FY 2009 AVERAGE SYSTEM COST DRAFT REPORT

FOR

Idaho Power Company

Docket Number: ASC-09-IP-01
Effective Date: October 1, 2008

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

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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)
- Idaho Power Company (IPC)
- 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 (Snohomish)

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 2006

Effective Exchange Period: FY 2009 (October 1, 2008 – September 30, 2009)

Statement of Purpose:
Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine IPC's ASC for FY 2009 based on BPA's 2008 ASC Methodology (ASCM). This Draft Report describes the process, evaluation, and initial results of BPA's ASC review. After reviewing parties' comments on this Draft Report, BPA will publish a Final Report in June, 2009.

NOTE: If the filing utility or an intervenor wishes to preserve any issue regarding BPA's ASC Reports for subsequent administrative or judicial appeal, they must raise such issue in their comments on BPA's Draft ASC Reports. If a party fails to do so, the issue will 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 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 Annual Reports, including 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) 2006.

The table below summarizes CY 2006 Base Period ASC based on (1) the ASC information filed by IPC on October 1, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process. This table does not reflect Exchange Period ASC, which is noted in subsequent tables.

Table 2.1: CY 2006 Base Period ASC
(Results of Appendix 1 calculations)

	October 1, 2008 As Filed	**April 13, 2009 Draft Report**
Production Cost	$404,130,168	$404,807,767
Transmission Cost	$94,384,838	$89,497,636
(Less) NLSL Costs	($21,145,238)	($24,934,112)
Contract System Cost	$447,369,767	$469,371,290
Total Retail Load (MWh)	13,939,314	13,939,314
(Less) NLSL	(385,440)	(385,440)
Total Retail Load (Net of NLSL)	13,553,874	13,553,874
Distribution Losses	961,813	961,813
Contract System Load	14,515,687	14,515,687
CY 2006 Base Period ASC ($/MWh)	**32.89**	**32.34**

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 2009). The forecast covers the period from the end of the Base Period (December, 2006) to the end of the Exchange Period (September, 2009). 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 2009).

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 1, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process.

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

As-Filed FY 2009 Exchange Period ASC				
Resource	**Danskin**	**N/A**	**N/A**	**N/A**
Expected On-Line Date	March 2008			
Delta*	**1.01**			

Draft Report FY 2009 Exchange Period ASC				
Resource	**Danskin**	**N/A**	**N/A**	**N/A**
Expected On-Line Date	March 2008			
Delta*	**0.88**			

*The Delta is the incremental change in the ASC as the new resources come on line. Danskin meets the minimum materiality threshold of 2.5 percent. See Section 5.6 for details.

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

As-Filed FY 2009 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

Draft Report FY 2009 Exchange Period ASC				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On-Line Date				
Delta*				

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

2.3. FY 2009 Exchange Period ASC for the Draft Report

The following table identifies the Exchange Period ASC as filed on October 1, 2008, and as-adjusted by BPA for this Draft 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 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 2009 ASC ($/MWh)
Prior to New Resource Additions

Date	October 1, 2008 As-Filed	April 13, 2009 Draft Report
FY 2009	34.60	33.43

The as-filed Appendix 1 Filing, including the ASC Forecast Model and supporting documentation submitted by IPC, can be viewed at BPA's Residential Exchange Program (REP) website: **http://www.bpa.gov/corporate/finance/ascm/filings.cfm**.

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 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. *See generally* 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 discretionary 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.

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 September 30, 2008, the Commission granted interim approval to BPA's 2008 ASCM.

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. <u>ASC Review Process - FY 2009</u>

Under the 2008 ASCM, utilities' ASCs are generally established prior to the calculation and payment of REP benefits. The ASC Review Process for FY 2009, however, has occurred during the Exchange Period in which the as-filed ASC is in effect. This is because the 2008 ASCM was completed in June 2008, which did not allow the ASC Review Process to occur and establish final utilities' ASCs until after FY 2009 had begun. Therefore, the REP for FY 2009 is implemented based on as-filed ASCs, and payments are then trued up for the final ASCs determined by BPA. In the future, the ASC Review Process will occur before the beginning of the Exchange Period.

On October 1, 2008, exchanging utilities submitted ASC filings for the FY 2009 Exchange Period. The as-filed ASCs went into effect on an interim basis at that time and will be trued-up based on the results of the respective ASC Final Reports, which are scheduled for publication in June, 2009. All data were submitted using two Excel-based models: the Appendix 1 and the ASC Forecast Model. Additional 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 2009 (October 1, 2008, through September 30, 2009), the Base Period (CY 2006) ASC is first calculated using the Appendix 1.

BPA then uses the ASC Forecast Model to escalate the Base Period ASC forward to the effective Exchange Period. The Base Period and Forecast 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 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 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 September 30, 2008. Parties had a full and complete opportunity to intervene in BPA's ASC Review Processes and to submit comments on the utilities' ASC filings. The Review Processes for FY 2009 ASCs are still in progress at this publication date. Upon completion of the formal reviews and final ASC determinations, BPA will publish, in June 2009, Final Reports for each participating utility.

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. <u>Explanation of Schedules</u>

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which 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.

The resulting Total 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 Total Rate Base. 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.

3.3.2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the FERC Form 1, 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 on 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.

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 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. 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 NLSL, pursuant the 2008 ASCM. The CSL is the denominator in calculating ASC.

3.3.8. 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.

3.3.9. Purchased Power and Sales for Resale

Purchased Power is an Account of 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. 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.

3.3.10. 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 <u>all</u> post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

NLSLs and the associated costs to serve them are not included in utilities' ASCs.

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 (CY 2006) ASC data forward to the Exchange Period, which in this case is FY 2009. 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 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.

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 fiscal year for the FY 2009 Exchange Period to calculate Exchange Period ASCs. 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.

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. 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, all resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period. 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. BPA uses the method outlined in the 2008 ASCM, Section IV, *Rules for Determining Exchange*, Subsection D.

4. REVIEW OF THE ASC FILING

Pursuant to 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. 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 amendment or refinement of determinations made herein when addressed in future ASC reviews.

4.1. Identification and Analysis of Issues from BPA Issue List

BPA raised the following issues during the ASC Review Process, and IPC submitted responses. No other party raised or commented on IPC's responses. Each issue pertains to the October 1, 2008, filing unless otherwise noted.

Although a utility's State regulatory bodies or FERC may allow a particular functionalization to a specific account, this does not require that BPA will follow the same functionalization for the same account in calculating a utility's ASC. BPA retains the discretion to make an independent determination of the appropriateness of inclusion or exclusion of particular costs, as well as the functionalization method used in the calculation of that cost, in conformance with the 2008 ASCM.

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..

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 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+ and Passport/PeopleSoft systems."

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

When a direct analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts.

Account 303 also affects software costs in other accounts in Schedule 1, *Rate Base* (Amortization Reserve), and Schedule 3, *Expenses* (Amortization of Intangible Plant, Account 404). The functionalization must be the same in all accounts.

Summary of Parties' Positions:

IPC included CIS+ and General software 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+ 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.

Section VIII of the 2008 ASCM permits Direct Analysis only for specified accounts. 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.

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.

Under Section VII 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 General Software's purposes for this account, and therefore the applicability and justification of the functionalization to PTD.

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

<u>Draft Decision</u>:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software and will adjust the functionalization of General Software to the default of distribution (DIST). Furthermore, BPA will adjust the functionalization of CIS+ software to distribution (DIST).

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

CIS+ Software

	Total	Production	Transmission	Dist/Other
As-Filed	19,731,424	9,531,939	3,632,232	6,567,252
BPA Adjusted	19,731,424	0	0	19,731,424

General Software

	Total	Production	Transmission	Dist/Other
As-Filed	30,055,876	14,519,519	5,532,795	10,003,562
BPA Adjusted	30,055,876	0	0	30,055,876

4.2.2. Amortization Reserve, Amortization of Other Utility 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 reserves of software costs located in Accounts 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 this account is direct analysis with a default to distribution.

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+ and Passport/PeopleSoft systems."

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

When a direct analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts.

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

<u>Summary of Parties' Positions:</u>

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

<u>Analysis of Positions:</u>

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+ 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.

Section VIII of the 2008 ASCM permits Direct Analysis only for specified accounts. 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.

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.

Under Section VII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. The lack of additional information from IPC did not allow a clear understanding of the General Software's purposes for this account, and therefore the applicability and justification of the functionalization to PTD.

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

Draft Decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software and will adjust the functionalization of amortization reserves of General Software to the default of distribution (DIST). Furthermore, BPA will adjust the functionalization of amortization reserve of CIS+ software to distribution (DIST).

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

		CIS+ Software		
	Total	**Production**	**Transmission**	**Dist/Other**
As-Filed	17,081,318	8,251,715	3,144,391	5,685,212
BPA Adjusted	17,081,318	0	0	17,081,318

		General Software		
	Total	**Production**	**Transmission**	**Dist/Other**
As-Filed	18,979,873	9,168,877	3,493,884	6,317,112
BPA Adjusted	18,979,873	0	0	18,979,873

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

Statement of Issue:

Whether IPC can include SFAS 109, Regulatory Unfunded Accumulated Deferred Income Tax, in its 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.

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

In Data Response BPA-IP-07, 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.

Summary of 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.

Draft 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 (DIST).

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

	Total	Production	Transmission	Dist/Other
As-Filed	343,589,654	165,982,736	63,249,234	114,357,683
BPA Adjusted	343,589,654	0	0	343,589,654

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.

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-08, IPC defines this account as one that "records unrealized gains or losses on derivative instruments, which are primarily used for acquiring fuel and electricity."

Summary of 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 20, 2009, response to the ASC Issue List, Item 6, IPC stated that it accepts functionalization to distribution (DIST) for this item.

Draft Decision:

IPC's LT&ST Mark to Market will not be allowed in ASC. BPA will adjust the functionalization of LT&ST Mark to Market to the default of distribution (DIST).

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

	Total	Production	Transmission	Dist/Other
As-Filed	1,462,637	706,577	269,248	486,813
BPA Adjusted	1,462,637	0	0	1,462,637

4.2.5. Account 182.3, Other Regulatory Assets: Professional Fees and Minor Items.

Statement of Issue:

Whether Professional Fees and Minor Items should be included in 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.

IPC included Professional Fees and Minor Items in ASC and functionalized them to PTD.

In Data Response BPA-IP-07, IPC defines the Professional Fees account as one that was established to amortize professional fees paid to experts to participate in three rate cases. IPC defines the Minor Items as Intervenor Funding relating to the 2005 General Rate Case (Case No. IPC-05-28).

In Rate Order 29505, the IPUC allowed IPC to recover the expense and amortize the Professional Fees (*see* ORDER No. 29505 at 26-27). The IPUC did not allow IPC to include Professional Fees in rate base or receive a return on investment.

In Rate Order 30035, the IPUC allowed IPC to recover the expense on of Minor Items, Intervenor Funding (*see* ORDER No. 30035 at 8-9). The IPUC did not allow IPC to include Intervenor Funding in rate base or receive a return on investment.

Under the 2008 ASCM, exchanging utilities are required to conduct a direct analysis of regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. 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). 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.

Summary of Parties' Positions:

IPC included Professional Fees and Minor Items in rate base for ASC determination and functionalized them to PTD.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 7, IPC identified Professional Fees and Minor items as costs attributed to work in its general rate cases.

IPC clarified the Professional fees "are a result of bringing in consulting expertise to the Company to perform various tasks. These are not fees assessed by a regulatory commission." (Issue List, Item 7.) It is IPC's position that Professional Fees should be functionalized as LABOR.

IPC further contends that a standard method should be applied (PTD or LABOR) for the functionalization of Minor Items.

Section 4.10.4 of the 2008 ASCM ROD provides that 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.

Furthermore, the 2008 ASCM is independent of State Commission determinations and is not required to follow the same functionalization methodology as the Idaho Commission. Although the Commission may allow certain costs in rate treatment, this does not require the ASCM to do the same.

Because Professional Fees and Other Minor Items receive rate treatment, but are not allowed in rate base by the Idaho of Oregon Commissions, they should not be allowed in rate base for ASC purposes.

Draft Decision:

Professional Fees and Minor Items will not be allowed in rate base for purposes of ASC determination. For rate base, BPA will adjust Professional Fees and Minor Items and functionalize to distribution (DIST).

Table 4.2.5: Account 182.3 Other Regulatory Assets
Professional Fees ($)

	Total	Production	Transmission	Dist/Other
As-Filed	21,246	10,264	3,911	7,071
BPA Adjusted	21,246	0	0	21,246

Minor Items ($)

	Total	Production	Transmission	Dist/Other
As-Filed	33,969	16,410	6,253	11,306
BPA Adjusted	33,969	0	0	33,969

4.2.6. 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.

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

In Data Response BPA-IP-07, 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. 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, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts.

Summary of Parties' Positions:

IPC originally included Idaho DSM in rate base and functionalized to PTD. IPC would accept BPA's reallocation to production (PROD).

Analysis of Positions:

In a February 20, 2009, response to the ASC Issue List, Item 8, IPC supports re-allocation of DSM account to PROD, based on BPA's initial assessment.

Under the 2008 ASCM, exchanging utilities are required to conduct a direct analysis of regulatory assets so the individual items included in regulatory assets or liabilities can be properly functionalized and included in the calculation of ASC. 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). 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.

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.

Draft Decision:

Without additional documentation from IPC, BPA is unable to justify the use of the PTD or PROD ratios for DSM in Regulatory Assets, and will adjust the functionalization of the Idaho DSM to the default of distribution (DIST).

Table 4.2.6: Account 182.3, Other Regulatory Assets
Idaho DSM ($)

	Total	Production	Transmission	Dist/Other
As-Filed	11,349,143	5,482,592	2,089,192	3,777,360
BPA Adjusted	11,349,143	0	0	11,349,143

4.2.7. Account 186, Miscellaneous Deferred Debits, Prepaid PeopleSoft/Passport Software

Statement of Issue:

Whether IPC's direct analysis supports the use of PTD to functionalize the Prepaid PeopleSoft/Passport software cost.

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.

IPC included Prepaid PeopleSoft/Passport software in rate base and functionalized it using the PTD ratio.

In Data Response BPA-IP-09, IPC defined this software as related to miscellaneous contracts utilizing a PeopleSoft subsystem, including IT software maintenance contracts, and several other miscellaneous Admin-related contracts.

When a direct analysis is used, there must be a clear description and justification for the functionalization of all accounts and sub-accounts.

Summary of Parties' Positions:

IPC functionalized Prepaid PeopleSoft/Passport software using the PTD ratio.

Analysis of Positions:

In a February 20, 2009, response to the ASC Issue List, Item 9, IPC defines the use of PeopleSoft as "the Company's GL, tracking all of the Company's assets including Generation facilities, Transmission facilities, etc. Passport includes functionality to assist with payroll, purchasing, inventory (for generation, transmission, distribution, etc). The two software tools have too many functions to identify."

IPC supports a similar treatment for these systems across all facilities.

The 2008 ASCM is independent of State Commission ratemaking determinations and is not required to follow the same functionalization methodology as the Idaho Commission. Although the Commission may allow certain costs in rate treatment, this does not require the ASCM to do the same.

Based on the description of the PeopleSoft/Passport software, it relates to labor and not capital expenditures; as such, it should be functionalized using the Labor ratio.

Draft Decision:

BPA will adjust the functionalization of the Prepaid PeopleSoft software using the Labor ratio.

Table 4.2.7: Account 186, Miscellaneous Deferred Debits
Prepaid PeopleSoft Software ($)

	Total	Production	Transmission	Dist/Other
As-Filed	95,586	46,176	17,596	31,814
BPA Adjusted	95,586	37,012	15,264	43,310

4.2.8. Account 186, Miscellaneous Deferred Debits: Minor Items and Job Orders

Statement of Issue:

Whether IPC is justified in including the following Minor Items & Job Orders in its ASC.

CIS+
Allow Bad Debt
Cust Service Financing Prog
Allow Bad Debt – Cust Serv
Shelf Registration
Valmy PP

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.

IPC completed a direct analysis on these items and functionalized all to PTD. Its supporting documentation does not provide complete details of the items nor does it justify production or transmission costs.

In a February 20, 2009, response to the ASC Issue List, Item 10, IPC stated that the items in this account are below a significant dollar amount and, therefore, a functionalization process for each individual item would be inefficient.

When direct analysis is used, there is a requirement for a clear description and justification for the functionalization of all accounts and sub-accounts.

Summary of Parties' Positions:

IPC included the above listed Minor Items & Job Orders and functionalized using the PTD ratio.

Analysis of Positions:

IPC would prefer PTD functionalization applied to the account, as the items included support all of the Company's functions. There are no items of a value large enough to impact Idaho Power's ASC on any significant level.

IPC did not provide supporting documentation to justify functionalizing Minor Items & Job Orders using the PTD ratio.

Under 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 Minor Items' & Job Orders' purposes for this account, and therefore the applicability and justification of the functionalization to PTD.

Because IPC did not include additional supporting information of these line items, it can not justify including any line item in ASC.

Draft Decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio and will adjust the functionalization of the Minor Items & Job Orders to the default of distribution (DIST).

Table 4.2.8: Account 186, Miscellaneous Deferred Debits
Minor Items & Job Orders
($000s)

	Total	Production	Transmission	Dist/Other
As-Filed	46,896	22,655	8,633	15,608
BPA Adjusted	46,896	0	0	46,896

4.2.9. Account 253, Other Deferred Credits: City of Eagle Franchise Fees

Statement of Issue:

Whether the "City of Eagle" franchise fees can 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.

IPC included City of Eagle franchise fees in ASC and functionalized using the PTD ratio.

In Data Response BPA-IP-10, IPC described the account as representing amounts collected from the City of Eagle thru franchise fees for construction of underground distribution lines. The amounts are the revenues generated from the Franchise Fee, assessed by the City of Eagle, Idaho, to IPC's customers within that municipality.

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.

Summary of Parties' Positions:

IPC included City of Eagle franchise fees in ASC and functionalized using the PTD ratio.

Analysis of Positions:

IPC contends that this is a liability account showing that the Company owes the City of Eagle for Transmission-related investment. IPC suggests a change from PTD to Transmission.

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.

Draft Decision:

"City of Eagle" franchise fees will not be allowed in ASC. BPA will adjust this account and functionalize to the default of distribution (DIST).

Table 4.2.9: Account 253, Other Deferred Credits
City of Eagle Franchise Fees ($)

	Total	Production	Transmission	Dist/Other
As-Filed	53,437	25,815	9,837	17,786
BPA Adjusted	53,437	0	0	53,437

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

Statement of Issue:

Whether 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.

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

In Data Responses BPA-IP-11 and BPA-IP-07, IPC defined Regulatory Unfunded Accumulated Deferred Income Tax under SFAS 109as 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.

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.

Summary of 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.

Draft Decision:

Regulatory Unfunded Accumulated Deferred Income Tax will not be included in ASC. BPA will adjust this account and functionalize to the default of distribution (DIST).

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

	Total	Production	Transmission	Dist/Other
As-Filed	41,825,257	20,205,121	7,699,346	13,920,790
BPA Adjusted	41,825,257	0	0	41,825,257

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

Statement of Issue:

Whether IPC correctly functionalized 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.

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

In Data Response BPA-IP-11, IPC functionalized these revenues to "support analysis and implementation of new DSM programs." The specific language is as follows:

> <u>DSM RIDER, ID:</u> The IPUC 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 was increased to 2.5% in order 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.
>
> <u>DSM RIDER, OR:</u> 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-28, 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.

When direct analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts.

<u>Summary of Parties' Positions:</u>

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

<u>Analysis of Positions:</u>

In a February 27, 2009, response to the ASC Issue List, Item 13, IPC supports re-allocation of DSM Rider ID and DSM Rider OR to PROD.

The 2008 ASCM allows all conservation expenses to be functionalized to production. However, the 2008 ASCM does not allow return on regulatory assets that are not allowed by State Commissions in rate base. Section 4.10.1 of the 2008 ASCM ROD provides that 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. 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 functionalization to production, further analysis determined this account does not represent expense items but rather the revenues recovered from customers for these conservation programs.

IPC did not provide supporting rate order language to justify the inclusion of this account for regulatory accounting.

Upon further evaluation of this regulatory account, 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 functionalize to the default of distribution.

Draft Decision:

BPA is unable to justify the use of the PTD or PROD 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 (DIST).

Table 4.2.11: Account 254, Other Regulatory Liabilities
DSM Rider ID ($)

	Total	Production	Transmission	Dist/Other
As-Filed	5,934,462	2,866,845	1,092,437	1,975,180
BPA Adjusted	5,934,462	0	0	5,934,462

DSM Rider OR ($)

	Total	Production	Transmission	Dist/Other
As-Filed	393,731	190,205	72,479	131,046
BPA Adjusted	393,731	0	0	393,731

4.2.12. Account 254, Other Regulatory Liabilities: Emission Sales Interest Idaho

Statement of Issue:

Whether Emission Sales Interest ID 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.

IPC included Emission Sales Interest ID in ASC and functionalized it to production (PROD).

In data response BPA-IP-11, IPC described this item as Emission Sales Interest ID: "The balance in this account represents the tax portion of the Idaho Jurisdiction surplus emission allowance sales." However, for this same line item, IPC then described the regulatory treatment as the "Interest on the sale of the Company's emissions credits is provided to the Company's customers through its annual Power Cost Adjustment (PCA) mechanism."

IPC did not provide supporting rate order documentation to justify the inclusion of this account for regulatory accounting.

During the review process, BPA noted that the data response statements appeared to be in conflict with each other. In addition, the purpose of the liability was unclear. As a result, IPC responded in the February 27, 2009, ASC Issue List, Item 14, and clarified that this account "captures additional refunds to customers for the sale of emission credits through the Company's Power Cost Adjustment mechanism."

Summary of Parties' Positions:

IPC functionalized Emission Sales Interest ID to production (PROD).

Analysis of Positions:

IPC responded in a February 27, 2009, ASC Issue List, Item 14, and clarified that this account "captures additional refunds to customers for the sale of emission credits through the Company's Power Cost Adjustment mechanism."

IPC 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 4.10.4 of the 2008 ASCM ROD provides that 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. It is BPA's position that regulatory liabilities receive similar treatment as regulatory assets.

Under Section VII of the 2008 ASCM, utilities are responsible for supporting their proposed functionalizations of costs. Because IPC did not provide documentation showing that the Emission Sales Interest is allowed by the State Commission in rate base, BPA will not allow it in ASC rate base and will functionalize it to the default of distribution.

Draft Decision:

BPA will adjust Emission Sales Interest ID and functionalize it to the default of distribution (DIST).

Table 4.2. 12: Account 254, Other Regulatory Liabilities
Emission Sales Interest Idaho ($)

	Total	Production	Transmission	Dist/Other
As-Filed	27,025,013	13,055,357	4,974,863	8,994,793
BPA Adjusted	27,025,013	0	0	27,025,013

4.2.13. Account 254, Other Regulatory Liabilities: Other Deferred Credit – Power Cost Adjustment

Statement of Issue:

Whether IPC correctly functionalized Other Deferred Credit – PCA (Power Cost Adjustments) 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.

IPC included Other Deferred Credit – PCA in ASC and functionalized it to PTD.

In Data Response BPA-IP-11, IPC stated that this account was set up to conform to GAAP reporting requirements in the event a Regulatory Asset – 182.3 has a credit balance, in order to re-class that balance on a quarterly basis to a Regulatory Liability.

IPC did not provide supporting rate order documentation to justify the inclusion of this account for regulatory accounting.

Under 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. 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). 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. It is BPA's position that regulatory liabilities receive similar treatment as regulatory assets.

Summary of Parties' Positions:

IPC functionalized Other Deferred Credit – PCA to PTD.

Analysis of Positions:

In a February 20, 2009, response to the ASC Issue List, Item 15, IPC repeated its data response in that "this account was set up to conform to GAAP reporting requirements in the event a Regulatory Asset – 182.3 has a credit balance, to re-class that balance on a quarterly basis to a Regulatory Liability."

The 2008 ASCM states that 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. It is BPA's position that regulatory liabilities receive similar treatment as regulatory assets.

The lack of supporting rate order documentation from IPC did not allow a clear justification for the functionalization of Other Deferred Credit – PCA using the PTD ratio.

Draft Decision:

BPA will adjust Other Deferred Credit – PCA and functionalize it to the default of distribution (DIST).

Table 4.2.13: Account 254, Other Regulatory Liabilities
Other Deferred Credit-PCA ($)

	Total	Production	Transmission	Dist/Other
As-Filed	-11,851,702	-5,725,370	-2,181,704	-3,994,627
BPA Adjusted	-11,851,702	0	0	-11,851,702

4.2.14. Account 111, Amortization Reserves of Intangible Plant

Statement of Issue:

Whether IPC's direct analysis of this account is justified for all line items.

Statement of Facts:

IPC places costs for Amortization of Intangible Plant into Amortization of Other Utility Plant. However, IPC states "…intangible plant is excluded from this account."

The issue is whether or not Intangible Plant is included in Account 111. If not included in this account, where is the amortization of Account 303, including American Falls Dam Rebuild and all software accounts?

Summary of Parties' Positions:

IPC completed a direct analysis on this account and functionalized all costs using the PTD ratio.

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 16, IPC stated that the data response it supplied was in error and this account includes the accumulation of amortization expense on intangible plant. Retirements for intangible plant are processed against this account.

Draft Decision:

BPA is satisfied with IPC's response and considers the issue resolved. The clarification has no impact on ASC.

4.2.15. Account 123.1 Investment in Associate Companies

<u>Statement of Issue</u>:

Whether IPC provided all relevant data for this account.

<u>Statement of Facts:</u>

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

IPC includes costs of its investment in Idaho Energy Resource Company in this account; however, it is unclear if dividends or interests 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 of the Bridger thermal plant.

<u>Summary of Parties' Positions:</u>

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

<u>Analysis of Positions:</u>

In its February 20 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."

In its February 27 response to Issue List, item 17, 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.

<u>Draft Decision:</u>

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. SCHEDULE 2: Capital Structure and Rate of Return

No direct adjustments.

4.5. SCHEDULE 3: Expenses

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

Statement of Issue:

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.

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.

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+ and Passport/PeopleSoft systems."

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

When direct analysis is used, it requires a clear description and justification for the functionalization of all accounts and sub-accounts.

Summary of 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+ 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.

Section VIII of the 2008 ASCM permits Direct Analysis only for specified accounts. 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 BPA can determine if the functionalization is reasonable.

Furthermore, the 2008 ASCM is independent of State Commission ratemaking and 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.

Under Section VII 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 General Software's purposes for this account, and therefore the applicability and justification of the functionalization to PTD. 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.

Draft Decision:

Without additional documentation, BPA is unable to justify the use of the PTD ratio for General Software, and will adjust the amortization expense of General Software and functionalize it to the default of distribution (DIST). Furthermore, BPA will adjust the amortization expense of CIS+ software and functionalize it to distribution (DIST).

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

CIS+ Software ($)

	Total	Production	Transmission	Dist/Other
As-Filed	2,852,460	1,377,978	525,091	949,390
BPA Adjusted	2,852,460	0	0	2,852,460

General Software ($)

	Total	Production	Transmission	Dist/Other
As-Filed	5,524,259	2,668,682	1,016,926	1,838,651
BPA Adjusted	5,524,259	0	0	5,524,259

4.5.2. Account 908, Customer Assistance Expenses

Statement of Issue:

Whether IPC provided all relevant data for this account and correctly functionalized this account.

Statement of Facts:

The 2008 ASCM allows all conservation expense to be functionalized to Production.

IPC functionalized subaccount 908.001 (conservation) to PTD, and functionalized additional conservation costs in subaccount 908.000 to DIST.

In Data Response BPA-IP-12, IPC identified that the only expenses charged to this account are the payment to Idaho non-profit agencies (Community Action Program) for the Weatherization Assistance for Qualified Customers. No IPC labor is charged to this account. The full value of Account 908.001 is classified as conservation.

Summary of Parties' Positions:

IPC originally functionalized these conservation measures to PTD and distribution, but will accept BPA's reallocation to Production.

Analysis of Positions:

In a February 20, 2009, response to the ASC Issue List, Item 8, IPC Idaho Power supports re-allocation of this account to Production. BPA agrees.

Draft Decision:

BPA will functionalize Account 908, Customer Assistance Expenses to Production (PROD).

Table 4.5.2: Account 908, Customer Assistance Expenses ($)

	Total	Production	Transmission	Dist/Other
As-Filed	9,047,316	3,721,325	1,418,045	2,563,894
BPA Adjusted	9,047,316	9,047,316	0	0

4.5.3. Account 403.400, Common Plant-Electric

Statement of Issue:

Why does IPC show an entry for Common Plant-Electric?

Statement of Facts:

In IPC's Appendix 1, IPC shows a distribution cost (negative) in this account. IPC does not have a common plant.

Summary of Parties' Positions:

IPC included Common Plant – Electric in ASC and functionalized it to production (PROD).

Analysis of Positions:

In IPC's February 20, 2009, response to Issue List, Item 19, it verified that IPC "does not have a common plant nor an actual physical asset associated with this account." IPC further clarified that Account 403.400 records a regulatory write-off of disallowed costs as a counter to costs in Account 108/403.200.

Draft Decision:

BPA is satisfied with this response. There is no impact to ASC.

4.6. SCHEDULE 3A: Taxes

No direct adjustments.

4.7. <u>SCHEDULE 3B: Other Included Items</u>

4.7.1. Account 421, Miscellaneous Non-Operating Income

<u>Statement of Issue:</u>

Whether IPC's direct analysis support the use of PTD to functionalize the Rabbi Trust compensation plan.

<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 production.

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, it requires a clear description and justification for the functionalization of all accounts and sub-accounts

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

<u>Summary of Parties' Positions:</u>

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

<u>Analysis of Positions:</u>

In a February 20, 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.

Draft Decision:

BPA will adjust the functionalization of the Rabbi Trust compensation plan to the Labor ratio.

Table 4.7.111: Account 421, Miscellaneous Non-Operating Income
Rabbi Trust Accounts

421001

	Total	Production	Transmission	Dist/Other
As-Filed	3,493,435	1,687,624	643,084	1,162,728
BPA Adjusted	3,493,435	1,234,300	557,863	1,701,273

421050

	Total	Production	Transmission	Dist/Other
As-Filed	158,851	76,739	29,242	52,871
BPA Adjusted	158,851	56,125	25,367	77,359

421051

	Total	Production	Transmission	Dist/Other
As-Filed	372,952	180,167	68,654	124,131
BPA Adjusted	372,952	131,771	59,556	181,625

421052

	Total	Production	Transmission	Dist/Other
As-Filed	104,905	50,678	19,311	34,916
BPA Adjusted	104,905	37,065	16,752	51,088

4.7.2. Account 456, Other Electric Revenues, Standby Charges

Statement of Issue:

Whether IPC correctly functionalized Standby Charges and Standby Services.

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 (PROD).

IPC used a direct analysis and functionalized these accounts to distribution (DIST).

In Data Response BPA-IP-18, IPC provided a description of standby charges (two separate line items in this account). Through a clarification in Data Response BPA-IP-26, IPC corrected the second identification as a standby service and corrected the descriptions of both sub-accounts as follows:

Standby Charge: Amounts represent changes paid by customers under for the provision of standby electric service under Schedule 31 to a specific industrial customer who self generates.

Standby Service: Amounts represent charges for customers on Rate 46 (Alternate Distribution Service), which back up the customers' regular distribution circuit through an automatic switching device.

Each is functionalized to distribution (DIST).

The 2008 ASCM is independent of State Commission ratemaking and is not required to follow the same functionalization methodology as the Idaho or Oregon Commissions. Although the Commission may allow certain costs in rate treatment, this does not require the ASCM to do the same.

Summary of Parties' Positions:

IPC used a direct analysis and functionalized these accounts to distribution (DIST).

Analysis of Positions:

In a February 27, 2009, response to the ASC Issue List, Item 21, IPC stated "These 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)."

Both the standby charge and standby service are a reserve for production capacity and, as IPC states above, the "service is applicable to customers utilizing on-site generation." Reserve capacity is a production related cost and as such, should be functionalized accordingly.

Draft Decision:

Without additional documentation, BPA is unable to justify the functionalization of the standby charge and standby service and will functionalize to the default of production (PROD).

Table 4.7.2: Account 456, Other Electric Revenues
Standby Charges ($)

	Total	Production	Transmission	Dist/Other
As-Filed	103,594	0	0	103,594
BPA Adjusted	103,594	103,594	0	0

Standby Services ($)

	Total	Production	Transmission	Dist/Other
As-Filed	22,894	0	0	22,894
BPA Adjusted	22,894	22,894	0	0

4.8. SCHEDULE 4: Average System Cost

4.8.1. Distribution Losses - No adjustments.

4.8.2. Contract System Cost

FY 2006 Contract System Cost

As-Filed		BPA Adjusted	
Production	$ 404,130,168	Production	$ 394,024,484
Transmission	$ 94,384,838	Transmission	$ 87,071,314
Less NLSL	$ 21,145,238	Less NLSL	$ 24,934,114
Total	$ 477,369,767	Total	$ 456,161,684

4.8.3. Contract System Load

FY 2006 Contract System Load
(MWh)

	Total
As-Filed	14,515,687
BPA Adjusted	14,515,687

4.8.4. Average System Cost

FY 2006 Average System Cost (ASC)
($/MWh)

	Total
As-Filed	32.89
BPA Adjusted	31.43

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 load forecast time-line should be corrected.

Statement of Facts:

IPC submitted a calendar year (CY) total retail load forecast (January-December). IPC then submitted an erratum correction to the load forecast on November 21, 2008, to incorporate inaccurate CY data. This did not include the change to fiscal year data. Later during the Review Process, the error in submitting the calendar year instead of fiscal year data was noted.

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.

Summary of Parties' Positions:

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

Analysis of Positions:

The 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, the erratum correction to the calendar year data filed in November 2008, and the corrected fiscal year data filed with this draft report.

	CY As-Filed (Jan-Dec)	**CY Errata (Jan-Dec)**	**FY (Oct-Sept)**
2007	14,478,929	14,207,222	14,566,354
2008	14,755,632	14,478,929	14,653,961
2009	15,296,781	14,755,632	14,561,464
2010	15,605,691	15,296,781	15,214,573
2011	15,843,167	15,605,691	15,543,784
2012	15,975,336	15,843,167	15,794,344

Draft Decision:

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

5.6. New Resource Addition

Statement of Issue:

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

Statement of Facts:

IPC submitted information on new resources with its October 1, 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.

Summary of Parties' Positions:

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 2.72 percent based on the following values ($/MWh):

FY 2007 ASC without Danskin addition:	33.43
FY 2007 ASC with Danskin addition:	32.55
Delta:	0.88
CY 2007 ASC:	32.34

The materiality calculation is as follows:

$$(33.43-32.55)/32.34 = 0.0272$$

Danskin generation costs meet the materiality threshold and therefore will 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.

Draft Decision:

The Danskin CT1 generating plant meets the 2008 ASCM materiality threshold of 2.5 percent. BPA will include Danskin costs in ASC for FY 2009.

5.7. <u>ASC FORECAST MODEL: New Large Single Loads</u>

<u>Statement of Issue:</u>

Whether IPC may withhold information necessary to calculate the cost of serving its New Large Single Loads (NLSLs) from BPA.

<u>Statement of Facts</u>:

For all NLSL loads not served by dedicated resources (CF/CT prior to September 1, 1979), the 2008 ASCM requires utilities to submit information on all NLSL loads and the resource cost to serve those loads.

IPC does not support BPA's methodology to include 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-30, IPC submitted the requested data, but did so under protest.

<u>Summary of Parties' Positions:</u>

IPC submitted the appropriate data, but did so under protest.

<u>Analysis of Positions:</u>

IPC does not support BPA's methodology to include peaking plants (which it claims cannot for multiple reasons serve an NLSL) in the NLSL calculation.

BPA and the parties evaluated and discussed this matter during the 2008 Average System Cost Methodology 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 <u>all</u> resources and long term power purchases (five years or more in duration)…

<u>Draft Decision:</u>

The 2008 ASCM requires the submission of the above-noted data. IPC submitted the requested data. The issue has been resolved.

6. OTHER ISSUES

6.1. Generic Issue List

In addition to the above-noted issues specific to IPC, BPA raised seven issues that may be "generic" to all utilities. Following are the issues, which were discussed with the parties during the Review Process. In general, the IOUs responded in unison. Puget Sound submitted additional comments. Franklin PUD and Snohomish PUD did not respond in writing; however, Snohomish voiced support for the IOUs' proposal during the generic issue list discussion at the workshop held on March 4, 2009.

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 review of the ASC filings, BPA noticed that a direct analysis performed by the utilities resulted in different functionalizations for similar types of software. For example, metering and customer information system (CIS) software was functionalized to Distribution by PGE while Avista, IPC, PacifiCorp, Puget and NorthWestern functionalized such software using the PTD ratio. The direct analysis provide by utilities to support use of the PTD ratio to functionalize Account 303 – Software was minimal or non-existent.

The 2008 ASCM specifies that the default functionalization for Account 303 – Intangible Plant - Miscellaneous is Direct, with an option to Distribution.

Summary of 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.

However, parties filed separate responses concerning functionalization of software included in Account 303. For example, Puget 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.

PacifiCorp's February 11, 2009, response to BPA's Issues List stated many times 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." PacifiCorp also offered a conflicting rationale in response to a BPA Issue with a specific piece of software. For example, PacifiCorp's response to functionalization of a Customer Information System argued that "[i]n determining the proper functionalization, the focus should be on what costs the Company is recovering using this computer software."

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.

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.

Analysis of Positions:

Section VIII.B, Table 1 of the 2008 ASCM, provides that functionalization of Account 303 is direct analysis with an option to Distribution.

The 2008 ASCM states "Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. 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 16.

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 "BPA 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 17.

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 non existent, or weak and 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 using the PTD ratio. Such simple statements do not constitute a valid direct analysis.

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 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

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[1] See, for example, Data Responses ASC-09 PA-BPA-12 and ASC-09-PS-BPA-6

[2] See, for example, Data Response ASC-09-PS-BPA-12, and Excel file E302,303,E399,Common 2006 filed.xls, DATA for ASC tab, column W.

Ventyx, or by the application name such as Xcellant, Peace, or ConsumerLinX. Repeating this disparate method of recording software in a utility database for a 1,000 or more unique software products that a typical utility may have and the task of functionalizing the software for an ASC filing is difficult and time consuming for a utility analyst that may not have familiarity with the software and how and where it is used within the utility. 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 which incorporate most, if not all, production, transmission and distribution costs of the utility.

However, a utility's ASC may include only allowable production and transmission costs determined in accordance with the 2008 ASCM. Using the PTD or LABOR ratio for all software costs could result in an incorrect functionalization of costs. For example, the costs of certain software packages are very large relative to others in Account 303, which would cause simple ratios to functionalize a portion of distribution-related software into ASC. For example, in PacifiCorp's Response to BPA Data Request ASC-09-PA-12, PacifiCorp 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.

BPA decided to develop a general framework for use in software functionalization for Account 303 software. It did so to ensure that software costs will 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, it should allow utilities that decided not to undertake the task of functionalization of Account 303 – Software an "easy to use" framework for functionalization.

<u>Draft Decision</u>:

BPA will functionalize software systems to follow the operation they support or the labor expense that the software replaced. If a utility fails to provide adequate documentation, BPA will functionalize software systems to Distribution.

Below is a list that describes and categorizes the bulk of utility software, includes the accounts associated with utility software and the functionalization BPA will use for each type of software.

<u>System Categories</u>

- ***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 901-910.

- *Industrial Billing* – systems that manage the large industrial customers, bill calculation and presentation processes. Distribution - Accounts 901-910.

- *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 901-910.

- *Customer Relationship Management (CRM) System* – systems that manage information about the utility's customers. Distribution - Accounts 901-910.

- *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

Statement of Issue:

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

Statement of Facts:

There is an inconsistency in the way the IOUs functionalize Deferred Pension, Pay and other labor-related Assets and Liabilities. PGE, Avista and NW use the Labor Ratio. IPC uses PTD. PSE and PacifiCorp functionalize these assets to Distribution. 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.

Summary of Parties' Positions:

In PSE's February 25, 2009, response to BPA's Issue list, it 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.

Avista, Idaho Power, NorthWestern, PacifiCorp 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."

Analysis of Positions:

The 2008 ASCM ROD states that "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). *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." [3] The WUTC states 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." *Id.*

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.4

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 that all companies are subject to GAAP, but that differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.5

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 believes 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.

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.

Draft Decision:

Following the Review Processes and publication of the Final ASC Reports for FY 2009, BPA will work with the parties to develop a standard functionalization protocol for common types of regulatory assets and liabilities that are not included in the utility's jurisdictional rate base.

For the FY 2009 ASC Filings, BPA will use consistent decision criteria for common types of Regulatory Assets and Liabilities.

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[3] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[4] Ibid. 11-5
[5] Ibid.

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:

A direct analysis is required 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). 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.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, joint response to BPA's Issue Lists stated that "The IOUs agree that BPA should require that accounts that have a corresponding asset and liability account have the same functionalization."

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 182.3and 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 o 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.

Analysis of Positions:

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

Draft Decision:

BPA will require a common functionalization for asset accounts that have a corresponding liability account. 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 Other 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:

There is an inconsistency between utilities in the functionalization of Regulatory Assets and Liabilities that are not included in the utility's jurisdictional rate base. Some items in these accounts are included in working capital for ratemaking purposes. There is a concern 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, PacifiCorp and PSE functionalized all Other Regulatory Assets and Liabilities that are not in their jurisdictional rate base to distribution. IPC, PGE, and Avista functionalized several items in these same accounts, not included in their jurisdictional rate base based on the functional nature of the item.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, Response to BPA's Issue List stated that "There 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."

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.

Analysis of Positions:

The 2008 ASCM ROD states that "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). *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 regulatory agencies." [6] The WUTC states 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." *Id.*

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.[7]

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

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

permitted use of accelerated depreciation for income taxes 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 that all companies are subject to GAAP, but that differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.8

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.

Draft 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 6.1.1.1: Account 182.3, Other Regulatory Assets ($)
As-Filed October 1, 2008

Other Regulatory Assets (182.3)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement	PTD	11,206,056	5,413,469	2,062,852	3,729,736
Excess Power Amort	PROD	6,670,347	6,670,347	0	0
Security Costs 2001-2002	PTD	196,825	95,083	36,232	65,510
Security Costs 2003	PTD	137,588	66,467	25,328	45,794
IPUC Grid West Loans	TRANS	932,177	0	932,177	0
OPUC Grid West Loans	TRANS	56,007	0	56,007	0
FERC Grid West Expense	TRANS	302,117	0	302,117	0
Excess Power Def	PROD	2,889,117	2,889,117	0	0

[8] Ibid.

Table 6.1.1.2: Account 182.3, Other Regulatory Assets ($)
BPA-Adjusted for Draft Report April 13, 2009

Other Regulatory Assets (182.3)	Funct Method	Total	Production	Transmission	Distribution
Asset Retirement	DIST	11,206,056	0	0	11,206,056
Excess Power Amort	DIST	6,670,347	0	0	6,670,347
Security Costs 2001-2002	DIST	196,825	0	0	196,825
Security Costs 2003	DIST	137,588	0	0	137,588
IPUC Grid West Loans	DIST	932,177	0	0	932,177
OPUC Grid West Loans	DIST	56,007	0	0	56,007
FERC Grid West Expense	DIST	302,117	0	0	302,117
Excess Power Def	DIST	2,889,117	0	0	2,889,117

Table 6.1.1.3: Account 254, Other Regulatory Liabilities ($)
As-Filed October 1, 2008

Other Regulatory Liabilities (254)	Funct Method	Total	Production	Transmission	Distribution
Emission Sales Interest OR	PROD	4,118,000	4,118,000	0	0
Assett Retirement Obligation	PTD	156,162,048	75,439,419	28,746,878	51,975,750

Table 6.1.1.4: Account 254, Other Regulatory Liabilities ($)
BPA-Adjusted for Draft Report April 13, 2009

Other Regulatory Liabilities (254)	Funct Method	Total	Production	Transmission	Distribution
Emission Sales Interest OR	DIST	4,118,000	0	0	4,118,000
Assett Retirement Obligation	DIST	156,162,048	0	0	156,162,048

Table 6.1.1.5: Account 186, Miscellaneous Deferred Debits ($)
As-Filed October 1, 2008

Miscellaneous Deferred Debit Details (186)	Funct Method	Total	Production	Transmission	Distribution
Security Plan	PTD	28,102,337	13,575,795	5,173,181	9,353,361
Company owned life ins	PTD	5,952,711	2,875,661	1,095,797	1,981,254
Adj to unfunded pension	PTD	46,181,245	22,309,430	8,501,212	15,370,603

Table 6.1.1.6: Account 186, Miscellaneous Deferred Debits ($)
BPA Adjusted for Draft Report April 13, 2008

Miscellaneous Deferred Debit Details (186)	Funct Method	Total	Production	Transmission	Distribution
Security Plan	Labor	28,102,337	10,881,521	4,487,630	12,733,187
Company owned life ins	Labor	5,952,711	2,304,952	950,582	2,697,177
Adj to unfunded pension	Labor	46,181,245	17,881,864	7,374,630	20,924,751

Table 6.1.1.7: Account 253, Other Deferred Credits ($)
As-Filed October 1, 2008

Other Deferred Credits (253)	Funct Method	Total	Production	Transmission	Distribution
Postretirement Benefits	PTD	3,342,191	1,614,560	615,243	1,112,389
Dir Def Comp	PTD	3,716,793	1,795,524	684,201	1,237,068

Table 6.1.1.8: Account 253, Other Deferred Credits ($)
BPA-Adjusted for Draft Report April 13, 2009

Other Deferred Credits (253)	Funct Method	Total	Production	Transmission	Distribution
Postretirement Benefits	Labor	3,342,191	1,524,468	592,319	1,225,404
Dir Def Comp	Labor	3,716,793	1,439,181	593,530	1,684,081

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:

PacifiCorp reduced the amount of its purchased power expense and sales for resale revenue by book-outs and trading adjustments.

The inclusion of book-outs and trading adjustments in purchased power and sales for resale accounts affects the price spread calculation.

Summary of Parties' Positions:

Avista, IPC, NorthWestern, PacifiCorp and PGE's February 25, 2009, response to BPA's Issue List stated that "The 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 mare 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."

Analysis of Positions:

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.

Draft Decision:

Utilities shall not adjust their purchase power and sales for resale for the effects of bookouts and trading adjustments.

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

Statement of Issue:

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

Statement of Facts:

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

Summary of Parties' Positions:

Avista, IPC, NorthWestern, 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.

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.

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

> The 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.

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.

OPUCs March 10, 2009, response to issues reiterated the above statements and stressed the need 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.

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 BPA internal staff.

Analysis of Positions:

All of the respondents 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.

The 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 gas forecast would be one reasonable approach. However, using the utility-supplied natural gas forecasts from the utilities' October 1, 2009, ASC filings is a better option for FY 2009. Such forecasts would more closely match projected gas prices that were used to set the PF Exchange Rate in BPA's 2007 Supplemental Rate Proceeding than would using a more recent forecast. In addition, BPA has been paying REP benefits based on ASCs containing these natural gas price forecasts. Switching to a new forecast at this time could result in large true-ups when the final ASCs are determined. This approach is also reasonable on a one-time basis because it is based on the utilities' own forecasts, which the utilities presumed to be reasonable when filed. This approach for FY 2009, however, does not constitute a precedent for future ASC determinations.

Draft Decision:

BPA will accept the utilities' as-filed projected natural gas prices used for new resources for FY 2009 ASC filings.

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:

Projected capacity factors vary significantly between utilities for similar types of new resources, and the ranges are too wide to provide consistency among the utilities.

Summary of 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.

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, if a utility chooses to use capacity factor outside the above range for a new resource, the utility will have to supply complete justification and documentation for use of such a capacity factor.

After a discussion with the parties, BPA will defer a decision on this issue until after the FY 2009 ASC Review Process is completed 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. Based on the exceeding small amount of data on wind capacity factors BPA and parties reviewed, differences by location were observed, but more time and research needs to be devoted to this effort. BPA and some of parties believe that this issue should be deferred to future ASC filings to develop more robust estimates of projected capacity factors for new resources.

Some of the filing utilities submitted revised capacity factors which reduced somewhat 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 2009 ASCs.

Draft Decision:

The capacity factors submitted by each utility will be accepted for this FY 2009 Review Process. BPA, however, makes no precedential decision at this time. The issue will be revisited in future ASC filings.

7. FY 2009 ASC

Overall BPA adjustments, including all changes made to IPC's Appendix 1 filing, decrease IPC's FY 2006 ASC by $ 0.55/MWh and the decreased IPC's FY 2009 ASC by $1.17/MWh. IPC's ASC for FY 2009 is $33.43/MWh.

8. REVIEW SUMMARY

This draft ASC determination is BPA's best estimate of IPC's FY 2009 ASC based on the information and data provided by IPC to date, and based on the professional review, evaluation, and judgment of BPA's REP staff. BPA will solicit and review comments on this Draft Report and the Draft Reports of all other exchanging utilities' for FY 2009. After review of such comments, BPA will make final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2009. Final ASC determinations will be published in June, 2009.

The as-filed Appendix 1 Filing, ASC Forecast Model, NLSL assessment, and supporting documentation submitted by IPC, can be viewed at BPA's REP website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

9. ADMINISTRATOR'S APPROVAL

I have examined IPC'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 IPC's ASC.