on which the Utility is permitted to earn a specific rate of return (calculated in Schedule 2), in accordance with rules set by the state's Public Utility Commission or other regulatory agency. The Rate Base computation begins with a determination of the Gross Electric Plant-In-Service's historical costs for Intangible, General, Production, Transmission, and Distribution Plant.

For Exchanging Utilities that provide electric, natural gas, and water services, only the portion of common plant allocated to electric service is included. These values (and all subsequent values) are entered into the Appendix 1 as line items based on FERC's Uniform System of Accounts. Each line item ("Account") is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalizations prescribed in Table 1 of the 2008 ASCM.

The Net Electric Plant-In-Service is determined next by entering and functionalizing depreciation and amortization reserves in the Appendix 1 and adjusting the above-calculated Gross Electric Plant-In-Service for the depreciation and amortization reserves.

Total "Rate Base" is then determined by adjusting Net Electric Plant for Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and Deferred Credits.

3.2.2 Schedule 1A – Cash Working Capital

Cash working capital is an estimate of investor-supplied cash used to finance operating costs during the time lag before revenues are collected. This approach (cash) ignores the lag in recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The Cash Working Capital concept is widely used by State Commissions and is the basic premise of the Commission's proposed working capital formula. The purpose of working capital is to compensate a Utility for funds used in day-to-day operations.[2]

Cash Working Capital is a ratemaking convention that is not included in FERC's Uniform System of Accounts, but is part of all electric utility rate filings as a component of Rate Base. To determine the allowable amount of Cash Working Capital in Rate Base for a Utility, BPA allows one-eighth (1/8) of the functionalized costs of total production expenses, transmission expenses, and administrative and general expenses, less purchased power, fuel costs, and public purpose charges into Rate Base. *See* 18 C.F.R. § 301, End. f.

3.2.3 Schedule 2 – Capital Structure and Rate of Return

Schedule 2 calculates the Utility's rate of return ("ROR") on the Utility's Rate Base developed in Schedule 1.

The 2008 ASCM requires IOUs to use the weighted cost of capital ("WCC") from their most recent State Commission rate orders. The return on equity ("ROE") used in the WCC calculation is grossed-up for Federal income taxes at the marginal Federal income tax rate using the formula described in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b. The 2008 ASCM requires a COU to use a rate of return equal to the COU's weighted cost of debt.

3.2.4 Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production, transmission, and distribution of electricity. Each expense item is functionalized as outlined in Table 1 of the 2008 ASCM. Also included in Schedule 3 are additional expenses associated with customer accounts, sales, administrative and general expense, conservation program expense, and depreciation and amortization expense associated with Electric Plant-in-Service. The sum of the items in Schedule 3 reflects the Total Operating Expenses for the Utility.

3.2.5 Schedule 3A – Taxes

This schedule presents allowable ASC costs for Federal employment tax and certain non-Federal taxes, including property and unemployment taxes. COUs are allowed to include state taxes paid "in lieu" of property taxes. State income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this Schedule, but are functionalized to Distribution/Other and therefore not included in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 purposes.

[2] James C. Bonbright *et al*., *Principles of Public Utility Rates* 244 (2d ed. 1988).

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2 − Capital Structure and Rate of Return.

3.2.6 Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity for others (wheeling). The revenues in this schedule are deducted from the total costs of each Utility.

3.2.7 Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, Taxes, and Other Included Items. This schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the Utility's Base Period ASC ($/MWh).

<u>Contract System Cost</u>
CSC includes the Utility's costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. CSC does not include distributions costs or the cost of serving a Utility's NLSLs. CSC is the numerator in the ASC calculation.

<u>Contract System Load (MWh)</u>
CSL is the total regional retail load of a Utility, adjusted for distribution losses and NLSLs. CSL is the denominator in the ASC calculation.

3.2.8 Purchased Power and Sales for Resale

Purchased Power is an account in Schedule 3 – Expenses, and includes all power purchases the Utility made during the year, including power exchanges. Sales for Resale is an account in Schedule 3B – Other Included Items, and includes power sales to purchasers other than ultimate consumers. Listed in the information for both accounts are the statistical classification codes for all transactions. See FERC Form 1, pages 310-311 for Sales for Resale, and pages 326-327 for Purchased Power, for identification of the classification codes.

3.2.9 Load Forecast

Each IOU is required to provide a four-fiscal-year forecast of its total retail load beginning October 1 of the Base Year (*i.e.,* 10/2013 – 9/2017), as measured at the meter. For COUs, the total retail loads for this time period are forecast by BPA with the net requirements being computed consistent with the Tiered Rate Methodology ("TRM"). See the Tiered Rates tab in Appendix 1.

Additionally, each COU is required to provide a four-fiscal-year forecast of its qualifying residential and farm retail load, as measured at the retail meter. However, due to the 2012 REP Settlement Agreement, the IOUs are no longer required to submit residential and farm load forecasts.

The total retail load forecasts for all Utilities, and residential and farm load forecasts for the COUs, are adjusted for distribution losses. In addition, the total retail load forecasts are adjusted for any NLSL. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.2.10 Distribution Loss Calculation

Each Utility is required to provide a current distribution loss study as described in Endnote e of the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

3.2.11 Distribution of Salaries and Wages

This supporting tab is used to determine the Labor Ratio calculations. It includes salaries and wages from relevant operations and maintenance of the electric plant.

3.2.12 Ratios

The Ratios tab calculates all functionalization ratios by assigning costs included in the Utility's FERC Form 1 on a pro rata basis using values taken from the gross plant data (Schedule 1) for Production, Transmission, and Distribution/Other functions, and data taken from the salary and wage tab for Labor functions. For COUs, comparable information comes from the detailed salaries and wages data used in the Utilities' financial reports.

3.2.13 New Resources – Individual and Grouped

The 2008 ASCM allows a Utility's ASC to adjust during the Exchange Period to reflect the addition or loss of a major resource, when adding or removing the resource results in a change of the Utility's Base Period ASC of two and one-half percent (2.5%) (the materiality threshold) or more. New resources are defined as any new production or new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(3)(i)-(vii). For major resource reductions, the change to ASC will become effective when the resource is sold, retired, or transferred. 18 C.F.R. § 301.4(c)(2)

See Section 2.5 for a discussion of ASC Major Resource Additions or Removals.

To determine the effects of a major resource addition or reduction on a Utility's Exchange Period ASC, BPA performs one of the following calculations: (1) for major resources of all Exchanging Utilities that are expected to be on line, or be removed, prior to the start of the Exchange Period, BPA projects the costs of the resource forward to the midpoint of the Exchange Period; or (2) for major resources, of COUs only that are expected to be on line, or be removed, during the Exchange Period, BPA calculates the resource cost as if the resource came on line, or was removed, at the midpoint of the Exchange Period. Under the Rep Settlement, IOUs no longer include major resource additions that come on-line during the Exchange Period. See Section 2.5.

Each resource that satisfies the minimum materiality threshold of one-half percent (0.5%) may be entered individually in the "New Resources – Individual" tab. Resources that do not meet the two and one-half percent (2.5%) materiality requirement independently may be grouped together with other resources within "New Resources – Grouped" tab to meet the two and one-half percent (2.5%) materiality requirement. The grouping and timing of materiality for new resource additions is discussed in Section 3.2.14 of this Report.

3.2.14 Materiality for New Resource Additions

The 2008 ASCM states:

> Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's ASC within an Exchange Period provided that the major resource addition or reduction results in a 2.5 percent or greater change in a Utility's Base Period ASC. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.

18 C.F.R. § 301.4(c)(4)

Under the 2008 ASCM, a Utility may group or stack new resources that individually result in a change in a Utility's Base Period ASC by one-half percent (0.5%) or more to meet the two and one-half percent (2.5%) materiality threshold. A stacked group of resources will not be added to the Utility's ASC until the last resource in that stack comes on line. The grouping of resources together, therefore, has a significant impact on the timing of when a Utility's ASC is changed as a result of a new resource addition.

BPA made materiality determinations for all new resources submitted by each Utility in its Draft ASC Report. To make these determinations, BPA provided the following instructions to the Exchanging Utilities in the FY 2016-2017 Draft ASC Reports:

- The Utility must include the costs and operating characteristics for each new resource addition.
- The Utility must submit the resource additions (individual and/or grouped) that meet the materiality test(s) given the Utility's Base Period costs.
- BPA Staff will review each new resource addition submitted by the Utility to determine the adequacy of costs and operating characteristics.
- BPA Staff will calculate the materiality of a Utility's resources using the Utility's adjusted Base Period ASC (per the Draft ASC Report) and forecast natural gas prices used by BPA's Rate Case Initial Proposal. BPA Staff will remove all resources and/or groups of resource additions that do not meet the materiality test(s).

- BPA Staff will not unilaterally re-group resources.
- The Initial Proposal's (BP-16) natural gas price forecast will be the basis for the natural gas fuel costs used to calculate the materiality for new resource additions in both the Draft and Final ASC Reports.
- The Utility will have the option to recommend a "regrouping" of resource additions that meet the materiality test(s).
- Utilities must submit the regrouped resource additions in their comments on the Draft ASC Report.
- Only resources that were reviewed by BPA and participants can be used in the regrouping process.
- BPA Staff will make a determination of the new resource additions for the Final ASC Report.
- For the Final ASC Report, BPA will calculate the materiality of the Utility's resources under the Utility's final Base Period ASC.

The final grouping of new resources will be determined after considering the filing Utilities' and other parties' comments on the Draft ASC Report based on the foregoing instructions.

The materiality determinations provided in this Final ASC Report are based on the Utility's final Base Period ASC (per the Draft ASC Report) and reflect the natural gas price forecast from the BP-16 Rate Case Initial Proposal.

3.2.15 New Large Single Loads

This tab calculates the cost of resources in an amount sufficient to serve an NLSL, which BPA must exclude from a Utility's ASC pursuant to Northwest Power Act section 5(c)(7). An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility which was not CF/CT prior to September 1, 1979, and which will result in an increase in power requirements of ten (10) aMW or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)–(B). By law, BPA must exclude from a Utility's ASC the load associated with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a Utility's ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d.

3.2.16 Tiered Rates

All exchanging COUs have the right to purchase power at BPA's Tier 1 rate by executing Contract High Water Mark ("CHWM") Contracts with BPA. By signing the CHWM Contract, the Utility agrees to limit the resources it will exchange in the REP. Under the CHWM Contract, the COU agrees to exclude from its ASC the cost of resources necessary to serve the COU's

Above-RHWM load. The CHWM Contracts require the cost of serving Above-RHWM loads to be calculated using a methodology similar to Endnote d of the 2008 ASCM. See Section 3.3 of this Final ASC Report for details.

Data input in this tab is used to calculate the cost of Tier 1 Power Purchases from BPA, and comes from BPA's Power Rates group. For background information and details, see http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf .

3.2.17 Above-RHWM Base Calculation

The Above-RHWM Base Calc tab calculates the cost of resources in an amount sufficient to serve a COU's Above-RHWM load. Under the TRM and CHWM Contracts, BPA must exclude from a Utility's ASC any Above-RHWM load and an amount of resource costs sufficient to serve such Above-RHWM load. To determine the amount of resource costs to exclude from a Utility's ASC, BPA follows the methodology described in Exhibit D of the Utility's CHWM Contract.

The associated Above-RHWM Ratios tab calculates the functionalization ratios used to allocate the total amount of materials and supplies cost, general plant and general plant depreciation expense, administrative and general costs, Federal and state employment taxes, and property taxes that are to be included in the total costs of resources used to meet a Utility's Above-RHWM load.

3.3 Rate Period High Water Mark ASC Calculation Under the Tiered Rate Methodology

CHWM Contracts require that the cost of resources used to meet Above-RHWM loads be calculated using a methodology similar to Endnote d of the 2008 ASCM. BPA uses the following method to determine the ASC of a COU that is participating in the REP.

- $\text{RHWM ASC} = \dfrac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$

- NewRes$ is the forecast cost of resources used to serve a customer's Above-RHWM Load. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1, Endnote d, of BPA's 2008 ASCM and as described below.

- NewResMWh is the forecast generation from resources used to serve a customer's Above-RHWM Load. For this Final ASC Report, the NewResMWh has been set equal to the customer's Above-RHWM Load.

- For calculating both NewRes$ and NewResMWh, Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM (*see* TRM-12S-A-03, September 2009, Attachment C) and purchases of power at Tier 1 rates from BPA are excluded.

A number of considerations are used in calculating the cost of serving Above-RHWM Loads using Endnote d of the 2008 ASCM:

- Types of resources to serve Above-RHWM Loads may be different from those resources used in the NLSL resource cost calculation and will be recognized in calculating RHWM ASC:

  - ➢ Power purchases less than five years in duration.

- Total output of new resources may exceed Above-RHWM Load:

  - ➢ RHWM ASC does not specify removal of costs associated with this excess.

RHWM ASC calculation methodology:

- Set NewResMWh equal to Above-RHWM Load.
- NewRes$ = NewResMWh times Fully Allocated Cost (calculated using Endnote d).
- If output of material new resources fails to meet Above-RHWM Load, meet deficit with short-term ("ST") market purchases at utility-specific market price.
- If output of new resources exceeds Above-RHWM Load, reduce ST market purchases by excess to the extent possible in Contract System Cost calculation.
- Sell any remaining surplus at utility-specific Sales for Resale price in the Contract System Cost calculation.

3.4 ASC Forecast

Once the Base Period ASC is calculated, BPA uses the ASC Forecast Model to escalate forward the Base Period ASC to the midpoint of the Exchange Period. The ASC Forecast Model uses IHS Global Insight's (an international economic and market forecasting company) forecast of cost increases for capital costs and fuel (except natural gas), operations and maintenance ("O&M"), and general and administrative ("G&A") expenses; BPA's forecast of market prices for purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF rate and other products. For both the Draft and Final ASC Reports, BPA updates the escalators in the ASC Forecast Model to be consistent with the escalators used in the BP-16 rate proceeding. For additional background on the determination of Exchange Period ASCs, see the 2008 ASCM, 18 C.F.R. § 301.4.

3.4.1 Forecast Contract System Cost

Forecast Contract System Cost includes a Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. BPA escalates Base Period costs to the midpoint of the Exchange Period to calculate Exchange Period ASCs. *See* 18 C.F.R. § 301.4(a).

3.4.2 Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. Utilities are then allowed to include new plant additions and use utility-specific forecasts for the (1) price of long-term purchased power contracts, and (2) long-term sales for resale price contracts to value purchased power expenses and sales for resale revenue. *See* 18 C.F.R. § 301.4(b).

3.4.3 Forecast Contract System Load and Exchange Load

As a part of its ASC Filing, each IOU is required to provide a four-fiscal-year forecast of its total retail load, as measured at the meter. For the COUs only, the total retail forecast loads, as determined by BPA under the TRM, will be provided through the end of the Exchange Period. In addition, for the COUs, qualifying residential and farm retail loads, as measured at the retail meter, are required.

Each Utility is required to submit a current distribution loss study as described in the 2008 ASCM, Appendix 1, Endnote e. The total retail and the residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate). The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.4.4 Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecast utility-specific short-term purchased power price. To calculate the cost of serving load growth not served by new resource additions, BPA uses the method outlined in the 2008 ASCM. *See* 18 C.F.R. § 301.4(e).

4 REVIEW OF THE ASC FILING

Pursuant to the 2008 ASCM, the Rules of Procedure for ASC Review Processes, and section 5(c) of the Northwest Power Act, BPA is responsible for reviewing all costs, revenues, and loads used to establish ASCs for the REP. BPA began the FY 2016–2017 ASC Review Process of Idaho Power's ASC Filing in June 2014. BPA raised various issues related to Idaho Power's ASC Filing in the BPA Issues and Clarification List ("BPA Issues List"); no other party raised issues. Idaho Power responded to each issue raised in the BPA Issues List. This Final ASC Report summarizes the findings of Staff's review of Idaho Power's ASC Filing, the BPA Issues List and Idaho Power's responses thereto, and any comments received during the Draft Report comment period.

BPA's ASC determination is limited to specific findings on issues identified for comment, with the exception of ministerial or mathematical errors or deviations due to changes in functionalizations. There may be additional issues BPA has not identified for comment in this Final ASC Report. Acceptance of a Utility's treatment of an item without comment does not signify a decision as to the proper interpretation to be applied either in subsequent ASC Filings or universally under the 2008 ASCM. Similarly, further experience under the 2008 ASCM may result in BPA adopting a modified or different interpretation of the 2008 ASCM in future ASC reviews.

On April 3, 2014, prior to the start of the FY 2016-2017 ASC Review Processes, BPA held a workshop to review the schedule, rules of procedure, and past generic issues; explain the latest revisions to the Forecast Model; remind Utilities of general accounting and functionalization guidelines for the Appendix 1; and provide time to discuss other REP topics of interest identified by the Parties.

Following review and discussion, the Parties and BPA resolved all questions and were satisfied with the outcome. No further public discussions took place.

Table 4-1 summarizes any direct adjustments BPA made to Idaho Power's Appendix 1 in this Final ASC Report as a result of BPA's review and evaluation. Supporting arguments may be found in the Resolved Issues and/or Unresolved Issues sections listed in Table 4-1.

Although a Utility's state, county, or municipal regulatory bodies, or the Commission, may allow a particular functionalization for a specific account, BPA is not required to follow that treatment when calculating ASCs under the 2008 ASCM. Rather, BPA is tasked with making an independent determination of the appropriateness of inclusion or exclusion of particular costs, the reasonableness of the costs included in Contract System Costs, the appropriateness of Contract System Loads, and the functionalization method used in the calculation of any cost in conformance with the 2008 ASCM. *See* Rules of Procedure § 3.2.2.

Table 4-1: Summary of ASC Errata Corrections and Issues

Appendix 1 Schedule	Adjustment
Schedule 1 – Plant Investment/Rate Base	Direct adjustment. See Section 4.2.1.
Schedule 1A – Cash Working Capital	No direct adjustments.
Schedule 2 – Capital Structure and Rate of Return	No direct adjustments.
Schedule 3 – Expenses	No direct adjustments.
Schedule 3A – Taxes	No direct adjustments.
Schedule 3B – Other Included Items	No direct adjustments.
Schedule 4 – Average System Cost	No direct adjustments.
Appendix 1 Supporting Worksheets	**Adjustment**
Forecast Loads	No direct adjustments.
New Resource Additions	No direct adjustments.
NLSL Calculation	No direct adjustments.
Wind Resources	No direct adjustments.
Tiered Rates	No direct adjustments.
Salary and Wages	No direct adjustments.
Ratios	No direct adjustments.
ASC Forecast Model	**Adjustment**
Wheeling Revenues on New Resources Tab	BPA Erratum correction. See Section 4.4.1.
ASC Reported on ASC Tab	BPA Erratum correction. See Section 4.4.2.

4.1 Errata Corrections Filed by Utility

Idaho Power did not file any errata corrections to its June 2, 2014, ASC Filing.

4.2 Decisions on Draft Report Resolved Issues

During the ASC Review Process, BPA Staff raised the issues discussed in this section. Idaho Power responded to these issues in its September 3, 2014, Issue List. Following the issuance of the Draft ASC Report, Idaho Power submitted a letter ("Comment Letter") on April 13, 2015, notifying BPA that it "supports BPA Staff's position on all issues identified in the Draft ASC Report and recommends approval." No other Party raised issues or commented on Idaho Power's June 2, 2014, ASC Filing. BPA considers the issues identified in this section resolved.

4.2.1 Schedule 1 – Plant Investment/Rate Base

4.2.1.1 Account 317, Asset Retirement Costs for Steam Production
Account 374, Asset Retirement Costs for Distribution Plant

Issue:

Whether Idaho Power should include Asset Retirement Costs in the Steam Production Plant and Distribution Plant totals.

Parties' Positions:

Idaho Power omitted Asset Retirement Costs from its FERC Form 1, Accounts 317 and 374, in the sums for Schedule 1, Steam Production Plant and Distribution Plant.

BPA Staff's Position:

Asset Retirement Costs should be included in the sums for Steam Production Plant and Distribution Plant.

Evaluation of Positions:

In its Appendix 1, Idaho Power inadvertently omitted Asset Retirement Costs from its FERC Form 1, Account 317 (page 204, Line 15) and Account 374 (page 206, Line 74), in the sum for Steam Production Plant (Cell G22) and Distribution Plant (Cell G33).

When BPA developed the Appendix 1, BPA included FERC Form 1 Accounts 310–316 for total Steam Production Plant costs, and Accounts 360–373 for total Distribution Plant costs, but inadvertently omitted identifying Account 317, Asset Retirement Costs for Steam Production, and Account 374, Asset Retirement Costs for Distribution Plant, in the Appendix 1. It was always BPA's intention to include asset retirement costs in the Steam Production Plant totals and Distribution Plant totals. BPA discussed this omission with customers in a February 2012 workshop, and informed customers that BPA intended to include these accounts in the Appendix 1 as part of the total Plant costs.

BPA clarified its position with Idaho Power during a conference call on July 18, 2014, and Idaho Power agreed that the asset retirement costs in Accounts 317 and 374 should be added to its Appendix 1. BPA made the corrections to Idaho Power's Appendix 1.

This issue was addressed in the BPA Issue List for FY 2016-2017 ASC Filing: Idaho Power Company, No. 1.

Decision:

BPA will include the costs associated with Accounts 317 and 374 in Steam Production Plant (Cell G22) and Distribution Plant (Cell G33), respectively, in Idaho Power's Appendix 1.

Table 4.2.1.1-1: Schedule 1 – Steam Production (Line 22)

	Total	Production	Transmission	Dist/Other
As-Filed	$967,081,149	$967,081,149	$0	$0
Adjusted	$977,126,955	$977,126,955	$0	$0

Table 4.2.1.1-2: Schedule 1 – Distribution Plant (Line 33)

	Total	Production	Transmission	Dist/Other
As-Filed	$1,459,131,781	$0	$0	$1,459,131,781
Adjusted	$1,459,665,493	$0	$0	$1,459,665,493

4.2.1.2 Account 186, Miscellaneous Deferred Debits

Issue:

Whether Idaho Power correctly functionalized Line Items "186797, MSC DF DR-PPD COAL LT," and "186946, MSC DF DR-AM FALLS WTR QLTY," which were recorded in Account 186.

Parties' Positions:

In its June 2, 2014, ASC Filing, Idaho Power functionalized line items "186797, MSC DF DR-PPD COAL LT," and "186946, MSC DF DR-AM FALLS WTR QLTY," recorded in Account 186, to Production.

BPA Staff's Position:

Miscellaneous deferred debits "186797, MSC DF DR-PPD COAL LT," and "186946, MSC DF DR-AM FALLS WTR QLTY," should be functionalized to Distribution/Other.

Evaluation of Positions:

In supporting documentation tab 'DA 186,' Idaho Power functionalized Line Item "186797, MSC DF DR-PPD COAL LT," totaling $1,458,327.50, and Line Item "186946, MSC DF DR-AM FALLS WTR QLTY," totaling $2,805.76, to Production.

In response to data request BPA-IP-FY16-04, Idaho Power stated that, "these amounts should have been functionalized to Other because they are not reflected in currently approved rate base."

BPA agrees with Idaho Power's suggestion to change the functionalization of the deferred debit line items from Production to Distribution/Other. *See* Response to BPA Issue List for FY 2016-2017 ASC Filing: Idaho Power Company, No. 2.

Decision:

BPA will functionalize Account 186, Line Items 186797 and 186946, to Distribution/Other.

Table 4.2.1.2-1: Schedule 1 – Miscellaneous Deferred Debits, Account 186 (Line 128)

	Total	Production	Transmission	Dist/Other
As-Filed	$45,208,766	$3,466,159	$0	$41,742,607
Adjusted	$45,208,766	$2,005,025	$0	$43,203,740

4.2.1.3 Schedule 1, Account 303, Intangible Plant Miscellaneous, and Account 111, Amortization Reserves of Intangible Plant 303; Schedule 3, Account 404, Amortization Expense of Intangible Plant 303

Issue:

Whether Idaho Power correctly functionalized Software Project 27259746 – "WEBSITE REDESIGN" in its supporting documentation tab for Intangible Plant Account 303 and its associated accounts.

Parties' Positions:

In its supporting documentation tab "Acct 303," Idaho Power functionalized Software Project 27259746 – "Website Redesign" to LABOR.

BPA Staff's Position:

The "Website Redesign" software project should be functionalized to Distribution/Other.

This change would flow through to Account 111, Amortization Reserves of Intangible Plant 303, and Account 404, Amortization Expense of Intangible Plant 303.

Evaluation of Positions:

In response to data request BPA-IP-FY16-06, Idaho Power stated "This project was to implement a new Idahopower.com website which included updated infrastructure the site built on and new functionality and appearance so that Idaho Power customers will more easily obtain information about their accounts." Idaho Power also explained that employees interface with the website to provide information on business-related matters to the public.

The purpose of the website is to serve "retail" customers, and the applicable functionalization of the Website Redesign project should reflect the software's functionality. Software functionalization was addressed and resolved with participating Utilities in the FY 2010–2011 Final ASC Reports. See Section 6.1.1, System Categories and Related Functionalization, which states "… software assets should be functionalized based on where the labor cost savings or efficiency improvements occur, or the area of the utility organization in which the software is primarily used."

In response to BPA's Issue List No. 3, Idaho Power elaborated on its data request response, clarifying that the website is an all-purpose point of entry for current and potential production, transmission, and distribution customers. The Idahopower.com website provides information on many business facets of Idaho Power, such as transmission services, facility connection requirements for generators, wholesale energy for resale, Idaho Power's IRP, EE programs, and shareholder-specific information, in addition to account accessibility for residential customers. Idaho Power contends that the website interfaces with all of its various customers, thus supporting its application of functionalizing the Website Redesign software project to LABOR.

After review of Idaho Power's response to BPA's Issue List No. 3, BPA agrees with Idaho Power's functionalization of Software Project 27259746.

Decision:

The functionalization of Software Project 27259746 – WEBSITE REDESIGN, to LABOR will remain as reported in Idaho Power's As-Filed Appendix 1.

4.2.1.4 Account 111, Amortization Reserves of Intangible Plant 303

Issue:

Whether Idaho Power correctly functionalized Software Project 27266626 – "EEM SOFTWARE" in Account 303.

Parties' Positions:

In supporting documentation tab "Acct 303," Idaho Power functionalized Software Project 27266626 – "EEM Software" to Transmission.

BPA Staff's Position:

The EEM software project should be functionalized to Transmission and Distribution.

This change would flow through to Account 111, Amortization Reserves of Intangible Plant 303, and Account 404, Amortization Expense of Intangible Plant 303.

Evaluation of Positions:

The EEM software is used to track events causing faults and outages on both transmission and distribution systems. In response to data request BPA-IP-FY16-06, Idaho Power stated this software "... should have been functionalized to both transmission and distribution because this software is used to investigate both distribution events and transmission events."

BPA agrees with Idaho Power and will functionalize Software Project 27266626 to Transmission and Distribution. *See* Response to BPA Issue List for FY 2016-2017 ASC Filing: Idaho Power Company, No. 4.

<u>Decision:</u>

BPA will revise Idaho's Appendix 1 to reflect the change in functionalization of Software Project 27266626 – EEM Software from Transmission to TD (Transmission and Distribution).

Table 4.2.1.4-1: Supporting Tab "Acct 303" (Line 12)

	Total	Production	Transmission	Dist/Other
As-Filed	$453,935.40	$0	$435,935.40	$0
Adjusted	$453,935.40	$0	$181,751.66	$272,183.74

Table 4.2.1.4-2: Schedule 1 – Intangible Plant, Account 303 (Line 18)

	Total	Production	Transmission	Dist/Other
As-Filed	$32,001,618	$5,964,932	$3,943,839	$22,092,847
Adjusted	$32,001,618	$5,964,932	$3,671,655	$22,365,031

Table 4.2.1.4-3: Schedule 1 – Amortization Reserves, Account 111 (Line 66)

	Total	Production	Transmission	Dist/Other
As-Filed	$12,842,163	$2,393,711	$1,582,652	$8,865,800
Adjusted	$12,842,163	$2,393,711	$1,473,425	$8,975,027

Table 4.2.1.4-4: Schedule 3 – Amortization Expense, Account 404 (Line 83)

	Total	Production	Transmission	Dist/Other
As-Filed	$6,562,164	$1,223,153	$808,713	$4,530,299
Adjusted	$6,562,164	$1,223,153	$752,899	$4,586,112

4.2.2 Schedule 3B – Other Items

4.2.2.1 Account 421, Miscellaneous Operating Income

Issue:

Whether Idaho Power correctly functionalized all line items included in Account 421.

Parties' Positions:

Idaho Power functionalized all the line items recorded in Account 421 to Distribution/Other.

BPA Staff's Position:

Idaho Power correctly functionalized all entries in Account 421.

Evaluation of Positions:

In supporting documentation tab 'DA 421,' Idaho Power functionalized the following line items to Distribution/Other:

Table 4.2.2.1-1: Schedule 3B – Miscellaneous Operating Income, Account 421

Line Item	Description	Function
421000	MSC NONOP INC	Dist/Other
421001	MSC NONOP INC-SECURITY PLAN	Dist/Other
421006	MSC NONOP INC –PCA-FCA-IDAHO	Dist/Other
421008	MSC NONOP INC-EXCESS PWR	Dist/Other
421050	MSC NONOP INC-EX DEF COMP-INT&DIV	Dist/Other
421051	MSC NONOP INC-EX DEF COMP-RLZD GNS	Dist/Other
421052	MSC NONOP INC-EX DEF COMP-UNRLZ GN	Dist/Other

The revenues recorded in Account 421 relate to Carrying Charges on Regulatory Assets not currently included in Idaho Power's Rate Base for retail ratemaking purposes. In previous ASC Filings, BPA directed Idaho Power to functionalize these line items to Production or Labor.

Upon further review, BPA believes the carrying charges recorded in Account 421 should be treated consistently with their corresponding Regulatory Assets, and thus functionalized to Distribution/Other.

Regulatory Assets may not be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *See* ASCM Record of Decision, page 149; *see also* Idaho Power's FY 2010–2011 Final ASC Report, Section 6.1.2, Account 182.3, Other

Regulatory Assets; and Account 254, Other Regulatory Liabilities. Therefore, BPA believes the carrying charges recorded in Account 421 and accruing on Regulatory Assets not approved for recovery by the IPUC and/or OPUC should be excluded from ASC and functionalized to Distribution/Other.

BPA agrees with Idaho Power on its functionalization of these line items as filed. *See* Response to BPA Issue List for FY 2016-2017 ASC Filing: Idaho Power Company, No. 5.

This issue is included for clarification purposes only, and results in no changes to Idaho Power's Appendix 1.

Decision:

The functionalization of line items recorded in Account 421 will remain as reported in Idaho Power's As-Filed Appendix 1.

4.3 Decision on Draft Report Unresolved Issues

There were no unresolved issues identified in Idaho Power's Draft ASC Report. No other party raised issues with, or commented on, Idaho Power's June 2, 2014, ASC Filing.

4.4 ASC Forecast Model Errata Corrections

On May 15, 2014, BPA released its latest ASC Forecast Model to be used for the FY 2016–2017 ASC Review Processes. Following that release date and after the June 2, 2014, Utility submissions, BPA discovered two formula discrepancies in the ASC Forecast Model as described below.

4.4.1 Wheeling Revenues on New Resources Tab

BPA discovered a formula error in the worksheet that calculates the costs to be included in a Utility's Exchange Period ASC. The worksheet was not recognizing the wheeling revenues included on the Utility's New Resources Tab. BPA corrected this error for the Forecast Model used for the Final ASC Reports. See ASC Forecast Model, Line 311 of the Total & Functionalization Tab.

4.4.2 ASC Reported on ASC Tab

BPA discovered an error in the macro that reports the lowest ASC for Utilities that have either an NLSL or Above-RHWM load. When the ASC calculated with an NLSL was equal to the ASC calculated with both an NLSL and Above-RHWM load, the ASC Forecast Model would report the ASC calculated without removing the costs of serving the Utility's NLSL. BPA corrected the macro error for the ASC Forecast Model used for the Draft and Final ASC Reports. See ASC Forecast Model, Lines 106–131 of the ASCs Tab.

This page intentionally left blank

5 GENERIC ISSUES

In addition to the foregoing issues, which are limited to Idaho Power, Portland General raised one issue on the meaning of “most recently approved Regulatory Body Rate Order.” This issue may be generic to all IOUs, and was not included in BPA’s Issue List as a generic issue; it was included in the Draft ASC Reports. With the exception of Portland General and the Oregon Public Utility Commission, no comments were received. BPA has removed this generic issue from all ASC Reports and will address it prior to the June, 2016 ASC Filing. See Portland General’s Final ASC Report, Section 4.3.1, for additional information.

This page left intentionally blank.

6 FY 2016–2017 ASC

Idaho Power's As-Filed Base Period (CY 2013) ASC was $58.63/MWh. As a result of adjustments made during the ASC Review process, Idaho Power's Base Period ASC increased to $58.69/MWh.

Idaho Power's As-Filed Exchange Period ASC for FY 2016–2017 was $59.69/MWh. As a result of adjustments made during the ASC Review Process, Idaho Power's Exchange Period ASC decreased to $59.02/MWh. Idaho Power does not have any major resources coming on-line or being removed prior to the FY 2016-2017 Exchange Period.

This Exchange Period ASC does not reflect any changes in NLSL status. See Section 2.6 for potential adjustments to Exchange Period ASCs.

7 REVIEW SUMMARY

This Final ASC Report is BPA's determination of Idaho Power's FY 2016 and FY 2017 ASC based on the information and data provided by Idaho Power, including comments, if any, received in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA's REP Staff.

BPA has resolved the issues set forth in Section 4 of this Report in accordance with the 2008 ASCM and with generally accepted accounting principles. The information and analysis contained herein properly establish Idaho Power's ASC for FY 2016–2017.

8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION

I have examined Idaho Power's ASC Filing, as amended, and the administrative record of the ASC Review Process. Based on this review and the foregoing analysis of the issues, I certify that the calculated ASC conforms to the 2008 ASCM and generally accepted accounting principles, and fairly represents Idaho Power's ASC.

Issued in Portland, Oregon, this 23 day of July, 2015.

BONNEVILLE POWER ADMINISTRATION

By: /s/ Mark O. Gendron
Senior Vice-President for Power Services

This page intentionally left blank.

BONNEVILLE POWER ADMINISTRATION
July 2015