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

FY 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

PacifiCorp

July 2013

FY 2014–2015

FINAL
AVERAGE SYSTEM COST REPORT

FOR

PacifiCorp
Docket Number: ASC-14-PC-01

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

July 2013

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1 FILING DATA

Utility: **PacifiCorp**
825 NE Multnomah
Portland, Oregon 97232
http://www.pacificorp.com

Parties to the Filing:

Investor-Owned Utilities (IOUs):
Avista Corporation (Avista)
Idaho Power Company (Idaho Power)
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 section 7(b) of the Act. 16 U.S.C. § 839c(c)(1); 16 U.S.C. § 839e(b)(1). The benefits determined under 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 BPA's Administrator the authority to determine utilities' 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 PacifiCorp'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 PacifiCorp Background

PacifiCorp, which includes PacifiCorp and its subsidiaries, serves over 1.8 million retail customers, including residential, commercial, industrial, and other customers in a 136,000-square-mile service territory in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho, and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies, and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc.

PacifiCorp owns 16,200 miles of transmission lines and 62,930 miles of distribution lines. In 2011, PacifiCorp's 75 generating plants had nameplate generation capacity of approximately 11,316 megawatts (MW), and they produced 55,435,337 megawatthours (MWh). Details are shown in the table below:

PacifiCorp 2011 Total System Capacity and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Coal	6,614	58	40,777,809	65
Natural Gas	2,480	22	6,320,824	10
Wind	1,032	9	3,281,764	5
Geothermal	38	0	278,079	0
Bio-fuel	62	1	89,501	0
Hydro	1,090	10	4,431,379	7
Purchases			7,449,027	12
Misc Adj.			(2,356)	0
Total	**11,316**	**100**	**62,626,027**	**100**

PacifiCorp, 2011 FERC Form No. 1, April 18, 2012.

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 PacifiCorp'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	$1,133,582,162	$1,170,289,285
Transmission Cost	$255,831,120	$255,423,971
(Less) NLSL Costs	$0	$0
Contract System Cost (CSC)	**$1,389,413,282**	**$1,425,713,256**
Total Retail Load (MWh)	20,460,678	20,460,678
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	20,460,678	20,460,678
Distribution Losses	584,630	915,012
Contract System Load (CSL)	**21,045,308**	**21,375,690**
CY 2011 Base Period ASC (CSC/CSL)	**$66.02/MWh**	**$66.70/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 PacifiCorp's As-Filed Appendix 1 Distribution Loss Factor of 2.86 percent and supporting calculations. For the purposes of this Final ASC Report, BPA Staff used a Distribution Loss Factor of 4.47 percent. *See* Section 4.1.4 for background information and discussion concerning PacifiCorp'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 Rate Case 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	65.82	65.61

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 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, prior to the beginning of the Exchange Period (*i.e.*, January 1, 2012 – September 30, 2013).

PacifiCorp has no major new resources scheduled to come on line prior to the FY 2014–2015 Exchange Period.

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	**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 new resources come on line.

Resources that commence commercial operations 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.

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

As-Filed FY 2014–2015 Exchange Period ASC				
Resource	**New Resources Group A**	**New Resources Group B**	**N/A**	**N/A**
Expected On Line Date	October 2014	October 2014		
Delta*	3.05	1.96		

Final ASC Report FY 2014–2015 Exchange Period ASC				
Resource	**New Resources Group A**	**New Resources Group B**	**N/A**	**N/A**
Expected On Line Date	October 2014	October 2014		
Delta*	2.96	1.63		

*The Delta is the incremental change in the ASC as the new resources come on line. See the "New Resources" and "ASCs" tabs in the ASC Forecast Model for PacifiCorp's As-Filed and BPA-Adjusted Appendix1s. See also Section 4.1.5.2 of this Report.

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 d(3) 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.

In PacifiCorp's FY 2012–2013 ASC Filing, the utility believed it would have a new NLSL taking power prior to the end of the current Exchange Period (September 30, 2013). *See* FY 2012–2013 Final Average System Cost Report, PacifiCorp, July 2011, Section 2.5. At this time, PacifiCorp's new large single load forecast has not exceeded 10aMW in a 12-month period and therefore is not a measurable NLSL, and it appears it may not be a measurable NLSL prior to the end of the FY 2014–2015 Exchange Period. For this reason, PacifiCorp currently has no NLSLs on record or new NLSLs under review, and therefore no NLSL resource costs will be removed from its ASC.

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	No new resources coming on line prior to the start of the Exchange Period	$1,428,555,794	$78.41/MWh
During	New Resource No. 1	$1,493,034,830	$76.96/MWh
	New Resource No. 2	$1,463,911,689	$81.05/MWh
	New Resources Nos. 1 and 2	$1,528,349,523	$78.65/MWh

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

FY 2014–2015 Contract System Load
21,772,634 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 PacifiCorp'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 d(3) 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 PacifiCorp's ASC Filing in June 2012. During the interim period, various issues related to PacifiCorp's ASC Filing were identified by BPA Staff in the BPA Issues and Clarification List (BPA Issues List); no other party raised issues. PacifiCorp responded to each issue raised in the BPA Issues List. This Final ASC Report summarizes the findings of Staff's review of PacifiCorp's ASC Filing, the BPA Issues List and PacifiCorp'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 PacifiCorp'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 listed on the table.

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, 4.1.1.2, and 4.1.1.3.
Schedule 1A – Cash Working Capital	See Section 5.2, Generic Issues.
Schedule 2 – Capital Structure and Rate of Return	No direct adjustments.
Schedule 3 – Expenses	Direct adjustments: see Sections 4.1.1.1 and 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 4.1.4 Distribution Loss Calculation.
Appendix 1 Supporting Worksheets	**Adjustment**
Forecast Loads	Direct adjustment: see Section 4.1.5.1.
New Resource Additions	Direct adjustment: see Section 4.1.5.2.
NLSL Calculation	Direct adjustment: see Section 4.1.3.1.
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 Purchase 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. PacifiCorp responded to these issues in its September 21, 2012, Issue List response. Following the issuance of its Draft ASC Report, PacifiCorp submitted a letter ("Comment Letter") on April 10, 2013, notifying BPA that it did "not have specific comments regarding any of the utility-specific or generic issues raised by BPA." No other party raised issues with or commented on PacifiCorp'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 & Schedule 3 – Expenses

4.1.1.1 Schedule 1: Depreciation and Amortization Reserve, Account 111 – Amortization of Intangible Plant, Accounts 302 and 303, and Account 108 – Amortization of Other Utility Plant

Schedule 3: Depreciation and Amortization, Account 404 – Amortization of Intangible Plant Accounts 302 & 303

Issue:

Whether PacifiCorp correctly recorded the amortization reserves of Intangible Plant, Accounts 302 and 303, and Amortization of Other Utility Plant, Account 108.

Parties' Positions:

PacifiCorp recorded amortization reserves for its intangible plant in Account 108, Amortization of Other Utility Plant.

BPA Staff's Position:

For ASC purposes, amortization reserves for intangible plant should be recorded in Account 111 – Amortization of Intangible Plant, Accounts 302 and 303.

This change in treatment will also flow through to Schedule 3, Account 404 - Amortization of Intangible Plant Accounts 302 and 303.

Evaluation of Positions:

In response to data request BPA-PA-FY14-07, PacifiCorp stated that the reserves for Accounts 302 and 303 were recorded under Amortization of Other Utility Plant, page 200, line 21 (Schedule 1, Account 108). The $497,114,808 figure includes the following sub-account breakdown:

Account 302	$ 37,306,863
Account 303	$ 421,372,374
Other	$ 38,435,571
Total	$ 497,114,808

BPA Staff contends that Account 108 – Amortization of Other Utility Plant, should not include Depreciation and Amortization Reserves associated with Accounts 302 and 303; rather, the depreciation and amortization should be recorded under Account 111 – Amortization of Intangible Plant, Account 302, and Account 111 – Amortization of Intangible Plant, Account 303, respectively.

In PacifiCorp's Draft ASC Report, BPA proposed to move the Reserve amounts from Account 108 into Account 111. In order to complete this adjustment, BPA also matched the percentage allocations of the Pacific Northwest (PNW) states with allocation factors identified in Schedule 1, Intangible Plant - Franchises and Consents (Account 302) (row A), and Intangible Plant – Miscellaneous (Account 303) (row B), as identified in the chart below. For consistency, BPA then proposed to match the associated amortization expense account in Schedule 3, Expenses (Account 404), with the same allocation factors.

	PNW	OR	WA	ID
A (302)	40.18%	26.27%	7.85%	6.06%
B (303)	40.68%	27.89%	7.61%	5.18%

BPA also matched the direct analysis functionalization factors calculated in Schedule 1, Intangible Plant - Franchises and Consents (Account 302) (row A below) and Intangible Plant – Miscellaneous (Account 303) (row B below), with the associated amortization reserve (Account 111) and expense accounts (Account 404) in Schedule 1 and Schedule 3, respectively.

	PROD	TRANS	DIST
A (302)	98.79%	1.21%	0%
B (303)	37.56%	16.33%	46.10%

The adjustments to the PNW percentage allocations resulted in a slight discrepancy between the As-Filed values and the BPA-Adjusted values. For example, the PNW total moved from Account 108, Amortization of Other Utility Plant, was $187,363,312 ($203,063,643 – $15,700,331). However, once the percent allocations to the PNW states were adjusted, the total of Account 111, Amortization of Intangible Plants – 302 and 303, is $186,410,877. The discrepancy is a loss of $952,435 in amortization reserves. However, the discrepancy is too small to affect the ASC, and BPA Staff therefore supported using the adjusted PNW percent allocations.

In response to BPA's Issue List No. 1 and comments on the Draft ASC Report, PacifiCorp agreed with BPA's proposed changes. However, in comments made on the Issue List, PacifiCorp clarified that the amortization of Accounts 302 and 303 was not "recorded" in Account 108. As PacifiCorp's data response showed, "these amounts were recorded on the Company's books in Account 111 and entered in the FERC Form 1 on page 200 under Amortization of Other Utility Plant. The amounts were then transferred to Schedule 1, line 72, the line referencing page 200, Account 108. The amounts should have been entered in Schedule 1, lines 65 and 66, the lines for "Amortization of Intangible Plant – Account 302" and

"Amortization of Intangible Plant – Account 303." *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 1.

Decision:

BPA will revise PacifiCorp's Appendix 1 to reflect adjustments made to amortization reserves for Intangible Plant as described above.

Schedule 1 – Rate Base

Table 4.1.1.1-1: Depreciation and Amortization Reserve, Account 111 – Amortization of Intangible Plant Account 302 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	0	0	0	0
Adjusted	14,990,680	14,809,647	181,032	0

Table 4.1.1.1-2: Depreciation and Amortization Reserve, Account 111 – Amortization of Intangible Plant Account 303 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	0	0	0	0
Adjusted	171,420,198	64,393,199	27,997,810	79,029,189

Table 4.1.1.1-3: Depreciation and Amortization Reserve, Account 108 – Amortization of Other Utility Plant ($)

	Total	Production	Transmission	Dist/Other
As-Filed	203,063,643	110,886,280	23,996,931	68,180,432
Adjusted	15,700,331	8,196,351	1,995,544	5,508,436

Schedule 3 – Expenses

Table 4.1.1.1-4: Depreciation and Amortization: Account 404 – Amortization of Intangible Plant Account 302 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	4,718,428	4,698,297	20,131	0
Adjusted	4,742,778	4,685,503	57,272	0

Table 4.1.1.1-5: Depreciation and Amortization, Account 404 – Amortization of Intangible Plant Account 303 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	12,402,830	5,804,155	1,827,104	4,771,571
Adjusted	10,905,092	4,096,447	1,781,113	5,027,533

4.1.1.2 Account 303 – Intangible Plant – Miscellaneous

Issue:

Whether PacifiCorp correctly functionalized specific software items listed in Account 303, Intangible Plant – Miscellaneous.

Parties' Positions:

In PacifiCorp's Appendix 1 supporting documentation (EPIS tab), the utility functionalized certain software items identified in column "D" in Table 4.1.1.2-1 as shown in the Evaluation of Positions.

BPA Staff's Position:

The identified software items should be functionalized as shown in column "E" in Table 4.1.1.2-1.

Evaluation of Positions:

Section 301, Table 1 of the 2008 ASCM provides that functionalization of Account 303 is Direct Analysis with an option for Distribution/Other. *See* 18 C.F.R. PR. 301, TBL. 1.

When utilities perform a Direct Analysis on an account, they must submit sufficient documentation to permit BPA Staff to determine if the functionalization is reasonable. In July 2009, BPA adopted a common functionalization for similar types of software assets. In PacifiCorp's Draft ASC Report, BPA compared the item descriptions listed in the table below to the common software functionalizations. *See* Section 6.1, FY 2010–2011 PacifiCorp Final ASC Report, System Categories and Related Functionalizations.

In PacifiCorp's response to BPA's data request BPA-PA-FY14-01, PacifiCorp proposed that the functionalization of these items be revised as shown in column "E."

PacifiCorp and BPA are in agreement on this issue. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 2, and PacifiCorp's Comment Letter.

Table 4.1.1.2-1: Functionalization of Account 303 - Intangible Plant-Miscellaneous

A	B	C	D	E
			Functionalization	
Account	Description	Cost ($000)	As-Filed	PAC Data Response-BPA-Proposed
3032510	OPERATIONS MAPPING SYSTEM	$ 10,386	DIST	TD
3031780	OUTAGE REPORTING SYSTEM	$ 3,498	LABOR	DIST
3032480	OUTAGE CALL HANDLING INTEGRATION	$ 1,981	LABOR	DIST
3032670	C&T OFFICIAL RECORD INFO SYSTEM	$ 1,586	LABOR	PROD
3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE	$ 2,179	LABOR	DIST
3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	$ 1,581	PROD	TRANS
3034900	MISC – MISCELLANEOUS	$ 29,678	PROD	LABOR
3032710	ROUGE RIVER HYDRO INTANGIBLES	$ 196	TRANS	PROD

Decision:

BPA will revise PacifiCorp's Appendix 1 to reflect the changes identified in the table above.

Table 4.1.1.2-2: Account 303, Intangible Plant – Miscellaneous ($)

	Total	Production	Transmission	Dist/Other
As-Filed	263,364,778	107,243,333	39,925,413	116,196,031
Adjusted	263,364,778	98,931,753	43,014,983	121,418,042

4.1.1.3 Account 253 – Other Deferred Credits & Account 254 – Other Regulatory Liabilities

Issue:

Whether PacifiCorp correctly included and functionalized all line items in Account 253 – Other Deferred Credits, and Account 254 – Other Regulatory Liabilities.

Parties' Positions:

PacifiCorp included credits from all states in its service territory and functionalized all line items in Account 253 – Other Deferred Credits, and Account 254 – Other Regulatory Liabilities, to Distribution/Other.

BPA Staff's Position:

All line items in Account 253, Other Deferred Credits, and Account 254, Other Regulatory Liabilities, should be functionalized using Direct Analysis. Costs and revenues from California, Utah, and Wyoming should not be included in the ASC calculation.

Evaluation of Positions:

In Section 6.1.3 of the generic issues identified in PacifiCorp's FY 2010-2011 Final ASC Report (Docket Number ASC-10-PA-01), BPA and the parties agreed that asset accounts that have a corresponding liability account should be functionalized consistently.

In response to data request BPA-PA-FY14-22, PacifiCorp provided an updated functionalization for both accounts using Direct Analysis:

> Accounts 253 and 254 have been corrected and are now functionalized the same as in PacifiCorp's FY 2010-2011 Final ASC Report (Docket Number ASC-10-PA-01). Please see copies of tabs: Sch 1 – Rate Base, Sch 1 – OR Rate Base, Sch 1 – WA Rate Base, Sch 1 – ID Rate Base and Misc Rate Base, Lines 220 – 226 provided in the attached: 'BPA-PA-FY14-22-ATTACHMENT.xlsx'.

Through follow-up conversations with PacifiCorp, the utility further clarified (and its above documentation substantiates) that in PacifiCorp's As-Filed Appendix 1, it erred when it included deferred credits (Account 253) and regulatory credits (Account 254) from all states in its service territory and functionalized all of the accounts to Distribution/Other. In its correction "BPA-PA-FY14-22-ATTACHMENT.xlsx," which was provided in response to the above-noted data request, PacifiCorp removed costs and revenues from California, Utah, and Wyoming and completed a Direct Analysis for costs and revenues from its PNW service territory.

In PacifiCorp's Draft ASC Report, BPA proposed the corrected updates and PacifiCorp agreed. *See* PacifiCorp's Comment Letter. PacifiCorp and BPA are in agreement regarding the removal of other than PNW service territory costs and revenues, and the change in functionalization of Accounts 253 and 254 to Direct Analysis. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 3.

Decision:

BPA will revise PacifiCorp's Appendix 1 to reflect the above-noted adjustments to Other Deferred Credits, Account 253, and other Regulatory Liabilities, Account 254.

Table 4.1.1.3-1: Account 253 – Other Deferred Credits

	Total	Production	Transmission	Dist/Other
As-Filed	88,101,554	0	0	88,101,554
Adjusted	6,873,323	1,266,577	668,423	4,938,322

Table 4.1.1.3-2: Account 254 – Other Regulatory Liabilities

	Total	Production	Transmission	Dist/Other
As-Filed	44,362,382	0	0	44,362,382
Adjusted	6,570,269	6,090,421	203,135	276,712

4.1.2 Schedule 3 – Expenses

4.1.2.1 Account 908 – Customer Assistance Expenses (Major Only)

Issue:

Whether PacifiCorp correctly functionalized its conservation expenses.

Parties' Positions:

PacifiCorp included conservation expenses in Account 908 and functionalized them to Distribution/Other.

BPA Staff's Position:

Conservation expenses allocated to Account 908 should be functionalized to Production.

Evaluation of Positions:

The 2008 ASCM provides that Account 908 should be functionalized by Direct Analysis and that conservation costs funded by the utility are to be functionalized to Production in the utility's ASC. *See* 18 C.F.R. PT. 301, End. g.

In response to data request BPA-PA-FY14-08, PacifiCorp explained that it incorrectly assigned all conservation costs to Distribution/Other. In attachment BPA-PA_FY14-08-REVISED-O&M EXP, PacifiCorp provided an updated functionalization using Direct Analysis for its conservation expense of $36,997,913.

In PacifiCorp's Draft ASC Report, BPA proposed to correct this functionalization and PacifiCorp agreed. *See* PacifiCorp's Comment Letter. PacifiCorp and BPA are in agreement regarding the functionalization of conservation costs in Account 908 to Production. All other

Account 908 costs went to Distribution/Other. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 4.

Decision:

BPA will revise PacifiCorp's Appendix 1 to functionalize conservation costs in Account 908 to Production and functionalize all other costs in Account 908 to Distribution/Other.

Table 4.1.2.1-1: Account 908 Customer Assistance Expenses (Major Only)

	Total	Production	Transmission	Dist/Other
As-Filed	40,387,256	0	0	40,387,256
Adjusted	40,387,256	36,997,913	0	3,389,343

4.1.3 Supporting Schedule – New Large Single Loads (NLSL)

4.1.3.1 NLSL_Base_New-Calc

Issue:

Whether PacifiCorp left the Camas Co-Gen Resource out of its Appendix 1, NLSL_ Base_New-Calc Tab.

Parties' Positions:

PacifiCorp did not include the Camas Co-Gen generation plant as a resource in its NLSL calculation.

BPA Staff's Position:

Camas Co-Gen should be included as a resource in PacifiCorp's NLSL calculation.

Evaluation of Positions:

The 2008 ASCM prescribes that the cost of serving NLSLs is determined using the fully allocated cost of all escalated Base Period post-September 1, 1979, resources and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs. *See* 2008 ASCM, End. d; 18 C.F.R. § 301, TBL 1, End. d.

In data request BPA-PA-FY14-13, Staff requested that PacifiCorp explain why Camas Co-Gen (constructed in 1996), which is listed on page 403.3 in the FERC Form 1, was not included as a resource in the NLSL calculation (NLSL Base New Calculation tab).

In response, PacifiCorp stated that the "The Camas Co-Gen plant listed on page 403.3 of the FERC Form 1 was inadvertently left out of the post 1979 resource list for the NLSL resource calculation on the "NLSL_Base_New-Calc" tab. Please see the attachment "BPA-PA-FY14-13-ATTACHMENT.xls" which is a copy of the corrected tab included in the updated Appendix 1." In addition, as BPA was completing its final initial review of the NLSL_Base_New-Calc Tab, it realized that for Production Plant depreciation expenses (line 29), PacifiCorp used a percent allocation for its production O&M costs (38.20 percent) rather than the allocation for Production Plant (39.87 percent). In a follow-up conversation with PacifiCorp, the utility acknowledged this was an inadvertent error. In PacifiCorp's Draft ASC Report, BPA proposed to correct this error and PacifiCorp agreed. *See* PacifiCorp's Comment Letter.

BPA Staff and PacifiCorp are in agreement that Camas Co-Gen is included in the NLSL calculation and the percentage allocation for Production Plant should be used to allocate depreciation expense. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 5.

Decision:

BPA will update PacifiCorp's Appendix 1 to reflect the inclusion of Camas Co-Gen in the NLSL_Base_New-Calc Tab and adjust the percent allocation for Production Plant depreciation expenses from 38.20 percent to 39.87 percent.

Table 4.1.3.1-1: Supporting Schedule: NLSL_Base_New-Calc

	2011 Cost of serving NLSL Under Endnote d
As-Filed	80.79 $/MWh
Adjusted	80.81 $/MWh

4.1.4 Average System Cost – Distribution Losses

In PacifiCorp's Appendix 1, BPA Staff raised two issues simultaneously regarding PacifiCorp's distribution loss study calculation. The first issue concerns service territories in different states and the second concerns non-requirement loads. For clarity, each will be addressed as a separate issue with the overall impact of both adjustments shown in Table 4.1.4-1.

Table 4.1.4-1: Average System Cost – Distribution Losses

Contract System Load with **2.86%** Distribution Loss Factor and **Inclusion** of Non-Requirement Loads (MWh)	**Contract System Load** with **4.47%** Distribution Loss Factor and **Removal** of Non-Requirement Loads (MWh)
21,045,308	21,375,690

4.1.4.1 Distribution Loss Calculation, System Losses from All States in its Service Territory

<u>Issue 1</u>:

Whether PacifiCorp used the correct distribution loss factor. Specifically, whether PacifiCorp correctly included system losses from all five states to calculate its distribution loss factor.

<u>Parties' Positions:</u>

In its distribution loss factor calculation, PacifiCorp included the 2009 Analysis of System Losses reports for all states in its ASC Filing to calculate the distribution loss factor used in the FY 2014–2015 ASC Review, rather than distribution losses estimated for the PNW states only.

<u>BPA Staff's Position:</u>

Only the sales and losses from Washington, Oregon, and Idaho should be included in calculating PacifiCorp's distribution loss factor. Data for California, Wyoming, and Utah should be removed.

<u>Evaluation of Positions:</u>

In response to BPA's Issue List, Item No. 6, submitted September 5, 2012, PacifiCorp stated that "The 2009 Analysis of System Losses provided an analysis of system losses for each of the Company's six state jurisdictions and therefore, it is possible to use a state specific distribution loss calculation. These state specific reports were provided to Bonneville as part of PacifiCorp's initial filing. Summing just the sales and losses for the Idaho, Oregon and Washington state jurisdictions (Exhibit 1 of Appendix B) the new distribution loss factor is 4.47%." *See* PacifiCorp's Appendix 1 Workbook, "Loss Study Summary" Tab for both its As-Filed and BPA-Adjusted values.

In PacifiCorp's Draft ASC Report, BPA concurred with PacifiCorp's (1) calculation of its distribution loss factor using system losses from only PNW states, and (2) use of a 4.47% distribution loss factor in its Appendix 1. PacifiCorp and BPA are in agreement on this issue. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 6, and PacifiCorp's Comment Letter.

<u>Decision:</u>

BPA will revise PacifiCorp's Appendix 1 to reflect the change in its distribution loss factor from 2.86 percent to 4.47 percent.

4.1.4.2 Distribution Loss Calculation, Non-Requirements Loads

Issue 2:

Whether PacifiCorp correctly included Non-Requirements load in its distribution loss study.

Parties' Positions:

In its Loss Study Summary tab, PacifiCorp included a Non-Requirements load of 12,143,453 MWh as part of its loss factor calculation. The 2008 ASCM calculates the distribution loss factor as a percentage of the losses divided by Sales to Ultimate Consumers and Requirements Sales for Resale.

BPA Staff's Position:

Non-Requirements Sales for Resale already include losses and as such, should not be included in the loss factor calculation. *See* FERC Form 1, p. 401a, column b.

Evaluation of Positions:

In response to BPA Issue List, Item No. 7, submitted September 5, 2012, PacifiCorp stated that "Utilizing only the sales and losses for the three PNW states identified in Issue No. 6 makes Issue No. 7 a moot issue – there are no non-requirement sales in the state numbers."

In PacifiCorp's Draft ASC Report, BPA concurred with PacifiCorp's response. PacifiCorp and BPA are in agreement on this issue. *See* BPA's Issue List to PacifiCorp, Utility-Specific Issues, No. 7, and PacifiCorp's Comment Letter.

Decision:

BPA will remove all Non-Requirement Sales from PacifiCorp's distribution loss calculation. See Section 4.1.4.1.

4.1.5 Supporting Schedule – Load Forecast

4.1.5.1 Total Retail Load Forecast Calculation

Issue:

Whether PacifiCorp correctly performed the Total Retail Sales Forecast calculation in its Appendix 1.

Parties' Positions:

PacifiCorp inadvertently used incorrect months in the calculation of its fiscal year Total Retail Sales.

BPA Staff's Position:

The correct months should be used in the Total Retail Sales Forecast.

Evaluation of Positions:

Following the comments to the Issue List, BPA Staff discovered that PacifiCorp's calculation for determining the fiscal year Total Retail Sales @ Meter did not recognize the correct months in computing between calendar year and fiscal year. In addition, a New NLSL was recorded under FY 2015. See the Load Forecast tab in PacifiCorp's Appendix 1.

In a follow-up phone call with PacifiCorp, it acknowledged its error in the calculation and confirmed again that no new NLSL was coming on line in FY 2015. BPA and PacifiCorp are in agreement on the corrections made to the Forecast Load.

Decision:

BPA will correct the calculation and update the Total Retail Sales in PacifiCorp's Appendix 1.

Table 4.1.5.1-1: As-Filed Fiscal Year Load Forecast (MWh)

FY	2011	2012	2013	2014	2015
Total Retail Sales @ Meter	20,460,678	20,383,492	20,477,085	20,739,488	20,927,722
Distribution Losses	584,630	584,630	582,425	585,099	592,596
Contract System Load	21,045,308	20,968,122	21,059,510	21,324,586	21,520,318
New NLSL MWh	0	0	0	0	497,770

Table 4.1.5.1-2: BPA-Adjusted Fiscal Year Load Forecast (MWh)

FY	2011	2012	2013	2014	2015
Total Retail Sales @ Meter	20,460,678	20,383,492	20,463,099	20,734,852	20,946,409
Distribution Losses	915,012	911,560	915,120	927,273	936,734
Contract System Load	21,375,690	21,295,052	21,378,219	21,662,125	21,883,143
New NLSL MWh	0	0	0	0	0

4.1.5.2 Materiality Adjustment for New Resource No. 1

Issue:

Whether all of PacifiCorp's grouped resources meet the 0.5 percent materiality threshold.

Parties' Positions:

PacifiCorp did not have the opportunity to comment on this issue prior to the publication of the Draft ASC Report.

BPA Staff's Position:

New Resource No. 1 of PacifiCorp's grouped (stacked) resources fell below the 0.5 percent materiality threshold and therefore cannot be included in the stack of potential resources eligible to be included in the Exchange Period ASC.

Evaluation of Positions:

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 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.*

BPA's adjustments to PacifiCorp's As-Filed Appendix 1 resulted in the utility's Base Period ASC increasing from $66.02/MWh to $66.70/MWh. This adjustment caused one of three resources that PacifiCorp stacked together to fall out because it no longer met the 0.5 percent materiality threshold as defined under the rules of the 2008 ASCM.

Just prior to the publication of this Final ASC Report, BPA Staff noted that the Appendix 1 issued with the Draft ASC Report showed the change in materiality for New Resource No. 1. BPA Staff had inadvertently failed to incorporate the change within the Draft ASC Report at that time. *See* PacifiCorp's FY 2014–2015 Appendix 1, Materiality – Individual tab, cell P352.

There is no impact on PacifiCorp's Base Period ASC from this change. There also will be no impact in its Exchange Period ASC under the 2012 REP Settlement. On June 24, 2013, PacifiCorp was notified of this correction and agrees with the adjustment.

The materiality determinations provided herein are based on the utility's Base Period ASC as adjusted through the ASC Review Process and reflect the natural gas forecast from the BP-14 Rate Case Initial Proposal.

Decision:

BPA will remove New Resource No. 1 from PacifiCorp's grouped resource stack.

Table 4.1.5.2-1: PacifiCorp's New Resource No. 1

Base Period ASC	Materiality Change as a Result to the Updated Base Period ASC
As-Filed at $66.02/MWh	0.50309%
BPA-Adjusted at $66.70/MWh	0.49028%

4.2 Decision on Draft Report Unresolved Issues

There were no unresolved issues identified in PacifiCorp's Draft ASC Report. No other party raised issues with, or commented on, PacifiCorp's June 4, 2012, ASC Filing.

4.3 ASC Forecast Model Errata Corrections

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 PacifiCorp, 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 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 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

PacifiCorp's As-Filed, Base Period (CY 2011) ASC was $66.02/MWh. As a result of adjustments made during the review process, PacifiCorp's Base Period ASC increased to $66.70/MWh.

PacifiCorp's As-Filed, Exchange Period ASC for FY 2014–2015 was $65.82/MWh. As a result of adjustments made during the review process, PacifiCorp's Exchange Period ASC for FY 2014–2015 decreased to $65.61/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 PacifiCorp's FY 2014 and FY 2015 ASC based on information and data provided by PacifiCorp, 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 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 PacifiCorp's ASC for FY 2014–2015.

8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMNISTRATION

I have examined PacifiCorp'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 PacifiCorp'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

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BONNEVILLE POWER ADMINISTRATION
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