reinstatement; (2) Title; (3) Summary of the collection; (4) Description of the need for, and proposed use of, the information; (5) Respondents and frequency of collection; and (6) Reporting and/or Recordkeeping burden. OMB invites public comment.

The Department of Education is especially interested in public comment addressing the following issues: (1) Is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology.

Dated: February 4, 2008.

Angela C. Arrington,

IC Clearance Official, Regulatory Information Management Services, Office of Management.

Federal Student Aid

Type of Review: Revision.

Title: Fiscal Operations Report for 2007–2008 and Application to Participate for 2009–2010 (FISAP) and Reallocation Form E40–4P.

Frequency: Annually.

Affected Public: Not-for-profit institutions (primary), Businesses or other for-profit, Federal Government, State, Local, or Tribal Gov't, SEAs or LEAs.

Reporting and Recordkeeping Hour Burden:

Responses: 5,798.

Burden Hours: 27,935.

Abstract: This application data will be used to compute the amount of funds needed by each school for the 2009–2010 award year. The Fiscal Operations Report data will be used to assess program effectiveness, account for funds expended during the 2006–2007 award year, and as part of the school funding process. The Reallocation Form is part of the FISAP on the Web. Schools will use it in the summer to return unexpended funds for 2006–2007 and request supplemental FWS funds for 2008–2009.

Requests for copies of the proposed information collection request may be accessed from *http://edicsweb.ed.gov*, by selecting the ''Browse Pending Collections'' link and by clicking on link number 3581. When you access the information collection, click on ''Download Attachments'' to view. Written requests for information should be addressed to U.S. Department of Education, 400 Maryland Avenue, SW., LBJ, Washington, DC 20202–4537. Requests may also be electronically mailed to *ICDocketMgr@ed.gov* or faxed to 202–401–0920. Please specify the complete title of the information collection when making your request.

Comments regarding burden and/or the collection activity requirements should be electronically mailed to *ICDocketMgr@ed.gov*. Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339.

[FR Doc. E8–2259 Filed 2–6–08; 8:45 am]

BILLING CODE 4000–01–P

ELECTION ASSISTANCE COMMISSION

Sunshine Act Meeting Notice

AGENCY: United States Election Assistance Commission (EAC).

ACTION: Notice of Public Meeting Roundtable Discussion.

DATE & TIME: Friday, February 29, 2008, 9 a.m.–2 p.m. (EST).

PLACE: United State Election Assistance Commission, 1225 New York Ave., NW., Suite 150, Washington, DC 20005.

Agenda

The Commission will host a voting systems manufacturer roundtable discussion regarding the Technical Guidelines Development Committee's (TGDC) recommended voluntary voting system guidelines (VVSG). The discussion will be focused upon the following topics: (1) The dominant business model for voting system manufacturers and their role as innovators; (2) How to evaluate innovative systems, for which there are no standards for purposes of certification; (3) The value and risks associated with Open Ended Vulnerability Testing; (4) The processes associated with testing to the VVSG and possible modifications; (5) Whether the recommend TGDC standards create appropriate functional standards that promote innovation; (6) The cost implications of the proposed VVSG; (7) Development of systems to the proposed VVSG and possible time frames.

This meeting will be open to the public.

PERSON TO CONTACT FOR INFORMATION: Matthew Masterson, Telephone: (202) 566–3100.

Thomas R. Wilkey,

Executive Director, U.S. Election Assistance Commission.

[FR Doc. 08–565 Filed 2–5–08; 10:57 am]

BILLING CODE 6820–KF–M

DEPARTMENT OF ENERGY

Bonneville Power Administration

Proposed 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 Planning and Conservation Act

AGENCY: Bonneville Power Administration (BPA), DOE.

ACTION: Notice; request for comments (BPA File No.: ASCM–08).

SUMMARY: Bonneville Power Administration (BPA) proposes a revised methodology for determining the average system cost (ASC) of resources for regional electric utilities that participate in the Residential Exchange Program (REP) authorized by section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The ASC methodology is used in the determination of monetary benefits paid by BPA to utilities participating in the REP. The Northwest Power Act authorizes the BPA Administrator to determine utilities' ASCs based on a methodology developed by BPA in consultation with the Northwest Power and Conservation Council, BPA customers and state regulatory agencies in the Pacific Northwest. The existing methodology was adopted by BPA and approved by the Federal Energy Regulatory Commission (FERC or Commission) in 1984 (1984 ASC Methodology). On August 1, 2007, the Administrator initiated a series of public meetings in which informal comment was taken on 17 specific issues pertaining to the 1984 ASC Methodology. Based in part on public comment, the methodology proposed by BPA in this notice redefines the types of capital and expense items includable in ASC, establishes new data sources from which ASCs are to be derived, and changes the nature and timing of BPA's procedures for review of ASC filings by utilities participating in the REP. This notice also contains detailed procedures for public participation in the consultation proceeding.

This consultation proceeding is intended to facilitate the compilation of a full record upon which the Administrator will base his decision for a final ASC Methodology. Although preliminary informal comments have already been made by some groups and members of the public, this notice formally solicits public comment. With

the issuance of this proposal, BPA welcomes different approaches, new ideas and other types of feedback from interested parties. This proposal was developed with guidance from public workshops and is meant to provide a foundation that will facilitate further ideas and approaches.

In order to participate in the REP during FY 2009, a Pacific Northwest utility must notify BPA of its intent to participate by February 22, 2008. A utility also must submit an ASC filing (an Appendix 1) to BPA by March 3, 2008, or BPA will use the corresponding Appendix 1 from its WP–07 Supplemental Power Rate Adjustment Proceeding as the base filing to determine the utility's ASCs for FY 2009. During the comment period on the proposed ASC Methodology, interested parties will have the opportunity to participate in an expedited process for determining exchanging utilities' ASCs for FY 2009 based on the proposed methodology. In addition to the comments submitted, BPA expects to learn through this expedited process where improvements or changes to the proposed methodology can be made. Workshops will be held during the comment period to help facilitate feedback and explore different ideas. BPA strives to develop, in concert with the region, an ASC Methodology that will be legally sustainable, efficient, and durable over time.

ADDRESSES: Interested members of the public may make written comments between February 8, 2008, and May 2, 2008. Comments must be received by 5 p.m., Pacific Prevailing Time, on the specified date in order to be considered in the Record of Decision for the ASC Methodology, which will be submitted to FERC for interim and final approval. BPA will also post written comments online. Written comments may be made as follows: online at BPA's Web site: *http://www.bpa.gov/comment,* by mail to: BPA Public Affairs, DKE–7, P.O. Box 14428, Portland, OR 97293–4428, or by facsimile to 503–230–3285. Please identify written or electronic comments as ''2008 ASC Methodology.'' Information and comments received by BPA concerning the proposed ASC Methodology will be posted at *http://www.bpa.gov/corporate/Finance/ascm.*

FOR FURTHER INFORMATION CONTACT: Ms. Michelle Manary, Manager, Residential Exchange Program—FE–2, P.O. Box 3621, Portland, OR 97208. Ms. Leslie M. Dimitman, Paralegal Specialist, Office of General Counsel, LP–7, P.O. Box 3621, Portland, OR 97208. Interested persons may also call Ms. Dimitman at 503–230–5515, or the general BPA toll-free numbers 800–282–3713 (answered Monday through Friday 6:30 a.m. to 5 p.m.) or 866–879–2303 (answered by voice-mail).

SUPPLEMENTARY INFORMATION:

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I. Background

A. Relevant Statutory Provisions

Section 5(c)(1) of the Northwest Power Act, 16 U.S.C. 839c(c)(1), provides that BPA shall acquire certain amounts of power offered for sale to BPA by a Pacific Northwest electric utility at the average system cost of the utility's resources in each year. In exchange, BPA shall offer to sell ''an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.'' [1] *Id.* Sales to the utility may not be restricted below the amount of power acquired from the utility. 16 U.S.C. 839c(c)(6). Under this ''residential exchange,'' there is generally no power transferred either to or from BPA.[2] The ''equivalent amount of electric power'' exchanged by BPA with the participating utility is priced at the same rate as that for general requirements sales to BPA's preference customers (the ''Priority Firm or PF rate''), subject to adjustment pursuant to section 7(b)(2) of the Northwest Power Act (the ''PF Exchange rate''). *See* 16 U.S.C. 839e(b)(1)–(3). By establishing the REP, Congress intended to address the issue of wholesale rate disparity that can exist between BPA's preference customers and investor-owned customers. Because power sold by BPA to exchanging utilities must be treated as resold to the participating utility's residential consumers within the region, ''wholesale rate parity'' is achieved. This wholesale rate parity is the first attribute of the REP.

In contrast, the amount paid by BPA to the participating utility is not a conventional wholesale power rate. Section 5(c)(1) of the Northwest Power Act states that BPA is to pay ''the average system cost of that [exchanging] utility's resources.'' 16 U.S.C. 839c(c)(1). Section 5(c)(7) of the Northwest Power Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in consultation proceedings. 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).

Generally, the BPA PF rate has been lower than participating utilities' ASCs under the 1984 ASC Methodology. The resulting monetary benefits BPA paid to participating utilities, or ''net cost of the exchange,'' is the second attribute of the REP. As noted above, the REP is not a conventional power transaction. System schedulers do not dispatch the exchange; line losses are not incurred. The power purchase and sale concept was created by Congress for BPA ratemaking purposes. *See* 16 U.S.C. 839e(b)(1).[3] Practically speaking, the purpose of the REP is to exchange costs for the benefit of the residential and small farm ratepayers of participating utilities. When the BPA PF Exchange rate is lower than a participating utility's ASC, BPA pays the net cost to that utility. However, when the PF Exchange rate is higher than the ASC, *i.e.*, when the net cost of the exchange is negative, BPA has previously provided the utility a unilateral right to ''deem'' its ASC equal to the PF rate, so that no payment flows from the utility to BPA.[4]

Furthermore, Northwest Power Act section 5(c)(4), 16 U.S.C. 839c(c)(4), recognizes that BPA's PF rate, insofar as it applies to the REP, may carry one or more ''supplemental rate charges'' after July 1, 1985, due to implementation of section 7(b)(3) of the Northwest Power Act. 16 U.S.C. 39e(b)(3). Were this to occur and cause the PF Exchange rate to exceed a participating utility's ASC, that utility has the statutory right to terminate its participation in the REP. 16 U.S.C. 839c(c)(4).

The monetary benefits of the REP must be passed through directly to the participating utilities' residential and small farm consumers in accordance with section 5(c)(3) of the Northwest Power Act, 16 U.S.C. 839c(c)(3), guarding against the possibility that the

[1] The exchange was set equal to 50 percent of a participating utility's qualifying residential and small farm load as of July 1, 1980, and increased in equal annual increments to 100 percent of such load over 5 years. *See* 16 U.S.C. 839c(c)(2).

[2] Section 5(c)(5) allows BPA to acquire an ''equivalent amount of electric power from other sources to replace power sold to [a participating] utility,'' if the cost of such replacement acquisition is less than the applicable ASC. Implementation of this provision may result in actual power sales to the exchanging utility.

[3] The outcome of this consultation proceeding will not change the way in which BPA establishes rates under section 7 of the Northwest Power Act. The resource concept was devised by Congress to allocate the benefits and costs of the Federal Base System among competing classes of BPA customers. However, the resource concept should not obfuscate the nature of the REP as a transfer payment from BPA to the participating utilities.

[4] However, BPA has historically kept an account of such unpaid ''deemer'' amounts, which must be paid before the utility can receive positive REP benefits.

utility might set retail residential rates that counteracted the benefits of the REP. In addition, it is incumbent upon BPA to establish an ASC methodology that ensures that the net cost of the exchange does not exceed the limits established by Congress in the Northwest Power Act. *See* 16 U.S.C. 839c(c)(7)(A), (B) and (C).

The ASC methodology must also be designed so that BPA does not become the ''deep pocket'' to which participating utilities may shift excessive or improper resource costs. The ASC methodology should give participating utilities an incentive to minimize their costs. Otherwise, BPA may not be able to satisfy the requirement of section 7(a) of the Northwest Power Act that its rates recover its total revenue requirement. BPA is a self-financing government agency, which must recover its costs through rates for sales of electric power and energy.

B. Average System Cost Methodology Background

The first ASC Methodology was developed in consultation with the region in 1981. *See* 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984); *see also PacifiCorp* v. *F.E.R.C.,* 795 F.2d 816 (9th Cir. 1986). The 1984 ASC Methodology has been in effect since that time. In the mid-1990s, BPA and its participating ''Utilities'' [5] agreed to a number of settlements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implement the REP. Because these settlements did not require the participating utilities to submit ASC filings, BPA temporarily suspended its ASC review process.

Prior to BPA's WP–02 power rate proceeding, BPA sought to resolve REP disputes by offering REP Settlement Agreements (Settlement Agreements) to regional investor-owned utilities. Under these Agreements, BPA would provide the participating utilities 1,000 aMW of actual power and 900 aMW of financial benefits for the FY 2002–2006 period, and 2,200 aMW of benefits for FY 2007–2011. Power sales were made at the Residential Load (RL) Firm Power Rate. Financial benefits were calculated based on the difference between BPA's RL rate and a forecast of market prices.

The Settlement Agreements were challenged in the U.S. Court of Appeals for the Ninth Circuit. On May 3, 2007, the Court held that the Settlement Agreements executed by BPA and the investor-owned utilities were inconsistent with the Northwest Power Act. *See Portland General Elec. Co.* v. *Bonneville Power Admin.,* 501 F.3d 1009 (9th Cir. 2007). As a result of the Court's decision, BPA must be prepared to resume the REP by offering RPSAs to its Utility customers. In addition to the RPSAs, BPA is conducting this consultation proceeding to revise the ASC Methodology concurrent with a section 7(i) rate proceeding to consider revisions to the Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology, implement the section 7(b)(2) rate test, and develop rates consistent with the Court's remand in a related case. *See Golden NW Aluminum, Inc.* v. *Bonneville Power Admin.,* 501 F.3d 1037 (9th Cir. 2007).

C. The Current Average System Cost Methodology

Under the 1984 ASC Methodology, utilities file with BPA ''Appendix 1'' forms containing cost information based on rate orders from state utility commissions or consumer-owned utility governing bodies. BPA reviews each Appendix 1 for conformance with criteria specified in the Methodology. *See* 18 CFR 301.1. Appendix 1 filings are subject to review for 210 days from the start of the relevant exchange period, which is triggered by a change in retail rates. Not later than 80 days after a Utility files a new Appendix 1, Regional Power Sales Customers or their designee may submit written challenges to costs included in the Utility's Contract System Costs. Not later than 90 days following the date the Utility files its revised Appendix 1, BPA mails to the Utility and all parties a list of issues or challenged costs concerning the Utility's revised Appendix 1 and requesting comments from all parties. Written comments on the issues list from all parties are due 30 days after the issue list is filed. Parties may submit cross-comments in response to comments on the issues list up to 15 days after the written comments are submitted. Parties may request oral argument before the Administrator or the Administrator's designee up to 150 days after a Utility files a new Appendix 1. BPA also has the right under the 1984 ASC Methodology to issue a notice to parties requesting comments on costs that had not been challenged previously, on Contract System Loads, and other issues not raised previously. Comments from parties on such notice are due 150 days after a Utility files a new Appendix 1. Written cross-comments in response to comments on the BPA notice are due 165 days after a Utility files a new Appendix 1.

If BPA grants a request for oral argument, it is presented up to 180 days after a Utility files a new Appendix 1. BPA must issue a final determination on the revised Appendix 1 no later than 210 days after a Utility files a new Appendix 1.

Discovery is another component of the 1984 ASC Methodology. BPA can request data from a Utility any time during the 210-day review period. The Utility is required to respond within 30 days of receiving the data request. In addition, parties to the ASC review can submit data requests up to 40 days after the Utility files its revised Appendix 1. The Utility must respond within 65 days after the Utility files its revised Appendix 1.

Consumer-owned utilities may execute RPSAs for participation in the REP. Because consumer-owned utilities are not regulated by the state commissions in the Pacific Northwest, and because they are not required to make FERC Form 1 filings, preparation and review of ASC filings is more burdensome for all parties concerned. The difficulty in the preparation and review of ASC filings has been a major cause of disputes between BPA and participating consumer-owned utilities and became one of the issues leading BPA and the consumer-owned utilities to settle out their REP participation in the late 1980s.

D. BPA and Customer Concerns With the 1984 ASC Methodology

The reliance on state regulatory agencies to determine the level of costs included in the ASC of a participating Utility under the 1984 ASC Methodology, known as the ''jurisdictional costing approach,'' has resulted in a long, burdensome, expensive and often contentious review process that many BPA customers said could be improved and streamlined. The 210-day review period for each ASC filing under the current methodology means that BPA and its customers are almost always reviewing an ASC filing. Given the tremendous advancement in information and communication technology (ICT) since the early 1990s, the review process and implementation costs can be reduced substantially through use of electronic filings, e-mail and other aspects of ICT without changing the existing ASC Methodology. However, BPA believes that further efficiencies in the ASC filing and review process could be obtained if BPA were to adopt a new

[5] ''Utility'' is used here as a defined term: the investor-owned utility or consumer-owned utility that is a Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

framework for obtaining the data required for an ASC filing.

One issue related to the ''jurisdictional costing approach'' that has not changed since REP disputes were addressed through settlements is the volume of utility rate orders. Because any commission-ordered change in retail rates triggers a new ASC filing under the 1984 ASC Methodology, BPA and its customers could be faced with requirements to review several ASC filings a year for each investor-owned utility participating in the REP because of adjustment clauses and tracker filings in each state where the Utility provides retail electric service to customers.

BPA is mindful of the difficulty in preparing ASC filings for consumer-owned utilities that may want to participate in the REP and hopes that the proposed methodology will ease the burden of preparing and reviewing Appendix 1 filings.

E. Public Participation in the Consultation Proceeding

This consultation proceeding is intended to facilitate the compilation of a full record upon which the Administrator will base the decision to establish the ASC Methodology. Preliminary informal comments have already been submitted by groups, including investor-owned utilities, state regulatory agencies and consumer-owned utility customers. This notice solicits a new round of formal comments from interested members of the public.

Interested members of the public may make written comments between February 8, 2008 and May 2, 2008. Comments must be received by 5 p.m., Pacific Prevailing Time, on the specified date in order to be considered in the Record of Decision for the ASC Methodology. BPA will also post written comments online. Written comments may be made as follows: Online at BPA's Web site: *www.bpa.gov/comment*, by mail to: BPA Public Affairs, DKE–7, P.O. Box 14428, Portland, OR 97293–4428, or by facsimile to 503–230–3285. Please identify written or electronic comments as ''2008 ASC Methodology.'' Information and comments received by BPA concerning the proposed ASC Methodology will be posted at *http://www.bpa.gov/corporate/Finance/ascm*.

After the written comment stage, an opportunity will be provided for oral presentations before the Administrator, which will be transcribed for inclusion in the record. The date, time, and location of oral presentations will be specified in a future communication. Only those persons who participate in the written comment stage of the consultation will have the option of making an oral presentation before the Administrator. During any stage of the proceeding, negotiated resolutions of issues raised by BPA or by commenters may be incorporated into the record by means of written stipulations.

After completion of the foregoing proceedings, the Administrator will issue a Record of Decision on the revised ASC Methodology. The revised ASC Methodology will then be submitted to the Federal Energy Regulatory Commission for review and approval.

II. The Proposed Average System Cost Methodology

A. Introduction

The revised methodology proposed by BPA in this notice is intended to implement the Northwest Power Act, help alleviate the administrative burden and expense associated with the jurisdictional approach to ASC determinations, and to reflect changes in the organization and operation of the electric utility industry since the 1984 ASC Methodology was approved. In preparing this proposal, BPA took into account the issues and concerns raised by parties during workshops held in August through November of 2007. Although BPA is proposing a number of broad changes to the 1984 ASC Methodology, the proposal is not a complete reconstruction of the previous 1984 ASC Methodology. Several portions of the proposal reflect features from the 1984 ASC Methodology that remain viable in today's environment.

BPA anticipates that there will be a wide variety of comments on the proposed ASC Methodology, and also expects that comments will raise issues that may not have been apparent to BPA. BPA stresses the importance of written comments that precisely state each commenter's position on issues of concern, whether the comments be positive or negative, so that a complete record can be compiled. Numerical analyses and examples will be of particular assistance to BPA in developing a revised ASC Methodology. BPA also welcomes negotiations and possible settlements of issues.

B. The Uniform Cost Approach to Determining Average System Cost Under the Proposed Methodology

Both the 1981 and 1984 ASC Methodologies used the jurisdictional costing approach for ASC determinations. As noted above, using the jurisdictional cost approach as the data source for the ASC calculations has proven to be inefficient, cumbersome, and extremely contentious. BPA therefore is proposing to not use a jurisdictional costing approach for the revised ASC Methodology. In its place, BPA is proposing to use a data source that is uniform and that facilitates ease of administration for all parties. Such data can be found for investor-owned utilities in the FERC Form No. 1 (Form 1), a compilation of financial and operating information prepared annually in accordance with the Commission's Uniform System of Accounts for Public Utilities and Licensees. *See* 18 CFR 101 (2007). As explained more fully below, consumer-owned utilities that wish to exchange with BPA will be required to submit equivalent information to establish their ASCs.

Under the proposed ASC Methodology, the Utility may include in its ASC only actual costs documented in its Form 1 or equivalent, with limited exceptions. These exceptions include the following: First, equity return for investor-owned utilities will be determined in accordance with procedures described later in this notice; second, Federal income taxes will be included at the marginal Federal income tax rate; third, the Form 1 does not always contain enough information or level of detail to allow BPA to determine whether costs are includable in ASC, thus requiring supplemental information; and fourth, BPA will require utilities that do not file a Form 1 with FERC to submit audited financial data in a format comparable to the Form 1 and a detailed cost of service analysis prepared by an independent accounting or consulting firm, approved by the Utility's Regulatory Body [6] and used as the basis for setting retail rates currently in effect.

BPA is proposing an approach for determining a utility's ASC that is aimed at simplicity, transparency and minimal administrative burden for all parties. BPA recognizes this may make it difficult to reflect unique circumstances of individual utilities, which may have an impact on their ASCs. BPA is open to different types of approaches and welcomes such suggestions during the comment period.

[6] ''Regulatory Body'' is used here as a defined term: A state regulatory body, consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a jurisdiction.

C. Procedural Format for ASC Determinations Under Revised ASC Methodology

1. ASC Determination Process Guidelines

BPA proposes to review each Utility's filed ASC in a simplified administrative process. This process will commence during the period prior to BPA filing an initial proposal for a change in wholesale power rates, referred to as the Review Period. An investor-owned utility would submit a ''base period ASC'' to BPA using data from the prior year's Form 1 on or before May 1 of each year. For Utilities not required to submit a Form 1 to FERC, the base period ASC would be determined from a filing similar in format to a Form 1. The Utility's base period ASC will be projected by BPA to determine the ASC for the BPA rate period.[7] Escalating the cost data used to determine the base period ASC to be consistent with the test year(s) of the BPA rate proposal addresses many issues of temporal consistency between ASCs and BPA's PF Exchange rate. As a general matter, once the Administrator determines the ASC for each Utility, the ASC will remain at that level for the term of the BPA rate period.

Proposed changes to established ASCs would only be allowed under two specific conditions. First, the ASC may be adjusted in the event a Utility acquires a new service territory or relinquishes all or a portion of its service territory. A second adjustment may be made to account for major new resource additions, purchases, retirements or sales. In the event that a Utility has a resource that is projected to come on-line or be purchased and used to meet that Utility's retail regional load during the BPA rate period, the Utility will submit two ASC filings: (1) One conforming to the Form 1 described above, and (2) a second filing that incorporates the costs associated with the new resource based on the expected commercial operation date of the new resource or, for resource purchases, the date the sale is completed and the costs associated with the purchased resource used to meet that utility's regional retail load. In addition to including the estimated capital and operating costs of the new resource, the Utility must also estimate the changes in purchased power expense, sales for resale credit and other costs based on the additional generation provided by the new resource. Because the commercial on-line dates of power plants often change during the construction process, BPA will not adjust the Utility's ASC until the new generating resource begins commercial operation.

For a major resource used to meet the Utility's regional retail load that is projected to be unable to serve load, retired or sold during the BPA rate period, BPA proposes that the Utility make two ASC filings: (1) One conforming to the Form 1 described above, and (2) a second filing that excludes the costs associated with the retired or sold resource based on the expected retirement or closing date of the resource. In addition to including the reduction in estimated capital and operating costs of the retired or sold resource, the Utility must also estimate the changes in purchased power expense, sales for resale credit and other costs based on the generation formerly provided by the retired or sold resource. BPA proposes not to adjust the Utility's ASC until the official retirement or transfer date of the generating resource.

BPA proposes that all Utilities be required to submit ASC filings using BPA's electronic template (Appendix 1)[8] on or before May 1 of every year. Several areas of the ASC filing template require additional data and/or analyses. The additional data/analyses must also be in electronic format and submitted at the same time as the Appendix 1 template. The filing, along with the additional data and support, will be made available to BPA customers and other parties for review through BPA's external Web site. Each filing may be reviewed by BPA or its designee to determine whether the costs are consistent with Generally Accepted Accounting Principles for electric utilities and consistent with the ASC Methodology.

BPA envisions that this approach will reduce the time, administrative burden and cost to BPA, the Utility, other BPA customers and other interested parties without significantly affecting the accuracy of the ASC determination when compared to the more cumbersome process required under the 1984 ASC Methodology. BPA proposes that ASC determinations prior to BPA's rate cases will replace the multiple determinations in each year required under the 1984 ASC Methodology for each jurisdiction in which a Utility provides retail residential service upon each change in retail rates.

The revised ASC Methodology has characteristics similar to ratemaking based on an historical test year incorporating end-of-year data. Each Utility would be permitted to include the same types of costs in ASC based on actual data from the same calendar-year period. It is uniform in contrast to the 1984 ASC Methodology, which relied on data from retail rate proceedings throughout the Northwest, each using different ratemaking methodologies and test years.

Although the numbers included in Form 1 accounts by Utilities will help expedite ASC reviews, Utilities' ASC filings will continue to be scrutinized by BPA, its customers and other participants in the ASC review process. BPA has a statutory responsibility to ensure that all improper costs are excluded from ASCs. Each ASC filing must contain a statement, signed by a senior officer of the Utility, stating that all data submitted by the Utility were compiled in strict compliance with the Commission's Uniform System of Accounts, the ASC Methodology, and Generally Accepted Accounting Principles, and are consistent with applicable orders and policies of their Regulatory Body. For Utilities not required to submit a Form 1, the attestation will state that the data were compiled in strict compliance with the Utility's financial statements, the ASC Methodology, and policies and orders from the Utility's Regulatory Body. BPA proposes that any filing that does not contain this attestation will not be accepted by BPA for determination of an ASC.

BPA invites and welcomes comments on alternative sources of verifiable data for use in determining ASC. Such comments should contain detailed explanations of the verification safeguards inherent in any proposed alternative as well as procedural alternatives.

2. Transition Implementation of the REP

BPA hopes to begin the implementation of the REP for eligible utilities on October 1, 2008. To do so, BPA must negotiate and execute new RPSAs with Utilities, establish a revised ASC Methodology, and establish ASCs under the revised Methodology. As noted below, BPA also intends to implement the proposed ASC Methodology in an expedited ASC review during the spring of 2008 in order to identify any problems that might arise in implementing the Methodology. The results of the expedited ASC review will be used as a starting point for the determination of final ASCs for FY 2009. The expedited

[7] BPA will forecast the utility's ASC for an additional four years as required for the section 7(b)(2) rate test in BPA's wholesale power rate adjustment proceedings.

[8] Appendix 1 refers to the appendix to both the current and proposed ASC methodology containing the form on which the exchanging utility reports its Contract System Costs and other information required for the calculation of ASC.

ASC review will be implemented as follows.

After publication of the proposed ASC Methodology, a Utility intending to participate in the REP beginning October 1, 2008, must notify BPA of its intent by February 22, 2008. If a Utility fails to notify BPA of its intent to participate in the REP in FY 2009 by February 29, 2008, the Utility will be ineligible to receive any REP benefits during the FY 2009 rate period. A Utility must file its Appendix 1 based on the proposed ASC Methodology with BPA by March 3, 2008. If it fails to do so, BPA will rely on the Appendix 1 for the Utility included by BPA in its WP–07 Supplemental Rate Proposal to determine ASCs for FY 2009. BPA will provide electronic access to the Appendix 1 filings on March 4, 2008, to all Regional Power Sales Customers and other interested parties. BPA will review all Appendix 1 filings concurrently in an expedited public process. Interested parties will have the opportunity to intervene in BPA's review. Petitions to intervene must be filed with BPA by March 11, 2008. Data requests must be submitted by March 14, 2008. BPA will commence discovery workshops on all Appendix 1 filings on March 26, 2008. BPA and parties will address and resolve all discovery issues in the workshops. BPA and parties may electronically file an issue list identifying and providing full arguments regarding the contested elements of a Utility's Appendix 1 filing by April 10, 2008. The Utility will electronically file, and other parties may file, a response to the issue lists on April 24, 2008. A second workshop will be held on April 29, 2008, to discuss and resolve, to the extent possible, the identified issues. BPA will then review the parties' arguments, rule on such issues, and publish and electronically serve all parties with a Draft ASC Reports on May 9, 2008. The Utility and parties may file comments on the Draft ASC Reports by May 23, 2008. After reviewing the comments, the BPA Administrator will issue Final ASC Reports on June 6, 2008.

After BPA develops the final proposed ASC Methodology, BPA will file the Methodology with FERC for confirmation and approval. BPA hopes to receive interim approval of the Methodology on or around September 1, 2008. After FERC approval, BPA proposes to review the ASC determinations resulting from the expedited ASC review. BPA will compare the proposed ASC Methodology provisions with the FERC-approved Methodology. If there are no differences between the data included in the Utilities' initial Appendix 1s (or the Appendix 1 filings developed by BPA for the WP–07 Supplemental Rate Proposal) and the Appendix 1s to be filed under the final Methodology, the Utilities' initial Appendix 1s (or the default WP–07 Supplemental Appendix 1s) can be used for the Utilities' final ASC determinations. If the Appendix 1s are the same but the substantive criteria of the Methodology have changed from the initial proposed Methodology, BPA will recalculate each Utility's ASC by reviewing the initial Appendix 1 and applying the final Methodology criteria. Because the Utility's initial Appendix 1 will have been reviewed in the expedited review, BPA will conduct an abbreviated review with all interested parties to ensure that the Utilities' ASCs comply with the FERC-approved Methodology. If BPA determines that the ASCs comply, BPA will establish the ASCs as the Utilities' final ASCs for FY 2009.

BPA also must plan for the establishment of each Utility's ASC for FY 2010–2011. Under the proposed ASC Methodology, except for the initial one-year Exchange Period under the revised Methodology, and the second Exchange Period for FY 2010–2011, a Utility must file an Appendix 1 by May 1 of each year. If a Utility wishes to participate in the REP in the second Exchange Period for FY 2010–2011, it must file an Appendix 1 using 2007 data by July 1, 2008. If a Utility fails to file an Appendix 1 by July 1, 2008, the Utility will receive no REP benefits for the FY 2010–2011 period. After receiving all exchanging Utilities' Appendix 1s by July 1, 2008, BPA will promptly publish a schedule for review of the filings. Although BPA hopes to complete this review using the ASC review schedule contained in the ASC Methodology, BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs for FY 2010–2011 are established in time to be incorporated in BPA's FY 2010–2011 wholesale power rate initial proposal. After completing its ASC review process, BPA will establish ASCs for FY 2010–2011. If FERC approval of the ASC Methodology is subsequent to this ASC review, BPA will compare the Methodology used to calculate the ASCs with the FERC-approved Methodology. BPA will conduct an abbreviated ASC review will all interested parties to ensure that Utilities' ASCs comply with the final Methodology. If BPA determines that the ASCs comply, BPA will establish the ASCs as the Utilities' final ASCs for FY 2010–2011.

D. Invoicing and Payment Using Actual Residential Load

Although not a part of the ASC Methodology, BPA proposes to continue the contractual requirement that Utilities invoice BPA monthly based on actual eligible residential and small farm loads. A Utility's monthly REP payment is determined by subtracting the Utility's BPA PF Exchange Rate [9] from the Utility's ASC, and then multiplying the result by the Utility's actual eligible monthly residential and small farm load.

E. Treatment of Certain Resource Costs Under the Proposed Average System Cost Methodology

1. Transmission Investments and Related Expenses Included in Contract System Costs

Transmission investments and expenses were included in ASCs under BPA's 1981 ASC Methodology. The 1981 ASC Methodology was established pursuant to a negotiated settlement, agreed to by all parties. The Administrator's 1981 ASC Methodology Decision, at 1–2, explains the process by which most issues, including the propriety of adding transmission costs to ASC, were resolved through a negotiated settlement in the first consultation proceeding. The Commission granted final approval to the 1981 ASC Methodology on October 17, 1983. *See Sales of Electric Power to Bonneville Power Admin., Methodology and Filing Requirements,* 48 FR 46,970 (Oct. 17, 1983).

In the 1984 ASC Methodology, BPA included ''all existing transmission, as defined in the Commission Uniform System of Accounts, in service as of July 1, 1984 * * *'' and ''[f]or transmission plant commencing service after July 1, 1984, transmission plant costs that can be exchanged are limited to transmission facilities that are directly required to integrate resources to the transmission grid.'' [10] The Commission granted final approval to the 1984 ASC Methodology on October 5, 1984, which continued to allow certain transmission costs in ASC. *See Methodology for Sales of Electric Power to Bonneville Power Administration,* 49 FR 39,293 (October

[9] BPA is proposing in the WP–07 Supplemental Rate Proceeding to develop either Utility-specific PF Exchange rates or a PF Exchange rate with Utility-specific supplemental rate charges. In either case, the applicable BPA rate will be determined specifically for each Utility. This rate determination methodology requires that BPA know during the rate proceeding which Utilities intend to participate in the REP.

[10] 1984 Administrator's Record of Decision, Average System Cost Methodology at 42.

5, 1984), FERC Statutes and Regulations ¶ 30,601.

Even though the 1984 ASC Methodology allowed all transmission prior to 1984 but only a portion of it after 1984, upon further consideration BPA believes transmission should be included in the calculation of utilities' ASCs. One of the main reasons for this conclusion is that the exclusion of the transmission component of electricity production and delivery may introduce an inequity between Utilities that develop resources close to their service territory and those that develop geographically distant resources. Therefore, BPA proposes that the cost of resources should include all costs associated with the delivery of power to the Utility's load centers.

Furthermore, since implementation of the 1984 ASC Methodology and its approval by the Commission, the electric utility industry has undergone significant changes in structure, specifically, the development of wholesale power markets, creation of regional transmission organizations (RTOs) and the separation of generation and transmission functions of vertically integrated electric utilities mandated by Commission Order 888, which was issued in 1996. In 1999, BPA administratively separated its power and transmission functions to voluntarily comply with the Commission's order for investor-owned utilities to separate generation and transmission. Consequently, BPA now develops separate rates for power and transmission.

As a result of this change in industry structure, electric utilities have a variety of ways to acquire generation to serve their retail load. For example, utilities can: (1) Rely on wholesale power markets; (2) build centralized generation units close to the fuel source; or (3) build the generation close to the load center and transport the fuel source (e.g. coal by rail). In addition, many large power plants are owned by more than one utility. This diversity in the method of acquiring electric generating capacity to serve retail load means that excluding transmission costs from the ASC calculation would have adverse effects on Utilities. Exclusion of the transmission component of electricity production and delivery would introduce an inequity between Utilities that develop resources close to their service territory and those that develop geographically distant resources. In summary, BPA proposes that the cost of resources should include the cost of transmission used to deliver resources to retail load.

2. Treatment of Conservation Costs

In the 1984 ASC Methodology, the Administrator determined which conservation costs could be included in ASCs. The determinations ''were case specific, based on the information provided by exchanging utilities.'' [11] Generally, the 1984 ASC Methodology allows Utilities to include only the costs of ''measures for which power is saved by physical improvements or devices. Advertising, promotion and audit expenses are not resource costs and therefore are not includable in the ASC.'' [12]

BPA proposes to continue with the 1984 ASC Methodology's exclusion of advertising and promotion costs, except that the revised Methodology will allow Utilities to include the cost of energy audits. BPA proposes to allow energy audits because the only way to determine if a conservation program or measure will be cost effective is through an analysis or ''audit'' of the facility where the conservation measure will be installed. Some items such as energy efficient light bulbs are cost effective in almost any location. Others, like insulation, energy efficient windows or HVAC upgrade/replacements must be analyzed in advance to see if the measure is cost effective. In many ways, the audit is a form of or extension to the Utility's least-cost plan. If the audit is not done before the measure is installed, the funds could be used on a measure that is not cost effective. For this reason, BPA believes it is reasonable to allow the costs of audits in the ASC calculation.

3. Treatment of Oregon's Public Purpose Charge Related to the Acquisition of Conservation and Renewable Resources

Oregon's Public Purpose Charge (OPPC) was established in 1999 with passage of Oregon's electricity restructuring law, Senate Bill 1149. *See generally,* Or. Rev. Stat. § 757.612 (2005). The OPPC was established to ''fund new cost effective local energy conservation, new market transformation efforts, the above-market costs of renewable energy resources and new low income weatherization.'' *Id.* at § 757.612(2)(a). The OPPC is set at 3 percent of total retail sales of electricity for PacifiCorp-Oregon, Portland General Electric (PGE) and Idaho Power-Oregon. *Id.* The OPPC applies to consumer-owned utilities only if they allow direct access to any class of their customers. *Id.* At this time, BPA is not aware of any consumer-owned utilities that are participating in OPPC program. The OPPC replaces the conservation/DSM programs PGE, PacifiCorp-Oregon and Idaho Power-Oregon operated before Oregon SB 1149. When the OPPC was implemented by the utilities, the OPUC was directed to remove the costs of OPPC-like programs from retail rates. *Id.* at § 757.612(3)(g).

The OPPC was implemented on March 1, 2002, for PGE and PacifiCorp-Oregon, and in 2006 for Idaho Power-Oregon. Distribution of the OPPC funds are made monthly by the utilities to the following organizations in the following percentages:

Energy Trust of Oregon (ETO)—73.8%
Education Service Districts (ESD)—10.0%
Oregon Housing and Community Services (OHCS)—16.2%

PGE, PacifiCorp and Idaho Power do not show the OPPC on their financial statements or Form 1s. The utilities treat the revenue and expense as a direct pass-through. Accounting records are available from the utilities showing the revenue received and the payments made to the three recipient organizations. SB 1149 states that the OPPC funds be allocated in the following manner:

New cost-effective conservation and market transformation—63%
Above market cost of renewable energy resources—19%
Low-income weatherization—13%
Low-income bill payment assistance—5%

The 1981 and the 1984 ASC Methodologies did not address the cost treatment of charges like the OPPC. A key attribute of the OPPC has been that it effectively replaces the Utility's conservation program, which is typically included as part of a Utility's base rates. Because of this unique feature, BPA proposes that the OPPC is an alternative form of acquiring conservation and renewable resources, and therefore should be considered in determining ASC. In the same way that some utilities build thermal resources and others purchase power from the market, BPA proposes that the OPPC is a similar method of acquiring conservation and renewable resources. Another way of looking at the OPPC is as an outsourcing arrangement. While some utilities have their own conservation departments and programs, Oregon investor-owned utilities are effectively required to ''outsource'' their conservation activities to the ETO, OHCS and ESDs. BPA needs to have the right to review and audit the costs and programs of the organizations that receive OPPC funds in order to

[11] 1984 ASC Methodology Record of Decision at 73.

[12] Id. at 74

determine the portion of the Utility's costs that are excludable from their ASC. If an OPPC-recipient organization denies BPA the right to review and audit its costs and programs, then BPA will not include such costs in the Utility's ASC calculation. BPA will review the OPPC costs and functionalize the costs using the same procedure as used in reviewing Utility conservation costs.

4. Treatment of Return on Equity and Federal Income Taxes

In the **Federal Register** Notice for the 1984 ASC Methodology proposal, BPA stated that ''[i]n developing an ASC methodology the BPA Administrator has considerable discretion in deciding whether to permit inclusion of an equity return allowance and, if so, how that component is to be determined.'' [13] The Administrator's discretion was affirmed by the Commission in its order approving the 1984 ASC Methodology.[14] In the 1984 ASC Methodology, BPA excluded the cost of equity in the ASC determination in part because of concern that Regulatory Bodies may increase the allowed return on equity (ROE) to compensate Utilities for the cost of terminated plants and because ROE is primarily associated with the default risk of investor-owned utilities. On review, the Ninth Circuit affirmed BPA's view that ROE be excluded from the ASC calculation in light of BPA's experience with implementing the program and its need to avoid abuses. *PacifiCorp* v. *F.E.R.C.*, 795 F.2d 816, 823 (9th Cir. 1986). In making this finding, though, the Court held that ''[t]he statute itself, however, neither commands nor proscribes these adjustments in ASC methodology.'' *Id.* Consequently, the Court noted that it did not ''sanction any permanent implementation of these exclusions.'' *Id.* at 823.

The 1984 ASC Methodology did not allow ROE in ASCs, but instead permitted the inclusion of the Utility's long-term cost of debt. BPA now proposes that ROE should be allowable in ASC. The cost of debt is a cost of resources and, in the case of investor-owned utilities, the cost of debt is lowered by the contribution of equity by the company. Without the spreading of risk to shareholders there would be a significant increase in the cost of debt. State commissions and rating agencies require investor-owned utilities to maintain specific capital structures that affect the company's debt ratings. Therefore, debt alone is not an adequate reflection of the capital cost of a Utility's resources. Without an equity component in the cost of capital, a higher cost of debt is needed to reflect the true cost of financing resources.

BPA finds that enough changes have occurred in the PNW regulatory environment to reasonably ensure that terminated plant costs will not be included with allowable costs under the ASC Methodology. First, the costs of the Pebble Springs nuclear plant that were the basis of the terminated plant controversy in the mid-1980s have been completely written off by the utilities involved. Second, Oregon's establishment of a three-person appointed public utility commission greatly reduces the chance of improper communications between the Oregon PUC and utilities. Third, since 1984, Oregon has had a Citizens' Utility Board (CUB), which monitors the retail rate development of utilities conducting business in Oregon. CUB reviews retail rates in order to ensure, among other things, that terminated plant costs are excluded from such rates. Additionally, increased disclosure and filing requirements at the commission level make identifying inappropriate costs much easier. All four state commissions now have requirements that utilities under their review prepare Integrated Resource Plans. From these filings, BPA and its customers can likely determine if a Utility included the costs of terminated plant in its equity calculation. Thus, the risk that Regulatory Bodies will include inappropriate costs in the ROE has diminished significantly since 1984.

Because of these changes, and based on BPA's experience in implementing the ASC, BPA now proposes that Utilities should be allowed to exchange ROE. In the revised ASC Methodology, BPA is proposing to allow return on equity as determined by the Regulatory Bodies at a Utility's most recent commission-approved level. For purposes of determining return on rate base, the Utility will include the weighted cost of capital from its most recent rate order. For Utilities with service territories in more than one state, the Utility shall submit a weighted cost of capital based on the most recent Regulatory Body rate orders weighted by rate base in states within the PNW region.

In the 1984 ASC Methodology, BPA did not allow the inclusion of Federal income taxes in ASC. BPA's rationale stated that ''nothing in the [Northwest Power] Act or its legislative history requires the inclusion or exclusion of income taxes in computing the average system cost of a Utility's resources.'' [15] The Commission approved BPA's interpretation, albeit with some reservation because of an apparent ''contradiction'' in the allowance of a proxy for equity returns elsewhere in the methodology.[16] On review, the Ninth Circuit was equally reserved when reviewing the 1984 ASC Methodology. *PacifiCorp,* 795 F.2d at 823. As with ROE, which was decided in the same opinion, the Court affirmed BPA's interpretation with the notation that it did not ''sanction any permanent implementation of these exclusions.'' *Id.*

Under the revised ASC Methodology, BPA is proposing to allow Utilities to exchange the costs of certain taxes through their ASCs. BPA is proposing this change because it is necessary to have symmetry between its treatment of ROE and taxes. As noted above, BPA is proposing to allow the costs associated with equity return as a resource cost in calculation of ASC. If the cost of Federal income taxes at the marginal tax rate is not also included, then an investor-owned utility's cost of resources would be understated. When calculating the revenue requirement for an investor-owned utility, Regulatory Bodies typically gross up the cost of equity by the marginal Federal income tax rate to arrive at the ''after tax'' return. In the same manner, because BPA is proposing to include ROE as a resource cost in the ASC Methodology, BPA is also proposing to gross up the equity component by the Federal income tax rate when determining an investor-owned utility's weighted cost of capital in ASC.

5. Functionalization of Regulatory Assets and Liabilities in ASC

Regulatory assets and liabilities are expenses, revenues, gains or losses that would normally be recognized in net income in one period, but for an order of a Regulatory Body specifying a different recovery period in retail rates. Regulatory Assets and Liabilities, Accounts 182.3 and 254 in the Commission Uniform System of Accounts, were established in March 1993 in Commission Order No. 552,

[13] 49 FR 4230, 4235 (Feb. 3, 1984).

[14] 49 FR 39,293, 39,296 (Oct. 5, 1984): Congress chose the Administrator to determine cost of utility resources. Had the Congress intended that the Administrator must follow State commission determinations of a utility's resource costs, it could have easily included this requirement in the statute or simply left the Administrator out altogether and let the State commissions develop the ASC methodology. This was not done. The Administrator was chosen to develop a methodology to determine ASC, subject to the Commission's review.

[15] 1984 Administrator's Record of Decision, Average System Cost Methodology at 59.

[16] 49 FR 39,293, 39,297 (Oct. 4, 1984).

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.[17] Regulatory assets and liabilities were not addressed in the 1984 ASC Methodology.

For investor-owned utilities located in the Pacific Northwest, regulatory assets and liabilities are a significant portion of the balance sheet. Examples of costs and revenues that can be deferred and included as a regulatory asset or liability with Regulatory Body approval include: fuel costs subject to a power cost adjustment, storm damage, gains on reacquired debt, deferred compensation plans, stranded costs, phase-in plans, deferred income taxes, asset retirement obligations, asset impairment or disposal under Financial Accounting Standards Board 144, rate case expenses and intervenor funding, buyout costs for non-utility generation, deferred purchase capacity costs, deferred demand-side management costs, U.S. Department of Energy (USDOE) nuclear fuel enrichment clean-up fees, deferred revenue related to income taxes associated with allowance for funds used during construction (AFUDC), unamortized loss on reacquired debt, and deferred return on sales of emission allowances. The above list is only representative of the deferred costs and revenues that would be found in a typical Form No.1 or a Regulatory Body rate or accounting order.

There are three major issues for the revised ASC Methodology relating to treatment of regulatory assets and liabilities. First, how should regulatory assets and regulatory liabilities be functionalized between production, transmission, and distribution? Second, for the production-related assets and liabilities, what rate of return, if any, should the Utility earn on these items for purposes of determining a Utility's ASC? And finally, how should the amortization of regulatory assets and liabilities be handled in the ASC review process?

Functionalization of regulatory assets and liabilities raises several problems because of the lack of information contained in the Form 1 concerning the nature of these items. Descriptions of regulatory assets and liabilities are cryptic at best. Some of the deferred costs are of a short-term nature, such as power costs, which may be carried as a deferral for a matter of months. Other costs may be deferred and amortized 5 years or more, such as costs associated with storm damage and conservation. The Form 1 provides little or no detail on the length of the deferral period for each item. Nor does it provide information on whether the deferred assets and liabilities are included in rate base by the Utility's Regulatory Body. A brief review of several regional Regulatory Body rate orders revealed few references to regulatory assets in the list of items included in rate base. Finally, the Commission's Uniform System of Accounts does not provide specific rules for amortization of regulatory assets. Review of the Utilities' Form 1 filings reveal that some utilities amortize regulatory assets and liabilities to Accounts 407.3, Regulatory Debits and 407.4, Regulatory Credits, while others amortize regulatory assets and liabilities to specific income or expense accounts. For these reasons, BPA proposes that Utilities must perform a direct analysis and functionalize all regulatory assets and liabilities to Production, Transmission, or Distribution/Other. The Utility must provide documentation supporting its rationale for functionalization of the regulatory asset or liability. This documentation must consist of general ledger entries, a description of the item in sufficient detail to permit BPA to determine the functional nature of the cost, and all communications on the asset or liability between the Utility, its Regulatory Body and its external auditor. The documentation must also show that the asset or liability is included in the Utility's calculation of rate base approved by its Regulatory Body and the allowed return or carrying cost. In no case will the amount of regulatory assets and liabilities allowed in ASC exceed the amount included in retail rates for the same period by the regional Regulatory Bodies.

6. Treatment of Cash Working Capital in ASC

Cash Working Capital (CWC) is a component in almost all Regulatory Body determinations of rate base. Inclusion of CWC as an element of rate base is consistent with the principle that investors receive a fair return on investment that is used, useful and devoted to public service. One definition of CWC as used in regulatory proceedings is:

> The average amount of capital provided by investors, over and above the investment in plant and other specifically measured rate base items, to bridge the gap between the time expenditures are required to provide services and the time collections are received for such services.[18]

Because the 1981 and 1984 Methodologies relied on the jurisdictional approach, CWC was a part of the Utilities' rate base calculation in Regulatory Body rate orders. The 1981 and 1984 Methodologies simply set an upper limit on the amount of CWC included in rate base for the ASC calculation.[19]

Because the revised ASC Methodology proposes to use the Form 1 (which does not include a CWC value) as the basis for data for ASC filings, BPA believes it is important to include a separate determined value for CWC in the Utility's rate base calculation for ASC purposes. While determination of the proper amount of CWC in rate base is often very controversial, a standard and widely accepted measure is one-eighth of total O&M costs, less fuel and purchase power costs.[20] This one-eighth formula was the cap or maximum amount that BPA allowed for CWC in the 1984 ASC Methodology.

BPA is proposing to use this formula—one-eighth of total exchangeable O&M costs, less fuel and purchase power costs—for the CWC value included in the Appendix 1 filing. The details are shown in Schedule 1A of the revised ASC Methodology template.

7. Single ASC for Multi-Jurisdictional Utilities

Under the 1981 and 1984 ASC Methodologies, BPA used a jurisdictional approach to determining a Utility's ASC. For Avista, Idaho and PacifiCorp, Utilities that serve retail customers in more than one state, reliance on Regulatory Body rate orders for ASC determinations resulted in separate ASC filings for each state. Developing ASCs by state for multi-jurisdictional Utilities presents problems for those utilities because Form 1 filings are prepared on a total utility basis, and trying to separate and allocate the costs from the total system to individual states would be burdensome and expensive for both the Utility and BPA. For this proposal, BPA proposes to develop a single ASC for each Utility. Because PacifiCorp has service territories that are outside the Pacific Northwest region, it will be required to submit an ASC filing based on an allocation of its in-region resources and costs, based on the individual state results of operations

[17] G. Hahne and G. Aliff, Public Utility Accounting 11–5 (Mathew Binder 2005).

[18] *Id.* at 5–4.

[19] *See* 18 CFR 301.1 FN. h.

[20] G. Hahne and G. Aliff, Public Utility Accounting 5–5 (Mathew Binder 2005).

filings PacifiCorp files with each Regulatory Body.

8. Treatment of Purchased Power and Sales for Resale Credit

Purchased power and sales for resale are subject to significant variability for a number of reasons including:

Temperature—colder than normal winters increase the demand for electricity, resulting in increased purchases of electricity for utilities that rely on market purchases for meeting a portion of retail load.

Precipitation—heavier than normal precipitation in the Columbia River Basin increases the amount of electricity available at the regional hydroelectric facilities and could lower the need for additional electricity.

Prices—the price of electricity purchased by utilities varies with temperature and precipitation, but also the price of natural gas, which is the fuel on the margin for most hours of the year, and therefore affects the price of electricity in power markets.

Regulatory Bodies use a process called normalization to adjust quantity and price for purchased power and sales for resale in regulatory proceedings. Normalization of purchased power and sales for resale credits is a process used by utilities and Regulatory Bodies to adjust actual data to reflect what would likely occur under conditions (water, weather, market prices) that are closer to long-term averages. For this reason, BPA proposes to generally use a rolling 5-year average of short-term (less than 1 year) energy sales and energy purchases in the Appendix 1. For pricing, BPA proposes to use the same models and methodologies used to develop market price forecasts in BPA's wholesale power rate filings.

BPA understands this area is not simple, and its treatment can have a big impact on hydro-intensive utilities. BPA welcomes different approaches and ideas on how to account for the significant variability in this area.

9. Future Revision of Average System Cost Methodology To Address Tiered Rate Issues

BPA and its customers are currently discussing the design of a Tiered Rates Methodology (TRM) for BPA's future wholesale power rates. BPA expects to conduct a hearing under section 7(i) of the Northwest Power Act in 2008 in order to establish a TRM, which would be implemented in the rate period beginning FY 2012. The establishment of the TRM may affect the implementation of the REP for consumer-owned utilities. For example, BPA may propose as part of the TRM that a consumer-owned utility that elects to receive an individual Contract High Water Mark will have an ASC that excludes costs of any resources added by the utility after September 30, 2006. Other REP-related proposals and issues will undoubtedly be raised in connection with the TRM. Consequently, BPA has included placeholder language in the Proposed Revised Average System Cost Methodology that the Methodology will be revised if necessary or appropriate to accommodate establishment and implementation of tiered rates.

The Proposed Revised Average System Cost Methodology, Functionalization for Average System Cost Methodology, Endnotes and the Proposed Average System Cost template are incorporated herein by reference and are available at the following link: *http://www.bpa.gov/corporate/Finance/ascm*.

In consideration of the foregoing discussion, BPA proposes to revise the Average System Cost Methodology as set forth below.

Issued in Portland, Oregon, January 31, 2008.

Stephen J. Wright,

Administrator and Chief Executive Officer.

[FR Doc. E8–2258 Filed 2–6–08; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Bonneville Power Administration

[BPA Docket No. WI–09]

Proposed Wind Integration—Within-Hour Balancing Service Rate for Public Hearing, and Opportunity for Public Review and Comment

AGENCY: Bonneville Power Administration (BPA), Department of Energy (DOE).

ACTION: Notice of Wind Integration—Within-Hour Balancing Service Rate (Notice), BPA Docket No. WI–09.

SUMMARY: The purpose of the hearing is to adopt a rate for Wind Integration—Within-Hour Balancing Service. As increasing amounts of wind generation have integrated into BPA's Balancing Authority, the variability and uncertainty of wind generation have led to increased costs through the need for additional reserve capacity, the shift of energy generation from heavy load hours to light load hours, and reduced system efficiency. The Wind Integration—Within-Hour Balancing Service rate will ensure that these costs are borne by the parties causing the costs.

DATES: Persons wishing to intervene and become parties in the rate case must file a petition to intervene by 5 p.m., Pacific Standard Time, on February 13, 2008. The petition must state the name and address of the intervenor and the intervenor's interest in the outcome of the proceeding. Written comments by non-party participants must be received by BPA no later than April 15, 2008, to be considered in the Record of Decision (''ROD''). The Administrator will issue a Final Record of Decision in these proceedings by July 28, 2008.

ADDRESSES: Petitions to intervene should be directed to Brandon Hignite, Hearing Clerk—2009 Wind Integration Rate Case, L–7, Bonneville Power Administration, 905 NE 11th Avenue, Portland, OR 97232 or by e-mail to: *wi09rate@bpa.gov*, and must be received no later than 5 p.m., Pacific Standard Time, on February 13, 2008. In addition, a copy of the petition must be served concurrently on BPA's General Counsel and directed to Barry Bennett, LC–7, Office of General Counsel, Bonneville Power Administration, 905 NE 11th Avenue, Portland, OR 97232 or by e-mail to: *bbennett@bpa.gov*. Written comments may be made online at BPA's website: *www.bpa.gov/comment*, or by mail to: BPA Public Affairs, DKE–7, P.O. Box 14428, Portland, OR, 97293–4428. Please label your submission ''2009 Wind Integration Rate Case.''

FOR FURTHER INFORMATION CONTACT: Mr. Elliot E. Mainzer, Transmission Policy and Strategy Manager, at (360) 619–6252.

SUPPLEMENTARY INFORMATION:

Part I—Introduction and Procedural Background

A. Statutory Provisions Governing This Rate Proceeding

Section 7 of the Northwest Power Act, 16 U.S.C. 839e, sets forth a number of general directives that the BPA Administrator must consider in establishing rates for the sale of electric energy and capacity and transmission services. In particular, section 7(a)(1), 16 U.S.C. 839e(a)(1), provides in part that ''[s]uch rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the