FY 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

Idaho Power Company

July 2013

FY 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Idaho Power Company

Docket Number: ASC-14-IP-01

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

July 2013

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1 FILING DATA

Utility: **Idaho Power Company (Idaho Power)**
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 (PGE)
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:
Idaho Public Utility Commission (IPUC)
Public Utility Commission of Oregon (OPUC)
Average System Cost Base Period: Calendar Year (CY) 2011

Effective Exchange Period: Fiscal Years (FY) 2014–2015, October 1, 2013 – September 30, 2015

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"). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to the Bonneville Power Administration (BPA) at the average system cost (ASC) 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 7(b)(l) and 7(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).

The Northwest Power Act grants to BPA's Administrator the authority to determine ASCs based on a methodology established in a public consultation proceeding. *See* 16 U.S.C. § 839c(c)(7). In designing this methodology, 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.

BPA has conducted an ASC review to determine Idaho Power's ASC for FY 2014–2015 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). As noted above, the utilities' ASCs are used in the BP-14 Rate Case to calculate the utilities' benefits, which are then distributed through the REP.

This FY 2014–2015 Final Average System Cost Report (Final ASC Report) describes the 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*, 18 C.F.R. Part 301 *(*2009), available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Documents/2008%20FERC%20Published%20ASCM_FRN_74_FR_47052-01_9-30-09_1741.pdf, and the *Average System Cost Methodology Final Record of Decision (2008 ASCM ROD)*, June 30, 2008, available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

General information regarding the ASC Review Process can be found at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

NOTE: If the filing utility or an intervenor wished to preserve any issue regarding a BPA Final ASC Report 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, § 3.6.1.3 ("Rules of Procedure").

2 AVERAGE SYSTEM COST SUMMARY

2.1 Idaho Power Company Background

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 3,200 megawatts (MW). The company operates 17 hydroelectric generating plants on the Snake River and its tributaries; two natural gas-fired plants (Bennett Mountain and Danskin); and a share of three jointly owned coal-fired plants (Boardman, Jim Bridger, and Valmy). Generation statistics for 2011 are shown in the table below.

Idaho Power 2011 Electric Generation and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Hydro	1,709	52%	10,936,822	59%
Coal	1,118	34%	4,820,344	26%
Natural Gas	444	14%	137,803	1%
Other	5	0%	26	0%
Purchases			2,777,898	15%
Misc Adj.			(76,629)	-1%
Total	**3,276**	**100%**	**18,596,264**	**100%**

Idaho Power, 2011 FERC Form 1, April 13, 2012.

Idaho Power provides electric service to over 496,000 customers in Southern Idaho (95 percent of customer base) and Eastern Oregon. Idaho Power's 24,000-square-mile electric system includes over 4,828 miles of transmission lines and 26,714 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 FERC Form 1 data for IOUs, and for COUs, the most recent audited financial statements (Annual Reports), and for both, the underlying accounting system data. For purposes of this FY 2014–2015 filing period, the Base Period is CY 2011 (January 1, 2011 – December 31, 2011). The submitted information includes the "Appendix 1," an Excel-based workbook populated with financial and load data used in calculating the Base Period ASC.

The table below summarizes the CY 2011 Base Period ASC based on (1) the information contained in Idaho Power's June 4, 2012 ASC Filing, including any errata corrections ("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 2011 Base Period ASC
(Results of Appendix 1 calculations)

	June 4, 2012 As-Filed	July 24, 2013 Final ASC Report
Production Cost	$600,063,783	$599,554,462
Transmission Cost	$120,998,565	$120,780,061
(Less) NLSL Costs	$20,595,313	$20,571,011
Contract System Cost (CSC)	**$700,467,036**	**$699,763,512**
Total Retail Load (MWh)	13,734,430	13,734,430
(Less) NLSL	223,028	223,028
Total Retail Load (Net of NLSL)	13,511,402	13,511,402
Distribution Losses	515,196	674,361
Contract System Load (CSL)	**14,026,598**	**14,185,763**
CY 2011 Base Period ASC (CSC/CSL)	**$49.94/MWh**	**$49.33/MWh**

2.3 FY 2014–2015 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.

The losses are the distribution energy losses occurring between the transmission portion of the utility's system and the meters measuring firm energy load. The distribution losses can be measured using one of the 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 comparable data source.

BPA Staff reviewed Idaho Power's As-Filed Appendix 1 Distribution Loss Factor of 3.75 percent and supporting calculation. For purposes of this Final ASC Report, BPA Staff used a Distribution Loss Factor of 4.91 percent. *See* Section 4.2.1.1 for background information and discussion concerning Idaho Power's Distribution Loss Factor.

2.4 FY 2014–2015 Exchange Period ASC

BPA and the intervenors review, evaluate, and comment on the Appendix 1 historical costs and forecast loads submitted in the ASC Review Process. Once the Base Period ASC is determined, the cost data is escalated forward using the "ASC Forecast Model," an Excel-based forecast model, to the midpoint of the Exchange Period, which in this instance is October 1, 2014. For purposes of this FY 2014–2015 ASC Review Period, the Exchange Period is October 1, 2013, to September 30, 2015 ("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. For all utilities, BPA updates its natural gas and market price forecasts, which factor into the escalation calculations BPA uses in developing a utility's Exchange Period ASC. For calculating the FY 2014-2015 Exchange Period ASC, gas prices decreased slightly and market prices rose slightly from the BP-14 Rate Case Initial Proposal. BPA also updates escalators used in the ASC Forecast Model that rely on data from Global Insight, including its coal escalators, which decreased from the BP-14 Initial Proposal. For the COUs only, BPA updated the RHWMs and the associated Tiered Rates. See the "Inputs" and "Tiered Rates" tabs 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 as filed by the utility on June 4, 2012, including errata corrections if filed, 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, subject to the conditions in Section 2.5 of this Report, or the utility makes a New Large Single Load adjustment as described in Section 2.6.

Table 2.4-1: Exchange Period FY 2014–2015 ASC ($/MWh) With No New Resource Additions

Date	June 4, 2012 As-Filed	July 24, 2013 Final ASC Report
FY 2014–2015	49.46	48.47

2.5 New Resource Additions

Under the 2008 ASCM, a utility's ASC may be adjusted to reflect the addition or loss of a major new 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 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 new 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 resources that affect a utility's Base Period ASC by 2.5 percent or more will be considered major new resources. 18 C.F.R. § 301.4(c)(4). The 2008 ASCM 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 0.5 percent or more. *Id.* See also Section 3.2.14 of this Final ASC Report.

For ASC calculation purposes, a new resource adjustment may be included in the utility's ASC at the commencement of the Exchange Period if such new resource becomes commercially operational (or ceases production) after the Base Period ends, but *before* the Exchange Period begins. In order to be included in the utility's Exchange Period ASC, a New Resource

Attestation must be received by BPA no later than the tenth (10th) business day after the Exchange Period begins.

Table 2.5-1 below summarizes the new major resource additions, prior to any NLSL adjustments that are projected to become commercially operational prior to the beginning of the Exchange Period (*i.e.*, January 1, 2012 – September 30, 2013).

Table 2.5-1: New Resource Additions Coming On Line
***Prior to* the Exchange Period ($/MWh)**

As-Filed FY 2014–2015 Exchange Period ASC				
Resource	**Langley Gulch**	**N/A**	**N/A**	**N/A**
Expected On Line Date	07/01/2012			
Delta*	1.81			

Final ASC Report FY 2014–2015 Exchange Period ASC				
Resource	**Langley Gulch**	**N/A**	**N/A**	**N/A**
Expected On Line Date	07/01/2012			
Delta*	1.75			

*The Delta is the incremental change in the ASC as new resources come on line. See the "New Resources" and "ASCs" tabs in the ASC Forecast Model for Idaho Power's As-Filed and BPA-Adjusted Appendix 1s.

Resources that commence commercial operation during the Exchange Period are normally reflected in the ASC calculation following receipt by BPA of the utility's New Resource Attestation. Table 2.5-2 below summarizes the new major resource additions (prior to any NLSL adjustments) that are projected to become commercially operational and major resource reductions that will cease to be commercially operational during the Exchange Period (*i.e.*, October 1, 2013 – September 30, 2015).

Although the 2008 ASCM permits a utility's ASC to be adjusted to reflect the inclusion of a major new resource during the Exchange Period, as part of the 2012 Residential Exchange Program Settlement Agreement, BPA Contract No. 11PB-12322 (2012 REP Settlement Agreement), all six regional investor-owned utilities 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. Nevertheless, for informational purposes, BPA has retained Table 2.5-2 in the ASC Report because the 2012 REP Settlement is currently being challenged in the U.S. Court of Appeals for the Ninth Circuit. BPA intends to continue to identify major resource additions in its Draft and Final ASC Reports until such time as all legal challenges to the 2012 REP Settlement have been resolved. The final FY 2014–2015 ASC calculation shown in Section 6 of this Report *does not* include any adjustment for new resources during the Exchange Period for setting rates for the FY 2014–2015 Rate Period.

Idaho Power has no major new resources scheduled to come on line during the FY 2014–2015 Exchange Period.

Table 2.5-2: New Resource Additions Coming On Line *During* the Exchange Period ($/MWh)

As-Filed FY 2014–2015 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line Date				
Delta*				

Final ASC Report FY 2014–2015 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line Date				
Delta*				

*The Delta is the incremental change in the ASC as the new resources come on line.

2.6 NLSL Adjustment

A new large single load (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 the 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 the Final Interpretation and Implementation of Endnote 3(d) of the 2008 ASC Methodology (February 2012).

NLSLs are not determined in ASC review proceedings. 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 has no potential NLSLs on record or under review.

Table 2.6-1: New Large Single Loads Under Review

As-Filed FY 2014–2015 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Final ASC Report FY 2014–2015 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 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2014–2015 Exchange Period ASC				
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 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2014–2015 Exchange Period ASC				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

2.7 NLSL Formula Rate

During two separate customer workshops held on February 2 and April 11, 2012, BPA Staff proposed a formula rate calculation for removing resource costs from a utility's ASC when an NLSL occurs during the Exchange Period. The NLSL formula rate was developed to mitigate two issues that arise when a large industrial/commercial load has been determined to be an NLSL and has a determined NLSL start date.

In previous Exchange Periods, BPA calculated the costs of serving a prospective NLSL in the ASC Review Process based on forecasts of the projected NLSL MWhs and start date as provided by the filing utility. BPA Staff 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. First, new NLSL(s) start dates may differ from the forecast; and second, the actual MWh amounts of the NLSL may differ substantially from forecast amounts contained in the Final ASC Report.

To address the potential disconnect between the forecast amount and start date of an NLSL, BPA Staff proposed a formula rate. In late April 2012, parties submitted formal responses to the NLSL topic discussed at the February 2 and April 11 workshops. Avista, Idaho Power, NorthWestern, PGE, PacifiCorp, and Puget all submitted comments in support of the NLSL Formula Rate. With the exception of PGE, all the parties agreed with BPA's formula rate calculation proposal to calculate a utility's ASC when a new NLSL materializes. PGE, in its response, commented on issues outside the scope of the proposed NLSL Formula Rate.

For purposes of the Final ASC Reports, no utility identified potential NLSLs that would begin service prior to or during the FY 2014–2015 Exchange Period, January 1, 2012 through September 30, 2015. 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 Staff will review and evaluate the NLSL and, as necessary, calculate a new ASC using the inputs and formula method as defined below:

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

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 NLSL. 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 & Cost of Serving NLSL

Inputs for both *Prior to* and *During* the Exchange Period			
	Timing of New Resource	**Contract System Cost**	**Cost of Serving NLSL**
Prior to	Group 1	$743,144,965	$87.06/MWh
During	N/A	N/A	N/A

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

FY 2014–2015 Contract System Load
14,798,259 MWh

3 FILING REQUIREMENTS

3.1 ASC Review Process – FY 2014–2015

Utilities' ASCs are established in ASC Review Processes. The ASC Review Processes for FY 2014–2015 began on June 4, 2012, with the submittal of ASC Filings by the following eight utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, PGE, Puget, and Snohomish. An "ASC Filing" consists of two Excel-based models developed by BPA (the Appendix 1 workbook and the ASC Forecast Model) and all supporting data and documentation provided by the utility.

Notice of the ASC Review Processes was provided on BPA's public web site, Secure REP Web Site, and via email. Prior to the June 4, 2012 filing deadline, the utilities posted ASC Filings on BPA's Secure REP Web Site. 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 multiple opportunities to request data, submit comments, and raise issues with the utilities' ASC Filings. The filing utilities, in turn, were afforded opportunities to respond to requests for data, raise and respond to issues, and answer any questions relating to the ASC Filings.

Draft ASC Reports were issued on November 14, 2012 for each of the eight utilities. On December 14, 2012, BPA Staff held a clarification workshop to review and discuss the Draft ASC Reports. Thereafter, the utilities and intervenors had the opportunity to request oral argument before BPA's Administrator. No request was received by the February 1, 2013, deadline. Finally, utilities and intervenors could submit comments on the Draft ASC Reports through April 10, 2013. See Sections 4 and 5 to review comments, if any, submitted by the utilities and intervenors.

This Final ASC Report reflects BPA's findings and final decisions from its review of Idaho Power's ASC Filing and addresses the issues and questions raised by the utility, intervenors, and BPA Staff during the ASC Review Process.

For details of the ASC Review Process and guidelines, please see the *ASCM Rules of Procedure for the ASC Review Process (Rules of Procedure)* available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx.

Final ASC Reports for each utility are available at http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/FY-14-15-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 present 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 – Individual and Grouped
15. New Large Single Loads (NLSL Base New-Calc)
16. Tiered Rates

3.2.1 Schedule 1 – Plant Investment/Rate Base

Schedule 1 of the Appendix 1 establishes the utility's Rate Base. 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 the FERC 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.[1]

Cash Working Capital is a ratemaking convention that is not included in the FERC Uniform System of Accounts, but is a 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 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.

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

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

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. The schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the utility's Base Period ASC ($/MWh).

Contract System Cost
Contract System Cost (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 the cost of serving a utility's NLSLs. CSC is the numerator in the ASC calculation.

Contract System Load (MWh)
Contract System Load (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 is the statistical classification code for all transactions. Please refer to the 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 utility is required to provide a four-fiscal-year forecast beginning October 1 of the Base Year (FY 2012–2015) of its total retail load, as measured at the meter, and its qualifying residential and farm retail load, as measured at the retail meter. For the COUs only, the total retail forecast loads for the Exchange Period are the load forecasts determined by BPA under the Tiered Rate Methodology (TRM).

The total retail and 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.

3.2.10 Distribution Loss Calculation

Each utility is required to measure its distribution losses using one of the methods 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 Ratio 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 new resource, subject to the materiality threshold of 2.5 percent. 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). However, as part of the 2012 REP Settlement, the IOUs agreed to waive the right to include the costs of new resources in their ASCs during the Exchange Period. See Section 2.5 for a discussion of New Resource Additions.

To determine the effects of a major new resource addition or reduction on a utility's Exchange Period ASC, BPA performs one of the following calculations: (1) for new resources that are expected to be on line prior to the start of the Exchange Period, BPA projects the costs of the new resource forward to the midpoint of the Exchange Period; or (2) for new resources that are expected to be on-line during the Exchange Period, BPA calculates the new resource cost as if the resource came on-line at the midpoint of the Exchange Period.

Each resource that satisfies the minimum materiality threshold of 0.5 percent may be entered individually in the "New Resources – Individual" tab. Resources that do not meet the 2.5 percent materiality requirement independently may be grouped together with other resources within "New Resources – Grouped" to meet the 2.5 percent 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 – Individual and Grouped

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 resources that individually affect a utility's ASC by 0.5 percent or more to meet the 2.5 percent 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 can expect to see its ASC changed for a new resource addition.

BPA Staff 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 at the outset of this ASC Review Process:

- The exchanging 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 exchanging 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 an exchanging utility's resources using the utility's adjusted Base Period ASC (per the Draft ASC Report) and forecast natural gas prices used by BPA in the BP-14 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 regroup resources.
- The BP-14 Rate Case Initial Proposal's natural gas price forecast will be the basis for the natural gas fuel costs used for new resource additions in both the Draft and Final ASC Reports.

- The exchanging utility will have the option to recommend a “regrouping” of resource additions that meets the materiality test(s).

- Exchanging 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 for the Final ASC Report is determined after considering the filing utilities’ and other parties’ comments, if any, on the Draft ASC Report, based on the foregoing instructions.

The materiality determinations provided herein are based on the utility’s Base Period ASC (per the Draft Report) as adjusted through the ASC Review Process and reflect the natural gas price forecast from the BP-14 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 the utility’s ASC pursuant to Northwest Power Act Section 5(c)(7). 16 U.S.C. § 839c(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 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, 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 prescribed in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d and the Final Interpretation and Implementation of Endnote 3(d) of the 2008 ASC Methodology (February 2012).

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 not to include in its ASC the cost of resources necessary to serve the COU’s Above-Rate Period High Water Mark (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 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 (PSR). For background information and details, see http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf.

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.

- 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 the RHWM ASC:
    - Power purchases less than five years in duration.

- Total output of new resources may exceed the Above-RHWM Load:
    - The RHWM ASC does not specify removal of costs associated with this excess.

The RHWM ASC calculation methodology provides:

- Set NewResMWh equal to the Above-RHWM Load.
- NewRes$ = NewResMWh times Fully Allocated Cost (calculated using Endnote d).
- If the output of material new resources fails to meet the Above-RHWM Load, meet the deficit with short-term (ST) market purchases at a utility-specific market price.
- If the output of new resources exceeds the Above-RHWM Load, reduce ST market purchases by the excess to the extent possible in the Contract System Cost calculation.
- Sell any remaining surplus at the 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 Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and 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 power 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-14 Rate Case. 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 ("FCSC") 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). BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

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 utility is required to provide a four-fiscal-year forecast of its total retail load, as measured at the meter, and its qualifying residential and farm retail load, as measured at the retail meter. For the COUs only, total retail forecast loads, as determined by

BPA under the TRM, will be provided through the end of the Exchange Period. Also required is a distribution loss calculation as prescribed 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 Staff began the FY 2014–2015 ASC Review Process for Idaho Power's ASC Filing in June 2012. During the interim period, various issues related to Idaho Power's ASC Filing were identified by BPA Staff 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 and mathematical errors. There may be additional issues that 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 of the proper interpretation to be applied either in subsequent 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.

Prior to the start of the FY 2014–2015 ASC Review Processes, BPA held workshops on February 2, 2012, and April 11, 2012, to discuss and evaluate new, BPA-proposed procedures, policies, and topics that may affect future ASC Reviews. Topics for discussion included NLSL reviews and determinations; the NLSL Formula Rate; definitions of individual new resources for conservation and renewables; FERC accounting questions regarding wind reporting, generation statistics, distribution loss calculations, purchased power and sales for resale; and the treatment of items included under Other Expenses (FERC Account 557) when evaluating the Cash Working Capital calculation.

Following considerable review and discussion of these topics, the Parties and BPA Staff either resolved each issue or determined the issue was not significant enough to warrant a change in policy or procedure. Therefore, with exception of the NLSL Formula Rate (further described in Section 2.7) and the treatment of items included under other expenses (FERC Account 557) when evaluating the Cash Working Capital calculation (Section 5.2.1), BPA has no additional comments regarding the resolved issues and will not separately address them in this ASC Report. BPA and the Parties retain the right to bring any of the topics forward during a later review process.

Table 4-1 summarizes all 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 for these adjustments may be found in the Decisions on Draft Report Resolved Issues and/or Decisions on Draft Report Unresolved Issues sections.

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 Issues

Appendix 1 Schedule	**Adjustment**
Schedule 1: Plant Investment/Rate Base	Direct adjustments: see Sections 4.1.1.1 and 4.1.1.2.
Schedule 1A: Cash Working Capital	Direct adjustments: see Section 4.1.2 and Section 5.2.
Schedule 2: Capital Structure and Rate of Return	No direct adjustments.
Schedule 3: Expenses	Direct adjustment: see Section 4.1.2.1.
Schedule 3A: Taxes	No direct adjustments.
Schedule 3B: Other Included Items	No direct adjustments
Schedule 4: Average System Cost	Direct adjustment: see Section 4.2.1.1 Distribution Loss Calculation.
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	Updated. See Tiered Rates Tab of Appendix 1.
Salary and Wages	No direct adjustments.
Ratios	No direct adjustments.
ASC Forecast Model	**Adjustment**
Tier 1 Power Purchases from BPA	See Section 5.3.1, Generic Issues.
Calculation of ASC Delta for New Resource Additions	See Section 5.3.2, Generic Issues.
PF Rates	Updated. See the PF_Rates Tab.
Purchased Power and Sales for Resale	Erratum Correction. See Section 4.3.1.
Natural Gas and Market Prices	Erratum Correction. See Section 4.3.2.
Cash Working Capital	Erratum Correction. See Section 4.3.3.

4.1 Decisions on Draft Report Resolved Issues

During the ASC Review Process, BPA Staff raised the issues discussed in this section and the "Unresolved Issues" discussed in Section 4.2.1, below. Idaho Power responded to these issues in its September 21, 2012 Issue List response. Following the issuance of its Draft ASC Report, Idaho Power submitted two separate comments: "Initial Comments" dated December 20, 2012, and additional comments dated April 10, 2013 ("Additional Comments"). No other party raised issues with, or commented on Idaho Power's June 4, 2012 ASC Filing. BPA Staff considers the issues identified in this section resolved.

4.1.1 Schedule 1 – Plant Investment/Rate Base

4.1.1.1 Account 182.3 – Other Regulatory Assets

Issue:

Whether the Other Regulatory Asset Account line item 182336 - "OATT REV DEF ORD 30940" should be included in the calculation of Idaho Power's Appendix 1 and functionalized to Transmission.

Parties' Positions:

In its June 4, 2012 ASC Filing, Idaho Power functionalized $2,064,469 in an existing deferral account to Transmission.

BPA Position:

Regulatory asset OATT REV DEF ORD 30940 should be functionalized to Distribution/Other.

Evaluation of Positions:

In February 2012, Idaho Power filed an application with the Idaho Public Utility Commission (IPUC) to amortize $2.064 million in an existing deferral account over three years. The deferral account was created to allow Idaho Power to recover certain transmission costs associated with its Federal Energy Regulatory Commission rate case, Docket ER06-787. In Order 32540, the IPUC approved amortization of this account beginning in June 2012. Idaho Power was not allowed a rate of return or carrying costs for this account.

BPA Staff's position is that this asset should be functionalized to Distribution/Other for two reasons. First, under the 2008 ASCM, if a utility's state commission does not include a regulatory asset in the utility's rate base for retail rate purposes, then that regulatory asset is similarly excluded from the rate base calculation used to determine the utility's ASC. The 2008ASCM ROD states: "[u]nder no conditions would regulatory assets be included in the ASC at a level greater than regulatory commissions allow them to be recovered in retail rates." 2008 ASCM ROD at 149. Since the IPUC did not allow Idaho Power to include carrying costs or earn a rate of return on OATT REV DEF ORD 30940, it must be functionalized to Distribution/Other.

Second, the ASCM requires that an asset must be included in the utility's rate base during the Base Period, which in this case is CY 2011, to be included in ASC. The 2008 ASCM is designed to minimize the time and complexity of establishing ASCs. One way in which the 2008 ASCM accomplishes this objective is by minimizing the changes that can occur between the historic Base Period ASC and the Exchange Period ASC. Section 301.4(a) of the 2008 ASCM specifically identifies the elements of the Base Period ASC that may change after the Base Period. Adjustments for new regulatory assets approved by a regulatory body are not among the approved changes. Since amortization of the asset did not begin until after the Base Period, it must be functionalized to Distribution/Other.

In its Issue List Response, Idaho Power agrees with BPA Staff's assessment that this line item, 182336, should be functionalized to Distribution/Other in Schedule 1, Account 182.3. *See* BPA's Issue List to Idaho Power, Utility-Specific Issues, No. 1.

Decision:

BPA will functionalize Other Regulatory Asset Account line item 182336 - "OATT REV DEF ORD 30940" in the amount of $2,064,469 to Distribution/Other.

Table 4.1.1.1-1: Account 182.3 – Other Regulatory Assets ($)

	Total	Production	Transmission	Dist/Other
As-Filed	989,194,015	0	2,221,134	986,972,882
Adjusted	989,194,015	0	156,665	989,037,351

4.1.1.2 Renewable Energy Credits

Issue:

Whether revenue received from the sale of Renewable Energy Credits (RECs) is properly recorded in Idaho Power's FY 2014-2015 Appendix 1.

Parties' Positions:

Idaho Power believes that REC revenue should be reported as an offset to net power supply costs in Account 557 – Other Expenses.

BPA Position:

Revenue received from the sale of RECs should be recorded as a revenue line item on Schedule 3B, Other Included Items.

Evaluation of Positions:

In response to BPA's September Issue List, Idaho Power provided detailed information and a T-Account analysis as documentation in support of its response. Idaho Power also clarified that (1) a small portion, approximately $364,000, of REC revenue is recorded in Schedule 3B, Account 411.8, and (2) the remaining REC sale revenue is recorded as a reduction to the deferral of net power supply costs (PCA) in Schedule 1, Accounts 182.3 and 254, which ultimately results in a lower amortization amount for PCA costs included in Account 557 on Schedule 3. *See* BPA's Issue List to Idaho Power, Utility-Specific Issues, No. 2.

After reviewing the documentation provided in Idaho Power's response to BPA's Issue List, Staff accepts Idaho Power's treatment of revenues associated with the sale of Renewable Energy Credits.

Decision:

The recording of revenues from the sale of RECs in CY 2011 will remain as reported in Idaho Power's As-Filed Appendix 1.

4.1.2 Schedule 3 – Expenses

4.1.2.1 Account 557, Other Expenses and Schedule 1A – Cash Working Capital.

Issue:

Whether Power Cost Adjustment (PCA) costs included in FERC Account 557, Other Expenses, may be included in the Cash Working Capital Calculation in Schedule 1A of Appendix 1. For additional background on this issue, please see the generic issue addressing Account 557, Other Expenses in Section 5.2.

Parties' Positions:

Idaho Power recorded PCA costs in the calculation of Cash Working Capital on Schedule 1A of Appendix 1.

BPA Position:

PCA-related expenses must be removed from the calculation of Cash Working Capital.

Evaluation of Positions:

Endnote (f) of the 2008 ASCM states:

> f/ Cash working capital (CWC) is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a

> Utility, BPA will allow no more than 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 Charge.

18 C.F.R. § 301, Table 1, End. f.

Pursuant to Endnote (f), PCA costs recorded in Account 557 are not appropriate costs to include in the calculation of Cash Working Capital which is ultimately included in a utility's ASC.

In response to Data Request ASC-14-IP-10, Idaho Power provided an itemization of expenses included in FERC Account 557. The breakout included PCA costs of $38,497,391.10 which were then included in the calculation of Cash Working Capital on Schedule 1A.

BPA Staff's position is that PCA costs recorded in Account 557 should be excluded from the Cash Working Capital calculation on Schedule 1A of Idaho Power's Appendix 1. In Idaho Power's Issue List response, Idaho Power agreed with BPA Staff's determination to exclude these costs from the Cash Working Capital calculation. *See* BPA's Issue List to Idaho Power, Utility-Specific Issues, No. 3.

Decision:

BPA will include PCA costs from Account 557, Other Expenses, in the line item calculation of "Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs" on line 20 of Schedule 1A. This will remove $38,497,391 from the Cash Working Capital calculation.

Table 4.1.2.1-1: Schedule 1A – Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs (Line 20) ($)

	Total	Production	Transmission	Dist/Other
As-Filed	288,415,620	288,415,620	0	0
Adjusted	326,913,011	326,913,011	0	0

Table 4.1.2.1-2: Schedule 1A – Revised Total O&M Expenses (Line 21) ($)

	Total	Production	Transmission	Dist/Other
As-Filed	420,686,367	229,786,556	49,077,662	141,822,149
Adjusted	382,188,976	191,289,165	49,077,662	141,822,149

4.2 Decisions on Draft Report Unresolved Issues

During the ASC Review Process, BPA Staff raised the "Resolved Issues" discussed in Section 4.1, above, and the "Unresolved Issues" identified below. Idaho Power responded to these issues in its September 21, 2012Issue List response, and to the Idaho Power Draft ASC Report in two separate responses dated, respectively, December 20, 2012 (Initial Comment) and April 10, 2013 (Additional Comment). No other party raised issues with, or commented on Idaho Power's June 4, 2012, ASC Filing. BPA Staff considers the issues identified in this section now resolved.

4.2.1 Schedule – Average System Cost

4.2.1.1 Distribution Losses

Issue:

Whether Idaho Power provided sufficient documentation to support its distribution loss factor calculation.

Parties' Positions:

Idaho Power contends that the default loss factor calculation method described in Endnote e/ of the 2008 ASCM should not be used. Instead, BPA should either accept Idaho Power's modified methodology for determining distribution losses or accept the distribution loss study it submitted in November of 2012.

BPA Staff's Position:

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., pp. 64-65. Idaho Power's modified method for determining distribution losses is not permitted by the 2008 ASCM. Idaho Power's November 2012 distribution loss study is permissible under Method 1 of Endnote e.

Evaluation of Positions:

The 2008 ASCM requires a utility to include with its ASC filing a current distribution loss analysis as described in Endnote e:

> The losses shall be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss can be measured using one of the following 3 methods:
>
> > Method 1, Distribution Loss Study: Losses shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall be in sufficient detail so as to accurately identify average distribution losses

associated with the Utility's total load, excluded loads, and the residential load. Distribution losses shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

Method 2, Revenue Grade Meters: If a Utility does not have a loss study, but it has sufficient revenue grade meters in its distribution system, BPA will permit the Utility to directly measure its distribution losses subject to BPA review and approval. A Utility that does not possess the capability to directly measure its distribution losses will be required to submit a distribution loss study every seven years.

Method 3, Default: If a Utility does not have a current loss study or grade meters, BPA will accept the following method for determining a Utility's distribution loss factor.

i. Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.

ii. From this 5-year total system loss factor, subtract the loss factor for BPA's transmission system.

iii. The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

18 C.F.R. § 301 End e.

In effect, if a utility does not have a current distribution loss study, and if the utility does not have revenue grade meters, Endnote e requires a utility to calculate its distribution loss factor using an average distribution loss factor based on the losses submitted in the utility's previous five FERC Form 1s, ending with the Base Period (*e.g.*, CY 2007–2011). *See* 18 C.F.R. § 301 End e., p. 65, (Method 3).

In its initial ASC Filing, Idaho Power reported a distribution loss factor of 3.75 percent based on a combination of 2011 FERC Form 1 data and an excerpt from a transmission and distribution loss study titled, "1985 – 1987 Average Energy Flow Diagram." However, this method for determining distribution losses was not an approved method under the ASCM because it both relied on a distribution loss study that was older than seven years and because it mixed components of Method 1 with Method 3. As a result, BPA Staff did not accept this calculation in evaluating Idaho Power's ASC. Instead, as required by the 2008 ASCM, BPA Staff used Method 3 to determine Idaho Power's distribution loss factor in the Draft ASC Report, which yielded a distribution loss factor of 7.02 percent. *See* BPA's Issue List to Idaho Power, Utility-Specific Issues, No. 4.

In response to BPA's September 5, 2012 Issue List, Idaho Power provided additional information regarding its distribution losses. First, Idaho Power submitted an excerpt from a more recent Transmission and Distribution Loss Study conducted in 2003 (2003 Loss Study). *See* Idaho Power's Response to BPA's Issue List, Utility-Specific Issues, No. 4. When substituted in the 'Loss Calc' tab of Idaho Power's Appendix 1, this more recent loss data changed Idaho Power's distribution loss from 3.75 percent to 4.53 percent. To support this calculation, Idaho Power also provided an affidavit which states that no significant changes were made to the Company's transmission and distribution system since the 2003 Loss Study with one exception - the newly constructed Hemingway substation, which officially came on-line in 2010.

While the distribution loss data Idaho Power provided was more recent, it still failed to comply with the express terms of the 2008 ASCM. The 2008 ASCM makes clear that if the utility cannot directly measure distribution losses and does not have a formal Distribution Loss Study prepared within the last seven years, the utility must use the default method to calculate its distribution losses. 18 C.F.R. § 301 End. e. Based on this rule, Method 3 of endnote e was the correct method for calculating Idaho Power's distribution loss factor.

Idaho Power then filed its initial comments to BPA's Draft ASC Report on December 20, 2012. In its comments, Idaho argues that the 2008 ASCM default methodology is flawed for two reasons. First, Idaho Power claims the default methodology described in Endnote e of the 2008 ASCM is flawed because it imputes an arbitrary transmission loss factor of 1.9% to Idaho's transmission system. Second, Idaho Power asserts there is no correlation between BPA's default calculation of 7.02% and the loss factor of 6.88% obtained by multiplying the distribution loss coefficients provided in the 2003 Loss Study because, once again, using a factor of 1.9% as a proxy for Idaho's transmission system losses is completely arbitrary. Both of these objections, however, are outside of the scope of this proceeding because they challenge the 2008 ASCM itself. The 2008 ASCM expressly *requires* BPA to subtract from a utility's loss calculation the losses associated with BPA's transmission system when determining distribution losses under Method 3 of Endnote e. 18 C.F.R. § 301 End. e(ii) ("From this 5-year total system loss factor, subtract the loss factor for BPA's transmission system.") Moreover, BPA expressly considered and rejected the argument that the utility's transmission system losses (as opposed to BPA's system losses) should be used in developing a distribution loss factor under Method 3. *See* 2008 ASCM ROD, at 151 ("BPA disagrees with the IOUs concerning use of their own transmission system loss factor in place of BPA's system loss factor.") Because the 2008 ASCM was approved and confirmed by FERC in September of 2009, challenges to the 2008 ASCM are outside of the scope of this ASC Review Process.

Along with its comments, Idaho Power submitted the results of a new Distribution Loss Study conducted in November, 2012, based on the direct measurement of distribution losses. The new study measured inputs to the distribution system using a combination of MV90 revenue grade meters and data obtained from the Pi system installed at the distribution substation. Customer load data was obtained from recently installed Advanced Meter Infrastructure (AMI). Using this methodology, Idaho Power calculated a distribution loss factor of 4.74 percent.

BPA Staff met with representatives from Idaho Power on January 30, 2013, to discuss the new distribution loss study to determine which, if any, of the Endnote e methods the study may qualify for under the 2008 ASCM. At this meeting, BPA and Idaho Power staff discussed that even though MV90 data is revenue grade, inputs to the Pi system may or may not be. If Pi input data is obtained from a MV90 meter, then the data is revenue grade. If, however, the data originates from substation current and voltage transformers that are used for relay purposes, then the Pi data is not revenue grade. Therefore, based on the current loss study data and the information presented during discussions with Idaho Power, BPA Staff informed Idaho Power that they did not believe the new study would qualify under Method 2.

Idaho Power submitted additional comments on April 10, 2013. In these comments, Idaho Power revised its calculation of distribution losses from 4.74 percent to 4.91 percent. Idaho Power made the change after finding a clerical error in the Pi system data used for October 2011.

In addition, Idaho Power stated in its April 10, 2013, comments that the new distribution loss study should be accepted because it qualified under both Methods 1 and 2 of Endnote e of the 2008 ASCM. Specifically, Idaho Power argues that its loss study qualifies under Method 1 because it was conducted in a rigorous and professional manner under the supervision of a licensed engineer. "Engineering and expert judgment was exercised in analyzing the data produced by Idaho Power's AMI system, Pi system, and MV-90 meters and applying it to determine a distribution loss factor. Engineering and expert judgment was also utilized to arrive at the conclusion that the 99 percent of Idaho Power's customers that are part of the AMI system are representative of the 1 percent that are not part of the AMI system." *See* Additional Comment at 2. Idaho Power also claims nothing in Endnote e precludes a loss study from incorporating actual measurement data where it is useful and verifiable. Idaho Power argues that it would be "unprofessional for an engineer to willfully ignore actual verifiable data, when the actual data is more reliable for the purpose than standardized or 'proxy' assumptions." *Id.*

BPA agrees that Idaho Power's November 2012 loss study, as amended in its April 10, 2013 comments, qualifies as an engineering loss study under Method 1 of Endnote e. As noted above, Endnote e provides that a study qualifies as a Method 1 distribution loss study if it is established

> according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load.

18 C.F.R. § 301 End. e.

BPA Staff has reviewed the study and believes that it reflects a study based on engineering and statistical data that reasonably represents the distribution losses Idaho Power is experiencing on its system.

Idaho Power also contends that its distribution loss study qualifies under Method 2 of Endnote e, which requires the utility to conduct a direct measurement using "revenue grade" meters. Idaho Power argues that its loss study was conducted using data obtained from its revenue grade AMI metering system, revenue grade MV-90 meters, and Pi system. Idaho Power claims that this system is superior to an engineering study that relies on assumptions and estimates. Idaho Power has the ability to directly measure actual metered losses in its distribution system. There are no assumptions or estimates that have to be made or used, except with respect to the 1 percent of the customers not part of the AMI system. Idaho Power believes that the study recently completed and submitted to BPA is a more precise measurement of Idaho Power's actual distribution losses.

Because Idaho Power's distribution loss study qualifies under Method 1 of Endnote e, the issue of whether this data would have qualified under Method 2 is moot. BPA expresses no opinion on whether Idaho Power's distribution loss study would qualify under Method 2 of the 2008 ASCM.

Finally, Idaho Power restates in its April 10, 2013, comments its assertion that Method 3 should not be used because "…it would be arbitrary and unreasonable to substitute BPA's 1.9 percent transmission system loss factor as a proxy for Idaho Power's transmission system loss factor…". *See* Idaho Power Comments, April 10, 2013, at 5. This argument is both outside of the scope of this proceeding and moot. First, it is outside the scope of this proceeding because it is a direct challenge to the FERC-approved 2008 ASCM. Method 3 of Endnote e specifically requires BPA to subtract from the utility's loss calculation ". . . the loss factor for BPA's transmission system." Because BPA's transmission system losses are 1.9%, subtracting 1.9% is directly required by the 2008 ASCM, and challenges to this adjustment is a direct challenge to the 2008 ASCM. Second, as already noted above, BPA will accept Idaho Power's distribution loss study under Method 1, so this issue is also moot.

<u>Final Decision:</u>

For Idaho Power's FY 2014-2015 ASC Filing, BPA will use the distribution loss factor of 4.91 percent which was calculated using Method 1 of Endnote e described in the 2008 ASCM.

Table 4.2.1.1-1: Schedule 4 – Distribution Loss Factor

	Distribution Loss Factor (%)	Distribution Losses (MWh)
As-Filed	3.75	515,196
Adjusted	4.91	674,361

4.3 <u>ASC Forecast Model Errata Corrections</u>

On April 18, 2012, BPA released its latest ASC Forecast Model to be used for the FY 2014-2015 ASC Review Processes. Following that release date and after the June 4 utility submissions, BPA Staff discovered three formula discrepancies in the ASC Forecast Model as described below. In the utilities' Draft ASC Reports, BPA proposed the following errata corrections to the Forecast Model. No party provided comments.

4.3.1 Purchased Power and Sales for Resale

BPA Staff discovered a formula error in the worksheet that calculates purchased power expense and off-system sales revenue. Specifically, the forecast model was not recognizing the cost of the Base Period Tier 1 purchases from BPA. This error affected the forecast ASCs of Snohomish County PUD and Clark County PUD only. BPA Staff corrected the error and issued an updated ASC Forecast Model on July 18, 2012. *See* Cell E163 on the OSS & PurPWr Forecast (2) Tab of the ASC Forecast Model.

4.3.2 Market Price Forecast

BPA Staff discovered a formula error in the worksheet that calculates the individual utility market purchase price and market sales price. The worksheet was not recognizing the correct Base Period (CY 2011) actual market price in the INPUTS Tab. The error affected the Exchange Period purchased power expense and sales for resale revenues of all participating utilities. BPA Staff corrected the error prior to providing Exchange Period ASCs for the BP-14 Rate Case Initial Proposal. The ASC Forecast Model with the correction was uploaded simultaneously with the Draft ASC Reports and Draft Appendix 1 models. *See* cell C46 on the INPUTS Tab of the ASC Forecast Model.

4.3.3 Cash Working Capital Calculation

BPA Staff discovered a formula error in how the ASC Forecast Model was forecasting Cash Working Capital. The Model was not removing fuel and purchased power costs from Account 557 prior to forecasting Cash Working Capital. BPA Staff corrected the error prior to providing Exchange Period ASCs for the BP-14 Rate Case Initial Proposal. The ASC Forecast Model with the correction was uploaded simultaneously with the Draft ASC Reports and Draft Appendix 1 models. The correction affected the Exchange Period ASCs of Avista and Idaho Power Company. *See* Row 85 in the Base Data Tab of the ASC Forecast Model.

5 GENERIC ISSUES

5.1 Introduction

In addition to the foregoing issues, which are limited to Idaho Power, BPA raised the following issues that may be generic to all exchanging utilities. Following the publication of the Draft ASC Reports, no Party commented on any of these generic issues.

5.2 Schedule 1A – Cash Working Capital

5.2.1 Account 557 – Other Expenses

Issue:

Whether expenses associated with purchased power or fuel costs that are recorded in Account 557- Other Expenses, should be removed for the purposes of calculating Cash Working Capital (Schedule 1A).

Parties' Positions:

Any fuel-related expenses reported in Account 557 should be excluded in the Cash Working Capital calculation.

BPA Staff's Position:

Any expenses associated with purchased power or fuel costs that are recorded in Account 557- Other Expenses, should be removed for the purposes of calculating Cash Working Capital (Schedule 1A).

Evaluation of Positions:

Endnote f of the 2008 Average System Cost Methodology, Final Record of Decision, states that purchased power and fuel costs should be excluded from the Cash Working Capital calculation.

> f/ Cash working capital (CWC) is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a Utility, BPA will allow no more than 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 Charge.

18 C.F.R. § 301, End. f.

This issue was discussed, evaluated, and resolved during the February 2 and April 11, 2012, REP Workshops. No additional comments were provided following the publication of the Draft ASC Reports. The IOUs and BPA agreed that any expenses associated with purchased power or fuel costs that are recorded in Account 557, Other Expenses, should be removed from the Cash Working Capital (Schedule 1A) calculation.

See BPA Issues List, Generic Issues, No. 1.

Decision:

Any expenses associated with purchased power or fuel costs that are recorded in Account 557-Other Expenses, will be removed for the purposes of calculating Cash Working Capital (Schedule 1A).

5.3 ASC Forecast Model

5.3.1 Tier 1 Power Purchases from BPA

Issue:

What level of the COUs' Tier 1 purchases is appropriate to include in the Exchange Period ASC calculation?

Parties' Positions:

BPA raised this issue for the first time in the Draft ASC Report. No Party filed comments on this issue following publication of the Draft Report.

BPA Staff's Position:

The ASC Forecast Model should set Tier 1 purchase amounts equal to the lesser of RHWM (based on Slice amounts assuming critical water) or net requirements, plus the COU's Slice share of Federal Columbia River Power System (FCRPS) surplus under average water.

Evaluation of Positions:

Under the 2008 ASCM, the calculation of IOUs' and COUs' ASCs begins with actual historical data from a Base Period, which is then escalated to the midpoint of the Exchange Period (*i.e.*, October 1, 2014) in accordance with the formulas and rules of the ASC Forecast Model. For the FY 2014–2015 ASC Review Process, the Base Period is calendar year 2011. For both COUs and IOUs, long-term power purchases in the Base Period reflect the utilities' actual purchases. For COUs, the Base Period purchases reflect all power purchases the utility received from BPA (including surplus under Slice).

Differences arise between the COUs and IOUs, however, when BPA escalates the long-term power purchases from the Base Period to the Exchange Period in the ASC Forecast Model.

For IOUs, the 2008 ASCM requires that the output from the utility's own generation and the amount of power from long-term and intermediate power purchases remain constant at the Base Period level; thus, if a utility had 100 aMW of power purchases in CY 2011, BPA would assume that, for the rate period, the utility would again have 100 aMW of long-term power purchases annually. If the utility's existing and long-term resources are insufficient to meet the utility's forecast annual rate period load, the ASC Forecast Model makes up the difference by increasing the utility's short-term market purchases. 18 C.F.R. § 301.4(e).

For COUs, the 2008 ASCM requires BPA to calculate ASC by using "the RHWM System Resources as determined in the [TRM] process." 18 C.F.R. § 301.4(g)(1). To implement this language, BPA Staff designed the ASC Forecast Model to update the COUs' PF power purchases for the Exchange Period (*i.e.*, FY 2014–2015) with the RHWM purchases BPA establishes as part of the RHWM process. These RHWM purchases are based on a critical water assumption, and do not include surplus power that Slice customers may otherwise be entitled to during the Exchange Period. The effect of this modeling input is that COUs' ASCs are based on two different long-term power purchase assumptions: (1) a Base Period long-term power purchase amount determined using *actual* purchases (which reflects actual water conditions), and (2) Exchange Period long-term power purchases determined using *critical* water conditions. If the projected purchases under critical water in (2) are less than the long-term purchases under actual water conditions in (1), the ASC Forecast Model projects that the utility is resource-deficient during the Exchange Period and automatically increases the utility's market purchases (at market prices) to make up the difference. This is the case even though the utility's *actual* power deliveries from BPA are likely to be much greater than the critical water assumption used in calculating the utility's RHWM.

BPA Staff contends that using actual-water-based PF power purchases in the Base Period and then critical-water-based PF power purchases in the Exchange Period is logically inconsistent and not the intent of the 2008 ASCM. Had this modeling anomaly been identified earlier, BPA Staff would have revised the ASC Forecast Model to ensure that both the Base Period and Exchange Period calculations of PF power purchases were using consistent methods. Having now identified the anomaly, BPA Staff proposed in the Draft ASC Reports to make the modeling change to the ASC Forecast Model for purposes of calculating the COUs' ASCs. In determining how to remedy the modeling anomaly, BPA Staff examined three alternatives:

> Alternative 1: Set Tier 1 purchase amounts equal to Base Period PF/Tier 1 purchases. This is the same method used for all other long-term purchases of COUs and long-term purchases of IOUs. The water condition of the base year is assumed to occur in the forecast years; the same assumption is used for IOUs.
>
> Alternative 2: Set Tier 1 purchase amounts equal to the lesser of RHWM or net requirements (the firm Slice amounts), plus the COU's Slice share of FCRPS surplus under average water (thereby using the same assumption as in rates: part

of BPA's surplus generation is taken by Slice customers). This alternative sets the COU purchase amounts from BPA according to the "RHWM System Resources" established by BPA in its Power Rate Proceeding.

Alternative 3: Set Tier 1 purchase amounts equal to the lesser of the amounts determined in Alternatives 1 and 2, above.

In the Draft ASC Report, BPA Staff recommended that the COUs' ASCs be calculated using Alternative 2. No Party commented in opposition on this issue following the publication of the Draft Reports. Therefore, BPA will adopt Alternative 2. Alternative 2 will create an "apples-to-apples" comparison between the long-term purchases considered in the Base Period (which includes surplus under *actual* water conditions) and the long-term purchases updated in the Exchange Period (which includes surplus under average water conditions). This method also adheres to the ASCM's requirement that BPA use the "the RHWM System Resources as determined in the [TRM] process," which would continue to form the primary basis for the long-term projections used in the ASC Forecast Model. Finally, this method meets the intent of the 2008 ASCM with respect to determining the ASCs of COUs by basing a COU's ASC on the best projection of the utility's PF purchases from BPA during the Exchange Period.

Decision:

BPA will use Alternative 2 to determine what level of Tier 1 purchases is appropriate to include in the Exchange Period ASC calculation: Set Tier 1 purchase amounts equal to the lesser of the RHWM or net requirements (the firm Slice amounts), plus the COU's Slice share of FCRPS surplus under average water.

5.3.2 Calculation of ASC Delta for New Resource Additions

Issue:

What is the appropriate method to calculate the ASC delta for new resource additions?

Parties' Positions:

BPA raised this issue for the first time in the Draft ASC Report. No Party filed comments on this issue following publication of the Draft Report.

BPA Staff's Position:

BPA will calculate an ASC delta for each new resource addition, and combination of new resource additions, contained in the utilities' ASC Filings.

Evaluation of Positions:

During the ASC reviews, BPA Staff became aware of an issue regarding the calculation of the ASC delta for new resource additions. PGE is the only utility affected by this issue in the FY 2014–2015 Review Processes, but other utilities may be affected in the future.

For a utility with multiple new resource additions that meet the materiality threshold of 2.5 percent and with an existing NLSL, the ASC delta can differ depending on which new resource (or combination of new resources) has previously come on line. The differing ASC deltas result from the effect of the particular new resource addition, or specific combination of new resource additions, on the $/MWh cost to serve NLSLs. To determine the ASC delta under every scenario, BPA calculated an ASC delta for each new resource, individually, and each possible combination of new resources. In the event a new resource, or specific combination of new resources, comes on line, the corresponding ASC delta is the amount to be added to PGE's Exchange Period ASC, which was calculated before the addition of any new resources. The ASC deltas are shown on Table 2.7-1 in PGE's Final ASC Report.

Decision:

For the Final ASC Reports, where applicable, BPA will calculate an ASC delta for each new resource addition, and each combination of new resource additions, contained in the utilities' ASC Filings.

6 FY 2014–2015 ASC

Idaho Power's As-Filed, Base Period (CY 2011) ASC was $49.94/MWh. As a result of adjustments made during the review process, Idaho Power's Base Period ASC decreased to $49.33/MWh.

Idaho Power's As-Filed, Exchange Period ASC for FY 2014–2015 was $51.27/MWh. As a result of adjustments made during the review process, Idaho Power's Exchange Period ASC for FY 2014–2015 decreased to $50.22/MWh.

These adjustments include new resources, if any, that came on line prior to the Exchange Period.

The proposed Exchange Period ASC does not reflect any changes in NLSL status. Please refer to Section 2.7 for potential NLSL adjustments to Exchange Period ASCs.

7 REVIEW SUMMARY

This Final ASC Report is BPA's determination of Idaho Power's FY 2014 and FY 2015 ASC based on information and data provided by Idaho Power, including comments received, if any, 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 Sections 4 and 5 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 2014–2015.

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 24th day of July, 2013.

BONNEVILLE POWER ADMINISTRATION

By: */s/ Mark. O. Gendron*
Vice-President, Northwest Requirements Marketing

BONNEVILLE POWER ADMINISTRATION

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