FY 2010-2011 AVERAGE SYSTEM COST DRAFT REPORT

FOR

Snohomish County Public Utility District

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

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

April 13, 2009

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1. FILING DATA

Utility: **Snohomish County PUD**
2320 California Street
Everett, Washington 98201
http://www.snopud.com

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
- Oregon Public Utility Commission (OPUC)
- Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

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

Statement of Purpose:
Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Snohomish County PUDs ASC for FY 2010-2011 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 July, 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) 2007.

The table below summarizes CY 2007 Base Period ASC based on (1) the ASC information filed by Snohomish County PUD on October 15, 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 2007 Base Period ASC
(Results of Appendix 1 calculations)

	October 15, 2008 As Filed	April 13, 2009 Draft Report
Production Cost	269,400,580	269,544,820
Transmission Cost	30,449,717	30,330,696
(Less) NLSL Costs		
Contract System Cost	299,850,297	299,875,515
Total Retail Load (MWh)	6,774,641	6,774,641
(Less) NLSL		
Total Retail Load (Net of NLSL)	6,774,641	6,774,641
Distribution Losses	338,732	247,274
Contract System Load	7,113,373	7,021,916
CY 2007 Base Period ASC ($/MWh)	**42.15**	**42.71**

2.2. ASC New Resource Additions

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

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

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

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information 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 2010-2011 Exchange Period ASC				
Resource	**N/A**	**Resource #1**	**Resource #2**	**N/A**
Expected On-Line Date		10/01/08	03/01/09	
Delta*		**0.25**	**2.41**	

Draft Report FY 2010-2011 Exchange Period ASC				
Resource	Enron	**Resource #1**	**Resource #2**	**N/A**
Expected On-Line Date	01/01/08	10/01/08	03/01/09	
Delta*	**-2.48**	**0.29**	**2.71**	

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

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

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	Resource #3	Resource #4	**N/A**	**N/A**
Expected On-Line Date	10/01/10	10/01/10		
Delta*	**3.87**	**0.25**		

Draft Report FY 2010-2011 Exchange Period ASC				
Resource	Resource #3	Morgan Stanley	**N/A**	**N/A**
Expected On-Line Date	10/01/10	10/01/10		
Delta*	**0.15**	**-1.40**		

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

2.3. <u>FY 2010-2011 Exchange Period ASC for the Draft Report</u>

The following table identifies the Exchange Period ASC as filed on October 15, 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 2.3.1: Exchange Period FY 2010-2011 ASC ($/MWh)
Prior to New Resource Additions

Date	**October 15, 2008 As-Filed**	**April 13, 2009 Draft Report**
FY 2010 - 2011	**46.96**	**45.53**

The as-filed Appendix 1 Filing, including the ASC Forecast Model and supporting documentation submitted by Snohomish County PUD 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. <u>Introduction</u>

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 2010-2011</u>

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

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

To determine a utility's Exchange Period ASC for FY 2010-2011 (October 1, 2009, through September 30, 2011), the Base Period (CY 2007) ASC is first calculated using the Appendix 1.

BPA then uses the ASC Forecast Model to escalate the Base Period ASC forward to the 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 15, 2008, ASC filings began the formal review and comment processes, referred to as the Review Period, to establish the utilities' respective ASCs. For the Draft 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 2010-2011 ASCs are still in progress at this publication date. Upon completion of the formal reviews and final ASC determinations, BPA will publish Final Reports in July, 2009 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 that present the data necessary to calculate ASCs. The schedules and support data are as follows:

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

3.3.1. Schedule 1 – Plant Investment/Rate Base

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

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

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 Total Production and Total Transmission (calculated in the Total Rate Base) are 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 Uniform System of Accounts, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a utility, BPA allows one-eighth of the functionalized costs of total production expenses, transmission expenses and administrative and general expenses, less purchased power, fuel costs, and public purpose charges.

3.3.3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the utility to develop the rate of return applied to the utility's rate base developed 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 NLSLs, 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 all 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 ASC data forward to the Exchange Period, which in this case is FY 2010-2011. BPA used Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For the Draft Reports, the escalators were updated to be consistent with the escalators used in the WP-10 Power Rate Case. 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 FY 2010-2011 Exchange Period (October 1, 2010) 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 resource investments, 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. All resources included prior to the start of the Exchange Period are projected forward to 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. <u>Identification and Analysis of Issues from BPA Issue List</u>

BPA raised the following issues during the ASC Review Process, and Snohomish County PUD submitted its responses. No other party raised or commented on Snohomish County PUD's responses. Each issue pertains to the October 15, 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. <u>SCHEDULE 1: Plant Investment/Rate Base:</u>

4.2.1. Account 303, Intangible Plant Miscellaneous: Functionalization of Account 303

<u>Statement of Issue:</u>

Should the percentage allocation of Account 303 be changed to 11% Transmission and 89% Distribution?

<u>Statement of Facts:</u>

Snohomish stated in response to DATA REQUEST NUMBER: BPA-SN-3 that the dollars in Account 304 (listed in the Appendix 1 as 304) are for intangible software.

Snohomish states that "there are a large number of software items that make up these accounts, it is difficult to functionalize by line item, so we chose to be conservative and use the transmission 10%/ distribution (90%) ratio for the software."

Snohomish has provided a summary breakout of Account 303/304 to verify the percentage allocation between Production/Transmission and Distribution. Snohomish's documentation verifies that the final percentages, based on a direct analysis of the Account, are 30% Production, 2% Transmission and 68% Distribution. *See* 'Direct Analysis Account 304' spreadsheet provided."

Snohomish stated that the final percentages for that ratio are 11%/89% based on its revised direct analysis.

Summary of Parties' Positions:

Snohomish contends that the final percentages for that ratio are 11%/89% based on its revised direct analysis.

Analysis of Positions:

Snohomish provided sufficient detail to allow BPA to make a determination of the functionalization of individual 303 Accounts. BPA, however, takes exception to some of the functionalizations. (*See* 5.1.2 and 5.1.3 for the exceptions and an explanation of BPAs adjustments)

Draft Decision:

BPA accepts Snohomish's direct analysis of Account 303 and will be changed to the functionalizations with exception describe in section 5.1.2 and 5.1.3. (*See* 5.1.2 and 5.1.3 for the exceptions and an explanation of BPAs adjustments)

Table 4.2.1: Account 303, Intangible Plant Miscellaneous: Functionalization of Account 303

	Account Description	Historical Cost	Prod	Tran	Dist
PTD	Passport Supply Chain - Phase 1	4,011,978	1,140,129	311,388	2,560,460
PTD	WorkGroup Computing - MS Outlook	565,719	160,767	43,908	361,044
TD	APSS-Project Scheduling - Engineering	609,577	-	66,095	543,482
PTD	Data Warehouse Software	859,220	244,174	66,688	548,357
PTD	Passport/Peoplesoft	4,190,642	1,190,902	325,255	2,674,484
PROD	ESS CAPITAL (SW) (from 304201 Jan 2002)	352,822	41,858	10,276	300,689
PTD	PASSPORT/PeopleSoft Budget Module	3,096,383	879,934	240,325	1,976,124
DIST	CIS Data Warehouse	1,333,755	-	-	1,333,755
PROD	Risk Management Computer System (Aces & Contango)	701,810	83,261	20,440	598,109
		15,721,906	3,741,027	1,084,375	10,896,504

4.2.2. Account 303, Intangible Plant Miscellaneous: *Miscellaneous software*

<u>Statement of Issue:</u>

What is the correct functionalization of Account 303 – Miscellaneous Software?

<u>Statement of Facts:</u>

Miscellaneous Software is defined as that software that does not easily fit into other categories; such as Customer Information System (CIS), Billing, Metering, Employee Information, Facilities Management, etc. These are software systems that generally make employees more efficient at their jobs. For example, MICROSOFT OFFICE XP LICENSES is a license for Microsoft office suites that is used by employees' computers.

Snohomish's explanation of the items was not sufficiently clear to allow an understanding of the software's purposes and therefore the applicability and justification of the functionalization to PTD or Distribution.

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

Snohomish supports functionalization most of the software that BPA has classified as miscellaneous using the PTD ratio.

<u>Analysis of Positions:</u>

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

Snohomish's explanation of the items was not sufficiently clear to allow an understanding of the software's purposes and therefore the applicability and justification of the functionalization to PTD or Distribution.

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 or the cost of the software is less than 1% of the total cost in Account 303 – Software. LABOR

Miscellaneous Software is more accurately functionalized to the operation it supports or replaces, which is Snohomish's employees. Therefore, the Labor ratio more accurately reflects the appropriate functionalization.

<u>Draft Decision:</u>

Account 303 – Miscellaneous Software will be functionalized to Labor.

Table 4.2.2: Account 303, Intangible Plant Miscellaneous:
Miscellaneous software

	Account Description	Historical Cost	Prod	Tran	Dist
AS FILED					
PTD	Passport Supply Chain - Phase 1	4,011,978	1,140,129	311,388	2,560,460
PTD	WorkGroup Computing - MS Outlook	565,719	160,767	43,908	361,044
		4,577,697	1,300,896	355,297	2,921,504
ADJUSTED					
Labor	Passport Supply Chain - Phase 1	4,011,978	475,972	116,845	3,419,161
Labor	WorkGroup Computing - MS Outlook	565,719	67,116	16,476	482,127
		4,577,697	543,088	133,321	3,901,288

4.2.3. Account 303, Intangible Plant Miscellaneous: *Enterprise Resource Planning Software*

Statement of Issue:

What is the correct functionalization of Account 303 – Enterprise Resource Planning Software?

Statement of Facts:

PeopleSoft software is an *Enterprise Resource Planning (ERP) System*, which provides 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.

Summary of Parties' Positions:

Snohomish contends the account should be functionalized to PTD.

Analysis of Positions:

Table 1 of the 2008 ASCM provides that the functionalization method for this account is direct analysis with a default 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 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 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:

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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.

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 will 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.

BPA's software cost functionalization framework functionalizes cost related to Enterprise Resource Planning ERP systems using the Labor ratio because the primary benefit of ERP systems is increased productivity of the utility's work force. ERP systems are not installed to reduce line losses or increase heat rates of power generation equipment. While utilities may experience an increase in the productivity of assets, the cause is a result of the more accurate, timely and higher quality information provided to labor, thus resulting in a more efficient use of utility assets.

<u>Draft Decision:</u>

Account 303 – Enterprise Resource Planning Software will be functionalized to Labor.

Table 4.2.3: Account 303, Intangible Plant Miscellaneous:
Enterprise Resource Planning Software

	Account Description	Historical Cost	Prod	Tran	Dist
AS FILED					
PTD	Data Warehouse Software	859,220	244,174	66,688	548,357
PTD	Passport/Peoplesoft	4,190,642	1,190,902	325,255	2,674,484
PTD	PASSPORT/PeopleSoft Budget Module	3,096,383	879,934	240,325	1,976,124
		8,146,245	2,315,011	632,268	5,198,966
ADJUSTED					
Labor	Data Warehouse Software	859,220	101,936	25,024	732,260
Labor	Passport/Peoplesoft	4,190,642	497,169	122,048	3,571,425
Labor	PASSPORT/PeopleSoft Budget Module	3,096,383	367,348	90,179	2,638,856
		8,146,245	966,453	237,252	6,942,540

4.2.4. Account 111 - Other Deferred Credits: *Functionalization of Account 111*

<u>Statement of Issue:</u>

Should the functionalization of Account 111 follow the functionalization of Account 303?

Statement of Facts:

Snohomish stated in response to DATA REQUEST NUMBER: BPA-SN-5 that Account 111 is an amortization of Accounts 303 and 304. Therefore the ratio is based on the same percentages, 20% to Production, 10% to Transmission and 70% to Distribution.

The percentages in the as-filed Account 111 are different from the percentage allocation in Account 303.

During the Review Process, BPA and Snohomish agreed that the functionalization of Account 111 should follow the functionalization of Account 303.

Summary of Parties' Positions:

Snohomish agrees the functionalization of Account 111 should follow the functionalization of Account 303.

Analysis of Positions:

BPA and Snohomish agree the functionalization of Account 111 should follow the functionalization of Account 303.

Draft Decision:

Account 111 will be functionalized to follow the relationship of Production, Transmission, and Distribution to Total in Account 303.

Table 4.2.4: Account 303, Intangible Plant Miscellaneous:
Functionalization of Account 111

AS FILED							
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	40,601,110	8,120,222	4,060,111	28,420,777
ADJUSTED							
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	40,601,110	10,129,419	382,831	30,088,860

4.2.5. Account 186 Miscellaneous Deferred Debits

Statement of Issue:

Does Snohomish correctly functionalize Accounts 186.107, 186.108, and Account 186.110?

Statement of Facts:

Snohomish functionalized Account 186.107, "Misc Def Deb Est Jackson Pwr"; Account 186.108, "Misc Def Debit Oth Gen.; and Account 186.110, "Misc Def Debit Everett Cogen" to Production.

Snohomish responded to Data Request 18, stating "The Electric System and Generation System are two separate legal entities owned by Snohomish County PUD; therefore, any accounting between the two entities must be at 'arms length' transaction that is why there payable and receivables."

Snohomish stated it has consolidated the Electric System entity with the Generation System entity for this filing. BPA does not have sufficient information to determine if the functionalization of the account should be to Production.

Summary of Parties' Positions:

Snohomish contends that these Accounts are offset by Account 253 and have minimal impact upon ASC.

Analysis of Positions:

BPA agrees with Snohomish that Account 253 offsets the Account 186 entries and there is a minimal impact on ASC. BPA, however, will revisit this issue in the future.

Draft Decision:

BPA did not change the functionalization, but will review this in the future.

4.3. SCHEDULE 1A: Cash Working Capital

No direct adjustment.

4.4. SCHEDULE 2: Capital Structure and Rate of Return

No direct adjustment.

4.5. SCHEDULE 3: Expenses

4.5.1. Account 555, Purchased Power: *Enron Contract*

Statement of Issue:

Should the $18,000,000 Purchased Power Expense - Enron Power Contract Term in the "data for 2007 ASC" be removed in FY 2008 and beyond and should the contract be reclassified to Account 557 - Other Expenses?

Statement of Facts:

Snohomish stated in response to DATA REQUEST NUMBER: BPA-SN-14 that it entered a power purchase and sale agreement with Enron in January 2001 using the EEI-NEMA Master Agreement form, with certain modifications. The major transaction under that agreement was for delivery of a 25 MW flat block of power from April 1, 2001, through December 31, 2009. No generation source was specified. Snohomish took power under that transaction from April 1, 2001, until November 29, 2001, when the contract was terminated due to the downgrade of Enron's credit ratings to below investment-grade. Enron and Snohomish also entered into a number of shorter-term transactions using the same Master Agreement. Snohomish took 145,800 MWh under the long-term transaction.

Snohomish initially assigned this cost to Account 555.216, Purchased Power, but requests that BPA modify the account coding for this cost to 557, Other Expenses.

Snohomish states "[t]he amount listed in the "Data for 2007 ASC" in tab "ELIS" is a power purchase contract termination payment made in 2007. This is a one-time payment and completes the contractual relationship between Enron and Snohomish. There are no future obligations."

Summary of Parties' Positions:

Snohomish believes the Enron Contract should be moved to Account 557.

Analysis of Positions:

Snohomish acknowledged that that the Enron Contract is a one-time payment and completes the contractual relationship between Enron and Snohomish. There are no future obligations.

BPA agrees with Snohomish that the expense should be moved from Account 555 to Account 557 and removed in 2008.

Draft Decision:

The Enron Contract will be moved from Account 555 to Account 557 for 2007 and removed for 2008.

Table 4.5.1a: Account 555 to Account 557:
Enron Contract –

		Total	Production
AS-FILED			
Purchased Power (Excluding REP Reversal)	PROD	284,335,229	284,335,229
Other Expenses	PROD	6,628,227	6,628,227
ADJUSTED			
Purchased Power (Excluding REP Reversal)	PROD	266,335,229	266,335,229
Other Expenses	PROD	24,628,227	24,628,227

Table 4.5.1b: New Resources:
Enron Contract –Contract Removal

		01/01/08
Other Expenses	557	(18,000,000)

4.5.2. Purchased Power: *Morgan Stanley Contract*

Statement of Issue:

Should the Morgan Stanley Contract be removed from the calculation of forecasted ASC?

Statement of Facts:

On January 7, 2009, Snohomish sent BPA a revised forecast model (SNPD Update ASC_Forecast_Model_FY2010-11_New Resources MS Removed 112508 Rev02.xls) that removed the Morgan Stanley contract from ASC on January 1, 2010.

Summary of Parties' Positions:

Snohomish acknowledged the need to remove the Morgan Stanley contract when it expires.

Analysis of Positions:

BPA and Snohomish agree it is appropriate to remove the Morgan Stanley contract when it expires.

Draft Decision:

BPA will remove the Morgan Stanley contract from the forecast on January 1, 2010 (Forecast Model – New Resource tab).

Table 4.5.2: New Resources:
Morgan Stanley –Contract Removal

		01/01/2010
Purchased Power (Excluding REP Reversal)	557	(22,995,000)
Purchased Power (MWh)		(219,600)

4.6. <u>SCHEDULE 3A: Taxes</u> - No Adjustments

No direct adjustment.

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

5. SUPPORTING DOCUMENTATION:

5.1. <u>Purchased Power and Sales for Resale</u>

5.1.1. 3-YEAR PP & OSS Work Sheet: *Long-Term Purchased Power*

<u>Statement of Issue:</u>

Should BPA adjust the 3-YEAR PP & OSS WorkSheet to reflect Snohomish's actual Long-Term Purchased Power contracts?

<u>Statement of Facts:</u>

Snohomish's Initial Filing included all of its purchased power in "OS' and SF. In its price spread calculation, Snohomish accurately identified its long-term contracts and classified them as LF.

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

Snohomish accurately reflected its long-term contracts in its Price Spread worksheet.

<u>Analysis of Positions:</u>

BPA and Snohomish agree the Company accurately reflected its long-term contracts in its Price Spread worksheet.

Draft Decision:

BPA will adjust the Long-Term Purchased Power in the 3-YEAR PP & OSS WorkSheet.

Table 5.1.1: 3-YEAR PP & OSS WorkSheet:
Long-Term Purchased Power

	Settlement Total	MWh Purchased
AS FILED		
SF	$212,445,459	7,693,114
ADJUSTED		
LF	$212,445,459	7,693,114

5.2. Salaries and Wages

No direct adjustment.

5.3. Labor Ratios

No direct adjustment.

5.4. Distribution Loss Factor

5.4.1. Loss Factor

Statement of Issue:

Should Snohomish's loss factor be changed to reflect the five (5)-year average of actual losses?

Statement of Facts:

Snohomish's original Appendix 1 filing contained a 5% distribution loss factor.

On January 7, 2009, Snohomish provided an errata distribution loss estimate of 3.59% based on the five (5)-year average of actual losses.

Table 5.4.1: Distribution Losses
Snohomish County PUD No. 1, Yearly Loss Factor Calculation

	Yearly Losses (MWh)	%
2003	317,455	3.97%
2004	259,570	3.18%
2005	292,860	3.57%
2006	322,775	3.62%
2007	297,880	3.60%
5-yr. Avg.	298,108	3.59%

Loss values are from Snohomish PUDs Electric System Statistics
Note: All values have been reduced for BPA Transmission Losses

Summary of Parties' Positions:

During the Review Process, Snohomish provided a utility-specific loss factor of 3.59% based on a five (5)-year average of actual losses.

Analysis of Positions:

BPA and Snohomish agree that the distribution loss factor should be 3.59% rather that the 5% in the original filing.

Draft Decision:

BPA will adjust Snohomish's distribution loss factor to 3.59%.

5.5. NEW RESOURCES

5.5.1. New Resource Additions: Reclassification

Statement of Issue:

Whether a confidential resource on-line date should be adjusted to the mid-point of the rate period and whether the resource should be reclassified as a hydro facility.

Statement of Facts:

Snohomish classified a hydro facility in its new resource additions as a purchased power contract.

Snohomish also identified a resource that was misclassified as a purchase power contract and was in fact a hydro facility.

Snohomish forecasted the online date for this resource to be 1/1/10

Section 4.2.4 of the 2008 ASCM requires that new resource additions forecasted to come on-line during the rate period will be brought on-line at the mid-point of the rate period for ASC purposes.

October 1, 2010 is the mid-point of the rate period for ASC purposes.

Summary of Parties' Positions:

Snohomish supports the reclassification of the costs of a confidential resource from purchased power to a hydro facility.

Analysis of Positions:

Both Snohomish and BPA agree that the costs of the confidential resource should be reclassified as a hydro facility.

Section 4.2.4 of the 2008 ASCM requires that new resource additions forecasted to come on-line during the rate period will be brought on-line at the mid-point of the rate period for ASC purposes.

Draft Decision:

BPA will reclassify the purchased power resource to hydro and move the online date to the midpoint of the rate period.

Table 5.5.1a: New Resource Additions: Re-Classification Purchased Power to a Hydro Facility

	Confidential resource # 3dated 10/1/2008
AS FILED	
Online Date	01/01/10
Purchased Power (Excluding REP Reversal)	29,170,100
Purchased Power (MWh)	17,900
ADJUSTED	
Online Date	10/01/10
Hydraulic Production	29,170,100
Hydraulic - Maintenance	220,000
Expected Annual Generation (MWh)	17,900

Table 5.5.1b: New Resource Additions: Re-Classification On-line Date

	Online date
AS FILED	01/01/10
ADJUSTED	10/01/10

5.5.2. New Resource Additions: Adjustment

Statement of Issue:

Should Confidential Resource No. 1's on-line date of October 1, 2008, be adjusted?

Statement of Facts:

Snohomish notified BPA of an adjustment to costs for Confidential Resource No. 1, which was expected on-line on October 1, 2008.

Summary of Parties' Positions:

Snohomish supports an adjustment to the costs for Confidential Resource No. 1, which was expected on-line on October 1, 2008. .

Analysis of Positions:

BPA and Snohomish agree that the costs for Confidential Resource No. 1, which was expected on-line on October 1, 2008, should be adjusted.

Draft Decision:

BPA will adjust the costs for Confidential Resource No. 1, which was expected on-line on October 1, 2008.

Table 5.5.2: New Resource Additions:
Cost Adjustment
Confidential Resource No. 1 dated 10/1/2008

	Confidential Resource No. 1 dated 10/1/2008
AS FILED	
Purchased Power (Excluding REP Reversal)	7,762,800
Purchased Power (MWh)	156,160
ADJUSTED	
Purchased Power (Excluding REP Reversal)	6,553,900
Purchased Power (MWh)	138,640

5.5.3. New Resource Additions: Materiality

Statement of Issue:

Does Resource No 4 in Snohomish's Initial Filing meet the 2008 ASCMs materiality criteria?

Statement of Facts:

Snohomish's initial filing included a Transmission of Electricity to Others (Wheeling) resource addition of $1,804,600 on January 1, 2011. This resource did not meet the 5% materiality threshold.

During the Review Process, Snohomish removed the Transmission of Electricity to Others (Wheeling) resource from its January 5, 2009, response.

Summary of Parties' Positions:

Snohomish supports the removal of the Transmission of Electricity to Others (Wheeling) resource.

Analysis of Positions:

Snohomish's Transmission of Electricity to Others (Wheeling) resource addition of $1,804,600 on January 1, 2011, did not meet the 2008 ASCMs 5% materiality threshold.

BPA and Snohomish support the removal of the Transmission of Electricity to Others (Wheeling) resource.

Draft Decision:

BPA will remove the Transmission of Electricity to Others (Wheeling) resource (Forecast Model – New Resource tab).

5.6. ASC FORECAST MODEL:

No direct adjustments.

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 provides 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"[3] or "supports all areas of the company."[4] 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.

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

[4] 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.

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 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.

Draft Decision:

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.

System Categories

- ***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." [5] 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.[6]

Regulatory assets and liabilities are a subset of the larger issue of the difference between accounting for utilities that are subject to price regulation and Generally Accepted Accounting Principles (GAAP). The issue can be traced back to the Internal Revenue Act of 1954 which permitted use of accelerated depreciation for income tax purposes. In 1962, the Accounting Principles Board (precursor to FASB) issued Opinion No. 2, which dealt comprehensively with the issue of accounting for industries subject to price regulation, was prepared in response to questions surrounding the creation of investment tax credits by Congress. Opinion No. 2 stated that all companies are subject to GAAP, but those differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.[7]

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

After review of the parties' comments and the 2008 ASCM ROD, BPA 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 2010-2011, 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.

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

For the FY 2010-2011 ASC Filings, BPA will use consistent decision criteria for common types of Regulatory Assets and Liabilities.

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 or liability being booked in opposing accounts. For example, PSE normally nets debits and credits (other than taxes) and books the net in the appropriate asset or liability account.

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." [8] 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.[9]

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

[8] 6 *See* §11.03[2], G. Hahne and G. Aliff, *Public Utility Accounting*, pages 11-5 (Mathew Binder 2005).
[9] 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 those differences may arise, generally surrounding recognition of cost, for companies subject to price or rate regulation.[10]

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.

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

[10] Ibid.

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."

<u>Analysis of Positions:</u>

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

<u>Draft Decision</u>:

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

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

<u>Statement of Issue:</u>

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

<u>Statement of Facts:</u>

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

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

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

Avista, IPC, PGE, PacifiCorp and NWEs 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 OPUCs 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:

> . . . [t]hat BPA adds 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.

<u>Analysis of Positions:</u>

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

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

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

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

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

<u>Decision:</u>

BPA will use the natural gas forecast used in the BPA rate case for new gas-fired resources in the ASC Forecast Model.

6.1.7. ASC Forecast Model – Capacity Factors

<u>Statement of Issue:</u>

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.

<u>Statement of Facts:</u>

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 2010- 2011 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 2010-2011 ASCs.

Draft Decision:

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

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

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

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

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

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information from the ASC Draft Report as adjusted by BPA after the ASC Review Process.

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

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

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

System Costs, divided by the average of the start of rate period and end of rate period Contract System Loads.

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

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

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

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

7. FY 2010-11 ASC

Overall BPA adjustments, including all changes made to Snohomish's Appendix 1 filing increased Snohomish's CY 2007 ASC by $ 0.56/MWh. These changes decreased Snohomish's FY 2010-2011 ASC before exchange period resource additions by $1.43/MWh. Snohomish's ASC for FY 2010-2011, prior to the addition of any new resources, is $45.53/MWh.

8. REVIEW SUMMARY

This draft ASC determination is BPA's best estimate of Snohomish's FY 2010-2011 ASC based on the information and data provided by Snohomish 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 2010-2011. After review of such comments, BPA will make final ASC determinations used to calculate REP benefits for each exchanging utility for FY 2010-2011. Final ASC determinations will be published in July, 2009.

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

9. ADMINISTRATOR'S APPROVAL

I have examined Snohomish'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 Snohomish's ASC.