PGE Revised FY 2009 Draft ASC Report Changes

BPA has revised PGE's draft FY 2009 ASC Report and is seeking additional comments for one week on these changes. The specific changes reflect responses to comments, errors and omissions. PGE's specific changes are outlined below and are explained in the body of the revised PGE draft FY 2009 ASC Report.

Changes affecting most or all ASC Reports

1. BPA updated its forecast of electricity market prices and gas prices. The result of this update can be seen in the price used to forecast short term purchase power and sale for resale, and the cost of fuel for those resources that rely on natural gas as a component of their fuel cost.
2. BPA revised the NLSL adjustment to include transmission losses. During the comment period it was pointed out that BPA had not included transmission losses in the calculation of the cost of resources used to serve NLSLs. BPA revised the cost of resources used to serve NLSLs to reflect transmission losses between the resource and delivery to the NLSL. All NLSLs are assumed to be served at transmission voltage and transmission losses include the transmission network losses for PGE, in addition to losses of other networks that power from resources travel over to get to the PGE network.

PGE specific changes

1. BPA discovered that its forecast for three utilities' purchase power expense and sales for resale revenue needed to be revised to better reflect the utilities' actual purchased power expense in their base ASC filings and related forecasts (this is referred to as the "REP reversal").
2. No other changes.

If you have any questions please feel free to contact Robert Young at 503-230-4058 or reyoung@bpa.gov or Michelle Manary at 503-230-5858 or mlmanary@bpa.gov.

REVISED DRAFT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Portland General Electric Company

Docket Number: PG-PB-08-01
Effective Date: October 1, 2008

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

August 4, 2008

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Section **Page**

I. FILING DATA

Utility	Parties to the Filing
Portland General Electric Company 121 SW Salmon St. Portland, OR 97204	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 Revised Amended
Production Cost	$932,953,681	$855,327,775	$780,278,890
Transmission Cost	113,905,007	108,758,429	$108,758,429
(Less) New Large Single Load Costs	13,165,394	16,433,428	$15,957,669
Total Contract System Cost	**$1,033,693,293**	**$947,652,776**	**$873,079,649**
Total Retail Load (MWh)	18,432,527	18,432,527	18,432,527
(Less) New Large Single Load	328,992	328,992	328,992
Total Retail Load (Net NLSL)	18,103,535	18,103,535	18,103,535
Plus Distribution Losses	986.333	868,172	868,172
Total Contract System Load (MWh)	**19,089,868**	**18,971,707**	**18,971,707**
FY 2006 Base Period ASC ($/MWh)	**$54.15**	**$49.95**	**$46.05**

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008	August 4, 2008
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$52.16**	**$50.22**

C. FY 2009 ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions - See Table1 in Section III.B for details

Resource	Port Westward	Biglow Canyon	Selective Water Withdrawal	Biglow Canyon 2	
Delta*	$3.16	$1.35	$0.63	$1.99	

* Base ASC is $50.22/MWh. The Delta is the differential between the additions of each of the four resource groups starting with the Base ASC.

D. July 8, 2008 - FY 2009 ASC with New Resource Additions ($/MWh)

Resource	Port Westward	Biglow Canyon	Selective Water Withdrawal	Biglow Canyon 2	
Delta*	$3.38	$1.36	$0.63	$2.00	

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at 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. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be 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 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to 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.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through 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 Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

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 of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process was to estimate exchanging Utilities' ASCs for FY 2009 that could be incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding relied on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ‘‘base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 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.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.

The 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.
In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a Base Period ASC determination, BPA used the ASC Forecast model, an Excel-based spreadsheet, to escalate the Base Period ASC forward to the effective rate period, FY 2009 (October 1, 2008 thru September 30, 2009). The Base Period and Forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. 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 & Off-System Sales
10. New Large Single Load
11. Labor Ratios

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 total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to 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 Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net 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, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but is a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

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.

IOUs use the weighted cost of capital (WCC) from the 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 ASC Methodology, 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.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as outlined in the ASCM, Table 1. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein 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*.

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.

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 lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's 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. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

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

9. Purchased Power and Sales for Resale

The Purchased Power (excluding REP reversal expenses) is an Account of Schedule 3, *Expenses*, and includes all 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 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A 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 will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) 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.

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 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 Year filing.

D. ASC Forecast

Once BPA determines the Base Period ASC, it applies this data in an Excel-based forecasting model to escalate the base year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Cost

Forecast Contract System Cost (CSC) are the 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 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost,* Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

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. The 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. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, 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%. 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 addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

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 mid-point of the Exchange Period.

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 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. <u>August 4, 2008 - Identification and Analysis of Issues</u>

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. 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 ASC Methodology.

The following is a summary of the Contract System Cost and Contract System Load filed on May 7, 2008 by Portland General Electric Company (PGE), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base: - No Changes from July 8, 2008 Report

SCHEDULE 1A: Cash Working Capital: – Changed due to changes from in Schedule 3

SCHEDULE 2: Capital Structure and Rate of Return: - No Changes from July 8, 2008 Report

SCHEDULE 3: Expenses:

1 **REP Reversal:** PGE included the difference between the mark-to-market value of the purchase of BPA power at the RL rate and the cost of the RL power in its ASC filing as an REP Reversal. The BPA-PGE RL purchase power contract expired in September of 2006 ASC Filing.

a <u>Statement of Issue</u>: Should the mark-to-market value of the PGE purchase of power at the RL rate be included in ASC on Schedule 3.

b <u>Statement of Facts</u>: In the May 7th filing, PGE included mark-to-market value of the power it purchased from BPA at the RL rate. This contract was a part of BPA's REP Settlement Agreements that were invalidated by the 9th Circuit Court of Appeals in 2007. Under the REP Settlement agreement, BPA sold power to PGE at a rate far below what PGE could purchase the power for in the market. The difference between the value of the RL purchase at market prices and the cost of the power from BPA was distributed to PGE residential and small customers. The amount distributed to PGE customers was reported on Schedule 3 as REP Reversal.

c <u>Analysis of Position and Decision:</u> BPA made two adjustments to PGE's ASC filing to remove the effects of the REP Settlement Agreements. First, the REP reversal amount will be removed from Schedule 3 because the benefits distributed by PGE to its eligible customers are not an expense for ASC purposes. Second, because the purchased power contract between BPA and PGE associated with the REP Reversal expired in September of 2006, BPA will remove the MWh and cost for the RL purchase included in Account 555, Purchased Power in the 2009 ASC Forecast Model. The RL purchase will be replaced with purchases at the market price of power. This adjustment will show up as a negative in the Resource Additions table. Despite its language in the July 9, 2008 Draft Report that it made the above described adjustment, BPA did not make this adjustment in that Report, but has made it this version of PGE's ASC Report.

SCHEDULE 3A: Taxes: - No Changes from July 8, 2008 Report

SCHEDULE 3B: Other Included Items: - No Changes from July 8, 2008 Report

SCHEDULE 4: Average System Cost

1 **Contract System Load:** New Large Single Load (NLSL)

PGE Comment. PGE's July 23, 2008 comment stated that the New Large Single Load for 2006 was 22,950 MWhs.

BPA Response. PGE did not supply any documentation to support a reduction in the 2006 NLSL. BPA will continue to assume the NLSL value used in its PGE Draft ASC Report.

2 **Contract System Cost:** New Large Single Load (NLSL) Costs

a BPA revised the cost of resources used to serve NLSLs to reflect transmission losses between the resource and delivery to the NLSL. All NLSLs are assumed to be served at transmission voltage and transmission losses include the transmission network losses for PGE, in addition to losses of other networks that power from resources travel over to get to the PGE network.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – No Changes from July 8, 2008 Report

SUPPORTING DOCUMENTATION: Salaries and Wages – No Changes from July 8, 2008 Report

SUPPORTING DOCUMENTATION: Labor Ratios - No Changes from July 8, 2008 Report

Miscellaneous Comments

PGE Comment. PGE's July 23, 2008 comment letter also suggested two minor corrections which BPA adopted.

PGE Comment. PGE's July 23, 2008 comment letter suggested that PGE's ASC Forecast Model did not accurately reflect the utility's value of production, transmission and general plant after 2010 and suggests that BPA apply the five year average growth rate for production, transmission and general plant for the period 2002-2006 to the 2010-2013 period in the ASC Forecast Model.

BPA Response. PGE's issue is valid and BPA recognizes that some growth factor may by appropriate to apply in the ASC Forecast model. PGE's suggestion to use a five-year historical growth rate is but one of many possible methods to use to adjust projected production, transmission and general plant for replacements. BPA will defer consideration of this issue to its next Wholesale Power Rate Case when BPA and other parties will have the opportunity to analyze this issue in greater detail.

B. <u>July 8, 2008 - Identification and Analysis of Issues</u>

SCHEDULE 1: Plant Investment/Rate Base:

1 **Account 302,** Intangible Plant Franchises and Consents: insufficient support and documentation for Direct Analysis

a <u>Statement of Issue</u>: In the May 7th filing, PGE directly assigned this account to Production.

b <u>Statement of Facts</u>: The 2008 ASCM permits Direct Analysis only for specified accounts. When utilities perform a Direct Analysis on an Account, they must submit sufficient documentation so that BPA can determine if the functionalization is reasonable. PGE's initial ASC filing did not contain enough information to determine if the functionalization of this Account to Production was reasonable. BPA raised this as an issue in its May 19, 2008 Issue List noting that Direct Analysis of an Account requires detailed documentation and support. In PGE's June 6, 2006 response to BPA's Issue List, additional documentation was provided that supports the functionalization of this Account to Production. PGE's documentation showed that all of the costs in this Account are related either to DEQ Permit costs for Coyote Springs power plant and hydro reliscensing costs.

c <u>Analysis of Position and Decision</u>: BPA accepts PGE's functionalization of Account 302, Intangible Plant Franchises and Consents.

2 **Account 303,** Intangible Plant Miscellaneous: insufficient support and documentation for Direct Analysis

a <u>Statement of Issue</u>: In the May 7th filing, PGE directly assigned this Account.

b <u>Statement of Facts</u>: The 2008 ASCM permits Direct Analysis only for specified accounts. PGE's initial ASC filing did not contain enough information to determine if the functionalization of this Account to was reasonable. BPA raised this as an issue in its May 19, 2008 Issue List noting that Direct Analysis of any an Account requires detailed documentation and support. In PGE's June 6, 2006 response to BPA's Issue List, additional documentation was provided that supports the functionalization of this Account. The documentation contained a detailed breakdown of the software costs by function and the allocation of the costs to Production, Transmission and Distribution/Other. The information was prepared using the OPUC unbundling methodology required under Oregon Senate Bill 1149. BPA agrees with PGE's functionalization. All of the costs contained in this Account are related to computer software.

c Analysis of Position and Decision: BPA accepts PGE's functionalization of Account 303, Intangible Plant Miscellaneous.

3 **Account 182.3,** Other Regulatory Assets: functionalization of Price Risk and Derivative Assets.

a Statement of Issue: In the May 7th filing, PGE functionalized Price Risk and Derivative Assets included in Account 182.3 directly to production.

b Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC functionalized derivative related costs that were included in Account 182.3, Regulatory Assets to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE noted that it has argued that these accounts are production-related and has no further comments.

c Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Regulatory Assets does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 182.3 to Distribution/Other.

4 **Account 186,** Miscellaneous Deferred Debits.

a Statement of Issue: In the May 7th filing, PGE functionalized electricity option premium paid cost included in Account 186 directly to Production.

b Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC filing functionalized derivative related costs that were included in Account 186, Miscellaneous Deferred Debits to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE did not respond to this issue.

c Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Miscellaneous Deferred Debits does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 186 to Distribution/Other.

5 **Account 253,** Other Deferred Credits.

a Statement of Issue: In the May 7th filing, PGE functionalized deferred premiums on power options sold included in Account 253 directly to Production.

b Statement of Facts: The 2008 ASCM functionalizes Accounts 175, 176, 244 and 245, derivative assets and liabilities to distribution other. PGE's initial ASC filing functionalized derivative related costs that were included in Account 253, Other Deferred Credits to Production. BPA raised this as an issue in its May 19, 2008 Issue List noting that Derivative related costs are functionalized to Distribution/Other. In PGE's June 6, 2006 response to BPA's Issue List, PGE did not respond to this issue.

c Analysis of Position and Decision: The 2008 requires that Accounts 175, 176, 244 and 245, derivative assets and liabilities be functionalized to Distribution/Other. The fact that PGE records some derivative related costs as Other Deferred Credits does not allow PGE to functionalize these costs to Production. All derivative related costs are to be functionalized to Distribution/Other, irrespective of what Account they are recorded in. BPA disagrees with PGE on this issue and will functionalize the derivative and price risk management costs included in Account 253 to Distribution/Other.

SCHEDULE 1A: Cash Working Capital – Changed due to changes from in Schedule 3

SCHEDULE 2: Capital Structure and Rate of Return:

1 **Weighted Cost of Capital:** Weighted Cost of Capital from most recent commission rate order.

a Statement of Issue: In the May 7th filing, PGE included the Weighted Cost of Capital from its Oregon PUC Rate filing that is currently under review by the Oregon Public Utility Commission.

b Statement of Facts: BPA's 2008 ASCM allows utility's a return on equity in ASC starting from a Utility's most recent Regulatory Body-approved return. The utility includes the Weighted Cost of Capital from its most recently approved rate order on Schedule 2, which is then grossed up for Federal Income Taxes at the marginal tax rate. In the May 7th filing, PGE included the Weighted Cost of Capital from its Oregon PUC Rate filing that is currently under review by the Oregon Public Utility Commission. When notified of this in the ASC Expedited Review process, PGE submitted a corrected ASC filing, including the Weighted Cost of Capital from its most recently approved rate order.

c Analysis of Position and Decision: BPA accepted PGE's revised changes to its Weighted Cost of Capital.

SCHEDULE 3: Expenses:

2 **REP Reversal:** PGE included the financial portion of the REP Reversal on Schedule 3 of its Initial ASC Filing.

a Statement of Issue: In the May 7th filing, PGE included the financial portion of the REP Reversal on Schedule 3.

b Statement of Facts: In the May 7th filing, PGE included the financial portion of the REP Reversal on Schedule 3. BPA raised this as an issue in its May 19, 2008 Issue List noting that the costs included in the REP Reversal should not include the financial portion of this transaction. In PGE's June 6, 2006 response to BPA's Issue List, agreed with BPA.

c Analysis of Position and Decision: BPA will remove the financial portion of the REP Reversal from the amount included on Schedule 3. Because the purchased power contract between BPA and PGE associated with the REP Reversal expired in September of 2006, BPA will remove the REP

Reversal and the associated entry included in Account 555, Purchased Power for the BPA/PGE contract in the 2009 ASC Forecast Model.

SCHEDULE 3A: Taxes:

1 **Account 408.1** Federal Employment Taxes**:** Support for amounts included in Account 408.1.

a <u>Statement of Issue</u>: In the May 7th filing, PGE did not included an explanation of the amounts included in Account 408.1 Federal Employment Taxes

b <u>Statement of Facts</u>: In the May 7th filing, PGE did not included an explanation of the amounts included in Account 408.1 Federal Employment Taxes. BPA raised this as an issue in its May 19, 2008 Issue List asking for an explanation of amounts included in Account 408.1. In PGE's June 6, 2006 response to BPA's Issue List, PGE provided an explanation.

c <u>Analysis of Position and Decision:</u> BPA accepts PGE's explanation of the amounts included in Account 408.1.

SCHEDULE 3B: Other Included Items:

1 **Account 456** Other Electric Revenues**:** Support for direct analysis of this account.

a <u>Statement of Issue</u>: BPA's 2008 ASCM requires that Account 456 Other Electric Revenues be functionalized using Direct Analysis with a default Functionalization to Production. In the May 7th filing, PGE did not perform a Direct Analysis and used the default functionalization to Production.

b <u>Statement of Facts</u>: BPA's 2008 ASCM requires that Account 456 Other Electric Revenues be functionalized using Direct Analysis with a default Functionalization to Production. In its May 7th filing, PGE chose the default functionalization to Production for Account 456. BPA raised this as an issue in its May 19, 2008 Issue List asking for an explanation of amounts included in Account 456. In PGE's June 6, 2006 response to BPA's Issue List, PGE stated that it did not have time to perform a Direct Analysis on Account 456 and used the default functionalization to Production, but reserved the right to Perform a Direct Analysis in its October 2008 ASC filing on Account 456.

c Analysis of Position and Decision: BPA accepts PGE's functionalization of Account 456.

SCHEDULE 4: Average System Cost

3 **Distribution Loss**:

a Statement of Issue: In its filing, PGE used a 5% Distribution Loss Factor in determination of its ASC.

b Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years.

Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c Analysis of Position and Decision: For purposes of the expedited filing, BPA completed the Distribution Loss Factor calculation outlined in the ASCM ROD, Section 4.10.5.

4 **Contract System Load:** New Large Single Load (NLSL)

a Statement of Issue: PGE submitted data identifying two potential NLSLs with usage of 328,992 MWh.

b Statement of Facts: PGE submitted data identifying two potential NLSLs with usage of 328,992 MWh. BPA reviewed data on the NLSL supplied by PGE.

c Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of servicing an NLSL to be included in the calculation of a Utility's ASC and BPA agrees with PGE's removal of the 2 potential NLSLs from Contract System Load.

5 **Contract System Cost:** New Large Single Load (NLSL) Costs

a Statement of Issue: The May 7th filing Appendix 1 template includes an estimate of the costs of resources used to serve the 2 potential NLSLs.

b Statement of Facts: PGE's estimate of the costs of resources used to serve the 2 potential NLSLs was prepared before BPA published the 2008 ASCM. BPA determined the cost of serving the potential NLSL using the fully allocated cost of all escalated base period post-September 1, 1979, resources and major resource additions and long-term power purchases (5 years or longer contracts) used to determine Exchange Period ASCs as outlined in the ASCM ROD, section 4.5.

c Analysis of Position and Decision: Section 5 (c) of the Northwest Power Act does not permit costs of serving an NLSL to be included in the calculations of a Utility's ASC. BPA revised the costs of resources used to serve the 2 potential NLSLs in the Appendix 1 amended filing. The results are noted in Schedule 4 of the amended Appendix 1 filing and in Table 2 at the end of this report. In addition, BPA will publish its calculation of resource costs used to serve NLSLs for PGE and other utilities at the ASCM web site: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale –

1 **Account 555** Purchased Power: PGE's RL contract with BPA.

a Statement of Issue: PGE's 2006 FERC Form 1 includes the costs and MWH associated with a purchase contract that expired in September of 2006.

b Statement of Facts: BPA's ASC template did not include revenue associated with the Fale-Safe Corporation Purchase on Page 327.2, Line 8 and several miscellaneous adjustments included on Page 327.7.

c Analysis of Position and Decision: For purposes of the expedited filing, BPA corrected PGE's ASC filing to include the items missed by the ASC template. It will review the ASC template to ensure that such items are not omitted in the future.

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1 **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

a Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

b Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

c Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

C. August 4, 2008 - Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, 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.

PGE submitted the following information on new resources with their ASC filing. The first column shows the effect of removing the RL purchase from BPA. The model will replace the MWhs purchased at the RL rate with market purchases.

Table 1: ASC New Resource Additions

		Online Year	2007	2007	2007	2009	2009
		Online Month	1	6	12	4	4
			01/01/07	06/01/07	12/01/07	04/01/09	04/01/09
Other Production Plant							
Other Production	340-346			250,408,852	226,295,378	80,500,000	345,000,000
Fuel Stock	151						
Plant Materials and Operating Supplies	154			89,568			
EPA Allowances	158.1-158.2						
Other Expense							
Other Power - Fuel	547			90,340,172	3,244,333		2,296,333
Other Power - Operations (Excluding 547 - Fuel)	546-550			1,849,114	1,157,000		
Other Power - Maintenance	551-554			4,323,592	3,727,000		
Property Insurance	924			145,000	530,000	188,537	808,015
Depreciation	403	OK		4,582,000	11,718,000	1,610,000	17,864,748
Firm Sales for Resale ($)	447	OSS & PP					
Firm Sales for Resale (MWh)		OSS & PP					
Expected Annual Generation (MWh)		OSS & PP		2,033,378	417,515	0	501,018
Property Taxes Production							
Total Production Property	262			2,437,809	2,094,000	1,208,912	5,181,051
Purchased Power Contracts (From BPA)							
PF Purchase Cost ($)							
PF Purchased Power (MWh)							
Slice Purchase Cost ($)							
Slice Purchased Power (MWh)							
PF Generic #1 Purchase ($)							
PF Generic #1 Purchasd Power (MWh)							
PF Generic #2 Purchase ($)							
PF Generic #2 Purchasd Power (MWh)							
Contract Termination ($)							
Contract Termination (MWh)							
Purchased Power Contracts (Market)							
Contract Termination ($)		OSS & PP	(43,681,235)				
Contract Termination (MWh)		OSS & PP	(1,690,158)				
Purchased Power (Excluding REP Reversal)	555	OSS & PP					
Purchased Power (MWh)		OSS & PP					
System Control and Load Dispatching	556						
Other Expenses	557						
Transmission Plant							
Transmission Plant	350-359			23,632,333			
Plant Materials and Operating Supplies							
Transmission Expenses							
Transmission of Electricity to Others (Wheeling)	565						
Total Operations less Wheeling	560-567						
Total Maintenance	568-573						
Property Insurance	924						
Depreciation	403			491,580			
Other Electric Revenues	456						
Revenues from Transmission of Electricity of Others (i)	456.1						
Property Taxes Transmission							
Total Transmission Property	262						

D. July 8, 2008 - Exchange Period ASC New Resource Additions

Table 2: ASC New Resource Additions

			Online Year	2007	2007	2009	2009	2007
			Online Month	6	12	4	4	1
				06/01/07	12/01/07	04/01/09	04/01/09	01/01/07
Other Production Plant								
Other Production	340-346			250,408,852	226,295,378	80,500,000	345,000,000	
Fuel Stock	151							
Plant Materials and Operating Supplies	154			89,568				
EPA Allowances	158.1-158.2							
Other Expense								
Other Power - Fuel	547			90,340,172	3,244,333		2,296,333	
Other Power - Operations (Excluding 547 - Fuel)	546-550			1,849,114	1,157,000			
Other Power - Maintenance	551-554			4,323,592	3,727,000			
Property Insurance	924			145,000	530,000	188,537	808,015	
Depreciation	403	OK		4,582,000	11,718,000	1,610,000	17,864,748	
Firm Sales for Resale ($)	447	OSS & PP						
Firm Sales for Resale (MWh)		OSS & PP						
Expected Annual Generation (MWh)		OSS & PP		2,033,378	417,515	0	501,018	
Property Taxes Production								
Total Production Property	262			2,437,809	2,094,000	1,208,912	5,181,051	
Purchased Power Contracts (From BPA)								
PF Purchase Cost ($)								
PF Purchased Power (MWh)								
Slice Purchase Cost ($)								
Slice Purchased Power (MWh)								
PF Generic #1 Purchase ($)								
PF Generic #1 Purchasd Power (MWh)								
PF Generic #2 Purchase ($)								
PF Generic #2 Purchasd Power (MWh)								
PF Generic #3 Purchase ($)								
PF Generic #3 Purchasd Power (MWh)								
Purchased Power Contracts (Market)								
Purchased Power (Excluding REP Reversal)	555	OSS & PP						(118,730,120)
Purchased Power (MWh)		OSS & PP						(1,690,158)
System Control and Load Dispatching	556							
Other Expenses	557							
Transmission Plant								
Transmission Plant	350-359			23,632,333				
Plant Materials and Operating Supplies								
Transmission Expenses								
Transmission of Electricity to Others (Wheeling)	565							
Total Operations less Wheeling	560-567							
Total Maintenance	568-573							
Property Insurance	924							
Depreciation	403			491,580				
Other Electric Revenues	456							
Revenues from Transmission of Electricity of Others (i)	456.1							
Property Taxes Transmission								
Total Transmission Property	262							

V. August 4, 2008 - FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following table summarizes the forecast of Contract System Cost and Contract System Load for purposes of determining PGE's forecast ASC for FY 2009 through FY 2013. The procedure in making the determinations are outlined in the 2008 ASCM ROD and described in this report. The results shown herein are forecast for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and for use in the calculation of the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 3: FY 2009-2013 ASC Summary

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	$986,346,826	$979,019,415	$1,010,360,845	$1,033,551,441	$1,060,622,115
Transmission	114,158,885	114,630,209	115,352,492	116,117,639	116,958,740
NLSL Fully Allocated Cost ($/MWh)	73.33	69.43	69.48	68.77	67.96
(Less) NLSL Costs	24,124,218	22,842,949	22,859,327	22,623,455	22,359,524
Total Contract System Cost	$1,076,381,493	$1,070,806,676	$1,102,854,011	$1,127,045,625	$1,155,221,331

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) NLSL	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net or NLSL)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss	859,034	877,933	897,247	916,987	937,160
Total Contract System Load	18,768,552	19,188,698	19,618,087	20,056,923	20,505,413

AVERAGE SYSTEM COST

ASC ($/MWh)	**$57.35**	**$55.80**	**$56.22**	**$56.19**	**$56.34**

VI. July 8, 2008 - FINAL EXPEDITED ASC FORECAST for FY 2009-2013

Table 4: FY 2009-2013 ASC Summary

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	983,882,624	986,083,703	997,133,635	1,018,504,435	1,042,287,576
Transmission	114,158,885	114,630,209	115,352,492	116,117,639	116,958,740
NLSL Fully Allocated Cost ($/MWh)	70.98	69.33	67.47	66.69	65.89
(Less) NLSL Costs	23,352,660	22,810,279	22,197,059	21,940,281	21,678,532
Total Contract System Cost	1,074,688,849	1,077,903,633	1,090,289,068	1,112,681,794	1,137,567,783

CONTRCT SYSTEM LOAD

Total Retail Load @ Meter	18,238,510	18,639,757	19,049,832	19,468,928	19,897,245
(Less) NLSL	328,992	328,992	328,992	328,992	328,992
Total Retail Load (Net or NLSL)	17,909,518	18,310,765	18,720,840	19,139,936	19,568,253
Distribution Loss	859,034	877,933	897,247	916,987	937,160
Total Contract System Load	18,768,552	19,188,698	19,618,087	20,056,923	20,505,413

AVERAGE SYSTEM COST

ASC ($/MWh)	**57.26**	**56.17**	**55.58**	**55.48**	**55.48**

VII. BPA STATEMENT

This ASC determination is BPA's best estimate of PGE's FY 2009 ASC based on the information and data provided from PGE during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination, FY 2009. This determination is made solely for purposes of providing estimated FY 2009 ASCs for use in the development of BPA's FY 2009 power rates in BPA's WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such review will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance to the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System Cost of PGE for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The amended Appendix 1 Filing, Forecast Model, and resource cost determination to the NLSL assessment used to calculate PGE's ASCs can be viewed at BPA ASC website: http://www.bpa.gov/corporate/finance/ascm/filings.cfm.