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 2010-2011

FINAL
AVERAGE SYSTEM COST REPORT

IDAHO POWER COMPANY

July 2009

This page intentionally left blank.

FY 2010-2011

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Idaho Power Company

Docket Number: ASC-10-IP-01
Effective Date: October 1, 2009

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

July 21, 2009

This page intentionally left blank.

TABLE OF CONTENTS

Section **Page**

List of Tables

This page intentionally left blank.

1. FILING DATA

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

Parties to the Filing:

Investor-Owned Utilities (IOUs):
- Avista Utilities (Avista)
- NorthWestern Energy (NorthWestern or NWE)
- PacifiCorp (PAC)
- Portland General Electric (PGE)
- Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):
- Franklin County PUD (Franklin)
- Snohomish County PUD (SNOPUD)

Other Participants to the Filing:
- Idaho Public Utility Commission
- Public Power Council
- Public Utility Commission of Oregon (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine IPC's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

2. AVERAGE SYSTEM COST SUMMARY

2.1. 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 most recent Annual Reports, including the most recent Cost of Service Analysis (COSA), for COUs. The submitted information includes the "Appendix 1," an Excel-based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by IPC on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

Table 2.1: CY 2007 Base Period ASC
(Results of Appendix 1 calculations)

	October 15, 2008 As Filed	**July 21, 2009 Final Report**
Production Cost	$ 461,275,498	$ 461,434,297
Transmission Cost	$ 104,444,121	$ 95,664,101
(Less) NLSL Costs	($ 20,611,958)	($ 25,276,624)
Contract System Cost (CSC)	**$ 545,107,660**	**$ 531,821,775**
Total Retail Load (MWh)	14,541,825	14,541,825
(Less) NLSL	(385,400)	(385,400)
Total Retail Load (Net of NLSL)	14,156,425	14,156,425
Distribution Losses	1,003,386	1,003,386
Contract System Load (CSL)	**15,159,811**	**15,159,811**
CY 2007 Base Period ASC (CSC/CSL)	**$ 35.96/MWh**	**$ 35.08/MWh**

2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the mid-point of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period ($/MWh)

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	**Danskin**	**N/A**	**N/A**	**N/A**
Expected On-Line Date	March 2008			
Delta*	0.71			

Final Report FY 2010-2011 Exchange Period ASC				
Resource	**Danskin**	**N/A**	**N/A**	**N/A**
Expected On-Line Date	March 2008			
Delta*	0			

*The Delta is the incremental change in the ASC as new resources come on line. Danskin did not meet the materiality threshold. *See* Section 5.6 for additional details.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period ($/MWh)

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Final Report FY 2010-2011 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.

2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come on-line, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC ($/MWh) Prior to New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010-2011	39.19	35.65

3. FILING REQUIREMENTS

3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power 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 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 the BPA rate established pursuant to section 7(b)(l) 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 small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings. Subsequent REP Settlement Agreements with BPA's investor-owned utility customers were in effect from approximately 2001 through 2007, but were terminated following a judicial decision issued on May 3, 2007. *See generally, Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007).

In 2007, BPA began administrative efforts to resume the full implementation of the REP, including the development of new RPSAs and a consultation proceeding to revise the 1984 ASC Methodology. As with the 1981 and 1984 ASC Methodologies, the 2008 ASCM was developed in a consultation proceeding with interested parties through, in part, a series of working group meetings conducted by BPA Staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound and comport with the Northwest Power Act. The ASCM is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission). On October 10, 2008, the Commission granted interim approval to BPA's 2008 ASCM. *See Sales of Elec. Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology*, 73 Fed. Reg. 60,105 (Oct. 10, 2008).

BPA maintains a significant role in reviewing utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision, 2008 Average System Cost Methodology*, June 30, 2008.

3.2. ASC Review Process - FY 2010-2011

Under the 2008 ASCM, utilities' ASCs are generally established prior to the calculation and payment of REP benefits, and the ASC Review Processes occur before the beginning of the Exchange Period.

On October 15, 2008, exchanging utilities submitted ASC filings for the FY 2010-2011 Exchange Period. All data were submitted using two Excel-based models: the Appendix 1 and the ASC Forecast Model. Supporting documentation was also submitted. A utility's submission of the models and supporting documentation is defined as the utility's "ASC filing."

To determine a utility's Exchange Period ASC for FY 2010-2011 (October 1, 2009, through September 30, 2011), the Base Period (CY 2007) ASC is first calculated using the Appendix 1. BPA then uses the ASC Forecast Model to escalate the Base Period ASC forward to the mid-point of the effective Exchange Period. The Base Period and Exchange Period ASC results are reported herein.

The 2008 ASCM allows utilities to file multiple, contingent ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

The exchanging utilities' October 15, 2008, ASC filings began the formal review and comment processes, referred to as the Review Period, to establish the utilities' respective ASCs. For the Draft ASC Reports, BPA completed a preliminary review of the utilities' ASC filings in conformance with the 2008 ASCM, which was approved by FERC on an interim basis on

October 10, 2008. IPC's comments on this Draft ASC Report are noted and addressed herein. In addition, parties had a full and complete opportunity to intervene in BPA's ASC Review Processes and to submit comments on the utilities' ASC filings and BPA's Draft ASC Reports.

The Review Processes for the FY 2010-2011 ASCs are complete. The final ASC determinations and supporting justifications are published in the respective Final ASC Reports for each participating utility and can be reviewed at http://www.bpa.gov/corporate/finance/ascm/fy10-asc-final-reports.cfm.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision, 2008 Average System Cost Methodology, June 2008*, entitled *2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

3.3. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information that present the data necessary to calculate ASCs. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital Calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power and Off-System Sales
10. New Large Single Loads
11. Labor Ratios

3.3.1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the utility. The calculation begins with a determination of the Gross Electric Plant In-Service, which includes the historical costs of the Intangible, General, Production, Transmission, and Distribution Plant. For exchanging utilities that provide electric and natural gas service, the portion of common plant allocated to electric service is also included. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on the FERC Uniform System of Accounts. In general, each line item (Account) is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Gross Electric Plant-In-Service to determine the Net Electric Plant-In-Service.

The resulting Net Electric Plant is adjusted, where appropriate, to reflect additions in Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, and Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits. The outcome of these adjustments defines the Production, Transmission, and/or Distribution/Other components of Total Rate Base.

3.3.2. Schedule 1A – Cash Working Capital

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.

3.3.3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the utility to develop the rate of return applied to the utility's rate base developed in Schedule 1 to determine the utility's return on investment.

Investor-owned utilities (IOU) use the weighted cost of capital (WCC) from their most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. 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 found in the ASCM, Attachment A, Section IX, Endnote b. For consumer-owned utilities (COU), the rate of return is equal to the COU’s weighted cost of debt times total rate base as determined in Schedule 1.

When the Net Production and Transmission Plant-In-Service is multiplied by the Rate of Return as determined in Schedule 2, the result is the utility's return on investment.

3.3.4. Schedule 3 – Expenses

This schedule represents operations and maintenance expense for the production, transmission and distribution of electricity. Each expense item is functionalized as outlined in the 2008 ASCM, Table 1. 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 are also included. The sum of these costs is Total Operating Expenses.

3.3.5. Schedule 3A – Taxes

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

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

3.3.6. 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 to others (wheeling). Items in this schedule are deducted from the total costs of each utility.

3.3.7. New Large Single Loads

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 the specific customer of ten average megawatts (10 aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

By law, NLSLs and the associated costs to serve them are not included in utilities' ASCs. *See* 16 U.S.C. § 839c(c)(7)(A).

3.3.8. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other 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 ASC ($/MWh).

<u>Contract System Cost</u>:
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 Appendix 1. Costs to serve NLSLs are excluded from ASC calculations. CSC becomes the numerator in calculating ASC.

<u>Contract System Load (MWh)</u>:
The Contract System Load (CSL) is the total regional retail load, adjusted for distribution losses and NLSLs, pursuant the 2008 ASCM. The CSL is the denominator in calculating ASC.

3.3.9. Distribution of Salaries and Wages

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

3.3.10. 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 of 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.

3.3.11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for Production, Transmission, and Distribution/Other functions included in the utility's most recently filed FERC Form 1. For COUs, comparable data is used based on the cost of service analysis (COSA) study used as the basis for retail rates in effect during the Base Period filing.

3.4. <u>ASC Forecast</u>

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model (ASC Forecast Model) to escalate the Base Period ASC data forward to the mid-point of the Exchange Period, which in this case is October 1, 2010. BPA used 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 IOU 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 and other products. For the Final ASC Reports, the escalators were updated to be consistent with the escalators used in BPA's 2010 Rate Adjustment Proceeding. For additional background on the determination of Exchange Period ASCs, see the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection A. *See also* 18 C.F.R. § 301.5(a).

3.4.1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) includes a utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection A, "Forecast CSC," BPA escalates base period costs to the midpoint of the FY 2010-2011 Exchange Period (October 1, 2010) to calculate Exchange Period ASCs. *See* 18 C.F.R. § 301.5(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 a utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection B. *See* 18 C.F.R. § 301.5(b).

3.4.3. Forecast Contract System Load and Exchange Load

All utilities are required to provide, with their Appendix 1 filings, a four-year forecast of their total retail load, as measured at the meter, and their qualifying residential and small farm retail load, as measured at the retail meter. Also required is a current distribution loss study as described in the 2008 ASCM, Attachment A, Endnote e. The total retail and residential and small 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. Major Resource Additions

BPA uses the method outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5 percent. *See* 18 C.F.R. § 301.5(c). These additions include 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.

The exchanging utility provides its forecast of major resource additions and all associated costs. The forecast covers the period from the end of the Base Period to the end of the Exchange Period.

The forecast of the major resource costs to be included in the utility's Exchange Period ASC is reviewed and determined during the Review Period. When calculating the utility's Exchange Period ASC, the costs of all resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period. The costs of all resources included during the Exchange Period will be included at the midpoint of the Exchange Period.

3.4.5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted 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, Section IV, *Rules for Determining Exchange*, Subsection D. *See* 18 C.F.R. § 301.5(d).

4. REVIEW OF THE ASC FILING

Pursuant to Section III, Subsection C of the 2008 ASCM and section 5(c) of the Northwest Power Act, BPA is responsible for reviewing all costs and loads used to establish ASCs. *See* 18 C.F.R. § 301.4(c)(1). During this review and evaluation, numerous issues may be identified for comment by BPA or other parties. BPA's ASC determination is limited to specific findings on those issues identified for comment, with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASCM. Similarly, given that the current report is one of the first published under the 2008 ASCM, further experience under the 2008 ASCM may result in BPA adopting a modified or different interpretation of the methodology in future ASC reviews.

On April 13, 2009, BPA published the Draft ASC Report for IPC. IPC and each intervenor had the opportunity to comment on the Draft Report by May 11, 2009. All comments have been reviewed and addressed in reaching a final decision on each issue.

As noted in Section 1 above, if IPC or any intervenor failed to comment on a specific issue outlined in the Draft ASC Report, the utility or intervenor waives the right to subsequent appeal of that issue. To the extent any party argued it should not be required to raise issues in its comments on BPA's Draft ASC Reports in order to preserve such issues for appeal, BPA disagrees. If parties did not raise issues in their comments on BPA's Draft ASC Reports, BPA would not know whether the parties agreed or disagreed with BPA's draft decisions. Because BPA would not know the parties' arguments, BPA would be unable to consider and possibly adopt such arguments in determining a utility's ASC.

4.1. Identification and Analysis of Issues from BPA Issue List

During the ASC review process, BPA raised a number of issues regarding IPC's ASC. IPC responded to these issues during the ASC Review Process and in comments on the Draft ASC Report. No other party raised issues with or commented on IPC's responses. Each issue pertains to the October 15, 2008, filing unless otherwise noted.

Although a utility's State, county, or municipal regulatory bodies or FERC may allow a particular functionalization to a specific account, BPA is not required to follow this 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* 2008 ASCM, Section III.C; 18 C.F.R. § 301.4(c)(1).

4.2. SCHEDULE 1: Plant Investment/Rate Base:

4.2.1. Account 303, Intangible Plant - Miscellaneous, CIS+ and General Software

Statement of Issue:

Whether IPC's Direct Analysis supports the use of PTD to functionalize the CIS+ and General Software in Account 303.

Statement of Facts

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC completed a Direct Analysis of its software and functionalized all software using the PTD ratio.

In Data Response BPA-IP-03, IPC defined the CIS+ software as IPC's software used for billing "all of the services provided to retail customer," and the General Software "as all of the computer software used by IPC excluding CIS+."

When a Direct Analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2). IPC did not provide software titles, product descriptions/purposes (with the exception of CIS+), or specific cost allocations.

Account 303 also affects software costs in other accounts in Schedule 1, *Rate Base* (Depreciation and Amortization Reserve), and Schedule 3, *Expenses* (Depreciation and Amortization). The functionalization must be the same in all accounts.

Parties' Positions:

IPC included CIS+ and General software in rate base and functionalized all software using the PTD ratio.

Analysis of Positions:

In Data Response BPA-IP-03, IPC states that "A return on plant associated with CIS+ and General Software is recovered through [IPC's] retail rates within its State jurisdiction."

In a February 27, 2009, response to the ASC Issue List, Item 4, IPC stated that "for the State of Idaho retail regulation, this account, in its entirety, is allocated based upon a PTD-like allocation method. For the Company's FERC jurisdiction, this account is allocated using a LABOR-like allocation method. Both methods include the CIS+ software within Production and Transmission functions, which is appropriate as the Company uses the CIS+ software in support of all of the Company's functions."

IPC suggests that either Labor or PTD is an appropriate allocation method for an integrated utility that has been authorized to use this method by both FERC and State Commissions in the last 10 plus years of rate recovery filings.

IPC further states that because it has hundreds of software titles that change annually, and which are not functionalized within any sort of account management system, IPC supports Direct Analysis for items greater than a specified multi-million dollar threshold value. IPC supports either PTD or Labor for balance of the account.

IPC responded May 11, 2009, to BPA's treatment of this issue in its Draft ASC Report. IPC reiterated:

> It is unreasonable for the Draft ASC Reports to penalize Idaho Power, because Idaho Power does not utilize an accounting system that allocates the costs of General Software Costs to production, distribution or transmission functions. It is also unreasonable and arbitrary for the Draft ASC Reports to assume that all such costs should be assigned to the distribution function.   Other regional utilities may have, for their own corporate or regulatory purposes, implemented accounting practices that functionalize General Software Costs by function. Idaho Power does not follow such accounting practices, and in any event would have been unable to complete a study to functionalize the costs of General Software that has been already acquired.

IPC further contends that:

> It is also unfair to assume, as do the Draft ASC Reports, that Idaho Power could have conducted a study within the time constraints of the ASC review process to functionalize costs of particular software titles, or to allocate costs to particular functions where particular titles are shared among functions. For Idaho Public Utilities Commission purposes, General Software Costs are accounted for using a PTD-type allocation method. For FERC purposes, these costs are accounted for using a LABOR method. Therefore, either LABOR or PTD are appropriate and approved allocation methods for Idaho Power to allocate General Software Costs. Therefore it is reasonable for the allocation of all General Software Costs in Account 303 for ASC purposes to be functionalized utilizing a LABOR or PTD method. It is unreasonable and arbitrary for the Draft ASC Reports to adjust the allocations so that all General Software Costs are assigned to the default of Distribution (DIST).

First, it should be noted that although the Idaho or Oregon Commissions may allow certain costs in rate treatment, the REP is different than typical ratemaking and may warrant different functionalizations.

More significantly, Section VIII of the 2008 ASCM permits a Direct Analysis only for specified accounts. *See* 18 C.F.R. § 301.9(a). The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable.

IPC was aware that the use of either the PTD or Labor ratio was not allowed as a substitute for a Direct Analysis, and that the ASCM requires the utility to demonstrate that the functionalization used assigns costs based upon the actual and/or intended functional use of those items. *See* 18 C.F.R. § 301.9(c)(2).

IPC participated fully in the public ASC workshops, either by phone or in person, and was allowed the opportunity to raise any issue regarding the Direct Analysis of software throughout the public process, including whether there were any impractical time constraints on a utility's ability to conduct a Direct Analysis.

As noted in the *Statement of Facts*, IPC responded to BPA's data requests and commented on this issue during the review process, but IPC did not raise any issue regarding time constraints until the Draft Report: "It is also unfair to assume, as do the Draft ASC Reports, that Idaho Power could have conducted a study within the time constraints of the ASC review process to functionalize costs of particular software titles, or to allocate costs to particular functions where particular titles are shared among functions." *See* Comments of Idaho Power Company to FY 2009 Average System Cost Draft Report (ASC-09-IP-01) and FY 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 9.

BPA understands that IPC may lack the resources to complete the foregoing task in an expedited manner. However, the FY 2009 ASC Review Process began on October 1, 2008. This formal process followed the FY 2009 Expedited Review Process that began March 3, 2008, more than 13 months prior to the publication of the Draft Report. This should have been enough time for IPC to complete a Direct Analysis of its software.

Also, BPA does not "assume that all of the costs associated with these titles relate to distribution," as stated in IPC's comments. *See* Comments of Idaho Power Company to FY 2009 Average System Cost Draft Report (ASC-09-IP-01) and FY 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 19. Under Section VIII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. *See* 18 C.F.R. § 301.9(c)(2). Failure to submit the documentation will result in the entire account being functionalized to Distribution/Other. *Id.*

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the Direct Analysis was not consistent among utilities. Some of the statements included by utilities to support functionalization of a specific piece of software using the PTD ratio used terms like "supports all functions of the company"[1] or "supports all areas of the company."[2] These catchall phrases, if taken to the extreme, could be used to rationalize using the PTD ratio to functionalize the entire ASC filing. Such simple statements do

---

[1] *See, for example*, Data Responses ASC-10-PA-BPA-8 and ASC-10-PS-BPA-5
[2] *See, for example*, Data Response ASC-10-PS-BPA-5 and
Excel file E302_303_399_Common_NBV_2007_Final.xls, DATA for ASC tab, column W.

not constitute a valid Direct Analysis. As such, under the ASCM, BPA has the authority to functionalize all of the items in Account 303 to Distribution/Other.

BPA appreciates the concerns raised by IPC regarding the complexity of a Direct Analysis. Thus, BPA and the parties have agreed to revisit the allocations surrounding software expenditure associated with Account 303 before the next formal Review Process in an effort to reduce the expense and burden of reviewing these accounts. Nonetheless, for this ASC period, IPC cannot avoid the requirements of the ASCM by simply claiming the requisite analysis is "unreasonable." Section VIII of the 2008 ASCM permits Direct Analysis only for specified accounts. *See* 18 C.F.R. § 301.9(c)(1). When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. *Id.* at § 301.9(c)(2).

Nonetheless, because this ASC Report is part of the first group of ASCs to be formally developed under the 2008 ASCM, BPA proposed to allow software costs into ASC based on the generic function of the software in the utility industry. This construct is described in more detail in the discussion of Section 6.1.1. In general, BPA's approach was to first look at the Direct Analysis performed by the utility. If the documentation supplied by the utility supported its proposed functionalization, BPA would follow the utility's treatment. However, if the utility could not support its proposed functionalization, BPA would then functionalize the costs to Distribution/Other unless BPA could determine the function that the software supported. For this, BPA looked to the function the software performed in the utility industry in general. If BPA could determine that a particular software program supported resource-related functions in the utility industry, the software system would be functionalized accordingly. BPA developed this approach for Account 303 because it ensured that software costs would be functionalized in accordance with the 2008 ASCM and it allowed similar types of software to be functionalized consistently among the exchanging utilities.

In the instant case, the lack of additional information from IPC precluded BPA from gaining a clear understanding of the General Software's purposes for this account, and therefore the applicability and justification of the functionalization to PTD. For these reasons, the appropriate functionalization for this account is Distribution/Other. Once again, BPA intends to work with interested parties to develop, if possible, a less burdensome and more efficient means of functionalizing software programs in Account 303.

CIS+ is software used for customer billing purposes and therefore considered used for the retail side of the business and functionalized only to Distribution/Other.

Decision:

Because BPA is unable to substantiate IPC's use of the PTD ratio for General Software and CIS+ software, BPA will adjust the functionalization of General Software to the default of Distribution/Other (DIST). Furthermore, BPA will adjust the functionalization of CIS+ software to Distribution/Other (DIST).

Table 4.2.1: Account 303, Intangible Plant – Miscellaneous ($)

	Total	CIS+ Software Production	Transmission	Dist/Other
As-Filed	19,731,424	9,245,166	3,858,846	6,627,412
BPA Adjusted	19,731,424	0	0	19,731,424

	Total	General Software Production	Transmission	Dist/Other
As-Filed	29,283,158	13,720,634	5,726,864	9,835,659
BPA Adjusted	29,283,158	0	0	29,283,158

4.2.2. Amortization Reserve, Amortization of Other Utility Plant – Account 303, CIS+ and General Software

Statement of Issue:

Whether IPC's Direct Analysis supports the use of PTD to functionalize the amortization reserves of software costs located in Accounts 303 – CIS+ and General Software.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL 1.

IPC completed a Direct Analysis of its software and functionalized all software using the PTD ratio.

In Data Response BPA-IP-04, IPC defined the CIS+ software as IPC's software for billing of "all of the services provided to retail customer," and General Software "as all of the computer software used by IPC excluding CIS."

IPC has not provided software titles, product descriptions/purposes (with the exception of CIS+), or specific cost allocations.

When a Direct Analysis is used, utilities must provide a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

The regulatory accounting of this account must be the same as Account 303, listed above.

Parties' Positions:

IPC used the PTD ratio to allocate the amortization reserve of all software in this Account.

Analysis of Positions:

In Data Response BPA-IP-04, IPC states that "A return on plant associated with CIS+ and General Software is recovered through [IPC's] retail rates within its State jurisdiction."

In a February 27, 2009, response to the ASC Issue List, Item 4, IPC stated that for the State of Idaho retail regulation, this account, in its entirety, is allocated based upon a PTD-like allocation method. IPC states that for the Company's FERC jurisdiction, this account is allocated using a Labor-like allocation method. IPC claims both methods include the CIS+ software within Production and Transmission functions, which is appropriate as the Company uses the CIS+ software in support of all of the Company's functions.

IPC suggests that either Labor or PTD is an appropriate allocation method for an integrated utility that has been authorized to use this method by both FERC and State Commissions in the last 10 plus years of rate recovery filings.

IPC further states that because it has hundreds of software titles that change annually, and are not functionalized within any sort of account management system, IPC supports Direct Analysis for items greater than a specified multi-million dollar threshold value. IPC supports either PTD or Labor for the balance of the account.

IPC responded May 11, 2009, to its Draft ASC Report. IPC reiterated:

> For the same reasons as stated in Idaho Power's Response to item 4.2.1., it is reasonable to utilize a LABOR or PTD method of allocation for the treatment of amortization reserves in Account 303 and unreasonable and arbitrary for the Draft ASC Reports to adjust the functionalization of amortization reserves of General Software to the default of Distribution/Other (DIST).

First, although the Idaho or Oregon Commissions may allow certain costs into the rate treatment, the REP is different than typical ratemaking and may warrant different functionalizations. More significantly, Section VIII of the 2008 ASCM permits a Direct Analysis only for specified accounts. *See* 18 C.F.R. § 301.9(a). The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable.

IPC was aware that the use of either the PTD or Labor ratio was not allowed as a substitute for a Direct Analysis and that the ASCM requires the utility to demonstrate that the functionalization used assigns costs based upon the actual and/or intended functional use of those items. *See* 18 C.F.R. § 301.9(c)(2).

IPC fully participated in the public ASC workshops, either by phone or in person, and was allowed the opportunity to raise any issue regarding the Direct Analysis of software throughout the public process, including whether there were any impractical time constraints on a utility's ability to conduct data collection.

BPA understands that IPC may lack the resources needed to be able to complete this task in an expedited manner. However, the FY 2009 ASC Review Process began on October 1, 2008. This formal process followed the FY 2009 Expedited Review Process that began March 3, 2008, more than 13 months prior to the publication of the Draft ASC Report. This should have been enough time for IPC to complete a Direct Analysis of its software.

As stated in Section 4.2.1 above, BPA does not assume the costs associated with the software titles relate solely to Distribution/Other. Under Section VIII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. *See* 18 C.F.R. § 301.9(c)(2). Failure to submit the documentation will result in the entire account being functionalized to Distribution/Other. *Id.*

CIS+ is software used for customer billing purposes and therefore considered used for the retail side of the business and functionalized only to Distribution/Other.

Decision:

Because BPA is unable to substantiate the use of the PTD ratio for General Software and CIS+ software, BPA will adjust the functionalization of amortization reserves of General Software to the default of Distribution/Other (DIST). Furthermore, BPA will adjust the functionalization of amortization reserves of CIS+ software to Distribution/Other (DIST).

Table 4.2.2: Amortization Reserves
Amortization of Other Utility Plant-Account 303 ($)

		CIS+ Software		
	Total	**Production**	**Transmission**	**Dist/Other**
As-Filed	19,497,559	9,135,588	3,813,109	6,548,862
BPA Adjusted	19,497,559	0	0	19,497,559

		General Software		
	Total	**Production**	**Transmission**	**Dist/Other**
As-Filed	16,077,465	7,533,102	3,144,246	5,400,117
BPA Adjusted	16,077,465	0	0	16,077,465

4.2.3. Account 182.3, Other Regulatory Assets: SFAS 109, Regulatory Unfunded Accumulated Deferred Income Tax.

Statement of Issue:

Whether SFAS 109, Regulatory Unfunded Accumulated Deferred Income Tax, should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL. 1.

IPC included SFAS 109, Regulatory Unfunded Accumulated Deferred Income Tax, in its ASC and functionalized it to PTD.

In Data Response BPA-IP-06, IPC defined Regulatory Unfunded Accumulated Deferred Income Tax under SFAS 109 as a current or deferred income tax liability or asset recognized for the current or deferred tax consequences of all events that have been recognized in the financial statements of tax returns, measured on the basis of enacted tax law.

Parties' Positions:

IPC functionalized Regulatory Unfunded Accumulated Deferred Income Tax to PTD.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 5, IPC stated it is "planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, IPC will accept suggested functionalization."

Section 4.8.2 of the 2008 ASCM ROD excludes state and local income- and revenue-related taxes, excise taxes and miscellaneous fees from ASC, although BPA will include property taxes that are functionalized using the PTDG ratio.

Decision:

SFAS 109, Regulatory Unfunded Accumulated Deferred Income Tax, is not allowed in ASC. BPA will adjust the functionalization of Regulatory Unfunded Accumulated Deferred Income Tax to the default of Distribution/Other (DIST).

Table 4.2.3: Account 182.3 Other Regulatory Assets
Regulatory Unfunded Accumulated Deferred Income Tax ($)

	Total	Production	Transmission	Dist/Other
As-Filed	357,913,795	167,700,637	69,996,678	120,216,480
BPA Adjusted	357,913,795	0	0	357,913,795

4.2.4. Account 182.3, Other Regulatory Assets: LT&ST Mark to Market.

Statement of Issue:

Whether LT&ST Mark to Market should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included LT&ST Mark to Market in ASC and functionalized it to Production (PROD). The 2008 ASCM does not allow derivative instruments to be included in ASC.

In Data Response BPA-IP-06, IPC defines this account as one that "records unrealized gains or losses on derivative instruments, which are primarily used for acquiring fuel and electricity."

Parties' Positions:

IPC included LT&ST Mark to Market in its ASC and functionalized it to Production (PROD).

Analysis of Positions:

During the 2008 ASCM consultation process, BPA and the parties reached general consensus that all derivative accounts would be functionalized to Distribution/Other.

In a February 27, 2009, response to the ASC Issue List, Item 5, IPC stated that it accepts functionalization to Distribution (DIST) for this item.

Decision:

IPC's LT&ST Mark to Market should not be included in ASC. BPA will adjust the functionalization of LT&ST Mark to Market to the default of Distribution/Other (DIST).

Table 4.2.4: Account 182.3 Other Regulatory Assets LT&ST Mark to Market ($)

	Total	Production	Transmission	Dist/Other
As-Filed	171,234	171,234	0	0
BPA Adjusted	171,234	0	0	171,234

4.2.5. Account 182.3, Other Regulatory Assets: Fin 48 Unfunded-Noncurrent

Statement of Issue:

Whether Account 182.3, Other Regulatory Assets: Fin 48 Unfunded-Noncurrent should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included Account 182.3, Other Regulatory Assets: Fin 48 Unfunded-Noncurrent in ASC and functionalized the Account using the PTD ratio.

In Data Response BPA-IP-06, IPC states "Under Fin 48, a tax liability is recognized for Uncertain Tax Positions (Account 253401) that had been reported on the tax returns. Since reg. assets had been established for these items through the provision, this account is necessary to eliminate those reg. assets."

Parties' Positions:

IPC included Fin 48 Unfunded-Noncurrent in ASC and functionalized the Account using the PTD ratio.

Analysis of Positions:

In a February 27, 2009, response to Issue List, Item 7, IPC stated "The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization."

Section 4.8.2 of the 2008 ASCM ROD excludes state and local income- and revenue-related taxes, excise taxes and miscellaneous fees from ASC, although BPA will include property taxes that are functionalized using the PTDG ratio.

The lack of additional information from IPC precludes a clear understanding of the Fin 48 purpose and the applicability and justification to allow in ASC.

Decision:

Account 182.3, Other Regulatory Assets: Fin 48 Unfunded-Noncurrent will not be included in ASC. BPA will adjust Fin 48 Unfunded-Noncurrent and functionalize the Account to Distribution/Other (DIST).

Table 4.2.5: Account 182.3 Fin 48 Unfunded-Noncurrent ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-37,067,740	-17,368,103	-7,249,284	-12,450,353
BPA Adjusted	-37,067,740	0	0	-37,067,740

4.2.6. Account 182.3 Other Regulatory Assets: Power Cost Adjustment (PCA) Deferral and Prior Year PCA Deferral

Statement of Issue:

Whether IPC correctly functionalized Power Cost Adjustment (PCA) Deferral and Prior Year PCA Deferral to PTD.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included PCA Deferral and Prior PCA Year Deferral in rate base and functionalized using the PTD ratio.

In Data Response BPA-IP-08, IPC stated this account is used to record the deferral of the current net power supply costs (PCA) for the Idaho jurisdiction for the PCA year from April 2007 through March 2008. IPC did not provide current rate order language to justify the inclusion of this regulatory asset in rate base.

Parties' Positions:

IPC included PCA Deferral and Prior PCA Deferral in rate base and functionalized them using the PTD ratio.

Analysis of Positions:

In a February 27, 2009, response to the Issue List, Item 8, IPC stated "The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization."

In IPC's response to the Draft ASC Report, IPC contends:

> The Draft ASC Report erroneously states that, "[t]he lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of PCA Deferral and Prior PCA Deferral using the PTD ratio." This account reflects actual net power expense and recovery of the balance in this account is authorized

> by the IPUC through rates charged to the Company's customers (IPUC Order No. 30047). This Order was provided to BPA in PDF format, as an email attachment on October 22, 2008, and is attached hereto…. A requirement to provide more specific "rate order language" than contained in IPUC Order No. 30047 would be unfair and unreasonable.

Comments of Idaho Power Company to 2009 Average System Cost Draft Report (ASC-09-IP-01) and 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 11-12.

BPA acknowledges IPC's submission of IPUC Order No. 30047. The rate order describes the PCA mechanism: "In summary, ratepayers receive a rate credit when power costs are low, but are assessed a surcharge when the power costs are high." IPC Rate Order No. 30047 at 2. There is no statement or implication that PCA is included in rate base.

Under Section 4.10.4 of the 2008 ASCM, exchanging utilities are required to conduct a Direct Analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. *See* 2008 ASCM ROD at 149. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Id.* Under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *Id.*

IPC did not provide any additional information, nor did IPC specifically state that the asset or liability is included in *rate base* by its State Commission(s) as required in Section 4.10.4 of the 2008 ASCM ROD. When a Direct Analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

Under Section VIII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. The lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of PCA Deferral and Prior PCA Deferral using the PTD ratio.

Decision:

BPA received insufficient documentation to justify the use of the PTD ratio for PCA Deferral and Prior PCA Deferral. BPA will adjust the Power Cost Adjustment Deferral (PCA) and Prior Year PCA Deferral and functionalize them to the default of Distribution/Other (DIST).

Table 4.2.6: Account 182.3, Other Regulatory Assets

Power Cost Adjustment Deferred PCA ($)

	Total	Production	Transmission	Dist/Other
As-Filed	85,731,733	40,169,634	16,766,430	28,795,669
BPA Adjusted	85,731,733	0	0	85,731,733

Prior Year Power Cost Adjustment Deferred ($)

	Total	Production	Transmission	Dist/Other
As-Filed	6,590,536	3,087,998	1,288,902	2,213,636
BPA Adjusted	6,590,536	0	0	6,590,536

4.2.7. Account 182.3, Other Regulatory Assets: Idaho DSM

Statement of Issue:

Whether IPC correctly functionalized Idaho DSM.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included Idaho DSM (Demand Side Management) in Other Regulatory Assets in rate base and functionalized it to PTD.

In Data Response BPA-IP-06, IPC stated that this account was used to record Demand Side Management/Conservation charges and approved recovery of the amortization.

The 2008 ASCM allows conservation program expenses to be functionalized to Production, including recovery of the amortization. *See* 18 C.F.R. § 301.9(a). However, Section 4.10.1 of the 2008 ASCM ROD does not allow return on regulatory assets that are not allowed by State Commissions in rate base.

When a Direct Analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

Parties' Positions:

IPC included Idaho DSM in Other Regulatory Assets in rate base and functionalized it using the PTD ratio. IPC would accept BPA's reallocation to Production (PROD) based on BPA's initial assessment.

Analysis of Positions

In a February 27, 2009, response to the ASC Issue List, Item 9, IPC supports re-allocation of DSM account to PROD, based on BPA's initial assessment.

Under Section 4.10.4 of the 2008 ASCM, exchanging utilities are required to conduct a Direct Analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. *See* 2008 ASCM ROD at 149. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Id.* Under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *Id.*

Upon further analysis, BPA notes that IPC did not provide supporting rate order language to show that either the IPUC or the OPUC allowed this Demand Side Management in IPC's rate base. In IPC's response to its Draft ASC Report, it states:

> The Draft ASC Report erroneously states, "[u]pon further analysis, BPA notes that IPC did not provide supporting rate order language to show that either the IPUC or the OPUC allowed this Demand Side Management in IPC's rate base." (Emphasis added). In fact, the amount in this account is recovered from the Company's customers through retail rates. The account includes Idaho Power Company DSM (Conservation) expense. This account was authorized for recovery in IPUC Order No. 27660. This Order was provided to BPA in PDF format, as an email attachment on October 22, 2008, and is attached hereto. (See Attachment "E", attached to these comments.) A requirement to provide more specific "rate order language" than contained in IPUC Order No. 27660 would be unfair and unreasonable.

Comments of Idaho Power Company to 2009 Average System Cost Draft Report (ASC-09-IP-01) and 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 11-12.

BPA acknowledges IPC's submission of IPUC Order No. 27660 and language noting the recovery of the DSM expense. In addition, IPC referenced IPUC Orders No. 27722 and 28041. All three orders describe the regulatory treatment for recovering DSM expenses through an accelerated amortization schedule. What BPA could not determine, however, is whether or not the Commission also allowed a return on the investment within regulatory assets in rate base. There was no direct statement or implication that recovery would be allowed with the rate of return in rate base and therefore it was not clear in the Rate Orders whether IPC received recovery in Account 182.3. BPA requested from IPC "specific language" to confirm that DSM was allowed by the IPUC or OPUC in rate base and would receive a rate of return. IPC did not provide any additional information, nor did IPC specifically state that the asset was included in *rate base* by its State Commission(s) as required in Section 4.10.4 of the 2008 ASCM ROD. When a Direct Analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

The lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of DSM Idaho using either the PTD ratio or Production (PROD).

Decision:

BPA received insufficient information to justify the use of the PTD or Production ratios for DSM in rate base, and will adjust the functionalization of the Idaho DSM to the default of Distribution/Other (DIST).

Table 4.2.7: Account 182.3, Other Regulatory Assets – Idaho DSM ($)

	Total	Production	Transmission	Dist/Other
As-Filed	8,106,539	3,798,322	1,585,384	2,722,833
BPA Adjusted	8,106,539	0	0	8,106,539

4.2.8. Account 182.3, Other Regulatory Assets, PS&I Coal Plant

Statement of Issue:

Whether IPC's Direct Analysis supports the functionalization of the PS&I Coal Plant costs to Production (PROD).

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included PS&I Coal Plant in rate base and functionalized it to Production (PROD).

In Data Response BPA-IP-08, IPC defined this asset as "representing the preliminary survey and investigation of a coal plant that was proposed in its 2006 IRP."

Parties' Positions:

IPC included PS&I Coal Plant in rate base and functionalized it to Production (PROD).

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 10, IPC stated “The Company is planning to review all functionalization of accounts in next year’s ASC filing. However, because of the quick turnaround required for the review process in this year’s filing, the Company will accept suggested functionalization.”

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. In addition, when not included in rate base, Table 1 functionalizes Preliminary Survey and Investigation Charges to Distribution/Other.

Under Section 4.10.4 of the 2008 ASCM, exchanging utilities are required to conduct a Direct Analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. *See* 2008 ASCM ROD at 149. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Id.* Under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *Id.*

IPC did not provide supporting rate order language to show that either the IPUC or the OPUC allowed PS&I Coal Plant costs in IPC’s rate base.

Decision:

The PS&I Coal Plant will not be allowed in ASC. BPA will adjust the functionalization to the default of Distribution/Other (DIST).

Table 4.2.8: Account 182.3, Other Regulatory Assets – PS&I Coal Plant ($)

	Total	Production	Transmission	Dist/Other
As-Filed	235,859	235,859	0	0
BPA Adjusted	235,859	0	0	235,859

4.2.9. Account 253, Other Deferred Credits: Fin 48 or Fin 48 Interest

Statement of Issue:

Whether Other Deferred Credits, Account 253, Fin 48 or Fin 48 Interest should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included Fin 48 (tax) and Fin 48 Interest in ASC and functionalized using the PTD ratio.

In Data Response BPA-IP-06, IPC states that "Under Fin 48, a tax liability is recognized for Uncertain Tax Positions (Account 253401) that had been reported on the tax returns. Since reg. assets had been established for these items through the provision, this account is necessary to eliminate those reg. assets."

Parties' Positions:

IPC included Fin 48 (tax) and Fin 46 Interest in ASC and functionalized using the PTD ratio.

Analysis of Positions:

In a February 27, 2009, response to Issue List, Item 7, IPC stated "The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization."

Section 4.8.2 of the 2008 ASCM ROD excludes state and local income- and revenue-related taxes, excise taxes and miscellaneous fees from ASC, although BPA will include property taxes that are functionalized using the PTDG ratio.

The lack of additional information from IPC precludes a clear understanding of the Fin 48 purpose the applicability and justification to allow in ASC.

Decision:

Account 253, Other Deferred Credits Fin 48 and Fin 48 Interest will not be included in ASC. BPA will adjust both accounts and functionalize to Distribution/Other (DIST).

Table 4.2.9: Account 253, Other Deferred Credits

Fin 48 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-9,169,981	-4,296,598	-1,793,360	-3,080,023
BPA Adjusted	-9,169,981	0	0	-9,169,981

Fin 48 Interest ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-802,050	-375,801	-156,856	-269,393
BPA Adjusted	-802,050	0	0	-802,050

4.2.10. Account 254, Other Regulatory Liabilities: Unfunded Accumulated Deferred Income Tax

Statement of Issue:

Whether Account 254, Other Regulatory Liabilities: Unfunded Accumulated Deferred Income Tax should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included Regulatory Unfunded Accumulated Deferred Income Tax in ASC and functionalized using the PTD ratio.

In Data Response BPA-IP-09, IPC defined Regulatory Unfunded Accumulated Deferred Income Tax under SFAS 109 as a current or deferred income tax liability or asset recognized for the current or deferred tax consequences of all events that have been recognized in the financial statements of tax returns, measured on the basis of enacted tax law.

Parties' Positions:

IPC included Regulatory Unfunded Accumulated Deferred Income Tax in ASC and functionalized it using the PTD ratio.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Items 12 and 5, IPC stated "it is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, IPC will accept BPA's suggested functionalization."

Section 4.8.2 of the 2008 ASCM ROD excludes state and local income- and revenue-related taxes, excise taxes and miscellaneous fees, including franchise fees, from ASC, although BPA will include property taxes that are functionalized using the PTDG ratio.

Decision:

Regulatory Unfunded Accumulated Deferred Income Tax will not be included in ASC. BPA will adjust this Account and functionalize it to the default of Distribution/Other (DIST).

Table 4.2.10: Account 254, Other Regulatory Liabilities
Unfunded Acc Def Inc Tax ($)

	Total	Production	Transmission	Dist/Other
As-Filed	42,967,558	20,132,465	8,403,102	14,431,991
BPA Adjusted	42,967,558	0	0	42,967,558

4.2.11. Account 254, Other Regulatory Liabilities: DSM Rider Idaho and DSM Rider Oregon

Statement of Issue:

Whether IPC correctly functionalized Account 254, Other Regulatory Liabilities: DSM Rider, ID and DSM Rider, OR accounts.

Statement of Facts

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included DSM Rider, ID, and DSM Rider, OR, in rate base and functionalized both using the PTD ratio.

In Data Response BPA-IP-09, IPC provided specific language as follows:

> DSM RIDER, ID: This account is to record the recognition of funds received from the customer through a rider on the customer's bill to fund Demand Side Management (DSM) programs.
>
> DSM RIDER, OR: The OPUC ordered the Company to establish a separate tariff rider in the amount of approximately 1.5% of each customer class's base revenues to support analysis and implementation of new DSM programs. This amount may be increased in the future if necessary to take advantage of other cost effective DSM measures as circumstances warrant. This rider appears as a line item expense on the customers' monthly bills so the customer is advised of what portion of their bill goes toward energy conservation. Conservation planning and program costs are then paid out of this account.

In Data Response BPA-IP-19, IPC submitted the DSM Rider, ID, and DSM Rider, OR expenses by funding source. Accounts 254.201 (Other Regulatory Liabilities-Idaho DSM Rider) and 254.202 (Other Regulatory Liabilities-Oregon DSM Rider) were listed. The Rider recovers these accounts.

The 2008 ASCM allows all conservation expenses to be functionalized to Production, including recovery of the amortization. However, the 2008 ASCM does not allow return on regulatory assets that are not allowed by State Commissions in rate base.

When Direct Analysis is used, utilities must provide a clear description and justification for the functionalization of all accounts and sub-accounts.

Parties' Positions:

IPC originally functionalized the DSM Rider, ID, and DSM Rider, OR conservation measures to PTD, and was willing to accept BPA's initial reallocation to Production (PROD).

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 13, IPC supports reallocation of DSM account to Production, based on BPA's initial assessment.

Under Section 4.10.4 of the 2008 ASCM, exchanging utilities are required to conduct a Direct Analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. *See* 2008 ASCM ROD at 149. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Id*. Under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *Id*. It is BPA's position that regulatory liabilities receive similar treatment as regulatory assets.

Although BPA allows conservation program expense, including recovery of the amortization expense, to be functionalized to Production, further analysis determined this account does not represent expense items but rather the revenues recovered from customers for these conservation programs. Furthermore, because the DSM Rider, ID and DSM Rider, OR are not allowed by the State Commissions in rate base, BPA will not allow them in ASC rate base, and will functionalize them to the default of Distribution/Other.

IPC did not provide supporting rate order language to justify the inclusion of the DSM Riders in Account 254, Other Regulatory Liabilities.

Decision:

BPA received insufficient information to justify the use of the PTD or Production ratios for DSM Rider ID and DSM Rider OR in Other Regulatory Liabilities, and will adjust the functionalization of the DSM Rider ID and DSM Rider OR to the default of Distribution/Other (DIST).

Table 4.2.11: Account 254, Other Regulatory Liabilities

DSM Rider ID ($)

	Total	Production	Transmission	Dist/Other
As-Filed	1,483,073	694,894	290,042	498,136
BPA Adjusted	1,483,073	0	0	1,483,073

DSM Rider OR ($)

	Total	Production	Transmission	Dist/Other
As-Filed	410,226	193,212	80,227	137,787
BPA Adjusted	410,226	0	0	410,226

4.2.12. Account 254, Other Regulatory Liabilities: FAS 133 Mark to Market and Mark to Market ST

<u>Statement of Issue</u>:

Whether Account 254, Other Regulatory Liabilities, FAS 133 Mark to Market and Mark to Market ST, should be included in ASC.

<u>Statement of Facts:</u>

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

In Data Response BPA-IP-09, IPC described these items as "unrealized gains or losses that otherwise would be recorded on the income statement are deferred until the contract settles at which time the balance in this account associated with the contract is reversed."

This account is associated with fuel for the generation of electricity and market energy prices. The 2008 ASCM does not allow derivative instruments to be included in ASC.

<u>Parties' Positions:</u>

IPC included FAS 133 Mark to Market and Mark to Market ST and functionalized them to Production (PROD).

<u>Analysis of Positions:</u>

During the 2008 ASCM consultation process, BPA and the parties reached general consensus that all derivative accounts would be functionalized to Distribution/Other.

IPC responded in a February 27, 2009, ASC Issue List, Item 14, and stated it "accepted distribution functionalization for this item."

<u>Decision:</u>

Account 254, Other Regulatory Liabilities: FAS 133 Mark to Market and Mark to Market ST will not be included in ASC. BPA will adjust both accounts and functionalize to the default of Distribution/Other (DIST).

Table 4.2.12: Account 254, Other Regulatory Liabilities

FAS 133 Mark to Market ($)

	Total	Production	Transmission	Dist/Other
As-Filed	33,160	33,160	0	0
BPA Adjusted	33,160	0	0	33,160

Mark to Market ST ($)

	Total	Production	Transmission	Dist/Other
As-Filed	553,042	553,042	0	0
BPA Adjusted	553,042	0	0	553,042

4.2.13. Account 254, Other Regulatory Liabilities: Fixed Cost Adjustment

Statement of Issue:

Whether Account 254, Other Regulatory Liabilities: Fixed Cost Adjustment should be included in ASC rate base.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

IPC included the Fixed Cost Adjustment in rate base and functionalized using the PTD ratio.

In Data Response BPA-IP-09, IPC described this item as a "true-up mechanism for residential and small general service customers."

Parties' Positions:

IPC included the Fixed Cost Adjustment in rate base and functionalized it using the PTD ratio.

Analysis of Positions:

IPC responded in a February 27, 2009, ASC Issue List, Item 15, and stated the "Fixed Cost Adjustment is the provision that was put in place to remove disincentives for Company performed Conservation measures. The FCA allows the Company to recover fixed Production, Transmission and Distribution plant investments even in the event that Conservation program lower Company sales. The Company is in support of either PTD or PROD (Conservation) functionalization for the account."

In response to the Draft ASC Report, IPC stated BPA's rationale to allocate the costs to distribution is based on the "'[t]he lack of supporting rate order language from IPC did not allow a clear justification for the functionalization of DSM Idaho using either the PTD ratio or Production (PROD).'"   IPC states that:

> …the amount in this account is passed through as a cost in the rates charged to Idaho Power's customers. This ratemaking treatment was authorized in IPUC Order No. 30267…The mechanism for recovery of these costs contains a functionalization component that is reset with each of the Company's General Rate proceedings that functionalizes costs. Idaho Power's proposed functionalization follows the order and should be utilized.

BPA acknowledges IPC's submission of IPUC Order No. 30267. The rate order defines FCA as a three-year pilot program designed to provide symmetry (surcharge/credit) when fixed cost recovery per customer varies above or below a Commission established base. *See* IPUC Order No. 30267 at 13. There was no direct statement or implication that the liability would be allowed in rate base. In fact, the order stated that "[t]he recommended return on equity adjustment, however, is a general rate case issue and can be addressed in the Company's next rate case." IPUC Order No. 30267 at 15.

The 2008 ASCM allows conservation measures to be functionalized to Production. *See* 18 C.F.R. § 301.9(a). However, under Section 4.10.4 of the 2008 ASCM, exchanging utilities are required to conduct a Direct Analysis on regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. *See* 2008 ASCM ROD at 149. The utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Id.* Under no conditions can regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates. *Id.* It is BPA's position that regulatory liabilities receive similar treatment as regulatory assets. *See* Section 6.1.2 of this report.

IPC did not provide any additional information, nor did IPC specifically state that the liability was included in *rate base* by its State Commission(s) as required in Section 4.10.4 of the 2008 ASCM ROD. When a Direct Analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

Again, the lack of supporting rate order language from IPC did not allow a clear justification for the inclusion of FCA in rate base and functionalizing the costs using the PTD ratio.

<u>Decision:</u>

Account 254, Other Regulatory Liabilities: Fixed Cost Adjustment should not be included in ASC rate base. BPA will adjust the Fixed Cost Adjustment and functionalize it to the default of Distribution/Other (DIST).

Table 4.2.13: Account 254, Other Regulatory Liabilities – Fixed Cost Adjustment ($)

	Total	Production	Transmission	Dist/Other
As-Filed	2,145,403	1,005,229	419,573	720,600
BPA Adjusted	2,145,403	0	0	2,145,403

4.2.14. Account 123.1 Investment in Associate Companies

Statement of Issue:

Whether IPC provided all relevant data for Account 123.1 - Investment in Associate Companies.

Statement of Facts:

IPC included Investments in Associated Companies in its ASC and functionalized to Production (PROD).

IPC includes costs of its investment in Idaho Energy Resource Company in this account; however, it is unclear if dividends or interest associated with this investment are recorded.

In Data Response BPA-IP-05, IPC identified this as an investment in IERCo (Idaho Energy Resources Company) and stated it is related to the fuel supply for the Bridger thermal plant.

Parties' Positions:

IPC included Investments in Associated Companies in its ASC and functionalized them to Production (PROD).

Analysis of Positions:

In its February 27, 2009, response to the Issue List, Item 17, IPC stated that "in the past, IERCo had paid dividends to IPC when it had excess cash. The last dividend was in 2002. IPC and IERCo have an interest-bearing intercompany note. The balance is currently a receivable on IPC's books and should be disclosed elsewhere on the Form 1. Any interest that has been charged on the note would affect IERCo's net income and thus IPC's investment in IERCo." IPC went on to clarify that the interest for this account is recorded in Account 123.1.

IPC stated it is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept BPA's suggested functionalization.

Decision:

BPA is satisfied with IPC's response and considers the issue resolved for this Review Process. BPA reserves the right to revisit this issue in future Review Processes. The clarification has no impact on ASC.

4.3. <u>SCHEDULE 1A: Cash Working Capital</u>

No direct adjustments.

4.4. <u>SCHEDULE 2: Capital Structure and Rate of Return</u>

No direct adjustments.

4.5. <u>SCHEDULE 3: Expenses</u>

4.5.1. Account 404, Amortization of Intangible Plant – Account 303, CIS+ and General Software

<u>Statement of Issue</u>:

Whether IPC's Direct Analysis supports the use of PTD to functionalize the amortization expense of software costs located in Account 303 – CIS+ and General Software.

<u>Statement of Facts:</u>

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

The regulatory accounting of this account must be the same as Account 303, Intangible Plant – Miscellaneous, in Schedule 1, Rate Base.

IPC completed a Direct Analysis to its CIS+ and General Software and functionalized all software using the PTD ratio.

In Data Response BPA-IP-04, IPC defined the CIS+ software as IPC's software used for billing "all of the services provided to retail customers," and the General Software "as all of the computer software used by IPC excluding CIS+."

When a Direct Analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

IPC did not provided software titles, product descriptions/purposes (with the exception of CIS+), or specific cost allocations.

Parties' Positions:

IPC included CIS+ and General software in ASC and functionalized all software using the PTD ratio.

Analysis of Positions:

In Data Response BPA-IP-04, IPC states that "A return on plant associated with CIS+ and General Software is recovered through [IPC's] retail rates within its State jurisdiction."

In a February 27, 2009, response to the ASC Issue List, Item 4, IPC stated that "for the State of Idaho retail regulation, this account, in its entirety, is allocated based upon a PTD-like allocation method. For the Company's FERC jurisdiction, this account is allocated using a Labor-like allocation method. Both methods include the CIS+ software within Production and Transmission functions, which is appropriate as the Company uses the CIS+ software in support of all of the Company's functions."

IPC suggests that either Labor or PTD is an appropriate allocation method for an integrated utility that has been authorized to use this method by both FERC and State Commissions in the last 10 plus years of rate recovery filings. *See* February 27, 2009, Response to ASC Issue List, Item 4.

IPC further states that because it has hundreds of software titles that change annually, and which are not functionalized within any sort of account management system, IPC supports Direct Analysis for items greater than a specified multi-million dollar threshold value. IPC supports either PTD or Labor for the balance of the account. *Id.*

IPC responded May 11, 2009, to the Draft ASC Report. IPC reiterated:

> For the same reasons as stated in Idaho Power's Response to item 4.2.1., it is reasonable to utilize a LABOR or PTD method of allocation for the treatment of amortization expense of General Software in Account 404 for ASC purposes.

Comments of Idaho Power Company to 2009 Average System Cost Draft Report (ASC-09-IP-01) and 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 11-12.

Section VIII of the 2008 ASCM permits Direct Analysis only for specified accounts. *See* 18 C.F.R. § 301.9(d)(1).

First, it should be noted that although the Idaho or Oregon Commissions may allow certain costs in rate treatment, the REP is different than typical ratemaking and may warrant different functionalizations.

More significantly, Section VIII of the 2008 ASCM permits a Direct Analysis only for specified accounts. *See* 18 C.F.R. § 301.9(a). The functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable.

IPC was aware that the use of either the PTD or Labor ratio was not allowed as a substitute for a Direct Analysis and that the ASCM requires the utility to demonstrate that the functionalization used assigns costs based upon the actual and/or intended functional use of those items. *See* 18 C.F.R. § 301.9(c)(2).

IPC participated fully in the public ASC workshops, either by phone or in person, and was allowed the opportunity to raise any issue regarding the Direct Analysis of software throughout the public process, including whether there were any impractical time constraints on a utility's ability to conduct a Direct Analysis.

BPA understands that IPC may lack the resources needed to complete this task on an expedited basis. However, the FY 2009 ASC Review Process began on October 1, 2008. This formal process followed the FY 2009 Expedited Review Process that began March 3, 2008, more than 13 months prior to the publication of the Draft Reports. This should have been enough time for IPC to complete a Direct Analysis of its software.

As stated in Section 4.2.1 above, BPA does not assume the costs associated with the software titles relate solely to Distribution/Other. Under Section VIII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. *See* 18 C.F.R. § 301.9(c)(2). Failure to submit the documentation will result in the entire account being functionalized to Distribution/Other. *See* 18 C.F.R. § 301.9(c)(2). IPC did not provide software titles, product descriptions/purposes (with the exception of CIS+), or specific cost allocations.

CIS+ is software used for customer billing purposes and therefore is considered used for the retail side of the business and should be functionalized to Distribution/Other.

Decision:

BPA received insufficient documentation to justify the use of the PTD ratio for General Software and will adjust the amortization expense of General Software and functionalize to the default of Distribution/Other (DIST). Furthermore, BPA will adjust the amortization expense of CIS+ software and functionalize it to Distribution/Other (DIST).

Table 4.5.1: Account 404, Amortization Expense of Intangible Plant - Account 303

CIS+ Software ($)

	Total	Production	Transmission	Dist/Other
As-Filed	2,416,241	1,132,131	472,541	811,570
BPA Adjusted	2,416,241	0	0	2,416,241

General Software ($)

	Total	Production	Transmission	Dist/Other
As-Filed	4,894,370	2,293,259	957,185	1,643,926
BPA Adjusted	4,894,370	0	0	4,894,370

4.5.2. Account 908, Customer Assistance Expenses

Statement of Issue:

Whether IPC provided all relevant data for this account and correctly functionalized the following accounts:

OPR CUST SRV-ID LIWA EXP
OPR CUST SRV-OR LIWA EXP
OPR CUST SRV-CUST ASSIST EXP
OPR CUST SRV-DSM RIDER

Statement of Facts:

IPC functionalized Account 908 subaccounts to PTD, CONS, and Distribution.

DIR-C was a functionalization ratio used during the Expedited Review process for BPA's 2007 Supplemental Wholesale Power Rate Case, and is no longer a valid functionalization ratio. IPC inadvertently used the DIR-C ratio and was made aware of the error through the discovery process.

The 2008 ASCM allows conservation measures to be functionalized to Production. *See* 18 C.F.R. § 301.9(a).

In Data Responses BPA-IP-11 and BPA-IP-19, IPC stated the only expenses charged to these accounts are for conservation measures; for example, the payment to Idaho non-profit agencies (Community Action Program) for the Weatherization Assistance for Qualified Customers, and promotion of energy efficiency and demand response programs. No IPC labor is charged to this account. The full value of Account 908.001 is classified as conservation. Other activities include promotion of energy efficiency and demand response program, customer education programs, customer visits, power quality issues, etc.

Parties' Positions:

IPC originally functionalized these conservation measures to PTD, CONS, and Distribution, but will accept BPA's reallocation to Production (PROD).

Analysis of Positions:

If a utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. *See* 18 C.F.R. § 301.9(d)(3).

Section VIII of the ASCM allows utilities that wish to include advertising and promotion costs related to conservation to do so with a Direct Analysis. *Id.*

In a February 27, 2009, response to the ASC Issue List, Item 8, IPC supports reallocation of this account to Production. BPA agrees.

Decision:

BPA will functionalize Customer Expenses conservation measures in Account 908 to Production (PROD).

Table 4.5.2: Account 908, Customer Assistance Expenses

OPR CUST SRV-CUST ASSIST EXP ($)

	Total	Production	Transmission	Dist/Other
As-Filed	7,194,787	0	0	7,194,787
BPA Adjusted	7,194,787	7,194,787	0	0

OPR CUST SRV-ID LIWA EXP ($)

	Total	Production	Transmission	Dist/Other
As-Filed	1,200,341	360,102	0	840,239
BPA Adjusted	1,200,341	1,200,341	0	0

OP CUST SRV-OR LIWA EXP ($)

	Total	Production	Transmission	Dist/Other
As-Filed	28,887	8,666	0	20,221
BPA Adjusted	28,887	28,887	0	0

OPR CUST SRV-ID DSM RIDER ($)

	Total	Production	Transmission	Dist/Other
As-Filed	13,487,460	6,319,554	2,637,723	4,530,183
BPA Adjusted	13,487,460	13,487,460	0	0

4.5.3. Account 930.1, General Advertising Expenses

Statement of Issue:

Whether Account 930.1, General Advertising Expenses, should be included in ASC.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other. *See* 18 C.F.R. PT. 301, TBL.1.

In Data Response BPA-IP-10, IPC described the expenses as "cost of labor, materials used and expenses incurred in advertising and related activities, the cost by which their content and purpose are not provided elsewhere."

Parties' Positions:

IPC included General Advertising Expenses in ASC and functionalized using the PTD ratio.

Analysis of Positions:

In IPC's February 27, 2009, response to Issue List, Item 17, it explained that currently, "the Company books all DSM and Conservation related advertising to a separate account. However, in the calendar year 2007, and included in the Company's FERC Form 1 data, there is the possibility that some of the advertising booked to [930.1] was for DSM or Conservation related programs. The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization."

Section VIII of the ASCM allows utilities that wish to include advertising and promotion costs related to conservation to do so with a Direct Analysis. If a Utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. *See* 18 C.F.R. § 301.9(d)(1); *see also* 18 C.F.R. § 301.9(d)(3).

Utilities are responsible for supporting their proposed functionalizations of costs. *See* 18 C.F.R. § 301.9(c)(2). The lack of supporting documentation from IPC did not allow a clear justification for the General Advertising Expense for DSM and Conservation-related programs in Account 930.1 and a functionalization using the PTD ratio.

Decision:

BPA received insufficient documentation to support the inclusion of General Advertising Expense in ASC. BPA will adjust the expense of General Advertising Expense and functionalize to Distribution/Other (DIST).

Table 4.5.3: Account 930.1, General Advertising Expenses ($)

	Total	Production	Transmission	Dist/Other
As-Filed	519,845	243,574	101,665	174,606
BPA Adjusted	519,845	0	0	519,845

4.6. SCHEDULE 3A: Taxes

No direct adjustments.

4.7. SCHEDULE 3B: Other Included Items

4.7.1. Account 421, Miscellaneous Non-Operating Income MSC NONOP INC

Statement of Issue:

Whether IPC's Direct Analysis supports the use of PTD to functionalize Account 421, Miscellaneous Non-Operating Income: MSC NONOP INC (Miscellaneous Non-Operating Income).

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production. *See* 18 C.F.R. PT. 301, TBL.1.

IPC completed a Direct Analysis and functionalized this Account to PTD.

In Data Response BPA-IP-18, IPC described the Account as "interest charges accrued on certain program and regulatory deferral. It also includes miscellaneous refunds received for activities that are recorded outside of utility operating income."

The functionalization of an account should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

Parties' Positions:

IPC recommends PTD, but will accept LABOR for this account.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 18, IPC stated that it is "planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, IPC will accept suggested functionalization."

Under Section VIII of the 2008 ASCM, when a Direct Analysis is used, utilities must provide a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2). The lack of additional information from IPC precluded a clear understanding for the reason Miscellaneous non-Operating Income was functionalized using the PTD ratio.

Decision:

IPC's analysis does not support the use of PTD to functionalize Account 421, Miscellaneous Non-Operating Income: MSC NONOP INC. BPA will adjust the functionalization of the MSC NONOP INC to the default Production (PROD).

Table 4.7.1: Account 421, Miscellaneous Non-Operating Income – MSC NONOP INC ($)

		421000		
	Total	**Production**	**Transmission**	**Dist/Other**
As-Filed	1,103,794	517,183	215,867	370,744
BPA Adjusted	1,103,794	1,103,794	0	0

4.7.2. Account 421, Miscellaneous Non-Operating Income, Rabbi Trust

Statement of Issue:

Whether IPC's Direct Analysis supports the use of PTD to functionalize Account 421, Miscellaneous Non-Operating Income, Rabbi Trust compensation plan.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production. *See* 18 C.F.R. PT. 301, TBL.1.

IPC completed a Direct Analysis and functionalized these accounts to PTD.

In Data Response BPA-IP-17, IPC described these accounts as "Rabbi Trust" accounts which hold compensation elected to be deferred by senior management. The following are the account descriptions:

421001: reflects gains on the sale of investment assets used for payment of benefits under a non-qualified pension plan
421050: reflects interest and dividend income
421051: reflects gains on the sales of investment assets
421052: reflects unrealized gains on investment assets

When a Direct Analysis is used, utilities must provide a clear description and justification for the functionalization of all accounts and sub-accounts. *See* 18 C.F.R. § 301.9(c)(2).

The functionalization of an account should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

Parties' Positions:

IPC recommends PTD, but will accept Labor for this account.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 10, IPC took no position other than recommending "PTD, but will accept LABOR for this account."

Based on the description of the Rabbi Trust compensation plan, all items in this account relate to labor and not capital expenditures; as such, it should be functionalized using the Labor ratio.

Decision:

IPC's Direct Analysis does not support the use of PTD to functionalize the Rabbi Trust compensation plan. BPA will adjust the functionalization of the Rabbi Trust compensation plan using the Labor ratio.

Table 4.7.2: Account 421, Miscellaneous Non-Operating Income - Rabbi Trust Accounts

421001

	Total	Production	Transmission	Dist/Other
As-Filed	1,513,979	709,376	296,087	508,517
BPA Adjusted	1,513,979	593,910	237,340	682,729

421050

	Total	Production	Transmission	Dist/Other
As-Filed	197,156	92,378	38,558	66,221
BPA Adjusted	197,156	77,341	30,907	88,908

421051

	Total	Production	Transmission	Dist/Other
As-Filed	283,051	132,624	55,356	95,071
BPA Adjusted	283,051	111,036	44,373	127,648

421052

	Total	Production	Transmission	Dist/Other
As-Filed	-20,683	-9,691	-4,045	-6,947
BPA Adjusted	-20,683	-8,114	-3,242	-9,327

4.7.3. Account 407.4, Regulatory Credits, CR-FCA DEFORDER 30267

Statement of Issue:

Whether IPC correctly functionalized Account 407.4, Regulatory Credits, Reg CR-FCA (Fixed Cost Adjustment) DEFORDER 30267.

Statement of Facts:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production. *See* 18 C.F.R. PT. 301, TBL.1.

In Data Response BPA-IP-15, IPC described this account as "used to record the income statement impact for the Fixed Cost Adjustments (FCA) decoupling or true-up mechanism for residential and small general service customers."

Parties' Positions:

IPC included the Fixed Cost Adjustment in ASC and functionalized using the PTD ratio.

Analysis of Positions:

IPC responded to a February 27, 2009, ASC Issue List, Item 20, and stated the "Fixed Cost Adjustment is the provision that was put in place to remove disincentives for Company reformed Conservation measures. The FCA allows the Company to recover fixed Production, Transmission and Distribution plant investments even in the event that Conservation program lower Company sales. The Company is in support of either PTD or PROD functionalization for the account."

Decision:

BPA will functionalize Account 407.4, Regulatory Credits, Reg CR-FCA DEFORDER 30267 using the PTD ratio. However, BPA reserves the right to revisit this issue in future Review Processes. There is no impact on ASC.

Table 4.7.3: Account 407.4, Regulatory Credits CR-FCA DEFORDER 30267 ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-2,093,195	-980,767	-409,363	-703,065
BPA Adjusted	-2,093,195	-980,767	-409,363	-703,065

4.7.4. Account 407.3, Regulatory Debits, Reg DR-ORDER 29509-Amortized Professional Fees

Statement of Issue:

Whether IPC correctly functionalized Account 407.3, Regulatory Debits, Reg DR-ORDER 29509-Amortized Professional Fees.

Statement of Facts:

In Data Response BPA-IP-16, IPC described the account as one "to amortize professional fees paid to experts to participate in three rate cases."

In Rate Order 29505, the IPUC allowed IPC to recover the expense and amortize the Professional Fees (*see* ORDER No. 29505 at 26-27).

Parties' Positions:

IPC used a Direct Analysis for the Amortization of Professional Fees and functionalized them using the PTD ratio.

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Distribution/Other (DIST).

In a February 27, 2009, response to the ASC Issue List, Item 21, IPC clarified that the Professional Fees "are a result of bringing in consulting expertise to the Company to perform various tasks. It is IPC's position that Professional Fees should be functionalized as LABOR."

BPA agrees. Based on the description of the Professional Fees, it relates to labor and not capital expenditures; as such, it should be functionalized using the Labor ratio.

Decision:

BPA will functionalize Account 407.3, Regulatory Debits, Reg DR-ORDER 29509-Amort Prof Fees by the Labor ratio.

Table 4.7.4: Account 407.3, Regulatory Debits Amortized Professional Fees ($)

	Total	Production	Transmission	Dist/Other
As-Filed	21,246	9,955	4,155	7,136
BPA Adjusted	21,246	8,335	3,331	9,581

4.7.5. Account 456, Other Electric Revenues, Standby Charge

Statement of Issue:

Whether IPC correctly functionalized Account 456, Other Electric Revenues, Standby Charge.

Statement of Facts:

In Data Response BPA-IP-18, IPC provided a description of the standby charge as "Amounts represent charges paid by customers for the provision of standby electric service under Schedule 31 to a specific industrial customer who self-generates. Distribution/Fees associated with use of distribution services."

Parties' Positions:

IPC used a Direct Analysis and functionalized these accounts to Distribution/Other (DIST).

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production (PROD).

In a February 27, 2009, response to the ASC Issue List, Item 22, IPC stated

> [t]hese are revenues received for the provision of bundled services delivered to retail customers. IPC believes that it is appropriate to functionalize these revenues to distribution (DIST) but would accept the use of PTD since the bundled services are delivered at the customers' premises. This service is applicable to customers utilizing on-site generation and not applicable to service for re-sale, to serve where on-site generation is used for only emergency supply or to co-generators or small power producers who have contracted to supply power and energy. The type of service provided is three-phase at approximately 60 cycles. If the customer opts for parallel operations, Idaho Power Company will install a system protection package at the Customer's expense, prior to the start of the parallel operations. The customer will also pay a Maintenance charge of 0.7 percent per month times the investment in the protection package. Charges under this tariff include Standby Reservation, Standby Demand, Excess Demand and Minimum ("Customer") Charges. Under Idaho Power's State Commission, this account has been directly assigned to Idaho Retail Customer(s) and functionalized as Distribution (similar to DIST functionalization). This account is not included for purposes of FERC jurisdictional ratemaking (i.e. Transmission).

Standby charges are a reserve for capacity and, as IPC states above, the "service is applicable to customers utilizing on-site generation." Reserve capacity is a production-related cost.

The 2008 ASCM is independent of State Commission ratemaking and BPA is not required to follow the same functionalization methodology as the Idaho or Oregon Commissions. Although the Commissions may allow certain costs in rate treatment, the REP is different than typical ratemaking and may warrant different functionalizations.

Decision:

BPA received insufficient information to justify IPC's functionalization of the standby charge to Distribution/Other, and will functionalize to the default of Production (PROD).

Table 4.7.5: Account 456, Other Electric Revenues – Standby Charges ($)

	Total	Production	Transmission	Dist/Other
As-Filed	113,656	0	0	113,656
BPA Adjusted	113,656	113,656	0	0

4.7.6. Account 456, Other Electric Revenues, Alternate Service Charge-Rate 46 and Alternate Distribution Service

Statement of Issue:

Whether IPC correctly functionalized Account 456, Other Electric Revenues, Alternate Service Charge-Rate 46 and Alternate Distribution Service.

Statement of Facts:

In Data Response BPA-IP-18, IPC provided a description for both Alternate Service Charge-Rate 46 and Alternate Distribution Service as "the provision of local service to the Lucky Peak generation project."

Parties' Positions:

IPC used a Direct Analysis and functionalized these accounts to Distribution/Other (DIST).

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production (PROD).

In a February 27, 2009, response to the ASC Issue List, Item 23, IPC stated "This charge recovers the cost of a secondary Distribution circuit to a customer, which back up the Customer's regular Distribution circuit. This account has been functionalized as Distribution for both State and FERC regulatory purposes."

BPA agrees. Based on the description provided by IPC, the account should be functionalized to Distribution/Other.

Decision:

BPA is satisfied with IPC's response and considers the issue resolved. Alternate Service Charge-Rate 46 and Alternate Distribution Service will be functionalized to Distribution/Other (DIST). There is no impact to ASC.

Table 4.7.6: Account 456, Other Electric Revenues - Alternate Service Charge-Rate 46 and Alternate Distribution Service ($)

	Total	Production	Transmission	Dist/Other
As-Filed	123,718	0	0	123,718
BPA Adjusted	123,718	0	0	123,718

4.7.7. Account 456, Other Electric Revenues, PV Rate

Statement of Issue:

Whether IPC correctly functionalized Account 456, Other Electric Revenues, PV Rate.

Statement of Facts:

In Data Response BPA-IP-18, IPC defined Account 456, Other Electric Revenues, as the "facilities charges for the use of photovoltaic equipment" and functionalized to Distribution. However, in Data Response BPA-IP-08, IPC functionalized the partial fees paid for the Photovoltaic Generator in Account 253, Other Deferred Credits to Production.

Parties' Positions:

IPC used a Direct Analysis and functionalized the account to Distribution/Other (DIST).

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM provides that the functionalization method for all line items in this account is Direct Analysis with a default to Production (PROD).

In a February 27, 2009, response to the ASC Issue List, Item 23, IPC stated "The Company is planning to review all functionalization of accounts in next year's ASC filing. However, because of the quick turnaround required for the review process in this year's filing, the Company will accept suggested functionalization." IPC offered no additional information.

Under Section VIII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. The lack of additional information from IPC precluded a clear understanding of the photovoltaic equipment, and therefore the applicability and justification of the functionalization to Distribution/Other. The functionalization of an account must follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM.

Decision:

BPA received insufficient documentation to justify IPC's functionalization of PV Rate as Distribution/Other. BPA will adjust the functionalization of Account 456, Other Electric Revenues, PV Rate, to the default of Production (PROD).

Table 4.7.7: Account 456, Other Electric Revenues – PV Rate ($)

	Total	Production	Transmission	Dist/Other
As-Filed	13,687	0	0	13,687
BPA Adjusted	13,687	13,687	0	0

4.8. SCHEDULE 4: Average System Cost

4.8.1. Distribution Losses

No direct adjustments.

4.8.2. Contract System Cost

CY 2007 Contract System Cost ($)

As-Filed		BPA Adjusted	
Production	461,275,498	Production	461,434,297
Transmission	104,444,121	Transmission	95,664,101
Less NLSL	20,611,958	Less NLSL	25,276,624
Total	545,107,660	Total	531,821,775

4.8.3. Contract System Load

CY 2007 Contract System Load (MWh)

	Total
As-Filed	15,159,811
BPA Adjusted	15,159,811

4.8.4. Average System Cost

CY 2007 Average System Cost (ASC) ($/MWh)

	Total
As-Filed	35.96
BPA Adjusted	35.08

5. SUPPORTING DOCUMENTATION

5.1. Purchased Power and Sales for Resale

No direct adjustments.

5.2. Salaries and Wages

No direct adjustments.

5.3. Labor Ratios

No direct adjustments.

5.4. Distribution Losses

IPC submitted Distribution Loss calculations. A Distribution Loss Factor of 6.90 percent was used.

5.5. Retail Load Forecast Data

Statement of Issue:

Whether IPC's total retail load forecast should be corrected.

Statement of Facts:

During the Review Process, it was discovered that IPC inadvertently submitted calendar year instead of fiscal year total retail load forecast data.

The ASCM requires a fiscal year (FY) total retail load forecast (October-September).

IPC was made aware of the error during the Review Process and subsequently submitted the correct time-line total retail load forecast.

<u>Parties' Positions:</u>

IPC confirmed the error and sent corrected data for total retail load (FY).

<u>Analysis of Positions:</u>

ASCs are based on fiscal year data and therefore require FY forecasts. The following table identifies the calendar year as filed by IPC in October 2008 and the corrected fiscal year data filed for this Report.

	CY As-Filed (Jan-Dec)	**FY (Oct-Sept)**
2007	14,541,825	14,541,825
2008	14,478,929	14,653,961
2009	14,755,632	14,561,464
2010	15,296,781	15,214,573
2011	15,605,691	15,543,784
2012	15,843,167	15,794,344

<u>Decision:</u>

BPA will adjust IPC's load forecast using IPC's updated information to reflect the fiscal year total retail load as detailed in the table above.

5.6. <u>New Resource Addition</u>

<u>Statement of Issue:</u>

Whether the Danskin CT1 generating plant meets the materiality threshold of 2.5 percent.

<u>Statement of Facts</u>:

IPC submitted information on new resources with its October 15, 2008, ASC filing.

Changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC.

<u>Parties' Positions:</u>

Based on IPC's data, Danskin Simple Cycle CT came on-line in March, 2008, prior to the start of the Exchange Period. IPC assumes Danskin meets the 2.5 percent materiality threshold in order to be considered a new resource.

Analysis of Positions:

Section 4.2.6 of the 2008 ASCM identifies a materiality threshold of a 2.5 percent change in a utility's Base Period ASC for determining when a change in ASC will be made for resource additions or reductions.

During the Review Process, BPA calculated the materiality calculation of Danskin at 1.62 percent based on the following values ($/MWh):

FY 2007 ASC without Danskin addition:	35.65
FY 2007 ASC with Danskin addition:	36.22
Delta:	0.57
CY 2007 ASC:	35.08

The materiality calculation is as follows:

$$(36.22-35.65)/35.08 = 0.0162$$

Danskin generation costs do not meet the materiality threshold and therefore will not be included in the calculations to determine IPC's Exchange Period ASC. No other new resource information was submitted that showed any resources coming on-line during the Exchange Period.

Decision:

The Danskin CT1 generating plant does not meet the 2008 ASCM materiality threshold of 2.5 percent. BPA will not include Danskin costs in ASC for FY 2010-2011.

5.7. ASC FORECAST MODEL: Natural Gas Escalators and Market Price of Energy

Statement of Issue:

Whether BPA should update the ASC Forecast Model escalators to reflect the natural gas and market price of electricity forecasts developed in BPA's 2010 Final Wholesale Power Rate Proposal.

Statement of Facts:

Section IV.A.2 of the 2008 ASCM states that:

> BPA will use Global Insight's (or its successor'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 IOU 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 and other products.

18 C.F.R. § 301.5(a)(2).

Section 4.2.1 of the 2008 ASCM ROD states that the:

> …. use of these escalators will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.

2008 ASCM ROD at 39.

Parties' Positions:

No party raised any comments on this issue.

Analysis of Positions:

As noted at the beginning of this ASC Report, utilities' ASCs make up only one component of the formula used to determine a utility's benefits under the Residential Exchange Program. In addition to a utility's ASC, BPA must also calculate a PF Exchange rate, which is being established in BPA's WP-10 Rate Proceeding. The PF Exchange rate generally reflects BPA's cost of power, with certain surcharges as required by section 7 of the Northwest Power Act. Although BPA's PF Exchange rate and the utilities' ASCs are established under different criteria, both sets of rates use certain common inputs. The forecasts used to determine the market prices of electricity and natural gas are one area where there is an overlap in the rate inputs.

The forecasts of electricity prices and natural gas prices play a significant role in determining the level of both the PF Exchange rate and utilities' ASCs. For example, they affect BPA's PF Exchange rate in that they determine the level of secondary revenue that is used to credit against BPA's cost of power. For ASCs, these forecasts impact the value the utility receives for its sales for resale and the costs the utility incurs for purchasing power on the open market. Because these forecasts are a central driver in establishing both sets of rates, the ASCM provides that BPA will use its own forecast for these commodities when calculating the escalators in the ASC Forecast Model. 18 C.F.R. § 301.5(a)(2). As noted above, the Administrator explained in the ASCM ROD that these BPA-generated forecasts were essential because they "will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period." 2008 ASCM ROD at 39. Without this parity, there could be a serious misalignment between the inputs used to determine BPA's PF Exchange rate and the utilities' ASCs, which could potentially result in abnormally high or low payments to utilities participating in the Residential Exchange Program.

Consistent with the terms of the ASCM and the ASCM ROD, for this Final ASC Report BPA has updated the electricity price forecast and natural gas price forecast used to determine the escalators in the ASC Forecast Model. BPA used the forecasts developed in BPA's Final Rate Proposal in the WP-10 Rate Proceeding as the source of its data for these updates. BPA chose the WP-10 Final Rate Proposal as its source of data because these forecasts are the most current available and reflect market conditions and BPA's expectation for future energy prices. In addition, the Final Rate Proposal forecasts achieve the parity described in the ASCM ROD by ensuring the market price assumptions used to set BPA's PF Exchange rate are consistent with the forecasts used to establish utilities' ASCs.

Decision:

BPA will update the ASC Forecast Model escalators to reflect the natural gas price forecast and market price of electricity forecast developed in BPA's 2010 Final Wholesale Power Rate Proposal.

Table 5.7.1: ASC Forecast Model: Natural Gas Escalators

	Price Escalators			
Calendar Year	**2008**	**2009**	**2010**	**2011**
As-Filed	33.8%	-19.4%	5.3%	-2.6%
Final	24.8%	-50.3%	30.0%	2.7%

See Excel File IPC_ASC_Forecast_Model_FY2010-11_Final.xls and IPC ASC Model FY10-11.xls

Table 5.7.2: ASC Forecast Model: Market Price of Electricity

	Price Escalators			
Fiscal Year	**2008**	**2009**	**2010**	**2011**
As-Filed	26%	-23%	2%	2%
Final	19%	-23%	-19%	8%

See Excel File IPC_ASC_Forecast_Model_FY2010-11_Final.xls and IPC ASC Model FY10-11.xls

5.8. ASC FORECAST MODEL: Price of BPA Power Products

Statement of Issue:

Whether BPA should update the ASC Forecast Model escalators to reflect the price of BPA power products developed in BPA's 2010 Final Wholesale Power Rate Proposal.

Statement of Facts:

Section IV.A.2 of the 2008 ASCM states that:

> BPA will use Global Insight's (or its successor'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 IOU 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 and other products.

18 C.F.R. § 301.5(a)(2).

Section 4.2.1 of the 2008 ASCM ROD states that the:

> …. use of these escalators will ensure parity in the forecast of costs included in BPA rates and costs included in ASCs during the rate period and Exchange Period.

2008 ASCM ROD at 39.

Parties' Positions:

No party raised any comments on this issue.

Analysis of Positions:

This issue is similar to the issue described above in Section 5.10. Consistent with the terms of the ASCM and the ASCM ROD, for this Final ASC Report BPA has updated the price of BPA power products to determine the escalators in the ASC Forecast Model. BPA used the prices developed in BPA's Final Rate Proposal in the WP-10 Rate Proceeding as the source of its data for these updates. Updating the ASC Forecast Model escalators with BPA's final rates from WP-10 Final Rate Proposal is reasonable because these prices reflect the actual rates BPA will charge during the Exchange Period for BPA's power products. In addition, the Final Rate Proposal rates achieve the parity described in the ASCM ROD by ensuring there is no misalignment between the cost components used to determine BPA's PF Exchange rate and the cost components used to determine the utilities' ASCs.

Decision:

BPA will update the ASC Forecast Model escalators to reflect the price of BPA power products developed in BPA's 2010 Final Wholesale Power Rate Proposal.

Table 5.8.1: ASC Forecast Model: Purchased Power PF

Price Escalators

Fiscal Year	2008	2009	2010	2011
As-Filed	0.0%	-3.7%	3.8%	0.0%
Final	0.0%	-3.7%	7.0%	0.0%

See Excel File IPC_ASC_Forecast_Model_FY2010-11_Final.xls and IPC ASC Model FY10-11.xls

Table 5.8.2: ASC Forecast Model: Purchased Power Slice

Price Escalators

Fiscal Year	2008	2009	2010	2011
As-Filed	0.0%	-3.7%	3.8%	0.0%
Final	0.0%	-0.2%	4.5%	0.0%

See Excel File IPC_ASC_Forecast_Model_FY2010-11_Final.xls and IPC ASC Model FY10-11.xls

5.9. ASC FORECAST MODEL: New Large Single Loads

Statement of Issue:

Whether peaking plants should be included in the cost of serving New Large Single Loads (NLSLs).

Statement of Facts:

Endnote d of the 2008 ASCM provides that, in the absence of a dedicated resource (CF/CT prior to September 1, 1979), BPA must include the cost of all of the utility's resources and long-term power purchases (five years or more in duration) in determining the cost of serving an NLSL.

IPC does not support BPA's 2008 ASCM on this matter, which includes peaking plants in the NLSL calculation, and did not immediately provide the requested resource cost data for all NLSL loads.

In Data Response BPA-IP-21, IPC submitted the requested data, but did so under protest.

Parties' Positions:

IPC argues that peaking plants should not be included in the cost of serving NLSLs.

Analysis of Positions:

IPC does not support BPA's inclusion of the cost of peaking plants (which it claims cannot for multiple reasons serve an NLSL) in the NLSL calculation. In response to the Draft Report, dated May 11, 2009, IPC states that it:

> [d]isagrees that it is reasonable to calculate the costs of serving New Large Single Loads by using costs that are developed utilizing the assumption that peaking generating plants are baseload resources. The Pacific Northwest Electric Power Planning and Conservation Act states that a utility's ASC shall not include, "the cost of additional resources in an amount sufficient to serve any new large single load of the utility." Pacific Northwest Electric Power Planning and Conservation Act, Sec. 5(c)(7); 16 U.S.C. § 839c(c)(7). Therefore, the 2008 ASC Methodology

provides for determining the cost of resources used to serve new large single loads, and then subtracting those costs from the utility's average system costs.

The practical result of the manner of the proposed implementation of the Revised 2008 ASC Methodology in determining Idaho Power's ASC is that the Draft ASC Reports disregard the very limited number of actual hours that Idaho Power's peaking facilities actually generate. For instance, Idaho Power's Bennett Mountain and Danskin simple cycle gas generating facilities had actual capacity factors of 3% during 2006. The 3% capacity factor only allowed for 263 hours of operation of each of these facilities in 2006. Because of the limited actual capacity factors, the Bennett Mountain and Danskin simple cycle gas generation plants should be disregarded for purposes of calculating the cost of service to new large single loads.

To the extent that "Endnote d" of the Revised 2008 ASC Methodology is intended, or interpreted by to mean that gas fired peaking resources are utilized by a retail utility to serve new large single loads, such intention or interpretation is fundamentally flawed and arbitrary. The interpretation of "Endnote d" set forth in the Draft ASC Reports does not take into account how service to a new large single load is planned for, or regularly provided by a utility, or how Idaho Power actually operated its Bennett Mountain and Danskin simple cycle gas generating facilities during 2006.

New large single loads are typically large manufacturing facilities with relatively high load factors. These manufacturing facilities typically maintain relatively flat continuous loads. Peaking plants are built to serve loads that vary significantly on an hourly basis. Residential and irrigation loads are examples of these loads, while large manufacturing facilities are not.

Idaho Power's Bennett Mountain and Danskin simple cycle gas generating facilities had actual capacity factors of 3% during 2006. The 3% capacity factor only allowed for 263 hours of operation of each of these facilities in 2006. By contrast, a new large single load draws power from the utility nearly every hour of the year. BPA's method of including costs for peaking facilities, disregards the actual generation of the facility, and arbitrarily assumes that the facilities generated power during every hour during the year that a new large single load takes service from Idaho Power. This assumption is simply wrong.

If Idaho Power Company were to serve New Large Single Load customers based upon the addition of a simple cycle combustion turbine (or more specifically, the cost of the Danskin plant, Bennett Mountain plant, or any combination thereof), the resulting rates would likely preclude any New Large Single Load customer from making an economic decision to locate within the Idaho Power Company service territory, because the average annual cost to serve the entire load of a new customer from either plant would be above the average annual market price of electricity available to Idaho Power Company or other utilities in the Pacific Northwest region.

> In support of the determination that electricity from the Danskin and Bennett Mountain facilities would be above the average annual market price during the majority of the year, the implied market heat rates can be extracted by dividing the daily Mid-Columbia (Mid-C) price index, a relevant electric price index for the Pacific Northwest by the daily Sumas gas index, a relevant natural gas price index for the Pacific Northwest, and comparing these implied market heat rates to both the Danskin and Bennett Mountain heat rates. Idaho Power Company would not plan, nor build a higher heat rate peaking plant to serve New Large Single Load customers or as a baseload resource for any customer class. Reasonable and economical use of these types of plants is for peaking activity and system reliability, which is limited in the above figure to the 0-15% probability range.
>
> Idaho Power plans to serve any new large single load on a continuous and economical basis. A peaking unit may add reliability to Idaho Power's system; however, Idaho Power does not plan to, and it is not considered economical in the utility industry as a whole, to dedicate a peaking resource to serve a continuous load. Moreover, air quality, warranty and other requirements may preclude use of a peaking resource to provide continuous service, except under emergency conditions.
>
> The assumption that Idaho Power's Bennett Mountain and Danskin, or similar peaking resources, are planned to serve, or actually serve, new single large loads on a kilowatt hour per kilowatt hour basis is erroneous, results in an over allocation of costs to peaking resources, and therefore exaggerates the costs of resources required to serve new large single loads. To the extent that the Draft ASC Reports interpret "Endnote d" of the 2008 ASC Methodology to require that the costs of Idaho Power's peaking generating plants must be assumed to generate every hour that a new large single load operates, the Draft ASC Reports are predicated upon a factually erroneous and arbitrary assumption, and should be revised, accordingly.

Comments of Idaho Power Company to 2009 Average System Cost Draft Report (ASC-09-IP-01) and 2010-2011 Average System Cost Draft Report (ASC-10-IP-01) at 13-17.

BPA and the parties evaluated and discussed this matter during the 2008 ASCM consultation proceeding. For those NLSLs not served by dedicated resources (CF/CT prior to September 1, 1979), or at BPA's NR rate, the following shall apply, as stated in the 2008 ASCM, Endnote d, page 24:

> …To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of such excess load shall be determined by multiplying the kilowatt-hours not served under subsections (1) and (2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of *all* resources and long term power purchases (five years or more in duration) …

(Emphasis added.) The issue of what constitutes an NLSL and the resource costs to serve an NLSL for ASC purposes is well defined in the 2008 ASCM, which is not subject to modification in the ASC Review Process. Any challenge on this issue must be directed at the 2008 ASCM, not the establishment of IPC's ASC in this report.

Decision:

Pursuant to Endnote d of the 2008 ASCM, BPA properly included the cost of IPC's peaking resources in IPC's cost of serving an NLSL.

6. OTHER ISSUES

6.1. Generic Issue List

In addition to the above-noted issues specific to the determination of IPC's ASC, BPA raised seven issues that may be "generic" to all exchanging utilities. The following issues were discussed with the parties during the ASC Review Processes and were published in the Draft ASC Reports. In general, the IOUs responded in unison. Puget Sound Energy (PSE) submitted additional comments. Franklin PUD did not respond in writing.

6.1.1. SCHEDULE 1: Plant Investment/Rate Base: Account 303, Intangible Plant - Miscellaneous

Statement of Issue:

Whether BPA should adopt a common functionalization for similar types of software assets.

Statement of Facts:

During BPA's review of the exchanging utilities' ASC filings, BPA noticed that the Direct Analysis performed by the utilities resulted in different functionalization for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution/Other by PGE while Avista, IPC, PAC, PSE and NorthWestern functionalized such software using the PTD ratio. Section VIII of the ASCM specifies that the default functionalization for Account 303 – Intangible Plant - Miscellaneous is Direct Analysis, with an option to functionalize the Account to Distribution/Other.

The documentation supplied by the utilities to support use of the PTD ratio to functionalize items in Account 303 – Software was minimal.

Parties' Positions:

The parties generally support the idea of a consistent functionalization of similar types of software. In their February 25, 2009, response to BPA's Issue List, the IOUs stated that:

> BPA should maintain consistency in the functionalization of these common types of programs, with costs greater than an identified threshold value, amongst utilities when calculating ASC. In our initial Appendix 1 filings the IOUs have not functionalized certain software the same, we are all in agreement that given a determination by BPA on the proper functionalization of these items the IOUs will support a consistent treatment.

IOU Generic Issue List Responses, pg. 1, filed February 25, 2009.

However, parties filed separate responses concerning functionalization of software included in Account 303. For example, PSE filed separate comments on functionalization of Account 303 software, arguing that:

> Functionalization of software assets should reflect the regulatory treatment of such software assets in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of similar types of software assets. In some cases, however, jurisdictional or cost differences may render a consistent or generic treatment insufficient. If BPA were to adopt common functionalization for similar types of software assets, such common functionalization should be a default from which a utility could opt out.

PSE Generic Issue List Responses, pg. 1, filed February 25, 2009.

In PAC's February 11, 2009, response to BPA's Issues List, PAC repeatedly stated in response to a BPA issue concerning functionalization of a specific piece of software that the "functionalization of a software system should follow the functionalization of the operation it supports." PAC Issue List Responses to BPA, pg. 3, filed February 11, 2009.

Later, however, PAC offered the following answer in response to an issue BPA raised regarding a specific piece of software. In response to BPA's functionalization of a Customer Information System, PAC argued that "[i]n determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software." PACs Issue List Responses to BPA, pg. 2, filed February 11, 2009.

PGE's February 11, 2009, response to BPA's Issues List stated that:

> Account 303 contains many different types of software, some of which should be functionalized using allocation factors rather than directly assigned. The account consists of the following categories and cost assignments:
>
> - Function Specific – Direct assigned
> - Customer Service – Direct assigned to distribution then allocated
> - Environmental Compliance – PTD allocation of $55,350
> - General Ledger/Payroll – Labor allocation
> - Common T & D Software – O&M Allocation, 15% T, 85% D

> This allocation method is a hybrid that combines the use of direct assignment and allocation factors. It was developed with oversight from the Oregon Public Utility Commission and is used in PGE rate cases. In the ASC Sch. 3 Expense allocations, A&G expenses, Office Supplies and Office Expenses are assigned using a Labor allocation. To be consistent, General Ledger and Payroll software should also be assigned using a Labor allocation. For PGE, a combination of direct and allocated methods is the most efficient and accurate way to functionalize Account 303.
>
> BPA should consider expanding their functionalization methodology to include the hybrid method described above. This method could prescribe a common functionalization based on the type of software. It would not apply a uniform allocation factor to the total of Account 303.

PGE Issue List Responses to BPA, pg. 1, filed February 11, 2009.

NorthWestern Energy's February 11, 2009, response to BPA's Issues List argued that:

> NWE believes it appropriate to adopt a common functionalization for similar types of software assets and still allow an IOU the option to functionalize based on its unique accounting applications supported with adequate documentation.

NorthWestern Energy Issue List Responses to BPA, pg. 1, filed February 11, 2009.

Snohomish County PUD's February 27, 2009, response to BPA's Issues List argued that:

> BPA should maintain consistency in the functionalization of these common types of software assets, with costs greater than an identified threshold value, amongst utilities when calculating ASC.
>
> Snohomish supports a consistent treatment for the accounting of similar types of software assets, but suggests that BPA also maintain direct assignment as an alternative.

On page 5 of PSE's comments on BPA's Draft ASC Report, PSE expressed concern about the manner in which the software functionalization was developed and whether it adequately and accurately reflects PSE's software. *See* PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009. For example, PSE is concerned that BPA associated the name of PSE software with the name of similar commercial products, resulting in misidentification of software. *Id.* In addition, PSE notes that commercial software is often modified and enhanced considerably to meet the requirements of a utility. *Id.* PSE is also concerned that BPA's software functionalization framework predetermines the functionalization of a software asset. *Id.* Finally, PSE suggests that BPA's software functionalization framework raises the burden on utilities that have tailored/enhanced software, which the utility believes changes the functional nature of software from the functionalization contained in BPA's general framework. *Id.*

PSE raised the following specific questions:

- How the general framework presented in Section 6.1.1 of the Draft ASC Report would be implemented in the ASC.
- Can a utility use the general framework as an alternative to Direct Analysis?
- If a utility were to use the general framework, would the utility need to provide additional documentation regarding the use of the functionalization method identified in the general framework, particularly if the general framework would functionalize the software systems to something other than Distribution?
- Does the 1% threshold apply for any asset in Account 303? If so, is the resulting functionalization Labor?
- How would the threshold work if a utility has software assets in both common and electric Accounts 303?

Id. at 5-6.

PSE requested that the listing of software assets as included in its April 2009 Draft ASC Report at pages 35-40 be described as preliminary and that the topic of software functionalization be addressed more fully in a workshop contemporaneous with the other discussions/workshops anticipated in the Draft ASC Report. *Id.*

Software systems should be functionalized to follow the operation they support or the labor expense that the software replaced.

<u>Analysis of Positions</u>:

Section VIII.B, Table 1 of the 2008 ASCM provides that functionalization of Account 303 is Direct Analysis with an option to Distribution/Other. *See* 18 C.F.R. PT. 301.9, Table 1.

The 2008 ASCM states as follows:

> Functionalization of each Account included in a utility's ASC must be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*. Direct analysis on an account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded.

Id. at § 301.9(a).

When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. In addition, the 2008 ASCM states that:

> Bonneville will not allow utilities to use a combination of direct analysis and a prescribed functionalization method for the same Account. The utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through direct [analysis] can justify how the ratio adequately

reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio.

Id. at § 301.9(d)(2).

BPA's review of the initial ASC filings revealed that most utilities either used the PTD or Labor ratio to functionalize a majority of Account 303 software. However, the functionalization methodology and rationale for the Direct Analysis provided by the utilities was generally nothing more than a generic statement that the software supported all of the utility's business functions. As a result, BPA was unable to determine whether the proffered functionalization treatment was appropriate. For example, some of the statements included by utilities to support functionalization of a specific piece of software with the PTD ratio used terms like "supports all functions of the company"[3] or "supports all areas of the company."[4] These catchall phrases, if allowed to serve as evidence of a Direct Analysis, could be used to support functionalizing the entire ASC filing with the PTD ratio. Such generic statements do not constitute a valid Direct Analysis under the ASCM.

BPA and the parties generally support the concept that the functionalization of a software system should follow the functionalization of the operation it supports and how the operation is functionalized under the 2008 ASCM. While the concept is easy enough to understand, it is difficult to implement within the context of a utility's ASC filing because of how the software is recorded or listed in internal databases of software in the utility's information systems and because of the sheer volume of the individual items of software.

For example, a utility may record its customer information system (CIS) as "Customer Information System" or record it by the name of the vendor such as Oracle, Harris, SAP or Ventyx, or by the application name such as Xcellant, Peace, or ConsumerLinX. Repeating this disparate method of recording software in a utility database for 1,000 or more unique software products that comprise a typical utility's software assets is a very time-consuming process. Given this difficulty, it is not surprising that most utilities and their regulatory commissions use a simple ratio, such as PTD or Labor, to functionalize most or all of the software in Account 303. This approach works well for development of retail rates that incorporate most, if not all, Production, Transmission, and Distribution costs of the utility. State commissions are generally less concerned if, for example, call center software, which is clearly related to the Distribution function, and generation maintenance software, which is clearly related to the Production function, are both functionalized with the PTD or Labor ratio. For most utilities, software represents a small percentage of net plant in service, between 1% and 5% for exchanging utilities. Thus, even if software assets are not correctly functionalized, it is unlikely that it would affect retail rates.

However, a utility's ASC may include only allowable production and transmission costs as determined in accordance with the 2008 ASCM. Using the PTD or Labor ratio for all software costs may result in the inclusion of inappropriate costs in a utility's ASC. For example, the costs of certain software packages are very large relative to others in Account 303, which could cause

---

[3] *See* Data Responses ASC-10 PA-BPA-8 and ASC-10-PS-BPA-5
[4] *See* Data Response ASC-10-PS-BPA-5 and
Excel file E302, 303, E399, Common 2006 filed.xls, DATA for ASC tab, column W.

simple ratios to functionalize a large portion of distribution-related software into ASC. For example, in PAC's Response to BPA Data Request No. 12, PAC stated that:

> The remaining $462 million consists of various computer hardware and software assets. Two assets dwarf the remaining assets – the Company's accounting software – SAP ($159 million) and Customer Service System ($102 million) which support all areas of the Company and have been allocated on the PTD factor.

This and other examples BPA found in the utilities' ASC Filings caused BPA to be concerned that, without more documentation and support, utilities could potentially include tens of millions of dollars of inappropriate costs in their ASCs through Account 303.

The 2008 ASCM is clear that if a utility does not provide, or chooses not to provide, sufficient detail so that BPA can determine the functional nature of Account 303 software assets, the software assets will be functionalized to Distribution/Other. *See* 2008 ASCM, Section VIII.B, Table 1; 18 C.F.R. § 301, Table 1. Rather than simply functionalize all of the items in Account 303 to Distribution/Other (which would be allowed under the ASCM), BPA decided to develop a general framework for evaluating software in Account 303. This framework served as a reference point as BPA considered the functionalization for the various software assets. BPA took these extra steps to ensure that software costs would be functionalized in accordance with the 2008 ASCM and that similar types of software would receive the same functionalization for all exchanging utilities to the greatest extent possible. In addition, BPA's generic software asset approach should help utilities that do not want to undertake the task of functionalizing all of the items in Account 303. The existence of BPA's general framework will not eliminate an exchanging utility's right to support a different functionalization through its own Direct Analysis.

In fact, for two utilities, Idaho and NWE, BPA reviewed the list of software assets provided by the utilities and functionalized the software based on the general framework and BPA's understanding and knowledge of the software. The BPA functionalization was then sent to the utilities for review. BPA discussed its preliminary decisions with the utility and made adjustments based on discussions with the utility about the nature and use of the software assets.

PSE's response to BPA's Draft ASC Report raised two general concerns regarding the use of BPA's general software functionalization framework. *See* PSE Comments on BPA Draft ASC Report, pg. 5-6, filed May 11, 2009. First, PSE raised general concerns regarding the manner in which BPA developed the general software functionalization framework and whether BPA's framework "adequately/accurately reflects PSE's software which may appear to have the same/similar name." *Id.* at 5. Specifically, PSE stated that BPA attempted "to associate certain software assets by name with similarly named commercially available software assets." *Id.* at 5.

The functionalization rules of the 2008 ASCM state that:

> The Utility must submit with its Appendix 1 any and all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs based upon the actual and/or intended functional use of

> those items. Failure to submit such documentation could result in the entire Account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

2008 ASCM, Section VIII.A.2; 18 C.F.R. § 301.9(c)(2).

In most cases, utilities, including PSE, did not perform a Direct Analysis on individual software assets. Instead, they relied on simple ratios to functionalize all software assets as a group without explaining why the ratios were appropriate. BPA functionalized the individual software assets *based on the information provided by the utility* to BPA in response to data requests and Issue Lists. The information provided by PSE and other utilities was primarily a simple listing of the software assets from an internal database and associated cost data. In many cases, the software asset list did not even contain the commercial name of the software asset.

Examples of items contained on software asset lists submitted to BPA by Idaho and NWE that were reviewed under a Direct Analysis include the Phoenix Project – Phase 1, Feeder Fielding Project, and Wire Vision Implementation (*see* IPC's Response to BPA Data Request 5, filed November 20, 2008); and IT Infrastructure Software, GUIXT Graphical Interface, and IT MTU Info Mobile Data Comp (*see* NWE's Response to BPA Data Request 5, filed February 20, 2009). Other than cost data associated with the software asset, utilities generally did not provide any other information about the use or function of these programs. BPA functionalized as many as 200 software assets for a utility based on nothing more than information similar to that shown in the previous example.

PSE argues that BPA's functionalization is inappropriate because BPA has used the name of the software in Account 303 as the means of functionalizing the respective programs. *See* PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009. PSE is concerned that this approach may have misidentified some items in Account 303 because the name of PSE's software does not always serve the same function as commercial software with the same or similar name. *Id.*

PSE's concerns are misplaced. First, to be clear, it is the *utility's* responsibility to submit to BPA sufficient documentation and information to support a Direct Analysis. *See* 2008 ASCM, Section VIII.B.2; 18 C.F.R. § 301.9(d)(2) ("*Utilities* can develop and use a functionalization ratio or use a prescribed functionalization method if the *Utility* through Direct Analysis *can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio*.") (emphasis added.) As such, BPA could have functionalized all of the software assets in Account 303 to Distribution/Other because the information supplied by the utilities did not support the utilities' suggested functionalizations, generally PTD. However, because this Final ASC Report concerns one of the first ASCs to be determined under the 2008 ASCM, BPA decided to allow certain software costs into ASC, provided that BPA could confirm that the software was generally used in the utility industry for resource-related activities. BPA believed that the software name was an appropriate identifier because review of corporate information provided by the software developer can generally result in identification of the proper functionalization of a software asset.

To the extent that PSE believes BPA misidentified any software assets, PSE had opportunities to supply BPA with additional information through its Direct Analysis or in response to BPA's data requests. For example, PSE could have provided the commercial name of the software and the primary users or function of the software, which would have greatly increased BPA's understanding of the software's use and purpose. Because PSE did not supply this information, Account 303 has been functionalized in a manner that is consistent with the evidence that was provided to BPA during the ASC Review Process.

PSE also states that commercial software is often significantly modified and enhanced and that such modifications "may necessitate a change in the functionalization used in the ASC." *See* PSE Comments on BPA Draft ASC Report, pg. 5, filed May 11, 2009. Additionally, PSE argues that BPA's software framework "predetermines a software asset's functionality and, by its existence raises the burden on the utility to accomplish a change to the tailored/enhanced software different from that shown in the general framework." *Id.* In response, BPA notes that if PSE has modified/tailored/enhanced a software asset such that its function is different than what is shown in BPA's general software functionalization framework, PSE may describe the modifications in its ASC filing or in response to BPA's data requests or issue lists.

PSE suggested that because of its concerns, BPA should state that the general software functionalization framework is preliminary and be the subject of future ASC workshops. *Id.* at 5. BPA agrees. The general framework for software assets described below will not be considered precedential for future ASC filings. BPA intends to revisit the software descriptions and functionalizations provided below in a workshop on its general software functionalization framework in September 2009.

PSE's response to BPA's Draft ASC Report also raised seven specific questions concerning the use of BPA's general software functionalization framework. *Id*.

PSE's first question asked if the general framework is an alternative to Direct Analysis. *Id.* In response, BPA notes that the general software functionalization template is not a substitute for a valid Direct Analysis. Rather, the template reflects BPA's understanding of the functional nature of the categories of software assets that are in general use by electric utilities.

PSE's second question asks BPA to clarify that if a utility were to use BPA's general framework, "would the utility need to provide additional documentation regarding the use of the functionalization method identified in the general framework, particularly if the general framework would functionalize the software systems to something other than Distribution?" *Id.* at 6. In response, the utility must provide sufficient documentation with its ASC filing so that BPA can determine that a software asset is correctly identified and functionalized. For example, the utility cannot simply provide a list containing software assets such as Wire Vision Implementation, Silicon Energy Software, Envision Management System Software and state that they are ERP or Wholesale Billing and Settlement and functionalize them via the Labor ratio. The utility would need to supply the software name and a brief description of its use. BPA will work with the utilities to determine the required information for software assets in the September 2009 ASC workshop.

PSE's third question asked if "the 1% threshold appl[ies] for any asset in Account 303? If so, is the resulting functionalization Labor? How would the threshold work if a utility has software assets in both common and electric Accounts 303?" *Id.* at 6. This issue is best left to the September 2009 ASC Workshop on Account 303 software assets.

PSE's fourth question asked if the "reference to IPC at page 32 of the Draft ASC Report intended to be a reference to PSE?" *Id.* In response, BPA made a typographical error in referencing IPC. The correct reference should have been to PSE.

PSE's fifth question concerned a sentence on page 34 of PSE's Draft ASC Report that PSE thought was unclear and asked that it be clarified in future ASC workshops. *Id.* BPA will discuss the meaning and intent of the referenced sentence in a future ASC workshop.

PSE's sixth question asked if the following interrogatory sentence was intended to be a declaratory sentence:

> If the regulatory asset or liability is included in the utility's jurisdictional rate base, then and only then will the utilities be permitted to functionalize the regulatory asset or liability based on the functional nature of the item?

Id. at 6. PSE is correct. The question mark at the end of the sentence should be a period and the above-referenced sentence should be declaratory.

PSE's seventh and final question asked if the determination in Section 6.1.4 requires the balance sheet accounts to be functionalized in the same manner as the related income statement accounts. *Id.* at 6. In response, BPA intends to functionalize regulatory assets and liabilities that are allowed in rate base for ASC purposes in a manner consistent with the rules and procedures of the 2008 ASCM.

BPA will schedule workshops after publication of the FY 2010-2011 Final ASC Reports to discuss the general software functionalization framework for Account 303. Utilities will have an opportunity to fully explore and analyze the general software functionalization framework, suggest changes and modifications to software definitions and functionalizations and the relationship between the general software functionalization framework and the documentation requirements for a Direct Analysis for Account 303.

Decision:

BPA will adopt a common functionalization for similar types of software assets in the FY 2010-2011 Final ASC Reports if the Direct Analysis supplied by the utility can not be substantiated by BPA. Following completion of the FY 2010-2011 Final ASC Reports, BPA intends to conduct workshops with interested parties to more fully explore BPA's general software functionalization framework, software definitions and functionalizations, and the documentation requirements for a Direct Analysis.

System Categories and Related Functionalizations

Below is a list that describes and categorizes the bulk of utility software, including the accounts associated with utility software and the functionalization BPA will use for each type of software. The following categorization reflects BPA's theory of software asset functionalization. In general, the primary purpose of utility software assets is to reduce labor cost, improve efficiency and provide better access to information and, therefore, software assets should be functionalized based on where the labor cost savings or efficiency improvements occur, or the area of the utility organization in which the software is primarily used. For example, CIS and call center software both reduce the cost of operating a call center and increase the efficiency and quality of utilities' interactions with their customers. Utility customer information and call center labor is normally recorded in Accounts 903-912, which are functionalized to Distribution/Other in the 2008 ASCM. BPA functionalized CIS and call center software assets to Distribution/Other. Automated meter reading software assets reduce the labor expense associated with reading utility meters and improve the accuracy and timeliness of customer data. Utility meter reading and related expenses are normally recorded in Accounts 901–903. BPA functionalized automated meter reading assets to Distribution/Other.

- ***Customer/Marketing*** – this category includes such applications as customer information systems for residential, commercial, and industrial customer billing, energy and demand management systems, meter reading, call center operations, and customer relationship management systems.

    - *Customer Information System (CIS)* – systems that manage the residential and small commercial customer information, bill calculation and presentation, and payment processes. Distribution - Accounts 903-912.

    - *Industrial Billing* – systems that manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 903-912.

    - *Energy and Demand Management Systems* – systems and software that design, administer, manage, track, and report on the utility's portfolio of Demand-Side Management (DSM) and Energy Efficiency (EE) programs. Production.

    - *Call Center Operations* - these systems manage the operations of customer call centers including telephony and data management and employee scheduling and performance management. Distribution - Accounts 903-912.

    - *Customer Relationship Management (CRM) System* – systems that manage information about the utility's customers. Distribution - Accounts 903-912.

    - *Advanced Meter Infrastructure (AIM) System* – systems that measure, collect and analyze energy usage from advanced devices through various communication media on request or on a pre-defined schedule. It also includes the infrastructure (*e.g.,* hardware, software, communications, customer associated systems, *etc*.) and the meter data management system components. Distribution – Account 902.

- *Meter Reading System* – systems that manage the meter reading for residential and commercial customers. It includes meter route management and performs limited meter read validation. Distribution - Accounts 902.

➢ ***Employee Information*** – this category includes such applications as employee benefits, human resources, training, time entry, payroll, and compensation management systems.

- *Payroll System* – systems that calculate pay for employees and produces payments (checks or direct deposits). LABOR – Account 920.

- *Human Resources* – systems that maintain employee information required to pay employees and maintain individual employee personal and work-related information. LABOR – Account 920.

- *Training System* – systems that maintain information about all employee training requirements, schedules, certifications, courses, and update/recertification requirements. LABOR – Account 920.

- *Time Entry System* – systems that capture actual time and attendance information for employees. LABOR – Account 920.

- *Compensation Management System* – systems that optimize and automate the salary planning process and maintain information on salary history, company guidelines, employee performance and job aspirations. LABOR – Account 920.

➢ ***Facilities Management*** – this category includes such applications as generation operations and management, transmission operations and management, substation operations and management, geographic information systems, asset/facilities management, and computer-aid design systems.

- *Geographic Information System (GIS)* – systems that integrate hardware, software, and data for capturing, managing, analyzing, and displaying all forms of geographically referenced information. Distribution - Accounts 580-599.

- *Computer Aided Design (CAD)* – systems that use computers to aid in the design and particularly the drafting (technical drawing and engineering drawing) of a part or product, including entire buildings. It is both a visual (or drawing) and symbol-based method of communication whose conventions are particular to a specific technical field. Distribution - Accounts 580-599.

➢ ***Financial Information*** – this category includes such applications as accounts receivable, accounts payable, general ledger, treasury and cash management, debt management, operations and capital budget preparation and management, asset accounting, work order accounting, and cost accounting systems.

- *Enterprise Resource Planning (ERP) System* – systems that provide a common foundation for business accounting including common functions such as accounts payable, general ledger, and accounts receivable. Representative vendor solutions include: Lawson Enterprise Financial Management, Oracle B-Business Suite, PeopleSoft Enterprise Financial Management Solutions, and SAP ERP Financials. LABOR – Account 920.

- *Treasury and Cash Management* – systems that maintain information on the cash accounts, investments cash pooling, and banking operations. Representative vendor solutions include: Oracle Cash and Treasury Management Solution, SymPro. LABOR – Account 920.

- *Debt Management* – systems that manage the debt owned by the utility including debt instruments, notes, bonds, commercial paper, and stocks. PTDG.

- *Budget Preparation* – systems that provide for the preparation of both the capital and operational budget. These systems are often incorporated in the ERP system (see above). LABOR – Account 920.

- *Asset Accounting* – systems that automate the continuing property records of the utility. PTDG.

- *Work Order Accounting* – systems that maintain an automated sub-ledger to the general ledger to account for work-in-progress accounting for both capital and operation and maintenance projects. PTDG.

- *Cost Accounting* – systems that provide a standard cost accounting capability for both capital projects and operations and maintenance activities. LABOR – Account 920.

➢ ***Management Information*** – this category includes such applications as executive information, key performance indicators, and data warehouse systems.

- *Executive Information* – systems that facilitate and support the information and decision-making needs of senior executives by providing easy access to both internal and external information relevant to meeting the strategic goals of the utility. LABOR – Account 920.

- *Key Performance Indicators* – systems that capture both internal and external information related to key business indicators for senior management. LABOR – Account 920.

- *Business Intelligence* – systems that provide historical, current, and predictive information about the operations of the utility. LABOR – Account 920.

➢ ***Market Operations and Trading*** – this category includes such applications as risk management, market simulation, market interface, transmission rights and access, transmission pricing and billing, wholesale billing and settlement, energy trading and tagging, and market dispatch systems.

- *Risk Management* – systems used to integrate loss data from a variety of sources to develop a comprehensive view of operational risk exposure to the utility. LABOR – Account 920.

- *Market Simulation* – systems used to provide a model of transmission and security-constrained optimization of the system resources against spatially distributed loads. These systems are used to produce realistic projections of market clearing prices and asset utilization levels across the transmission grid. Transmission.

- *Transmission Rights and Access* – systems that maintain data on the utility's transmission line rights and access policies. Transmission.

- *Transmission Pricing and Billing* – systems that, similar to the *Customer Information System* above, maintain information on transmission system customers, bill calculation and presentation, and payment processes. Transmission.

- *Wholesale Billing and Settlement* – systems that, similar to the *Customer Information System* above, maintain information on wholesale customers, bill calculation and presentation, and payment processes. LABOR – Account 920.

- *Market Dispatch* - LABOR – Account 920.

- *Energy Trading and Tagging* – systems that provide trade processing, risk control and invoicing, credit risk to manage credit exposure, collateral management, and counterparty evaluation. Representative vendor solutions include: Triple Point Technology's Commodity XL, Allegro, and ADICA's EMCAS system. Production.

➢ ***Planning Models*** – this category includes such applications as resource management, capacity plan, fuel plan, load forecast, purchased power, and financial/rate forecast systems. LABOR – Account 920.

➢ ***Resource Management*** – this category includes such applications as materials management, purchasing, warehouse management, inventory, fleet management, fuel management, and alternative energy supply systems.

- *Materials Management* – systems that maintain information on products, price lists, inventory receipts, shipments, movements, and counts within the utility, as well as to and from suppliers. These systems are often incorporated in the ERP system (see above). PTD.

- *Purchasing* – systems that automate the acquisition of goods and services. These systems are often incorporated in the ERP system (see above).   LABOR – Account 920.

- *Warehouse and Inventory Management* – systems that include the physical inventory, shipping, receiving, and picking of items, barcode labeling, and space management. These systems are often incorporated in the ERP system (see above). PTD – Account 163.

- *Fleet Management* – systems that provide for the management and maintenance of all vehicles and equipment used by the utility including scheduling maintenance and preventive maintenance. Distribution - Account 933.

- *Fuel Management* – systems that maintain information on fuel management for the utility's fleet operations. Distribution - Account 933.

- *Alternative Energy Supply* – systems that manage the availability of energy supply from alternative sources which may be outside the control of the utility. Production.

➢ ***System Operations*** – this category includes such applications as outage scheduling, system optimization, load control, generation control, SCADA, energy management, system dispatch, fault restoration, stability analysis, and state estimator systems.

- *Generation Control* – systems that regulate the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, and the relation of these to each other. Production.

- *Generation Operations and Management* – systems used to maximize plant operating income by optimizing output and heat rates and by reducing maintenance expenses. Production.

- *Substation Operations and Management* – systems used to monitor the operation of substations to maximize performance and ensure safe equipment operations. TD.

- *Supervisory Control And Data Acquisition (SCADA)* – systems that maintain the real-time, as-operated state of the electrical network, tracking remote control and local control operations, temporary network changes, and fault conditions. TD.

- *Energy Management (EMS)*– systems used to reduce energy losses, improve the utilization of the system, increase reliability, and predict electrical system performance as well as optimize energy usage to reduce cost. TD.

- *System Dispatch* – systems used to evaluate and optimize on an hour-ahead and day-ahead basis the dispatch of the utility's power plants to changing plant conditions, power markets, and contractual obligations. Production.

➢ ***Work Management*** – this category includes such applications as plant maintenance, work order, service order, outage management, trouble order, contractor management, and project management systems.

- *Plant Maintenance* – systems used to plan, manage, and evaluate the required major maintenance activities typically in generation facilities or other major facilities and substations. Production.

- *Work Order* – systems that manage longer-duration work, either capital or operations and maintenance frequently performed by multi-person crews. Distribution.

- *Service Order* – systems that manage the short-interval work of the utility typically performed by service crews. The system would include work scheduling, tracking, and order completion. Distribution.

- *Outage Management* – systems that prioritize restoration efforts based upon criteria such as locations of emergency facilities, size of outages, and duration of outages, extent of outages and number of customers impacted; calculate estimates of restoration times; provides information on crews needed and assisting in restoration; and predict the location of fuse or breaker that opened upon failure. Representative vendor solutions include: ABB, GE Energy, Intergraph, Oracle Utilities, and Trimble. Distribution.

➢ ***Miscellaneous Software*** **–** For software that is in general and widespread use throughout the utility such as Microsoft Office, Microsoft Exchange Server, Anti-Virus applications Adobe products, or for software where the functional nature cannot be determined and the cost of the software is less than 1% of the total cost in Account 303 – Software. LABOR.

6.1.2. SCHEDULE 1: Account 182.3, Other Regulatory Assets; Account 254, Other Regulatory Liabilities

<u>Statement of Issue</u>:

Whether BPA should adopt a common functionalization for similar types of regulatory assets and liabilities.

<u>Statement of Facts</u>:

The IOUs functionalized similar regulatory assets, such as Deferred Pension, Pay and other labor-related assets and liabilities, in a variety of ways. PGE, Avista and NW used the Labor ratio. IPC used the PTD ratio. PSE and PAC functionalized these assets to Distribution/Other. The issue is whether BPA should maintain consistency in the functionalization of Deferred Pension, Pay and other labor-related assets and liabilities among utilities when calculating ASC.

<u>Parties' Positions:</u>

In PSE's February 25, 2009, response to BPA's Issue List, PSE stated that:

> Functionalization of regulatory assets and liabilities should reflect the regulatory treatment of such regulatory assets and liabilities in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities to the extent that regulatory treatment of the account is the same across utilities and jurisdictions. In some cases, however, jurisdictional or cost differences may render a consistent or generic treatment insufficient. If BPA were to adopt common functionalization for similar types of software assets, such common functionalization should be a default from which a utility could opt out.

PSE Generic Issue List Responses, pg. 2, filed February 25, 2009.

Avista, Idaho Power, NorthWestern, PAC and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "BPA should maintain consistency in the functionalization of deferred pension, pay and other labor related assets and liabilities amongst utilities when calculating ASC. All of the IOUs agree that it is appropriate for purposes of determining a utility's ASC to functionalize these accounts by the LABOR ratio." *See* IOU Generic Issue List Responses, pg.1, filed February 25, 2009.

BPA Staff advocates the use of consistent decision criteria for common types of regulatory assets and liabilities.

Analysis of Positions:

The 2008 ASCM ROD states that:

> [t]he Utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.*

2008 ASCM ROD at 149 (emphasis added).

Regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. FERC defines them as "assets and liabilities that result from rate actions [of] regulatory agencies."[5] In the ASCM ROD, the WUTC noted that "regulatory assets are a creature of regulatory decisions made by state regulators or FERC. These assets represent costs a Utility is allowed to book and recover in rates over a period of time, rather than expense in a particular period." 2008 ASCM ROD at 149-150.

Regulatory Assets and Liabilities, Accounts 182.3 and 254 in the FERC Uniform System of Accounts, were established in March of 1993 in FERC Order No. 552, which established uniform accounting treatment for allowances associated with the 1990 Clean Air Act. Order No. 552 also dealt more broadly with accounting for regulatory assets and liabilities for electric and gas utilities.[6]

Regulatory assets and liabilities are a subset of the larger issue of the difference between accounting for utilities that are subject to price regulation and Generally Accepted Accounting Principles (GAAP). The issue can be traced back to the Internal Revenue Act of 1954, which permitted use of accelerated depreciation for income tax purposes. In 1962, the Accounting Principles Board (precursor to FASB) issued Opinion No. 2, which dealt comprehensively with the issue of accounting for industries subject to price regulation, was prepared in response to questions surrounding the creation of investment tax credits by Congress. Opinion No. 2 stated

[5] *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[6] *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).

that while all companies are subject to GAAP, differences may occur because of recognition of cost for companies subject to price or rate regulation.[7]

Simply because a utility recovers the expense associated with a regulatory asset in rates does not mean that the regulatory asset is also included in a utility's rate base and earning a return.

After review of the parties' comments and the 2008 ASCM ROD, BPA notes that functionalization of regulatory assets and liabilities is a two-step process. First, the regulatory asset or liability must be a component of the utility's jurisdictional rate base. If the regulatory asset or liability is *not* in its jurisdictional rate base, then it is functionalized to Distribution/Other.

If the regulatory asset or liability *is included* in the utility's jurisdictional rate base, then and only then will the utilities be permitted to functionalize the regulatory asset or liability based on the functional nature of the item.

Decision:

For the FY 2010-2011 ASC Filings, BPA will use consistent decision criteria for common types of regulatory assets and liabilities. If a regulatory asset or liability is included in the utility's jurisdictional rate base, then and only then will the utilities be permitted to functionalize the regulatory asset or liability based on the functional nature of the item.

6.1.3. Account 182.3, Other Regulatory Assets; Account 186, Miscellaneous Deferred Debits; Account 253, Other Deferred Credits; Account 254, Other Regulatory Liabilities

Statement of Issue:

Whether BPA should require a common functionalization for asset accounts that have a corresponding liability account; for example, whether pension costs in Accounts 182.3 and 254 should have the same functionalization.

Statement of Facts:

Table 1 of the 2008 ASCM requires a utility to perform a Direct Analysis in the functionalization of Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254). Assets in Accounts 182.3 and 186 are often offset by corresponding liabilities in Accounts 253 or 254. Because separate Direct Analyses are performed on each account, it is possible that an asset in one account could be functionalized one way, and then a corresponding liability functionalized another. A Direct Analysis should include maintaining a consistency in functionalization where there is an asset in either Account 182.3 or 186 and offsetting liabilities in either Account 253 or 254.

---

[7] *Id.*

Parties' Positions:

Avista, IPC, NorthWestern, PAC and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "[t]he IOUs agree that BPA should require that accounts that have a corresponding asset and liability account have the same functionalization." IOU Generic Issue List Responses, pg 1, filed February 25, 2009.

PSE's February 25, 2009, Issue List stated that:

> Functionalization of Account 182.3 and Account 254 should reflect the regulatory treatment of such accounts in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to maintain consistency in the functionalization of pension costs in Accounts 182.3 and 254 to the extent that there is a direct relationship between an Account 182.3 asset and an Account 254 liability and each such asset and liability receives the same regulatory ratemaking treatment.
>
> However, the appropriate functionalization of both the Account 182 asset and the Account 254 liability should fall out of the Direct Analysis rather than be constrained by predetermined expectations. Direct Analysis should go beyond just the name or title of the account and reflect the purpose and reason why each account was established. Other than deferred taxes, PSE is unaware of off sets on a particular regulatory asset or liability being booked in opposing accounts. For example, PSE normally nets debits and credits (other than taxes) and books the net in the appropriate asset or liability account.

PSE Generic Issue List Responses, pg. 3, filed February 25, 2009.

BPA Staff advocates the use of consistent decision criteria for common types of regulatory assets and liabilities.

Analysis of Positions:

BPA and the parties agree that asset accounts that have a corresponding liability account should be functionalized consistently.

Decision:

BPA will use consistent decision criteria for common types of regulatory assets and liabilities. This includes Other Regulatory Assets (Account 182.3), Miscellaneous Deferred Debits (Account 186), Other Deferred Credits (Account 253), and Other Regulatory Liabilities (Account 254).

6.1.4. Various Other Regulatory Assets and Liabilities

Statement of Issue:

What should be the functionalization of regulatory assets and liabilities that are not included in rate base by the regulatory authority? What should be the functionalization of the corresponding income statement accounts for the regulatory assets and liabilities that are not included in rate base by the regulatory authority?

Statement of Facts:

Utilities functionalized regulatory assets and liabilities that are not included in the utility's jurisdictional rate base in various ways. Some items in these accounts are included in working capital for ratemaking purposes. BPA is concerned that the treatment of the income statement accounts for the regulatory assets and liabilities are not consistent with the asset and liability treatment for ASC purposes.

For example, PAC and PSE functionalized all regulatory assets and liabilities that are not in their jurisdictional rate base to Distribution/Other. IPC, PGE, and Avista, however, functionalized these same types of costs (i.e., not included in jurisdictional rate base) based on the functional nature of the item.

Parties' Positions:

Avista, IPC, NorthWestern, PAC and PGE's February 25, 2009, Response to BPA's Issue List stated that "[t]here should be consistency between utilities in the functionalization of Regulatory Assets and Liabilities when not included in rate base. Regulatory Assets and Liabilities not included in Rate Base have no effect on the Company's income statement. All entries affect only the balance sheet." IOU Generic Issue List Responses, pg. 3, filed February 25, 2009.

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Functionalization of Other Regulatory Assets and Liabilities not included in rate base should reflect the regulatory treatment of such assets and liabilities in jurisdictional ratemaking.
>
> This issue illustrates an inconsistency that can exist in the Appendix 1 if an account on the balance sheet defaults to Direct Analysis, but the corresponding accounts on the income statement do not. To resolve this inconsistency, BPA should adjust the income statement to directly assign the component related to the balance sheet account. Forcing the balance sheet accounts to conform to the functional method used for the related income statement account is problematic because of the Direct Analysis default of the balance sheet account.
>
> With respect to the functionalization of balance sheet accounts for which the default functionalization is Direct Analysis, the utility should first determine the regulatory treatment of the balance sheet account. If the balance sheet account was directly included in rate base (i.e., the balance sheet account was included in

> rate base but not through the regulated working capital component of rate base calculation) for ratemaking purposes, the utility should further review the specific functional nature of the balance sheet account. If, however, the balance sheet account was either not included directly in rate base for ratemaking purposes or was included only via the regulated working capital calculation, the utility should functionalize the balance sheet account to DIST/Other.

PSE Generic Issue List Responses, pg. 7, filed February 25, 2009.

BPA Staff argues that regulatory assets and liabilities must be included in a utility's jurisdictional rate base in order to be included in rate base for ASC purposes.

Analysis of Positions:

The 2008 ASCM ROD states as follows:

> [t]he Utility must describe the functional nature of the regulatory asset or liability, whether or not the asset or liability is included in rate base by its state commission(s), and the return or carrying costs allowed by the state commission(s). *Under no conditions would regulatory assets be included in ASC at a level greater than regulatory commissions allow them to be recovered in retail rates.*

2008 ASCM ROD at 149 (emphasis added).

As noted previously in the discussion in Section 6.1.2, regulatory assets and liabilities exist in the balance sheets of electric utilities only because of the effects of regulation. Simply because a utility recovers the expense associated with a regulatory asset in rates does not mean that the regulatory asset is also included in the utility's rate base and earning a return.

Regulatory assets and liabilities will eventually be moved from the balance sheet to the income statement through recognition of the revenue or expense. They are only recorded on the utility balance sheets because of regulation. BPA and its customers reviewed revenue and expense accounts in detail during the 2008 ASCM consultation process and the 2008 ASCM has functionalization rules for those accounts. BPA will not change the functionalization of an income statement account as a result of a Direct Analysis on regulatory assets and liabilities.

Decision:

Regulatory assets and liabilities must be included in a utility's jurisdictional rate base in order to be included in rate base for ASC purposes. BPA will not change the functionalization rules of an income statement account as the result of a Direct Analysis of a regulatory asset or liability.

Below are the changes to the line items impacted by the foregoing determinations to IPC's Other Regulatory Assets (182.3), Other Regulatory Liabilities (Account 254), Miscellaneous Deferred Debits (Account 186) and Other Deferred Credits (Account 253) not previously addressed in Issues from Section 4. The tables below list each account as filed in October 2008, followed by adjustments made by BPA in concurrence with the regulatory treatment by the Idaho and/or Oregon State Commissions and the 2008 ASCM.

Table 6.1.4.1: Account 182.3, Other Regulatory Assets ($)
As-Filed October 15, 2008

Other Regulatory Assets (182.3)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement	PTD	12,188,065	5,710,722	2,838,602	4,093,741
Excess Power Deferral	PROD	2,106,816	2,106,816	0	0
Excess Power Amort	PROD	2,992,604	2,992,604	0	0
Security Costs 2003	PTD	68,794	32,233	13,454	23,107
IPUC Grid West Loans	TRANS	745,742	0	745,742	0
OPUC Grid West Loans	TRANS	60,407	0	60,407	0
FERC Grid West Expense	TRANS	302,113	0	302,113	0
Unfunded SFAS 106	PTD	8,006,409	3,751,401	1,565,802	2,689,201
Minor Items	PTD	75,007	35,145	14,669	25,193

Table 6.1.4.2: Account 182.3, Other Regulatory Assets ($)
BPA-Adjusted for Draft Report July 21, 2009

Other Regulatory Assets (182.3)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement	DIST	12,188,065	0	0	12,188,065
Excess Power Deferral	DIST	2,106,816	0	0	2,106,816
Excess Power Amort	DIST	2,992,604	0	0	2,992,604
Security Costs 2003	DIST	68,794	0	0	68,794
IPUC Grid West Loans	DIST	745,742	0	0	745,742
OPUC Grid West Loans	DIST	60,407	0	0	60,407
FERC Grid West Expense	DIST	302,113	0	0	302,113
Unfunded SFAS 106	DIST	8,006,409	0	0	8,006,409
Minor Items	DIST	75,007	0	0	75,007

Table 6.1.4.3: Account 254, Other Regulatory Liabilities ($)
As-Filed October 15, 2008

Other Regulatory Liabilities (254)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement Obligation	PTD	155,313,605	72,772,245	30,374,455	52,166,905

Table 6.1.4.4: Account 254, Other Regulatory Liabilities ($)
BPA-Adjusted for Draft Report July 21, 2009

Other Regulatory Liabilities (254)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement Obligation	DIST	155,313,605	0	0	155,313,605

Table 6.1.4.5: Account 186, Miscellaneous Deferred Debits ($)
As-Filed October 15, 2008

Miscellaneous Deferred Debit Details (186)	Funct Method	Total	Production	Transmission	Distribution
Security Plan	PTD	25,920,430	12,145,027	5,069,221	8,706,183
Company owned life ins	PTD	4,921,300	2,305,877	962,451	1,652,972
Prepaid PeopleSoft/Passport	PTD	51,343	18,875	8,266	24,203

Table 6.1.4.6: Account 186, Miscellaneous Deferred Debits ($)
BPA Adjusted for Draft Report July 21, 2008

Miscellaneous Deferred Debit Details (186)	Funct Method	Total	Production	Transmission	Distribution
Security Plan	LABOR	25,920,430	10,168,172	4,063,432	11,688,826
Company owned life ins	LABOR	4,921,300	1,930,548	771,491	2,219,262
Prepaid PeopleSoft/Passport	LABOR	51,343	20,141	8,049	23,153

Table 6.1.4.7: Account 253, Other Deferred Credits ($)
As-Filed October 15, 2008

Other Deferred Credits (253)	Funct Method	Total	Production	Transmission	Distribution
Postretirement Benefits	PTD	3,030,160	1,419,783	592,604	1,017,773
Dir Def Comp	PTD	4,004,241	1,876,189	783,104	1,344,949

Table 6.1.4.8: Account 253, Other Deferred Credits ($)
BPA-Adjusted for Draft Report July 21, 2009

Other Deferred Credits (253)	Funct Method	Total	Production	Transmission	Distribution
Postretirement Benefits	LABOR	3,030,160	1,188,684	475,025	1,366,452
Dir Def Comp	LABOR	4,004,241	1,570,800	627,727	1,805,714

6.1.5. Account 555, Purchased Power Expenses; Account 447, Sales for Resale; Price Spread

Statement of Issue:

How should book-outs and trading adjustments be treated for calculations of purchased power expense and sales for resale revenue and the price spread calculation? Should the treatment be consistent across utilities?

Statement of Facts:

PAC reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments. "Book-outs" are a netting of simultaneous buy and sell transactions of power between two utilities, where only the net or actual power transferred is shown.

The inclusion of book-outs and trading adjustments in purchased power and sales for resale accounts affects the price spread calculation that BPA uses to calculate a utility's Exchange Period ASC.

<u>Parties' Positions</u>:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, response to BPA's Issue List stated that "[t]he IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread. If Bonneville determines the amounts used to calculate each company's price spread and reported in the FERC Form 1 should be without book-outs the IOUs agree to report and calculate accordingly."

PSE's February 25, 2009, response to BPA's Issue List stated that:

> PSE supports the use of the price spread, and the calculation of the price spread should be the same across all utilities. PSE understands that the objective of the price spread is to reflect the individual utility's experience in the wholesale market. Introducing differences in the calculation from utility to utility introduces more than just market differences and may distort the result when compared across utilities. Such inconsistencies in the data input to the calculation of the price spread should be avoided.

PSE Generic Issue List Responses, pg. 4, filed February 25, 2009.

BPA Staff argues that utilities should not adjust their purchase power and sales for resale for the effects of book-outs and trading adjustments.

<u>Analysis of Positions:</u>

Both BPA and the IOUs support a consistent reporting of purchase power expenses and sales for resale among the exchanging utilities for the determination of price spread.

<u>Decision</u>:

Utilities cannot adjust their purchase power and sales for resale for the effects of book-outs and trading adjustments.

6.1.6. ASC Forecast Model: New Plant Additions – Natural Gas Prices

<u>Statement of Issue:</u>

Should BPA adopt a common natural gas price forecast in the ASC Forecast Model for all new natural gas-fired plant additions?

<u>Statement of Facts:</u>

Forecasted natural gas prices vary significantly between utilities that have new natural gas-fired generating resources coming on-line after the Base Period. None of the utilities submitted documentation or copies of firm natural gas supply contracts to support their projected natural gas prices.

The primary informational basis of the ASCM is the use of utility-specific FERC Form 1 historical data for IOUs and similar data for COUs. Use of utility-specific forecast data is consistent with this approach.

Parties' Positions:

Avista, IPC, PGE, PacifiCorp and NWE's February 25, 2009, response to BPA's Issue List stated that:

> The IOUs propose that it is reasonable to use a third party gas price forecast in the determination of an exchanging utility's ASC. The IOUs believe that the third party gas price forecast that BPA uses would be appropriate or another publicly available gas price forecast. In addition, if a given exchanging utility desires to use a different gas price for their new resource it is understood that they will have to supply all necessary data in support of their alternative gas price forecast.

IOU Generic Issue List Responses, pg. 2, filed February 25, 2009.

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Natural gas price forecasts should reflect the regulatory treatment of natural gas price forecasts in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to use a third party gas price forecast for the gas commodity component of fuel cost. If BPA were to use such a third party gas price forecast, BPA should then reflect basis or hub differences as adjustments to this commodity price. BPA should also make adjustments for firm gas transportation costs on a utility-by-utility, resource-specific basis. These transportation cost adjustments would reflect the extent to which firm gas transportation contracts are in place for the specific new resource. In some cases, however, jurisdictional or cost differences may render a third party gas price forecast insufficient. If BPA were to use a third party gas price forecast, such third party gas price forecast should be a default from which a utility could opt out.

PSE Generic Issue List Responses, pg. 5, filed February 25, 2009.

The OPUC March 3, 2009, response to BPA's Issue List recommended that BPA use:

> [t]he natural gas forward market prices existing at the time of utility filings for nearest available Hub, such as Sumas, to account for the average commodity cost of fuel for new natural gas generating resources unless a utility demonstrates other commodity contractual prices for its new resource(s). This would have the affect of removing BPA and utility guesses when accounting for the commodity cost of fuel for new natural generating resources. Natural gas market price forecasts are by their very nature tenuous.

OPUC Generic Issue List Response, pg. 1, filed March 3, 2009.

The OPUC also recommended:

> That BPA add charges for pipeline transportation and any other known fuel related charges to this commodity cost of fuel. In this regard, utilities include both fixed (Reservation) and variable pipeline charges in their Account 547, Other Power – Fuel. It should be recognized pipeline charges calculated on a unit basis, for instance dollars per MMBtu, vary with capacity factor. For example, Northwest Pipeline's tariff currently shows a maximum reservation charge of about 38 cents per MMBTU/day firm receipt/delivery capacity. If a utility plant having firm pipeline transportation for all of its maximum daily operation normally operates at 25 percent, then this pipeline charge equates to an average cost of $1.52 per delivered MMBTU (38 cents at full operation divided by 25 percent actual operation). So, when accounting for new resource other power fuel costs, BPA should also utilize pipeline tariffs in deriving the pipeline cost of transporting natural gas fuel from hub to plant gate along with plant capacity information unless a utility demonstrates other contractual pipeline charges.

OPUC Generic Issue List Response, pg. 1, filed March 3, 2009.

The OPUC March 10, 2009, response to issues reiterated the above statements and stressed that whatever forecast was chosen should be available to parties through discovery in order to allow the parties to consider the reasonableness of the forecast. OPUC Generic Issue List Response, pg. 1, filed March 10, 2009.

Snohomish supports a common natural price forecast that is used in the ASC Forecast Model. Snohomish would support the use (by BPA) of third-party forecasting for natural gas prices, rather than a BPA Staff projection. SNOPUD Issue List Response to BPA, Issue 12.

<u>Analysis of Positions:</u>

All of the responding parties supported the option of adopting a common natural gas price forecast in the ASC Forecast Model for all new natural gas-fired plant additions. The parties suggested that an independent third party should supply the natural gas forecast.

The parties also supported the principle that the natural gas price forecast should include adjustments for basis or hub differences, and adjustments for firm gas transportation costs on a utility-by-utility, resource-specific basis.

All parties contended that the use of a third-party gas price forecast should not preclude a utility from using its own forecast.

BPA agrees with the parties that a common natural gas price forecast would be reasonable. To that end, BPA considered using several commercially-available natural gas price forecasts. Unfortunately, the commercially-available forecasts are proprietary. Generally, the companies that provide these forecasts do not allow BPA to provide these forecasts to companies that do not subscribe to their services.

It is equally important that the costs included in the calculation of utility ASCs be consistent with the costs included in the calculation of the PF Exchange rate. Using the natural gas price forecast used to develop BPA's rates achieves this consistency. In addition, it allows all parties to BPA's rate case to examine and critique the forecast.

Decision:

BPA will use the natural gas forecast used in the 2010 BPA Rate Case Wholesale Power Rate Final Proposal for new gas-fired resources in the ASC Forecast Model.

6.1.7. ASC Forecast Model – Capacity Factors

Statement of Issue:

Whether BPA should use common representative capacity factors in the ASC Forecast Model for estimating the operating costs and expected energy output for new plant additions.

Statement of Facts:

When submitting a new resource addition for consideration in the ASC Review Process, utilities must submit a projected capacity factor for the new resource. The submitted projected capacity factors, however, varied significantly between utilities for similar types of new resources.

Parties' Positions:

PSE's February 25, 2009, response to BPA's Issue List stated that:

> Capacity factors for specific new resources should reflect the regulatory treatment of capacity factors in jurisdictional ratemaking.
>
> In calculating ASCs, it may sometimes be appropriate for BPA to use common, representative capacity factors in the ASC Forecast model. In some cases, however, jurisdictional or cost differences may render common, representative capacity factors insufficient. If BPA were to use common, representative capacity factors, such common, representative capacity factors should be a default from which a utility could opt out.

PSE Generic Issue List Responses, pg. 6, filed February 25, 2009.

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, response to BPA's Issue List stated that:

The IOUs propose that they will use a capacity factor within the range of capacity factors listed below for new resources coming online during the rate period.

Resource Type	Capacity Factor
Combined Cycle CT	45% to 75%

Simple Cycle CT	1% to 30%
Wind	25% to 45%
Geothermal	greater than 90%

Again, it is understood that if a utility chooses to use capacity factor outside the above range for a given new resource that utility will have to supply complete justification for such capacity factor.

Analysis of Positions:

After discussing this issue with the parties, BPA has decided to use the capacity factors submitted by the utilities for determining the capacity factors for new resources coming on-line during the FY 2010-2011 ASC Exchange Period. This decision to use the utilities' filed capacity factors, however, will be subject to further review in future ASC Review Processes. BPA is deferring this decision so that it can devote more time to this complex issue. Developing representative projected capacity factors for new resources is not a trivial exercise. For new natural gas-fired resources, projected stream flows, electric market prices, natural gas prices and heat rates must be analyzed before representative capacity factors can be developed. For projected wind resources the Pacific Northwest region is just beginning a major expansion of a resource with little historical data to use as a benchmark for developing representative capacity factors. BPA believes this issue should be deferred to future ASC filings to develop more robust estimates of projected capacity factors for new resources.

BPA's decision to use the utilities' submitted capacity factors is also influenced by the fact that several utilities submitted revised capacity factors, which reduced the variance in capacity factors for new generating resources. Partly for this reason, it is reasonable to accept utilities' respective as-filed capacity factors in establishing FY 2010-2011 ASCs.

Decision:

The capacity factors submitted by each utility will be accepted for this FY 2010-2011 Review Process. BPA, however, makes no precedential decision at this time. The issue will be revisited in future ASC filings.

6.2. ASC FORECAST MODEL: New Resource Additions during FY 2010-2011

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

6.3. ASC Forecast Model Calculates the Contract System Cost: Depreciation and Purchased Power

Under the 2008 ASCM, the BPA-approved Base Period costs are escalated to the midpoint of the rate period/Exchange Period to calculate Exchange Period ASCs. For a two year rate period the costs are escalated to the midpoint for a 2-year rate period/Exchange Period

To accomplish this, the ASC Forecast Model calculates the Contract System Cost at the start of the rate period, October 1, 2009, and the end of the rate period, September 30, 2011. The midpoint ASC is then calculated as the average of the start of rate period and end of rate period Contract System Costs, divided by the average of the start of rate period and end of rate period Contract System Loads.

The ASC Forecast Model uses a similar method to calculate the short-term (ST) purchased power expense included in Contract System Cost. Purchased power expense for the first year of the Exchange Period, FY 2010, is calculated by multiplying the amount of ST MWh purchases for FY 2010 by the utility's FY 2010 purchase price. Purchased power expense for the second year of the Exchange Period, FY 2011, is calculated by multiplying the amount of ST MWh purchases for FY 2011 by the utility's FY 2011 purchase price. The purchased power expense included in the calculation of the midpoint ASC is the average of the FY 2010 and FY 2011 purchased power expense. At the same time, the ASC Forecast Model calculates a weighted average purchased power price for the rate period.

When the exchanging utilities submitted their Appendix 1 filings in October 2008, they provided their forecasts of major new resource additions, including all associated costs. For new resources forecast to come on-line during the Exchange Period, all new resource costs except depreciation expense were included at the midpoint of the Exchange Period, October 1, 2010. To calculate the change in ST purchased power expense resulting from new generating resources or new purchased power contracts, the amount of ST power purchases for FY 2011 was decreased by the amount of MWH forecast to be provided by the new generating resource or purchased power contract. A new average 2-year average of ST purchased power MWhs was then calculated. The new 2-year MWh value was multiplied by the 2-year weighted average purchased power price calculated above to get the new ST purchased power cost included in Contract System Cost.

During the ASC Review Process, BPA examined how the costs of new resources added during the rate period were being included in a Utility's Contract System Cost. Further analysis revealed that, by using a new 2-year average of ST MWh purchases, only half of the reduction in purchased power expense was being removed from Contract System Cost. However, with the exception of the new resource's depreciation expense, the ASC Forecasting Model was including a full year's cost for the new generating resource or purchased power contract. To address this inconsistency, BPA determined that it would be more appropriate to include a full year's change in Contract System Cost resulting from new generating resources or purchased power contracts.

In order to capture the total reduction in purchased power expense, BPA revised the method to calculate ST purchased power expense when a new generating resource is added. Under the revised method, the forecast MWhs provided by the new resource are multiplied by the FY 2011 purchased power price to get the reduction in ST purchased power expense resulting from adding the new resource. This method assures that the entire reduction in purchased power expense is captured in Contract System Cost. BPA also included the new resource's full year depreciation expense in Contract System Cost in order to capture all the changes in cost resulting from adding new resources during the rate period/Exchange Period.

7. FY 2010-2011 ASC

Including all changes made to IPC's Appendix 1 filing, BPA decreased IPC's CY 2007 ASC by $0.88/MWh and decreased IPC's FY 2010-2011 ASC by $3.54/MWh. IPC's ASC for FY 2010-2011 is $35.65/MWh.

8. REVIEW SUMMARY

The FY 2010-2011 ASC Review Processes are complete with the publication of the Final ASC Reports. BPA requested and reviewed comments on the Draft ASC Reports of all other exchanging utilities for FY 2010-2011. After review of such comments, BPA completed final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2010-2011.

BPA has resolved the issues set forth in Sections 4, 5, and 6 of this report in accordance with the 2008 Average System Cost Methodology (ASCM) and with generally accepted accounting principles. BPA believes the information and analysis contained herein properly establish the Average System Cost of IPC for FY 2010-2011.

This Final ASC Report is BPA's determination of IPC's FY 2010-2011 ASC based on the information and data provided by IPC, including comments in response to the Draft ASC Reports, and based on the professional review, evaluation, and judgment of BPA's REP staff.

9. ADMINISTRATOR'S APPROVAL

I have examined Idaho Power Company'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 this ASC determination conforms to the 2008 ASC Methodology and generally accepted accounting principles, and fairly represents Idaho Power Company's ASC.

Issued in Portland, Oregon this 14th day of July, 2009**.**

/s/ Stephen J. Wright

Administrator

This page intentionally left blank.

This page intentionally left blank.