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September 17, 2008

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol St. N.E., #215
P. O. Box 2148
Salem, OR 97308-2148

Attention: Administrative Hearings Division

Re: Docket UM 926: Application for Approval of the Residential Purchase and Sale Agreement by and between Bonneville Power Administration and Portland General Electric Company for the Payment of Residential Exchange Program Benefits for FY 2009 though 2011 and the New Resource Firm Power Block Sales Agreement by and between Bonneville Power Administration and Portland General Electric Company

Dear Administrative Hearings Division:

Pursuant to ORS 757.663, Portland General Electric Company ("PGE") hereby requests that the Commission require it to sign the proposed (1) Residential Purchase and Sale Agreement ("RPSA") by and between PGE and Bonneville Power Administration ("BPA")and (2) the New Resource Firm Block Power Sales Agreement by and between PGE and BPA (the "NR Block Agreement", and collectively, the "BPA Contracts"). The BPA Contracts are enclosed as Attachments 1 and 2 to this letter and are described in more detail below. BPA has offered the proposed BPA Contracts for execution by PGE no later than September 30, 2008. PGE recommends that the Commission issue an order requiring PGE to sign the proposed contracts. We will be available for questions at the public meeting scheduled for September 23, 2008.

I. RPSA

The proposed RPSA provides the contractual terms under which PGE's small farm and residential customers will receive benefits under the Residential Exchange Program ("REP") with BPA. The REP is an exchange of power, with BPA purchasing power from an exchanging utility at the utility's average system cost ("ASC") and the exchanging utility purchasing power from BPA at the PF Exchange rate. However, it has been BPA's practice that no actual power sales have taken place under the REP. Instead, the REP benefits are provided as monetary benefits that pass through to PGE's residential and small farm customers in the form of a rate credit.

The formula for determining the level of REP benefits is established by statute and is set forth in the RPSA. The amount of REP benefits is based on three factors: the PF Exchange rate (which BPA determines in its power rate proceedings), PGE's average system cost for transmission and generation of power (the "ASC"), and PGE's eligible residential and small farm load. The level of REP benefits is determined by the difference between the PF Exchange rate and PGE's ASC, multiplied by the eligible load.

BPA is currently engaged in the WP-07 Supplemental wholesale power rate case ("WP-07S") which will establish a PF Exchange rate for FY 2009 (October 1, 2008, through September 31, 2009). Concurrent with the WP-07S proceeding, BPA has revised its ASC methodology and has conducted an expedited review of PGE's ASC. Under the terms of the RPSA, PGE will be required to make annual ASC filings that will establish the ASC under the RPSA and be used to establish the level of REP benefits. In addition, BPA has stated its intent to commence a power rate case that will establish the PF Exchange Rate for FY 2010 and 2011.

PGE has actively participated in WP-07S, the ASC Methodology proceeding, and all BPA proceedings that affect the level of REP benefits our customers receive. We recognize the importance of these benefits for our customers and will continue to advocate for BPA rates, policies and decisions that provide our customers with a fair and equitable share of the benefits of the federal hydro system.

BPA has stated that it will issue the WP-07S record of decision on September 22, 2008. By October 1, 2008 PGE will submit our FY 2009 ASC to BPA for a full review. We expect BPA's full review to be completed sometime in April 2009.

A. Term

The term of the RPSA will commence on October 1, 2008, and will end on September 30, 2011, unless terminated sooner. RPSA, §1.

B. In Lieu Transactions

Upon written notice to PGE, BPA may "in lieu" of purchasing power offered by PGE acquire an equivalent amount of electric power from other sources to replace power sold by BPA to the utility as part of the exchange. RPSA, §7. However, the cost of the "in lieu" power must be less than the utility's ASC. The result is a reduction in REP benefits by the difference between the in lieu price and PGE's ASC, multiplied by the amount of "in lieu" power. Under the proposed RPSA, BPA may not initiate an in-lieu transaction until it has adopted an In-Lieu Policy following appropriate notice and comment. RPSA, §7.2.

C. Balancing Account

If PGE's ASC is less than the applicable PF Exchange rate, the payment that would be owed to BPA in that circumstance is tracked and added to the balancing account. RPSA, §12.2. While there is an account balance, BPA will distribute no REP benefits but will first use REP benefits otherwise due to eliminate any balance in the account. PGE does not expect that this provision will adversely affect PGE's customers given that PGE's projected ASC is well above the expected PF Exchange rate.

D. Adjustments to Monetary Payments

In the current WP-07S proceeding, BPA is determining for each investor-owned utility, including PGE, the amount of alleged "overpayments" of REP benefits from October 1, 2001, through September 30, 2008. During this period IOUs received REP settlement benefits under settlement agreements which the Ninth Circuit Court of Appeals determined in 2007 exceeded BPA's authority and were not supported by the record before BPA at the time. The RPSA provides that monetary payments of REP benefits may be adjusted to account for such alleged overpayments (called "Lookback Amounts") in the past. In the draft record of decision in the WP-07S proceeding, BPA has proposed to recover (through offsetting against future REP benefits otherwise due) each IOU's Lookback Amount within seven years where possible. PGE and other IOUs have strenuously objected to this approach and argued for a 20-year recovery period to coincide with the Regional Dialogue Contracts.

PGE has vigorously argued against BPA's authority to assess such Lookback Amounts and its ratemaking determination of such amounts. The RPSA has a reservation of rights clause that provides that, by entering into the RPSA, neither BPA nor PGE waive any of its rights, arguments, or claims.

II. NR Block Agreement

The NR Block Agreement is proposed to be effective for the same term as the RPSA (October 1, 2008, through September 30, 2011) to meet requests for power sales contracts made by IOUs pursuant to 5(b) of the Northwest Power Act. Section 5(b) provides that whenever requested, BPA shall offer to sell to a requesting IOU power to meet its firm power load net of the utility's own resources used to serve such load. Power that BPA sells to an IOU under section 5(b) is priced at BPA's new resource firm power rate. The non-price terms of the NR Block Agreement are similar to the terms of the Firm Block Power Sales Agreement, which PGE executed in connection with the 2000 Settlement Agreement with BPA. PGE does not currently anticipate purchasing BPA power under the NR Block Agreement.

III. PGE's Recommendation

PGE respectfully requests that the Commission order it to execute the proposed RPSA and NR Block Agreement. While the exact level of REP benefits is unknown, PGE's customers are expected to receive substantial benefits under the REP. BPA currently estimates that PGE's customers will be entitled to $66.9 million in REP benefits in FY 2009 and will receive $51.4 million in benefits after reduction due to the recovery of a portion of PGE's Lookback Amount. The terms of the RPSA do not adversely affect PGE's ability to challenge BPA's legal authority and ratemaking decisions with respect to PGE's Lookback Amount. The RPSA will permit our customers to continue to receive REP benefits in the future.

The NR Block Agreement also may provide benefits to our customers. While PGE currently does not plan to purchase power from BPA at the NR rate, it would be prudent for PGE to execute the proposed NR Block Agreement. Signing the contract will permit PGE to purchase power from BPA under Section 5(b) in the future if the NR rate warrants such purchases. PGE may elect to purchase power under the NR Block Agreement but is not required to do so.

For the reasons stated above, the Commission should order PGE to execute the BPA Contracts.

Very truly yours,

David F. White, On Behalf of
Portland General Electric Company

DFW/cp

cc: UM 926 Service List
Enclosures

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Contract No. 08PB-11972

RESIDENTIAL PURCHASE AND SALE AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

PORTLAND GENERAL ELECTRIC COMPANY

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This RESIDENTIAL PURCHASE AND SALE AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and PORTLAND GENERAL ELECTRIC COMPANY (PGE), hereinafter individually referred to as "Party" and collectively referred to as the "Parties". PGE is an investor-owned utility organized under the laws of the State of Oregon to purchase and distribute electric power to serve retail consumers from its distribution system within its service area.

RECITALS

Section 5(c) of the Northwest Power Act provides that a Pacific Northwest Regional electric utility may offer to sell electric power to BPA and BPA shall purchase such electric power at the Average System Cost of that utility's resources, and in exchange BPA shall offer to sell in return an equivalent amount of electric power to such utility and such utility shall purchase such electric power at the PF Exchange rate. The cost benefits of such purchase and exchange sale attributable to a utility's residential load within a State shall be passed directly through to that utility's residential load within such State.

The Parties agree:

1. **TERM**
This Agreement shall take effect on the latter of (1) the date signed by the Parties, or (2) if required, upon acceptance for filing of this Agreement by the Federal Energy Regulatory Commission without change or condition unacceptable to either Party, and it shall terminate on September 30, 2011, unless terminated earlier pursuant to section 11 below. Performance by the Parties of their obligations under this Agreement shall commence on October 1, 2008. Upon termination of this Agreement, all obligations incurred hereunder shall be preserved until satisfied.

2. **DEFINITIONS**
Capitalized terms below shall have the meaning stated. Capitalized terms that are not listed below are either defined within the section or exhibit in which the term is used or, if not so defined, shall have the meaning stated in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs), or the ASC Methodology.

2.1 "Appendix 1" means the electronic form on which PGE reports its Contract System Costs and other necessary data to BPA for the calculation of PGE's Base Period ASC pursuant to the ASC Methodology.

2.2 "Average System Cost," or "ASC" means the rate charged by PGE to BPA for BPA's purchase of power from PGE under section 5(c) of the Northwest Power Act for each Exchange Period and is the quotient obtained by dividing Contract System Costs by Contract System Load, all in accordance with the ASC Methodology.

2.3 "ASC Methodology" means a methodology, as may be amended or superseded, used to determine ASC, as developed by BPA pursuant to section 5(c)(7) of the Northwest Power Act and attached to this Agreement for ease of reference purposes only as Exhibit C, 2008 Average System Cost Methodology. This Agreement is subject to the ASC Methodology but such ASC Methodology is not incorporated as part of this Agreement.

2.4 "Balancing Account," or "BA," means an account maintained by BPA comprised of amounts, if any, carried over from Contract No. DE-MS79-81BP90603 by and between PGE and BPA ("1981 RPSA"), plus any additional amounts accrued pursuant to section 12 of this Agreement.

2.5 "Base Period" means the calendar year of the most recent FERC Form 1 data at the commencement of the ASC review period.

2.6 "Base Period ASC" means the ASC determined in the Review Period using PGE's Base Period data, all in accordance with the ASC Methodology.

2.7 "Business Day(s)"means every Monday through Friday except Federal holidays.

2.8 "Contract System Costs" means PGE'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, all in accordance with the ASC Methodology. Under no circumstances shall Contract System Costs include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act.

2.9 "Contract System Load" means (1) the total Regional retail load included in the Form 1, or (2) for a consumer-owned utility (preference customer), the total Regional retail load from the most recent annual independently audited financial statement, as either may be adjusted pursuant to the ASC Methodology, all in accordance with the ASC Methodology.

2.10 "Diurnal" or "Diurnally" means the distribution of hours of months between Heavy Load Hours (HLH) and Light Load Hours (LLH).

2.11 "Due Date" shall have the meaning as described in section 8.2.2.

2.12 "Effective Date" means the effective date of this Agreement, as determined pursuant to section 1 above.

2.13 "Exchange Period" means the period during which PGE's ASC is effective for the calculation of PGE's benefits under this Agreement. Each Exchange Period shall be the period of time concurrent with the duration of each BPA wholesale power rate period.

2.14 "Fiscal Year" or "FY" means the period beginning each October 1 and ending the following September 30.

2.15 "Form 1" means the annual filing submitted to the Federal Energy Regulatory Commission required by 18 CFR §141.1, as specified in the ASC Methodology.

2.16 "In-Lieu PF Power" means firm power that is sold by BPA to PGE in an in-lieu transaction at the applicable Priority Firm Power Exchange Rate, or its successor.

2.17 "In-Lieu Power" means firm power acquired by BPA from a source(s) other than PGE at a cost less than PGE's ASC, as provided in section 5(c)(5) of the Northwest Power Act. The provisions for acquisition and delivery of In-Lieu Power shall be provided in a policy developed by BPA after this Agreement is executed.

2.18 "In-Lieu Power Policy" mans a policy to be developed by BPA that will contain provisions for (1) the acquisition and purchase of In-Lieu Power by BPA, and (2) the delivery and sale of In-Lieu PF Power to PGE.

2.19 "Jurisdiction" means the service territory of PGE within which a particular Regulatory Body has authority to approve PGE's retail rates. Jurisdictions must be within the Region.

2.20 "New Large Single Load" or "NLSL" has the meaning specified in section 3(13) of the Northwest Power Act and in BPA's NLSL Policy.

2.21 "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839, Public Law No. 96-501.

2.22 "Region" means the Pacific Northwest as defined in section 3(14) of the Northwest Power Act.

2.23 "Regulatory Body" means a state commission or consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

2.24 "Residential Exchange Program" means the program implemented under this Agreement and established by section 5(c) of the Northwest Power Act.

2.25 "Residential Load" means the Regional residential load to which PGE sells power, as that residential load is defined in the Northwest Power Act and as further defined in Exhibit A, Residential Load Definition.

2.26 "Residential Load Eligible for Monetary Benefits" means the monthly amounts of Residential Load determined pursuant to Exhibit A, Residential Load Definition, less:

(a) any amounts of Residential Load with respect to which BPA has issued a notice of the election, pursuant to section 7.3 below, to acquire In-Lieu Power and PGE has elected to either take physical delivery of In-Lieu PF Power or forego exchange benefits corresponding to the amount of In Lieu Power; or

(b) any amounts of Residential Load with respect to which BPA has issued a notice of the election, pursuant to section 7.3 below, to acquire In-Lieu Power and PGE has elected to suspend its sale and purchase under sections 5 and 6 of this Agreement, for the duration of the time specified in the in-lieu notice.

2.27 "Review Period" means the period of time during which PGE's Appendix 1 is under review by BPA. The Review Period begins on June 1 and ends on or about November 15 of the Fiscal Year prior to the Fiscal Year BPA implements a change in wholesale power rates.

2.28 "Uncontrollable Force" shall have the meaning specified in section 15.

3. APPLICABLE PF EXCHANGE RATE

Purchases by PGE under this Agreement are pursuant to the applicable Priority Firm Power Exchange (PF Exchange) rate and applicable GRSPs, or their successors, established by BPA in a proceeding pursuant to section 7(i) of the Northwest Power Act, or its successor. Sections 5 and 6 below establish purchases subject to the applicable PF Exchange rate schedule.

4. ESTABLISHMENT OF ASC TO ACTIVATE PARTICIPATION

The first Exchange Period during which PGE may activate its participation under this Agreement shall commence on October 1, 2008. PGE may activate its participation under this Agreement by filing an initial Appendix 1 for the initial Exchange Period that it has selected. Once PGE files an initial Appendix 1, PGE shall continue to file a new Appendix 1 for each subsequent Exchange Period, unless and until PGE elects to terminate or suspend this Agreement pursuant to section 11 below. Upon filing an Appendix 1 for an Exchange Period, PGE shall commence invoicing for Residential Load Eligible for Monetary Benefits, pursuant to section 8.1 below, in the month following the first full month of such Exchange Period.

5. OFFER BY PGE AND PURCHASE BY BPA

Beginning with the first month of the initial Exchange Period established under section 4 above, PGE shall offer and BPA shall purchase each month an amount of electric power up to or equal to the Residential Load Eligible for Monetary Benefits.

The rate for such power sale to BPA shall be equal to PGE's ASC, as determined by BPA using the ASC Methodology. PGE may only sell an amount of electric power under this section 5 that is up to or equivalent to the Residential Load Eligible For Monetary Benefits that PGE is authorized under State law or by order of the applicable State regulatory authority to serve.

6. OFFER BY BPA AND PURCHASE BY PGE

Simultaneous with the offer by PGE and purchase by BPA pursuant to section 5 above, BPA shall offer and PGE shall purchase each month an amount of electric power equal to the Residential Load Eligible for Monetary Benefits that PGE offers and BPA purchases each month pursuant to section 5.

The rate for such power sale to PGE shall be equal to BPA's applicable PF Exchange rate, as established pursuant to section 3 above.

7. IN-LIEU TRANSACTIONS

7.1 BPA's Right to In-Lieu

In lieu of purchasing all or a portion of the electric power offered to BPA pursuant to section 5 by PGE at a rate equal to its ASC, BPA may upon prior written notice acquire or make arrangements to acquire In-Lieu Power if the expected cost of such power is less than PGE's ASC(s).

If the expected cost of In-Lieu Power is less than the applicable PF Exchange Rate, then PGE may upon prior written notice suspend its sale and purchase under sections 5 and 6 of this agreement for all or a portion of the amount of Residential Load Eligible for Monetary Benefits that BPA proposes to serve with In-Lieu PF Power, for the duration of time specified in the in-lieu notice. PGE's election under this section shall be based on all or a percentage portion of PGE's Residential Load Eligible for Monetary Benefits that BPA has specified in its in-lieu notice. Amounts suspended under this section 7.1 shall not be added to PGE's balancing account under section 12.

7.2 In-Lieu Power Policy

The terms and conditions of an in-lieu transaction, including the above referenced notice provisions, the source(s) of In-Lieu Power, the amount of In-Lieu Power, the shape of In-Lieu Power, the expected cost of such In-Lieu Power, and the term of the In-Lieu PF Power sale, shall be subject to BPA's then effective In-Lieu Power Policy; *provided, however*, that each In-Lieu Power Policy shall conform to this section 7. BPA may not initiate an in-lieu transaction until it has adopted an In-Lieu Power Policy following notice and comment and the issuance of a final record of decision.

The Parties agree to work in good faith to amend this Agreement if, when, and as necessary to implement the then effective In-Lieu Power Policy. PGE acknowledges that in-lieu transactions are intended to lower the cost of the Residential Exchange Program to BPA, and agrees that it will not unreasonably withhold its consent to any amendment to this Agreement proposed by BPA.

7.3 In-Lieu Notice(s)

BPA shall, in each written notice of an in-lieu transaction, provide the following information, which shall include, but is not limited to (i) the source(s) of In-Lieu Power, (ii) the amount of In-Lieu Power, (iii) the shape of In-Lieu Power, (iv) the expected cost of such In-Lieu Power, and (v) the term of the In-Lieu PF Power sale. BPA shall keep PGE advised insofar as is practicable of BPA's plans to provide notice to PGE of BPA's election to acquire In-Lieu Power.

7.4 **In-Lieu Transaction Implementation Mechanisms**
The mechanisms by which in-lieu transactions are implemented, whether by the physical delivery of In-Lieu PF Power, the monetization of the value of such deliveries, some combination thereof, or some other mechanism, and all issues related thereto, shall be developed by and subject to the then effective In-Lieu Power Policy.

8. INVOICING, BILLING, AND PAYMENT

8.1 **Invoicing for Residential Load Eligible for Monetary Benefits**

8.1.1 PGE shall submit to BPA each month an accounting invoice that documents (i) the amount of Residential Load Eligible for Monetary Benefits that PGE has elected to exchange pursuant to sections 5 and 6 above, (ii) PGE's ASC, (iii) PGE's applicable PF Exchange rate, (iv) any adjustment pursuant to section 20, and (v) any adjustment pursuant to section 12. Such documentation shall include, but is not limited to, the kilowatt-hours of energy which PGE billed to the Residential Load Eligible for Monetary Benefits during the previous month. Each such invoice shall be subject to adjustment pursuant to section 9 below.

8.1.2 Within 30 days following the receipt of each monthly invoice from PGE, and subject to section 9 below, BPA shall verify the invoice and pay such invoice electronically in accordance with instructions on each such invoice.

8.2 **Billing and Payment for In-Lieu PF Power**
In the event monthly amounts of In-Lieu PF Power are physically delivered to PGE, amounts billed under this Agreement shall be the monthly amounts specified in the in-lieu notice that are delivered by BPA to PGE pursuant to section 7 above.

8.2.1 **Billing**
PBL shall bill PGE monthly, consistent with applicable BPA rates, including the GRSPs and the provisions of this Agreement. PBL may send PGE an estimated bill followed by a final bill. PBL shall send all bills on the bill's issue date either electronically or by mail, at PGE's option. If electronic transmittal of the entire bill is not practical, PBL shall transmit a summary electronically, and send the entire bill by mail.

8.2.2 **Payment**
Payment of all bills, whether estimated or final, must be received by the 20^{th} day after the issue date of the bill (Due Date). If the 20^{th} day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. If payment has been made on an estimated bill before receipt of a final bill for the same month, PGE shall pay only the

amount by which the final bill exceeds the payment made for the estimated bill. PBL shall provide PGE the amounts by which an estimated bill exceeds a final bill through either a check or as a credit on the subsequent month's bill. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. PGE shall pay by electronic funds transfer using BPA's established procedures.

8.2.3 **Disputed Bills**
In case of a billing dispute, PGE shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If PGE is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by BPA.

9. ACCOUNTING, REVIEW, AND BUDGETING

PGE shall keep up-to-date records, accounts, and related documents that pertain to this Agreement. These records, accounts, and documents shall contain information that supports:

(1) PGE's ASC as determined pursuant to the ASC Methodology;

(2) identification of the consumers that comprise PGE's Residential Load;

(3) the amount of Residential Load Eligible for Monetary Benefits invoiced to BPA; and

(4) evidence that the benefits received by PGE have been passed through to consumers that comprise PGE's Residential Load Eligible for Monetary Benefits, as provided for in section 10 below.

At BPA's expense, BPA or its agent may, from time-to-time, review or inspect, consistent with the provisions of section 18.3 of this Agreement, PGE's records, accounts, and related documents pertaining to this Agreement. BPA's agent shall be subject to approval by PGE; such approval shall not be unreasonably withheld. PGE shall fully cooperate in good faith with any such reviews or inspections. BPA retains the right to take action consistent with the results of such reviews or inspections to require the pass-through of such benefits to Residential Load Eligible for Monetary Benefits.

BPA's right to review or inspect PGE's records, accounts, and related documents pertaining to this Agreement for any Fiscal Year shall expire 60 months after the end of such Fiscal Year. As long as BPA has such right to review or inspect, PGE agrees to maintain such records, accounts, and related documents.

If BPA determines that PGE has received monetary benefits for ineligible load, including an NLSL, or that other errors have occurred in implementing this Agreement that result in an overpayment, then any such overpayment shall be returned to BPA within 30 days of BPA's determination, or BPA may adjust future monetary benefit payments to PGE. If BPA determines that PGE has not received monetary benefits due to errors in implementing this Agreement that result in an underpayment, then BPA shall pay PGE such monetary benefits within 30 days of BPA's determination that such benefits were not received. In the event PGE disputes BPA's determination regarding any overpayment or underpayment, such dispute shall be subject to resolution in the same manner as a disputed bill under section 8.2.3 above.

10. PASS-THROUGH OF BENEFITS

10.1 Except as otherwise provided in this Agreement, all benefit amounts received by PGE from BPA under this Agreement shall be passed through to residential and small farm customers as either: (1) a separately stated credit to applicable retail rates; (2) monetary payments; or (3) as otherwise directed by the applicable Regulatory Body(ies).

10.2 Benefits shall be passed through by PGE in a timely manner, as set forth in this section 10.2 provided, that, it is specifically acknowledged and agreed that distributions of benefits for the Residential Load may be made by PGE in advance of its receipt of any such benefits from BPA and that such benefits may be used to set off distributions to the Residential Load made by PGE before or after October 1, 2011. The amount of benefits held as described in section 10.3 below at any time shall not exceed the greater of (i) the expected receipt of monetary payments from BPA under this Agreement over the next 180 days, and (ii) monetary payments received from BPA under this Agreement over the preceding 180 days; provided, however, that if the amount of benefits held in the account is less than $1,000,000, then PGE may distribute benefits on a less frequent basis, provided that distributions are made at least once each Fiscal Year; provided, further, that any remaining benefits held shall be distributed to Residential Load no later than one year following the earlier of (x) the end of the term of this Agreement; or (y) termination or suspension of this Agreement.

10.3 Benefits shall be passed through consistent with any procedures developed by PGE's Regulatory Body(ies) that are not otherwise inconsistent with this Agreement, the Northwest Power Act, or other applicable federal law. Until PGE has passed through such benefits pursuant to section 10.1 above, benefits received by PGE shall be identified on PGE's books of account and shall accrue interest at the rate(s) established by PGE's Regulatory Body(ies).

10.4 Nothing in this Agreement shall require that any In Lieu PF Power delivered to PGE pursuant to section 7 be delivered on an unbundled basis to residential and small farm customers of PGE or that PGE provide retail wheeling for such In Lieu PF Power.

11. TERMINATION AND SUSPENSION OF AGREEMENT

11.1 Termination of Agreement

11.1.1 PGE may terminate this Agreement by providing BPA with written notice within 30 days following the date of approval by the Federal Energy Regulatory Commission of new BPA rates (on the earlier of such approval on an interim basis, or if interim approval is not granted, on a final basis) in which the supplemental rate charge provided for in section 7(b)(3) of the Northwest Power Act is applied and causes the PF Exchange rate charged PGE to exceed PGE's ASC. Such termination shall become effective as of the date of the notice.

11.1.2 Upon termination of this Agreement pursuant to section 11.1.1, PGE shall not participate in the Residential Exchange Program established in section 5(c) of the Northwest Power Act until PGE offers to sell electric power to BPA pursuant to a new Residential Purchase and Sale Agreement (RPSA) that has been executed by the Parties. Such RPSA shall become effective no earlier than the start of the first Exchange Period following such request.

11.2 Suspension of Agreement

11.2.1 PGE may suspend performance under this Agreement for any reason upon 30 days advance written notice to BPA. Such suspension shall become effective as of the date specified in the notice, and shall suspend the rights and obligations of both Parties as of such date, and such suspension shall continue through September 30, 2011.

11.2.2 Upon suspension of this Agreement pursuant to section 11.2.1, PGE shall not seek and shall not be entitled to receive a new RPSA until the expiration of this Agreement on September 30, 2011.

11.3 Remedies

If the Federal Energy Regulatory Commission (FERC) or a court of competent jurisdiction remands, reverses, or otherwise finds unlawful a BPA final decision or decisions that affect an exchanging utility's receipt, or failure to receive, Residential Exchange Program benefits, BPA will review and determine the rights and obligations of the Parties through additional administrative actions(s) as necessary to respond to such regulatory or court decisions.

12. BALANCING ACCOUNT

12.1 Balancing Account

The BA balance is zero as of the Effective Date.

The BA balance includes an adjustment for changes in the Western Region Consumer Price Index (all items) (CPI) applied to such balance beginning on October 1, 2008, and continuing until such time as the BA balance is reduced to zero, based on the methodology described below. BPA shall adjust such balance monthly effective October 1, 2008, to reflect actual monthly changes in the CPI. This BA balance (BA_B), if any, comprises the beginning balance for a balancing account described in this section.

As long as the BA_B is greater than zero, such balance shall be adjusted monthly by the change in the Consumer Price Index value for that month relative to the CPI value for the previous month as follows. For the current month (m).

$$\text{BA adjustment}_{m+1} = \{CPI_m/CPI_{m-1}-1\}*BA\_B_m$$

Where

CPI_m= current month's CPI Index value as determined below
CPI_{m-1}= Previous month's CPI Index value
BA_B_m = Current month's ending BA balance
BA_B_{m+1} = Next month's beginning BA balance

The CPI index value shall be the end of month Consumer Price Index – All Urban Consumers (West Region. All Items), as published on the Bureau of Labor Statistics web site: address: http://data.bls.gov/cgi-bin/surveymost?cu, (select "West Region, all items" and then select the applicable range of months and years).

The adjusted BA balance for the next month (m+1) shall then be:

$$BA\_B_{m+1} = BA\_B_m + \text{BA adjustment} - P$$

Where P is the amount by which the BA increases or decreases as determined by multiplying the difference of the PGE's current ASC minus the applicable PF Exchange rate by the utility's Residential Load Eligible for Monetary Benefits. If the ASC is less than the applicable PF Exchange rate, P will be negative and add to the BA balance; otherwise P will be positive and reduce the BA balance.

12.2 **Additions to the Beginning Balancing Account**
Whenever the ASC is less than BPA's then-current applicable PF Exchange rate during the period that this Agreement is in effect but not in suspension, pursuant to section 11.2, the payment that would otherwise be owed BPA will be tracked by BPA and added to the balancing account.

12.3 **Resumption of Monetary Benefits**
If there is a balance in the balancing account and the ASC is greater than the applicable PF Exchange rate, BPA will make no cash payments but will apply the amount that would have been paid in order to reduce the balance in the BA account. PGE will resume the receipt of exchange payments from BPA under this Agreement if and at such time that there is no longer a balance in the BA, or PGE makes payments to BPA to bring the balance in the BA to zero. PGE may elect to make cash payments to BPA in order to eliminate all or a portion of PGE's balance in the BA at any time.

12.4 **BA Balance Carry Over**
Any balance in the BA, upon termination of this Agreement, shall not be a cash obligation of PGE but will carry over as a non-cash liability of PGE to the BA of a successor RPSA or other agreement implementing the Residential Exchange Program.

13. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Either Party may change its address for notices by giving notice of such change consistent with this section.

If to PGE:

Portland General Electric Company
121 SW Salmon Street, 17th Floor
Portland, OR 97204

Attn: Jim Lobdell
Vice President for Power
Operations and Resource Strategy

Phone: 503-464-2723
FAX: 503-464-2222
E-Mail: jim_lobdell@pgn.com

If to BPA:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621

Attn: Charles W. Forman – PSW-6
Account Executive

Phone: 503-230-3432
FAX: 503-230-3242
E-Mail: cformanjr@bpa.gov

14. COST RECOVERY

14.1 Nothing included in or omitted from this Agreement creates or extinguishes any right or obligation, if any, of BPA to assess against PGE and PGE to pay to BPA at any time a cost under-recovery charge pursuant to an applicable transmission rate schedule or otherwise applicable law.

14.2 BPA may adjust the PF Exchange rate set forth in the applicable power rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2009 GRSPs, or successor GRSPs.

15. UNCONTROLLABLE FORCES

PBL shall not be in breach of its obligation to provide In-Lieu PF Power and PGE shall not be in breach of its obligation to purchase In-Lieu PF Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that impairs that Party's ability to perform its contractual obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

15.1 any unplanned curtailment or interruption for any reason of firm transmission used to deliver In-Lieu PF Power to PGE's facilities or distribution system, including but not limited to unplanned maintenance outages;

15.2 any unplanned curtailment or interruption, failure or imminent failure of PGE's distribution facilities, including but not limited to unplanned maintenance outages;

15.3 any planned transmission or distribution outage that affects either PGE or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL and PGE, that is functionally separated from the generation provider in conformance with FERC Orders 888 and 889, or their successors;

15.4 strikes or work stoppage, including the threat of imminent strikes or work stoppage;

15.5 floods, earthquakes, or other natural disasters; and

15.6 orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force also agrees to notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

Both Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

16. GOVERNING LAW AND DISPUTE RESOLUTION

This Agreement shall be interpreted in accordance with and governed by Federal law. The Parties shall make a good faith effort to negotiate a resolution of disputes before initiating litigation. During a contract dispute or contract issue between the Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable. PGE reserves the right to seek judicial resolution of any dispute arising under this Agreement.

17. STATUTORY PROVISIONS

17.1 Annual Financial Report and Retail Rate Schedules

PGE shall provide PBL with a current copy of its annual financial report and its retail rate schedules, as required by Section 5(a) of the Bonneville Project Act, P.L. 75-329.

17.2 New Large Single Loads

17.2.1 General

All existing NLSLs are listed in section 1 of Exhibit B. PGE shall provide reasonable notice to PBL of any expected increase in load that is likely to qualify as a new NLSL. PGE may either serve a NLSL with contracted power or with power from another source. For purposes of this section 15(c), "Consumer" means an end-user of electric power or energy.

17.2.2 Determination of a Facility

PBL, in consultation with PGE, shall make a reasonable determination of what constitutes a single facility, for the purpose of identifying a NLSL, based upon the following criteria:

(A) whether the load is operated by a single Consumer;

(B) whether the load is in a single location;

(C) whether the load serves a manufacturing process which produces a single product or type of product;

(D) whether separable portions of the load are interdependent;

(E) whether the load is contracted for, served or billed as a single load under PGE's customary billing and service policy;

(F) consistent application of the foregoing criteria in similar fact situations; and

(G) any other factors the Parties determine to be relevant.

PBL shall show an increase in load associated with a Consumer's facility which has been determined to be a NLSL in section 1 of Exhibit B. PBL shall have the unilateral right to amend Exhibit B to reflect such determinations when made.

17.2.3 **Determination of Ten Average Megawatt Increase**
An increase in load shall be considered a NLSL if the energy consumption of the Consumer's load associated with a new facility, an existing facility, or expansion of an existing facility during the immediately past 12-month period exceeds by 10 average megawatts or more the Consumer's energy consumption for such new facility, existing facility or expansion of an existing facility for the consecutive 12-month period one year earlier, or the amount of the contracted for, or committed to load of the Consumer as of September 1, 1979, whichever is greater.

17.2.4 **CF/CT Loads**
PGE has no loads that were contracted for, or committed to, as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

17.3 **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of P.L. 96-501 and the provisions of P.L. 88-552 as amended by section 8(e) of P.L. 96-501 are incorporated into this Agreement by reference. BPA agrees that PGE, together with other customers in the Region, shall have priority to BPA power, consistent with these provisions.

17.4 **BPA Appropriations Refinancing Act**
Section 3201(i) of P.L. 104-134 is incorporated by reference.

18. STANDARD PROVISIONS

18.1 Amendments

No oral or written amendment, rescission, waiver, modification or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

18.2 Assignment

This Agreement is binding on any successors and assigns of the Parties. BPA may assign this Agreement to another Federal agency to which BPA's statutory duties have been transferred. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. BPA shall consider any request for assignment consistent with applicable BPA statutes. Such consent shall not be unreasonably withheld. PGE may not transfer or assign this Agreement to any of its retail customers.

18.3 Information Exchange and Confidentiality

The Parties shall provide each other with any information that is reasonably required and requested in writing by either Party, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party, including metering data for each load that qualifies as an NLSL. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

18.4 Entire Agreement

This Agreement, including all provisions, exhibits that are incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

18.5 **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

18.6 **Liability of Delivery**
PGE waives any claims against BPA under this Agreement for non-delivery of power to any points beyond the applicable point(s) of delivery under section 7. In no event will either Party be liable under this Agreement to the other Party for damage that results from an Electrical Disturbance caused by or occurring on an electric system owned or operated by such other Party or a third-party. Electrical Disturbance means any sudden, unexpected, changed, or abnormal electrical condition occurring in or on an electric system which causes damage.

18.7 **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

18.8 **Waivers**
Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

18.9 **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's NLSL Policy, In-Lieu Power Policy, and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by PGE to such policy, nor shall it be construed to be a waiver of the right of PGE to seek judicial review of any such policy.

19. NOTICE PROVIDED TO RESIDENTIAL AND SMALL FARM CONSUMERS
PGE will ensure that any entity that issues customer bills to PGE's residential and small farm consumers shall provide written notice on such customer bills that the benefits of this Agreement are "Federal Columbia River Benefits supplied by BPA."

20. ADJUSTMENTS TO MONETARY BENEFITS
The monetary benefits provided under this Agreement shall be subject to adjustment by BPA to account for the overpayment of benefits, if any, for the period October 1, 2001, through September 30, 2008. Any such adjustments shall be limited to those formally established by BPA in its wholesale power rate adjustment proceedings or other forums established by BPA for the determination of the amount of overpayment to be recovered and the associated recovery period; provided

however, that any such adjustment is subject to the resolution of all administrative or judicial review thereof.

Notwithstanding anything in this Agreement to the contrary, it is hereby agreed that neither Party has waived or is waiving, either by virtue of entering into this Agreement, by making or accepting payments under this Agreement, or otherwise, any arguments or claims it has made or may make, or any rights or obligations it has or may have, regarding (i) the above referenced payments, if any, to PGE, or (ii) the calculation implementation or settlement of Residential Exchange Program benefits for any period of time, and each Party hereby expressly reserves all such arguments and rights. This section 20 shall survive the termination or the expiration of this Agreement and shall survive even if any other provision(s) of this Agreement is held to be not consistent with law, or void or otherwise unenforceable.

21. SIGNATURES

Each signatory represents that he or she is authorized to enter into this Agreement on behalf of the Party for whom he or she signs.

PORTLAND GENERAL ELECTRIC COMPANY	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By ______________________	By ______________________
Name ______________________ *(Print/Type)*	Name Charles W. Forman *(Print/Type)*
Title ______________________	Title Account Executive
Date ______________________	Date ______________________

Exhibit A
RESIDENTIAL LOAD DEFINITION

1. PGE's Residential Load means the sum of the loads within the Region eligible for the Residential Exchange Program under the tariff schedules described below, adjusted for distribution losses as determined pursuant to Exhibit C, 2008 Average System Cost Methodology, as revised, supplemented, or superseded. If BPA determines that any action changes PGE's general tariffs or service schedules in a manner which would allow loads other than Residential Loads, as defined in the Northwest Power Act, to be included under these tariff schedules, or that the original general tariffs or service schedules include loads other than Residential Loads, such nonresidential loads shall be excluded from this Agreement.

   Such tariff schedules as presently effective include:

   (1) for all schedules listed below, include the amount, expressed in kilowatt-hours, of Residential Load supplied by PGE under:

   (A) Residential Schedule 7

   (B) Schedule 15

   (C) Schedule 32

   (D) Schedule 38

   (E) Schedule 47

   (F) Schedule 49

   (G) Schedule 83/89

   (2) a portion of the Residential Load supplied by PGE as determined pursuant to section 2 of this exhibit.

2. Any farm's monthly irrigation and pumping load qualifying under this Agreement for each billing period shall not exceed the amount of the energy determined by the following formula:

   $$\text{Irrigation/Pumping Load} = 400 \times 0.746 \times \text{days in billing period} \times 24$$

   provided, however, that this amount shall not exceed that farm's measured energy for the same billing period.

   where:

   400 is equal to the horsepower limit defined in the Northwest Power Act,
   0.746 is the factor for converting horsepower to kW,

days in billing period	is determined in accordance with prudent and normal utility business practices, and
24	is the number of hours in a day.

3. When more than one farm is supplied from a common pumping installation, the irrigation and pumping load of the installation shall be allocated among the farms using the installation, based on the method (e.g., water shares, acreage) that the farms use to allocate the power costs among themselves. These allocated loads shall then be combined with any other irrigation and pumping loads attributed to the farms under section 2 of this exhibit. In no instance shall any farm's total qualifying irrigation loads for any billing month exceed 222,000 kWh.

4. A farm is defined as a parcel or parcels of land owned or leased by one or more persons (person includes partnerships, corporations, or any legal entity capable of owning farm land) that is used primarily for agriculture. Agriculture is defined to include the raising and incidental primary processing of crops, pasturage, or livestock. Incidental primary processing means those activities necessarily undertaken to prepare agricultural products for safe and efficient storage or shipment. All electrical loads ordinarily associated with agriculture as defined above shall be considered as usual farm use.

   Contiguous parcels of land under single-ownership or leasehold shall be considered to be one farm. Noncontiguous parcels of land under single-ownership or leasehold shall be considered as one farm unit unless demonstrated otherwise by the owner or lessee of the parcels as determined by BPA.

   Parcels of land may not be subdivided into a larger number of parcels in order to attempt to increase the number of farms. Ownership or leasehold interests in farms may not be changed in order to attempt to increase the number of farms, for example, by leases to family members or establishment of partnerships, corporations or similar devices. Acquisition of a parcel which was previously a separate farm becomes part of the single farm that acquired the parcel. In order for a noncontiguous parcel to constitute a separate farm, the farm must not share any equipment or labor with any other parcel and must maintain separate financial statements, accounting records, and tax returns as of May 1, 2000. Any new farms created after May 1, 2000, with irrigation loads, must submit an application for exchange benefits for such irrigation loads to PGE which shall then submit such application to BPA and such application must be reviewed and approved by BPA before the new farm is eligible to receive benefits for such irrigation loads. A number of additional factors may be used by BPA to determine whether noncontiguous parcels constitute one or more farms. These factors include but are not limited to:

   (1) use,

   (2) ownership,

   (3) control,

(4) operating practices, and

(5) distance between parcels.

5. Unused irrigation allocations may not be reallocated to other farms or to another billing period.

6. The operator of a farm is required to certify to PGE all irrigation accounts, including horsepower rating for that farm, including all irrigation accounts commonly shared. The operator of a farm is required to provide PGE and BPA all documentation requested to assist in the farm determination.

7. This exhibit shall be revised to incorporate additional qualifying tariff schedules, subject to BPA's determination that the loads served under these schedules are qualified under the Northwest Power Act.

Exhibit B
NEW LARGE SINGLE LOADS

1. PGE has an existing NLSL(s). The NLSLs are listed below.

Customer information is commercially sensitive and PGE does not have permission to release detailed information about large customers. PGE submits the following:

Customer A. The customer is served by distribution facilities in PGE's service area.

In addition, the following customer, currently being served by an ESS, may be an NLSL if they return to PGE service in the future.

Customer B. The customer is served by distribution facilities in PGE's service area.

Note: This customer is currently not on PGE's cost of service rate and is purchasing energy from an Energy Service Supplier. The customer's annual election period for the following year is in November. As this customer is not currently taking service from PGE they are not an NLSL customer.

2. When PGE has a NLSL this exhibit shall be revised to include estimated monthly HLH and LLH MWhs in a table below.

Customer information is commercially sensitive and PGE does not have permission to release detailed information about large customers. PGE submits the following:

Customer A. Load incremented over 10 aMW in a 12 month period in 1997. In 2006 the NLSL for this customer totaled 22,950 MWhs.

In addition, the following customer, currently being served by an ESS, may be an NLSL if they return to PGE service in the future.

Customer B. Load incremented over 10 aMW in a 12 month period in 2003. The customer is served by distribution facilities in PGE's service area.

Note: This customer is currently not on PGE's cost of service rate and is purchasing energy from an Energy Service Supplier. The customer's annual election period for the following year is in November. As this customer is not currently taking service from PGE they are not an NLSL customer.

Exhibit C
2008 AVERAGE SYSTEM COST METHODOLOGY

ATTACHMENT A
ASC METHODOLOGY

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AVERAGE SYSTEM COST METHODOLOGY
BONNEVILLE POWER ADMINISTRATION

The following rules set forth the procedures by which regional utilities will submit Average System Cost (ASC) filings to the Bonneville Power Administration (BPA) and by which BPA will review such filings. BPA's review shall determine a Utility's ASC for the purpose of participating in the Residential Exchange Program (REP) pursuant to section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. § 839c(c).

I. DEFINITIONS

A. **Appendix 1:** Appendix 1 is the electronic form on which a Utility reports its Contract System Costs and other necessary data to BPA for the calculation of the Utility's Base Period ASC.

B. **Average System Cost:** The rate charged by a Utility to BPA for the agency's purchase of power from the Utility under section 5(c) of the Northwest Power Act for each Exchange Period and is the quotient obtained by dividing Contract System Costs by Contract System Load.

C. **Base Period:** The calendar year of the most recent FERC Form 1 data.

D. **Base Period ASC:** The ASC determined in the Review Period using the Utility's Base Period data.

E. **Contract High Water Mark (CHWM):** The aMW amount used to define access to Tier 1-priced power. CHWM is equal to the adjusted historical load for each customer proportionately scaled to Tier 1 System Resources and adjusted for conservation achieved. The CHWM is specified in each eligible customer's Contract High Water Mark Contract.

F. **Commission:** The Federal Energy Regulatory Commission.

G. **Contract System Costs:** 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. Under no circumstances shall Contract System Costs include costs excluded from ASC by section 5(c)(7) of the Northwest Power Act.

H. **Contract System Load:** 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.

I. **Exchange Period:** The period during which a Utility's BPA-approved ASC is effective for the calculation of the Utility's REP benefits. The initial Exchange Period under this ASC Methodology is from October 1, 2008, through September 30, 2009. Subsequent Exchange

Periods shall be the period of time concurrent with the BPA rate period beginning October 1, or the effective date of BPA's rate period.

J. **Exchange Period ASC:** The Base Period ASC escalated to a year(s) consistent with the Exchange Period.

K. **Form 1:** The annual filing submitted to the Federal Energy Regulatory Commission required by 18 CFR §141.1.

L. **Jurisdiction:** The service territory of the Utility within which a particular Regulatory Body has authority to approve a Utility's retail rates. Jurisdictions must be within the Pacific Northwest region as defined in the Northwest Power Act.

M. **Labor Ratios:** The ratios which 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 consumer-owned utilities, comparable data shall be used based on the cost of service study used as the basis for retail rates at the time of review.

N. **New Large Single Load:** That load defined in section 3(13) of the Northwest Power Act and determined by BPA as specified in power sales contracts and Residential Sale and Purchase Agreements (RPSA) with its Regional Power Sales Customers.

O. **Public Purpose Charge:** Any charge based on a Utility's total retail sales in a Jurisdiction that is given to independent non-profit entities or agencies of state and local governments for the purpose of funding within the Utility's service territory: (i) conservation programs in lieu of utility conservation programs; and (ii) acquisition of renewable resources.

P. **Rate Period High Water Mark (RHWM).** The amount used to define each customer's eligibility to purchase power at a Tier 1 price for the relevant Rate Period, subject to the customer's Net Requirement, expressed in average megawatts (aMW). RHWM is equal to the customer's CHWM as adjusted for changes in Tier 1 System Resources. The RHWM is determined for each eligible customer in the RHWM Process preceding each rate case.

Q. **Regional Power Sales Customer:** Any entity that can contract directly with BPA for the purchase of power under sections 5(b), 5(c), or 5(d) of the Northwest Power Act for delivery in the region as defined by section 3(14) of the Northwest Power Act.

R. **Residential Purchase and Sale Agreement (RPSA):** The power sales contract pursuant to section 5(c) of the Northwest Power Act between BPA and the Utility that defines and implements the power purchase and sale.

S. **Review Period:** The period of time during which a Utility's Appendix 1 is under review by BPA. The Review Period begins on June 1 and ends on or about November 15 of the fiscal year prior to the fiscal year BPA implements a change in wholesale power rates.

T. **Regulatory Body:** A state commission or consumer-owned utility governing body, or other entity authorized to establish retail electric rates in a Jurisdiction.

U. **Utility:** An investor-owned or consumer-owned (preference) Regional Power Sales Customer that has executed a Residential Purchase and Sale Agreement.

II. FILING PROCEDURES

The following procedures state the filing requirements for all Utilities that file an Appendix 1 to participate in the REP. Utilities must file an Appendix 1 with BPA to permit the calculation of each Utility's ASC..

A. Initial Exchange Period (FY 2009) and Second Exchange Period (FY 2010-2011).

1. A Utility's ASC for fiscal year FY 2009 shall be determined by BPA in accordance with this ASC Methodology and shall constitute the effective ASC for the REP effective October 1, 2008, unless (1) the Commission fails to approve this Methodology; (2) the Commission amends the Methodology in a manner that changes the Utility's ASC established by BPA; or (3) the Methodology is legally challenged and not affirmed on appeal by the United States Court of Appeals for the Ninth Circuit. The Base Period Appendix 1 filing will be from CY 2006.

2. The initial Exchange Period under this Methodology shall commence October 1, 2008, provided that the Commission has granted the Methodology interim or final approval by that date. The initial Exchange Period shall end on September 30, 2009.

3. Since the initial Exchange Period under this Methodology commences on October 1, 2008 and the Utility filings for FY2009 are also due that same day, BPA will pay the exchanging Utilities based on their October 1, 2008 filed ASC and then calculate a true-up to the final ASC after the BPA Review Period is concluded and BPA has issued the final ASC reports. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section *C. Failure to File an Appendix 1 and Patently Deficient Appendix 1.* Prior to the commencement of the BPA Review Process in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be trued-up during FY 2009.

4. For the Second Exchange Period, Utilities are required to submit their ASC filings by October 1, 2008 for FY 2010-2011. If a Utility has failed to file an Appendix 1 by October 1, 2008, BPA will follow the procedures outlined in section C. *Failure to File an Appendix 1 and Patently Deficient Appendix 1.* Prior to the commencement of the BPA Review Period in this Methodology, BPA will publish a schedule for the review of the filings. BPA may issue a schedule different from the prescribed schedule in order to ensure that ASCs are established in time to be incorporated in BPA's FY 2010-2011 wholesale power rate case.

After BPA's Review Process is concluded, BPA will issue Utility ASC Reports to reflect the final Utility ASCs for the FY2010-2011 rate period.

B. Subsequent Exchange Period Filing Requirements

1. Subsequent Exchange Periods shall be equal to the term of subsequent BPA wholesale power rate periods. ASCs shall change during such Exchange Periods only for the reasons provided in this Methodology.

2. Except as provided for the initial and second Exchange Periods under this Methodology, Utilities shall electronically file at least one Appendix 1 with BPA by June 1 of each year. In years when BPA is not conducting a review process, these filings shall be for informational purposes only and shall not change a Utility's ASC. The Appendix 1 shall be accompanied by supporting documentation, studies and analysis used to prepare the Appendix 1. For investor-owned utilities, the Appendix 1 shall be based on the Utility's most recently filed Form 1 and limited information from prior FERC Form 1 filings as required. For consumer-owned utilities, the Appendix 1 shall be based on the Utility's most recent audited financial information and shall be accompanied by a cost of service analysis (COSA). Each Appendix 1 shall contain an attestation signed by a senior officer of the Utility stating that the filing has been compiled in accordance with the Commission's Uniform System of Accounts, this ASC Methodology, and Generally Accepted Accounting Principles and is consistent with applicable orders and policies of the Utility's Regulatory Body. See Appendix 2.

C. Failure to File an Appendix 1 and Patently Deficient Appendix 1

1. Failure to File an Appendix 1. If a Utility fails to timely file an Appendix 1 and refuses to cure the problem within the *Period to Cure* provided in step 3 below, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility failing to file an Appendix 1 will also allow BPA the discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

2. Filing a Patently Deficient Appendix 1. If a Utility files its initial Appendix 1 and it is patently deficient as determined by BPA and the period to cure, as outlined in paragraph 3 below, has expired, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility filing a patently deficient ASC filing will also allow BPA the discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

3. Period to Cure. If a Utility fails to timely file an Appendix 1, or if it files an ASC which BPA determines is patently deficient, BPA shall provide such Utility with written notice and a period of seven (7) calendar days within which to file, or re-file, as the case may be, a new or corrected Appendix 1. In the event the Utility fails to file or re-file, as specified above, by the end of the seven-day cure period, or if such re-filed Appendix 1, is likewise determined patently deficient, BPA will make the Utility's Appendix 1 filing. The Utility will waive its right to participate in the ASC review proceeding to establish its ASC. All other parties will be permitted to participate and present arguments challenging the Utility's ASC. A Utility filing a patently deficient ASC filing will also allow BPA discretion to set its ASC for the Exchange Period and BPA shall not be required to include any proposed adjustments for resource changes or changes in service territories in the Appendix 1 filing.

D. Failure to File an Appendix 1 because of a New Residential Purchase and Sale Agreement

1. *New Residential Purchase and Sale Agreement.* After the initial and second Exchange Periods, if a Utility fails to file its Appendix 1 by June 1 because it executed a Residential Purchase and Sale Agreement after the commencement of a Review Period or during the subsequent Exchange Period, then BPA may set the Utility's ASC equal to the PF Exchange rate until the end of the Exchange Period.

E. Notice of Filing of Appendix 1

1. After a Utility files electronically an Appendix 1, BPA shall post the filings and non-confidential documentation on BPA's electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

2. BPA shall advise parties of the right to file a petition to intervene in BPA's ASC review process.

III. BPA REVIEW PROCESS

During a Review Period, the following procedures apply. These procedures shall not apply to informational ASC filings made outside of a Review Period.

A. BPA may petition to intervene in each retail rate proceeding for each Utility participating in the Residential Exchange Program. If BPA or any of its Regional Power Sales Customers has been denied the right to intervene in a retail rate review proceeding of a filing Utility when such intervention is for purposes of obtaining any information regarding costs or facts relevant to the determination of a Utility's ASC (after having made a good faith effort to intervene in such retail rate proceeding and having timely complied with applicable procedures to intervene in such retail rate proceeding), BPA may set that Utility's ASC equal to the PF Exchange Rate for the following Exchange Period. Exchanging Utilities must provide BPA and Regional Power Sales Customers with at least 60 days notice of their intent to change their retail rates.

B. Each Appendix 1 shall be reviewed by BPA or its designee and subject to a public process to determine whether the Contract System Costs are consistent with Generally Accepted Accounting Principles for electric utilities, whether Contract System Costs contain only allowed costs, and whether the revised Appendix 1 complies with the requirements of this Methodology, including applicable definitions and requirements incorporated from the Commission's Uniform System of Accounts. In addition, each Appendix 1 shall be reviewed by BPA or its designee to determine whether the Contract System Load used by the Utility is an appropriate load for purposes of the Utility's ASC computation.

C. In calculating ASCs, BPA will make an independent determination of (1) the appropriateness of the inclusion of costs; (2) the reasonableness of the costs included in Contract System Costs; and (3) the appropriateness of Contract System Loads. BPA shall not be obligated to pay an ASC different than the ASC based on Contract System Costs and Contract System Load as determined by BPA; provided that if a final order of the Commission or a reviewing court rejects BPA's ASC determination, then the ASC payable by BPA shall be the ASC as revised by BPA on remand.

D. The Appendix 1 filing shall be subject to review as follows:

The BPA review process (not including the initial and second Exchange Periods) commences on June 1 (Day 1) of the Review Period (or such other date as may be established by BPA). BPA will review all Utilities' ASCs concurrently in a public process.

Note: The dates identified below and those listed on the Sample Timeline on pages 13-14 herein are generic and intended to illustrate a timeline that is representative of the ASC review process. Unless specified, the days listed represent calendar days. Each spring prior to the Review Period, BPA will post on its ASCM website (http://www.bpa.gov/corporate/finance/ascm/) or its successor, a detailed schedule, accommodating the applicable holidays and weekends, that shall be the official schedule for that Review Period.

1. Day 1: Utility filings due to BPA.

2. Day 3: BPA posts the Utility filings to its electronic website. Access to such information shall be subject to any confidentiality rules or requirements established by BPA.

3. Day 7: Deadline to file Utility specific petitions to intervene with BPA for the Review Process. Any Regional Power Sales Customer or state utility Regulatory Body who so requests will be accorded party status for BPA's ASC review process if said request is received by the established deadline. Other interested parties also may submit a petition to intervene and BPA shall grant party status at BPA's discretion. Petitions to intervene must state with particularity the petitioner's interest in the ASC review proceeding. Petitions to intervene must be filed for each respective BPA review proceeding in order for a party to comment on such individual proceedings. The filing Utility is automatically a party to its own ASC review proceeding. BPA will grant or deny petitions to intervene within seven days after the deadline for filing such petitions.

4. Day 10: BPA grants or denies petitions to intervene

5. Day 11-66: Parties allowed to submit Data Requests. BPA and parties shall electronically file data requests to the Utility and BPA. BPA will make data requests available to all parties. Each Utility shall respond to requests for information relevant to the Utility's Appendix 1 filing, provided that the furnishing of proprietary or confidential information to any party may be made

contingent on the granting of proper safeguards to prevent unauthorized use or disclosure. The responses should be sent to the requestor and BPA.

For each data request, the responding Utility has 7 days to provide the requested data or object. If a Utility files an objection to a data request, the party submitting the data request has 4 days to respond to the objection. After the response to the objection is received or the 4 days to respond has elapsed, BPA then has 7 days to issue a ruling as to whether the Utility's objection will be sustained or overruled. If the objection is overruled, the Utility must provide the data requested within 7 days after the ruling. If a Utility does not provide requested data, BPA may, in its discretion, remove from Contract System Costs all costs associated with the data not provided.

6. Day TBD: BPA will commence workshops on all Appendix 1 filings based on the specific schedules. Utilities filing Appendix 1s shall have staff or agents available for questioning by BPA and other parties to the proceeding. The primary purpose of the first workshop is to clarify data, work papers, supporting documentation and assumptions used to prepare the Appendix 1.

7. Day 88: By this day, BPA and parties may electronically file with BPA an issues list identifying contested elements of a Utility's ASC filing and the basis for the party's issues. BPA will make the issues lists available to all parties.

8. Day 102: By this day, each filing Utility will electronically file a response to issues lists. BPA and other parties also may file comments in response to issue lists.

9. Day 108: By this day, a workshop will be held to discuss and resolve issues raised by parties through their issues lists.

10. Day 111: Requests for oral argument before the Administrator or his/her designee must be submitted in writing to BPA by this day. Such requests shall contain a statement setting forth reasons why the party believes oral argument is necessary.

11. Day 114: BPA, at its discretion, may grant or deny any request for oral argument by this day.

12. Day 123: In the event a request for oral argument is granted, the requesting party shall present its argument first. Responding parties shall present their arguments thereafter. The Administrator or his/her designee, at his discretion, may provide an opportunity for the requesting party to reply. Oral argument shall be presented no later than this day.

13. Day 141: By this day, BPA will publish for comment and electronically serve Draft Utility ASC Reports on all parties. The Reports will contain analyses and decisions on all contested issues raised in the ASC review process.

14. Day 154: By this day, the Utility and parties may file comments on the Draft Utility ASC Reports.

15. Day 167: The BPA Administrator will issue Final Utility ASC Reports.

16. If BPA has not issued the Final Utility ASC Reports by the end of the Review Period, the ASC filed by the Utility shall be the Exchange Period ASC until the date BPA issues the Final Utility ASC Reports. The final ASCs determined by BPA shall then be the Exchange Period ASCs, effective back to the beginning of the Exchange period and until the end of the Exchange Period.

IV. RULES FOR DETERMINING EXCHANGE PERIOD AVERAGE SYSTEM COST

A. Escalation to Exchange Period

1. BPA will escalate BPA approved Base Period costs to the midpoint of the fiscal year for a 1-year rate period/Exchange Period, and to the midpoint of the 2-year period for a 2-year rate period/Exchange Period to calculate Exchange Period ASCs.

2. For purposes of the escalation referenced in paragraph 1 above, BPA will use 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. The following list of acronyms defines Global Insight's escalation codes, with exception of the natural gas escalator which is provided by BPA.

A&G	Administrative and General
CACNT	Customer Account
CD	Construction, Distribution Plant
CONSTANT	Constant
CSALES	Customer Sales
CSERV	Customer Service
COAL	Coal
DMN	Distribution Maintenance
DOPS	Distribution Operations
HMN	Hydro Maintenance
HOPS	Hydro Operations
INF	Inflation
NATGAS	Natural Gas
NFUEL	Nuclear Fuel
NMN	Nuclear Maintenance
NOPS	Nuclear Operations
OMN	Other Production Maintenance
OOPS	Other Production Operations
SMN	Steam Maintenance
SOPS	Steam Operations
TMN	Transmission Maintenance

TOPS	Transmission Operations
WAGES	Wages

Table 1 in section VIII shows the escalators to be used for each line item included in the Appendix 1.

3. If any of the escalators specified in the ASCM are no longer available, BPA will designate a replacement source of escalators that, as near as possible, replicates the results produced by the prior escalator and, if such a replacement source is not available, the replacement escalator will be the forecast of the GDP Price Deflator.

4. BPA will base the costs of power products purchased from BPA on BPA's forecast of prices for its products.

B. Treatment of Sales for Resale and Power Purchases

1. BPA will escalate long–term and intermediate-term (as defined by FERC) firm purchased power costs and sales for resale revenues at the rate of inflation.

2. BPA will not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period will be used as the starting values. A Utility will then be 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 to be included in the Rate Period ASC.

3. BPA will use the method as described below to determine separate market prices to forecast short-term purchased power expense and sales for resale revenues to calculate Exchange Period ASCs:

a. The Utility's average short-term purchased power price and short-term sales for resale price will be calculated for each year for the most recent three years of actual data (Base Period and prior two years).

b. The mid-point between the Utility's average short term purchased power price and short term sales for resale price will be calculated for each of the years in 1.

c. The percentage spread around the Utility's mid-point between the average short term purchase power price and short term sales for resale price will be calculated for each of the years in 1.

d. A weighted average spread for the Utility's most recent three years of actual data (Base Period and prior two years) will then be calculated. The following weighting scale will be used:

    i. 3 times Base Period spread

ii. 2 times (Base Period year minus 1) spread
iii. 1 times (Base Period year minus 2) spread

e. The Base Period mid-point price calculated in 2 will be escalated at the same rate as BPA's market price forecast.

f. The weighted average spread calculated in 4 will then be applied to the forecasted mid-point calculated in 5 to determine the purchased power and sales for resale price, to value purchased power expenses and sales for resale revenue to be included in Rate Period ASCs.

g. This same method will be used to calculate the market price forecast for short-term purchased power expense and sales for resale revenues for use in the load growth not met by new resource additions.

C. Major Resource Additions and Materiality Thresholds

During the Exchange Period, BPA will allow changes to a Utility's ASC to account for major new purchase power contracts or major new resource additions that come on-line and are used to meet the Utility's retail load. These changes, however, have to meet a materiality threshold in order for BPA to allow an ASC to change. These ASCs will be determined by BPA during the Review Period. The changes to the ASC will become effective when the resource begins commercial operation or power is received under the purchase power contract. Such criteria will also apply to resources that are sold, transferred or retired.

BPA will use the following method to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold. These additions will 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.

1. BPA will apply a materiality threshold of a 2.5 percent change in a Utility's Base Period ASC for determining when a change in ASC will be allowed for resource additions or reductions. BPA will allow a Utility 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. This treatment allows an exchanging Utility to include resources required under state renewable resource mandates while lessening the administrative cost and burden of verifying the resource cost estimates during the ASC Review Period.

2. At the time the Utility submits its Appendix 1 filing, the exchanging Utility will provide its forecast of major new resource addition and all associated costs. The forecast will cover the period from the end of the Base Period to the end of the Exchange Period.

3. BPA will calculate new transmission wheeling revenues associated with new transmission investment by the following formula:

$$NTWR = WR_{(before\ additions)} * [(NTP_{(before\ additions)} + NTA) / NTP_{(before\ additions)}]$$

Where:

- NTWR = New transmission wheeling revenues
- $WR_{(before\ additions)}$ = wheeling revenues (before additions)
- $NTP_{(before\ additions)}$ = (Net Transmission Plant (before additions)
- NTA = new transmission additions

4. The forecast of the major new resource costs to be included in the Utility's Exchange Period ASC will be reviewed and determined during the Review Period.

5. All major new resources included in an ASC calculation prior to the start of the Exchange Period will be projected forward to the mid-point of the Exchange Period.

6. For each major new resource addition forecast to be available to meet regional retail load during the Exchange Period, BPA will calculate the difference in ASC between the ASC without the new resource and the ASC with the new resource (the ASC delta) at the mid-point of the Exchange Period.

7. When the resource comes on-line, BPA will add the ASC delta to the Utility's then current ASC to determine its new ASC.

8. Steps 1 through 7 above will also be used in a similar manner for resources that are sold, transferred or retired.

9. BPA will escalate the Base Period average per-MWh cost of Distribution Plant forward to the mid-point of the Exchange Period, and use the escalated average cost to determine the distribution-related cost of meeting load growth since the Base Period. This cost will be included in the Exchange Period ASC.

10. BPA will issue special procedural rules to ensure the confidentiality of information provided by Utilities regarding any new major resource additions as part of its Review Process. BPA will provide parties with an opportunity to comment on the rules prior to their implementation in the Review Process. Failure to provide needed information may result in exclusion of the related costs from ASC. However, as is the case for other Utilities that do not have major resource additions in a particular year, load growth will be assumed to be met with purchases on the wholesale market, as described in section IV.E. of this Methodology. What the Utility loses by not supplying confidential resource data is the difference between the cost of the resource and the price of electricity in the wholesale market.

D. Forecasted Contract System 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 endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load will start with the Base Period and extend through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load will be provided on a monthly basis for the Exchange Period.

E. Load Growth Not Met by New Resource Additions

All forecast load growth not met by new resource additions will be met by purchased power at the forecasted Utility-specific short-term purchased power price.

1. The Utility's forecast load growth will be met with market purchases priced at the Utility's forecast short-term purchased power price unless the Utility has forecasted major resource additions.

2. In the event of major resource additions, forecast load growth will be met by the new resource. If the new resource is less than total forecast load growth, the unmet load growth will be met with market purchases priced at the Utility's forecast short-term purchased power price.

3. In the event that the power provided by a new resource exceeds the Utility's forecast load growth, the excess will be sold as surplus power into the market and priced at the Utility's forecast sales for resale price as determined by BPA in section IV.B.

F. Changes to Service Territory

In the event a Utility forecasts that it will acquire a new service territory or lose a portion of its service territory, and the resulting change in ASC falls within the 2.5% or greater materiality threshold, the Utility will submit two ASC filings:

1. A Base Period ASC that does not reflect the acquisition or loss of service territory, and

2. A second filing that incorporates:

a. The forecast of the increase or reduction in Contract System Load associated with the acquisition or reduction in service territory.

b. The forecast of the increase or reduction in Contract System Costs associated with the acquisition or relinquishment of the service territory.

c. In addition to including the forecast of capital and operating cost increases or reductions associated with the change in service territory, the Utility must also forecast the changes in purchased power expense, sales-for-resale credit and other costs based on the changes in the service territory

d. Because the date of the actual change to the Utility's service territory could differ from the forecast date used to determine the ASC during the Review Period, BPA will not adjust the Utility's ASC until the change in service territory takes place.

G. <u>ASC Determination for COUs that elect to execute Regional Dialogue HWM Contracts</u>

BPA will utilize the following approach:

1. Use the RHWM System Load as determined in the Tiered Rates Methodology (TRM) process.

2. Determine the RHWM Exchangeable Load (Residential/Small Farm Load).

3. During the Average System Costs Review process the Utility shall submit the data necessary to determine the fully allocated unit cost of resources in excess of the resource amounts used to calculate its CHWM.

4. Calculate the Utility's Total Unadjusted Contract System Cost (CSC) as described in the ASCM

5. Calculate a load growth credit {(Current System Load minus RHWM system Load) * Unit costs from 3 above}.

6. Total Exchangeable Contract System Cost = Total Unadjusted CSC minus load growth revenue credit (from 5 above).

7. HWM Average System Cost = Total Exchangeable Contract System Cost / RHWM System Load.

H. <u>Timely filing of Appendix 1</u>

Utilities must file ASC information by June 1 each year, as required in section II, for BPA's review and determination of a Base Period ASC. Utilities will file multiple, contingent, Base Period ASC filings to reflect changes to service territories as required in section F above.

V. CHANGE IN AVERAGE SYSTEM COST METHODOLOGY

The Administrator, at his or her discretion, or upon written request from three-quarters of the Utilities that are parties to contracts authorized by section 5(c) of the Northwest Power Act, or from three-quarters of BPA's preference customers, or from three-quarters of BPA's direct-service industrial customers may initiate a consultation process as provided in section 5(c) of the Northwest Power Act. After completion of this process, the Administrator may file a new ASC Methodology with the Commission. However, the Administrator shall not initiate any consultation process until one year of experience has been gained under the then-existing ASC Methodology, *viz;* one year after the then-existing Methodology has been adopted by BPA and approved by the Commission through interim or final approval, whichever occurs first.

The Administrator may, from time to time, issue interpretations of the ASC Methodology. The Administrator also may modify the functionalization code of any Account to comply with the limitations identified in section 5(c)(7)(A)-(C) of the Northwest Power Act or to conform to the Federal Energy Regulatory Commission's revisions to the Uniform System of Accounts.

VI. SAMPLE TIMELINE REVIEW PROCEDURES

Note: BPA's ASC review process of Utilities' Appendix 1s occurs only in the year before BPA establishes new Wholesale Power Rate Schedules. However, Utilities are required to file an Appendix 1 by June 1 of each year in order that BPA can maintain current data.

The schedule below is a generic schedule that is representative of the timeline for the ASC review process. Each spring in the year prior to BPA implementing new Wholesale Power Rates, BPA will post a detailed schedule incorporating the applicable holidays and weekends.

DAY[1]	EVENT
June1	Utilities file electronic Appendix 1s with BPA.
June 7	Deadline to file petitions to intervene with BPA.
June 10	BPA grants or denies petitions to intervene.
June 11	Begin Data Request period.
TBD	Workshop(s) on Utilities' Appendix 1 filings.
Aug 22	End Data Response period.
Aug 27	Deadline for BPA and parties' issue lists on Utilities' filings.
Sept 10	Deadline for reply issue lists from all parties on Utilities' filings.
Sept 16	Workshop to discuss issue lists on Utilities' filings.
Sept 19	Deadline to request oral argument.
Sept 22	BPA grants or denies requests for oral argument.
Oct 1	Oral argument (if granted).
Oct 19	BPA publishes Draft ASC Report.
Nov 1	Deadline for Utilities' and parties' comments on Draft ASC Report.
Nov 14	BPA Administrator issues Final ASC Report.

[1] Deadlines end at 5 p.m., Pacific Prevailing Time, of the due date.

VII. APPENDIX 1 INSTRUCTIONS

Appendix 1 is the form on which a Utility reports its Contract System Costs, Contract System Loads, and other necessary data for the calculation of ASC. Appendix 1 is an electronic template consisting of seven schedules and several supporting files that must be completed by the Utility in accordance with these instructions and the provisions of the Endnotes following the schedules.

Appendix 1 filings must be accompanied by an Attestation Statement of the Chief Financial Officer of the Utility or other responsible official who possesses the financial and accounting knowledge necessary to complete the Attestation Statement. The ASC Filing Attestation Statement is presented at Appendix 2. The primary source of data for the investor-owned utilities' Appendix 1 filings is the Utility's prior year FERC Form No. 1 (Form 1) filing. Any items not applicable to the Utility shall be so identified. For consumer-owned utilities that do not follow the Commission Accounts, filings must include reconciliation between Utility Accounts and the items allowed as Contract System Costs. In addition, the COSA must be reviewed by an independent accounting or consulting firm. The COSA report must be accompanied by a report from an independent accounting firm or a consulting firm that outlines the review work that was performed in preparing the COSA report along with an assurance statement that the information contained in the COSA report is presented fairly in all material respects. The COSA report statement is presented in Appendix 2, Exhibit A, Statement of Review and Compilation of Work Performed. An outline of the financial documents that accompany an ASC filing for both investor-owned utilities and consumer-owned utilities is presented in Appendix 2, Exhibit B.

The primary schedules are as follows. The ASC Appendix 1 template is available electronically at http://www.bpa.gov/corporate/finance/ascm/, or its successor site.

Schedule 1: Plant Investment/Rate Base
Schedule 1A: Cash Working Capital
Schedule 2: Capital Structure and Rate of Return
Schedule 3: Expenses
Schedule 3A: Taxes
Schedule 3B: Other Included Items
Schedule 4: Average System Cost

The filing Utility shall reference and attach work papers, documentation and other required information that supports costs and loads, including details of allocation and functionalization. All references to the Commission Accounts are to the Commission's Uniform System of Accounts as of July 1, 2006 or as amended by subsequent Commission actions. The costs includable in the attached schedules are those includable by reason of the definitions in the Commission Accounts. If the Commission Accounts are later revised or renumbered, any changes shall be incorporated into this form by reference, except to the extent BPA determines that a particular change results in a change in the type of costs allowable for REP purposes. In such event, BPA shall address the changes, including escalation rules, in its Review Process for the following Exchange Period.

BPA may require a Utility to account for all transactions with affiliated entities as though the affiliated entities were owned in whole or in part by the Utility, if necessary, to properly determine and/or functionalize the Utility's costs.

A Utility operating in more than one Pacific Northwest Jurisdiction shall file one Appendix 1.

A Utility operating in Jurisdictions outside the Pacific Northwest shall allocate its total system costs among its Jurisdictions within the Pacific Northwest and outside the Pacific Northwest in accord with the same allocation methods and procedures used by the Regulatory Body(ies) to establish Jurisdictional costs and resulting revenue requirements. Such Utility's Appendix 1 filing shall include details of the allocation.

This allocation shall exclude all costs of additional resources used to meet loads outside the region, as required by section 5(c)(7) of the Northwest Power Act. All schedule entries and supporting data shall be in accord with Generally Accepted Accounting Principles and practices as these principles and practices apply to the electric utility industry.

A Utility shall file an Attestation Statement with each Appendix 1 filing and supporting documentation for each Review Period. See Appendix 2.

VIII. AVERAGE SYSTEM COST METHODOLOGY FUNCTIONALIZATION

Functionalization of each Account included in a Utility's Average System Cost (ASC) shall be according to the functionalization prescribed in Table 1, *Functionalization and Escalation Codes*, beginning on page 18. Direct Analysis on an Account may be performed only if Table 1 states specifically that a Utility may perform a Direct Analysis on the Account with the exception of conservation costs. Utilities will be able to functionalize all conservation-related costs to Production, regardless of the Account in which they are recorded. The Direct Analysis must be consistent with the directions provided below.

The following chart identifies the functionalization codes:

DIRECT	Direct Analysis
PROD	Production
TRANS	Transmission
DIST	Distribution/Other
PTD	Production, Transmission, Distribution/Other Ratio
TD	Transmission, Distribution/Other Ratio
GP	General Plant Ratio
GPM	General Plant Maintenance Ratio
PTDG	Production, Transmission, Distribution/Other, General Plant Ratio
LABOR	Labor Ratio

A. Functionalization Rules:

1. Functionalization of certain Accounts may be based on Direct Analysis or with a default ratio associated with that specific Account as shown on Table 1. Once a Utility uses a specific functionalization method for an Account, the Utility may not change the functionalization for that Account without prior written approval from BPA.

2. The Utility must submit with its Appendix 1 any and all work papers, documents, or other materials that demonstrate that the functionalization under its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation could result in the entire Account being functionalized to Distribution/Other, or Production, or Transmission, as appropriate.

B. <u>Functionalization Methods</u>:

1. Direct Analysis, if allowed or required by Table 1, assigns costs to the production, transmission, and/or distribution function of the Utility. The only exception to this requirement is for conservation-related costs. Utilities will be able to identify and functionalize to Production any conservation-related costs, irrespective of the Account in which they are recorded. Such analysis is subject to BPA review and approval. Once a Utility uses a specific functionalization method for an Account, the Utility may not change the functionalization for that Account without prior written approval from BPA.

2. BPA will not allow Utilities to use a combination of Direct Analysis and a prescribed functionalization method for the same Account. The Utilities can develop and use a functionalization ratio or use a prescribed functionalization method if the Utility through Direct Analysis can justify how the ratio adequately reflects the functional nature of the costs included in any Account or cost item being functionalized by the ratio.

3. Utilities that wish to include advertising and promotion costs related to conservation will do so with a Direct Analysis. If a Utility records conservation costs in an Account that is normally functionalized to Distribution/Other, the Utility will identify and document the conservation-related costs included in the Account, and the balance of the costs will be functionalized to Distribution/Other. The presence of conservation-related costs in an Account does not give the Utility permission to perform a Direct Analysis on the entire Account. This option allows a Utility to assign costs in the specified Account to Production, Transmission and/or Distribution/Other based on analysis and support from the Utility that demonstrate such cost assignment is appropriate. The Utility must submit with its ASC filing any and all work papers, documents, and other materials that demonstrate the functionalization contained in its Direct Analysis assigns costs based upon the actual and/or intended functional use of those items. Failure to submit such documentation will result in the entire Account being functionalized to Distribution/Other for all schedules, with the exception of items included in Schedule 3B, *Other Included Items*, where certain Accounts shall be functionalized to Production as appropriate.

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Schedule 1: Plant Investment/Rate Base				
Intangible Plant:				
Intangible Plant - Organization	301	DIST		CONSTANT
Intangible Plant - Franchises and Consents	302	DIRECT	PTD	CONSTANT
Intangible Plant - Miscellaneous	303	DIRECT	DIST	CONSTANT
Production Plant:				
Steam Production	310-317	PROD		CONSTANT
Nuclear Production	320-326	PROD		CONSTANT
Hydraulic Production	330-337	PROD		CONSTANT
Other Production	340-347	PROD		CONSTANT
Transmission Plant:				
Transmission Plant	350-359.1	TRANS		CONSTANT
Distribution Plant:				
Distribution Plant	360-374	DIST		CD
General Plant:				
Land and Land Rights	389	PTD		CONSTANT
Structures and Improvements	390	PTD		CONSTANT
Furniture and Equipment	391	LABOR		CONSTANT
Transportation Equipment	392	TD		CONSTANT
Stores Equipment	393	PTD		CONSTANT
Tools, Shop and Garage Equipment	394	PTD		CONSTANT
Laboratory Equipment	395	PTD		CONSTANT
Power Operated Equipment	396	TD		CONSTANT
Communication Equipment	397	PTD		CONSTANT
Miscellaneous Equipment	398	PTD		CONSTANT
Other Tangible Property	399	DIRECT	PTD	CONSTANT
Asset Retirement Costs for General Plant	399.1	PTD		CONSTANT
Depreciation Reserve:				
Steam Production Plant	108	PROD		CONSTANT
Nuclear Production Plant	108	PROD		CONSTANT
Hydraulic Production Plant	108	PROD		CONSTANT
Other Production Plant	108	PROD		CONSTANT
Transmission Plant	108	TRANS		CONSTANT
Distribution Plant	108	DIST		CONSTANT
General Plant	108	GP		CONSTANT
Amortization of Intangible Plant - Account 301	111	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	111	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	111	DIRECT	DIST	CONSTANT
Mining Plant Depreciation	108	PROD		CONSTANT
Amortization of Plant Held for Future Use	111	DIST		CONSTANT
Capital Lease - Common Plant	108	DIRECT	PTD	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Leasehold Improvements	108	DIRECT	DIST	CONSTANT
In-Service: Depreciation of Common Plant	108	DIRECT	PTD	CONSTANT
Amortization of Other Utility Plant	108	DIRECT	DIST	CONSTANT
Amortization of Acquisition Adjustments	115	DIRECT	DIST	CONSTANT
Depreciation and Amortization Reserve (Other)		DIRECT	N/A	CONSTANT
Cash Working Capital:				
(Utility Plant) Held For Future Use	105	DIST		CONSTANT
(Utility Plant) Completed Construction - Not Classified	106	PTD		CONSTANT
Nuclear Fuel	120.2-120.6	PROD		NFUEL
Construction Work in Progress (CWIP)	107&120.1	DIST		CONSTANT
Common Plant		DIRECT	N/A	CONSTANT
Acquisition Adjustments (Electric)	114	DIRECT	DIST	CONSTANT
Other Property and Investments:				
Investment in Associated Companies	123.1	DIRECT	DIST	CONSTANT
Other Investment	124	DIST		CONSTANT
Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Current and Accrued Assets:				
Fuel Stock	151	PROD		COAL
Fuel Stock Expenses Undistributed	152	PROD		CONSTANT
Plant Materials and Operating Supplies	154	PTD		INF
Merchandise (Major Only)	155	DIST		INF
Other Materials and Supplies (Major only)	156	DIST		INF
EPA Allowance Inventory	158.1	PROD		CONSTANT
EPA Allowances Withheld	158.2	PROD		CONSTANT
Stores Expense Undistributed	163	PTD		INF
Prepayments	165	PTD		CONSTANT
Derivative Instrument Assets	175	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets	175	DIST		CONSTANT
Derivative Instrument Assets – Hedges	176	DIST		CONSTANT
Less: Long-Term Portion of Derivative Assets - Hedges	176	DIST		CONSTANT
Deferred Debits:				
Unamortized Debt Expenses	181	PTDG		CONSTANT
Extraordinary Property Losses	182.1	DIRECT	DIST	CONSTANT
Unrecovered Plant and Regulatory Study Costs	182.2	DIRECT	DIST	CONSTANT
Other Regulatory Assets	182.3	DIRECT	DIST	CONSTANT
Preliminary Survey and Investigation Charges (Electric)	183	DIST		CONSTANT
Preliminary Natural Gas Survey and Investigation Charges	183.1	DIST		CONSTANT
Other Preliminary Survey and Investigation Charges	183.2	DIST		CONSTANT
Clearing Accounts	184	DIST		CONSTANT
Temporary Facilities	185	PTDG		CONSTANT
Miscellaneous Deferred Debits	186	DIRECT	DIST	CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Deferred Losses from Disposition of Utility Plant	187	DIRECT	N/A	CONSTANT
Research, Development, and Demonstration Expenditures	188	DIST		CONSTANT
Unamortized Loss on Reacquired Debt	189	PTDG		CONSTANT
Accumulated Deferred Income Taxes	190	DIST		CONSTANT
Liabilities and Other Credits (Comparative Balance Sheet):				
Derivative Instrument Liabilities	244	DIST		CONSTANT
Less: Long-Term Portion of Derivative Instrument Liabilities	244	DIST		CONSTANT
Derivative Instrument Liabilities – Hedges	245	DIST		CONSTANT
Less: Long-Term Portion of Derivative Inst Liabilities–Hedges	245	DIST		CONSTANT
Customer Advances for Construction	252	DIST		CONSTANT
Other Deferred Credits	253	DIRECT	DIST	CONSTANT
Other Regulatory Liabilities	254	DIRECT	DIST	CONSTANT
Accumulated Deferred Investment Tax Credits	255	DIST		CONSTANT
Deferred Gains from Disposition of Utility Plant	256	DIRECT	N/A	CONSTANT
Unamortized Gain on Reacquired Debt	257	PTDG		CONSTANT
Accumulated Deferred Income Taxes-Accel. Amort.	281	DIST		CONSTANT
Accumulated Deferred Income Taxes-Property	282	DIST		CONSTANT
Accumulated Deferred Income Taxes-Other	283	DIST		CONSTANT
Schedule 3: Expenses				
Power Production Expenses:				
Steam Power Generation				
Steam Power – Fuel	501	PROD		COAL
Steam Power - Operations (Excluding 501 - Fuel)	500-509	PROD		SOPS
Steam Power – Maintenance	510-515	PROD		SMN
Nuclear Power Generation				
Nuclear – Fuel	518	PROD		NFUEL
Nuclear - Operation (Excluding 518 - Fuel)	517-525	PROD		NOPS
Nuclear – Maintenance	528-532	PROD		NMN
Hydraulic Power Generation				
Hydraulic – Operation	535-540.1	PROD		HOPS
Hydraulic – Maintenance	541-545.1	PROD		HMN
Other Power Generation				
Other Power – Fuel	547	PROD		NATGAS
Other Power - Operations (Excluding 547 - Fuel)	546-550.1	PROD		OOPS
Other Power – Maintenance	551-554.1	PROD		OMN
Other Power Supply Expenses				
Purchased Power (Excluding REP Reversal)	555	PROD		CONSTANT
System Control and Load Dispatching	556	PROD		CONSTANT
Other Expenses	557	PROD		CONSTANT
BPA REP Reversal	555	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION
2008 Average System Cost Methodology
Functionalization and Escalation Codes

Account Description	Acct No.	Functionalization Codes		Escalation Codes
		Method	Default	
Public Purpose Charges		DIRECT		CONSTANT
Transmission Expenses:				
Transmission of Electricity by Others (Wheeling)	565	TRANS		INF
Total Operations less Wheeling	560-567.1	TRANS		TOPS
Total Maintenance	568-574	TRANS		TMN
Distribution Expense:				
Total Operations	580-589	DIST		DOPS
Total Maintenance	590-598	DIST		DMN
Customer and Sales Expenses:				
Total Customer Accounts	901-905	DIST		CACNT
Customer Service and Information	906-907	DIST		CSERV
Customer assistance expenses (Major only)	908	DIRECT	N/A	CSERV
Customer Service and Information	909-910	DIST		CSALES
Total Sales Expense	911-917	DIST		CSALES
Administration and General Expense:				
Operation				
Administration and General Salaries	920	LABOR		A&G
Office Supplies & Expenses	921	LABOR		A&G
(Less) Administration Expenses Transferred - Credit	922	LABOR		A&G
Outside Services Employed	923	LABOR		A&G
Property Insurance	924	PTDG		A&G
Injuries and Damages	925	LABOR		A&G
Employee Pensions & Benefits	926	LABOR		A&G
Franchise Requirements	927	DIST		A&G
Regulatory Commission Expenses	928	DIST		A&G
(Less) Duplicate Charges - Credit	929	PTDG		A&G
General Advertising Expenses	930.1	DIRECT	DIST	A&G
Miscellaneous General Expenses	930.2	DIST		A&G
Rents	931	DIST		A&G
Transportation Expenses (Non Major)	933	DIST		A&G
Maintenance				
Maintenance of General Plant	935	GPM		A&G
Depreciation and Amortization:				
Amortization of Intangible Plant - Account 301	404	DIST		CONSTANT
Amortization of Intangible Plant - Account 302	404	DIRECT	PTD	CONSTANT
Amortization of Intangible Plant - Account 303	404	DIRECT	DIST	CONSTANT
Steam Production Plant	403	PROD		CONSTANT
Nuclear Production Plant	403	PROD		CONSTANT
Hydraulic Production Plant - Conventional	403	PROD		CONSTANT
Hydraulic Production Plant - Pumped Storage	403	PROD		CONSTANT
Other Production Plant	403	PROD		CONSTANT

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Transmission Plant	403	TRANS		CONSTANT
Distribution Plant	403	DIST		CONSTANT
General Plant	403	GP		CONSTANT
Common Plant - Electric	403 & 404	DIRECT	N/A	CONSTANT
Depreciation Expense for Asset Retirement Costs	403.1	DIRECT	N/A	CONSTANT
Amortization of Limited Term Electric Plant	404	DIRECT	N/A	CONSTANT
Amortization of Plant Acquisition Adjustments (Electric)	406	DIRECT	N/A	CONSTANT
Schedule 3A: Taxes				
FEDERAL:				
Income Tax (Included on Schedule 2)	409.1	DIST		CONSTANT
Employment Tax	408.1	LABOR		WAGES
Other Federal Taxes	408.1	DIST		CONSTANT
STATE AND OTHER:				
Property (or In-Lieu)	408.1	PTDG		CONSTANT
Unemployment	408.1	LABOR		WAGES
State Income, B&O, etc.	409.1	DIST		CONSTANT
Franchise Fees	408.1	DIST		CONSTANT
Regulatory Commission	408.1	DIST		CONSTANT
City/Municipal	408.1	DIST		CONSTANT
Other	408.1	DIST		CONSTANT
Schedule 3B: Other Included Items				
Other Included Items:				
Regulatory Debits	407.3	DIRECT	DIST	CONSTANT
Regulatory Credits	407.4	DIRECT	PROD	CONSTANT
Gain from Disposition of Utility Plant	411.6	DIRECT	PROD	CONSTANT
Loss from Disposition of Utility Plant	411.7	DIRECT	DIST	CONSTANT
Gain from Disposition of Allowances	411.8	PROD		CONSTANT
Loss from Disposition of Allowances	411.9	PROD		CONSTANT
Miscellaneous Nonoperating Income	421	DIRECT	PROD	CONSTANT
Sale for Resale:				
Sales for Resale	447	PROD		CONSTANT
Other Revenues:				
Forfeited Discounts	450	DIST		CONSTANT
Miscellaneous Service Revenues	451	DIST		CONSTANT
Sales of Water and Water Power	453	PROD		CONSTANT
Rent from Electric Property	454	TD		CONSTANT
Interdepartmental Rents	455	DIST		CONSTANT
Other Electric Revenues	456	DIRECT	PROD	CONSTANT
Revenues from Transmission of Electricity of Others	456.1	TRANS		CONSTANT
Labor Ratios				
Labor Ratio Input:				
Production		PROD		WAGES

Table 1: Functionalization and Escalation Codes

BONNEVILLE POWER ADMINISTRATION 2008 Average System Cost Methodology Functionalization and Escalation Codes				
Account Description	**Acct No.**	**Functionalization Codes**		**Escalation Codes**
		Method	**Default**	
Transmission		TRANS		WAGES
Distribution		DIST		WAGES
Customer Accounts		DIST		WAGES
Customer Service and Informational		DIST		WAGES
Sales		DIST		WAGES
Administrative & General		PTD		WAGES

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Appendix 1
ASC Utility Filing Template

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BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALES AGREEMENT
2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Intangible Plant:								
Intangible Plant - Organization	204-207	301	DIST			-	-	-
Intangible Plant - Franchises and Consents	204-207	302	DIRECT	PTD		-	-	-
Intangible Plant - Miscellaneous	204-207	303	DIRECT	DIST		-	-	-
Total Intangible Plant					$ -	$ -	$ -	$ -
Production Plant:								
Steam Production	204-207	310-317	PROD			-	-	-
Nuclear Production	204-207	320-326	PROD			-	-	-
Hydraulic Production	204-207	330-337	PROD			-	-	-
Other Production	204-207	340-347	PROD			-	-	-
Total Production Plant					$ -	$ -	$ -	$ -
Transmission Plant: (i)								
Transmission Plant	204-207	350-359.1	TRANS			-	-	-
Total Transmission Plant					$ -	$ -	$ -	$ -
Distribution Plant:								
Distribution Plant	204-207	360-374	DIST			-	-	-
Total Distribution Plant					$ -	$ -	$ -	$ -
General Plant:								
Land and Land Rights	204-207	389	PTD			-	-	-
Structures and Improvements	204-207	390	PTD			-	-	-
Furniture and Equipment	204-207	391	LABOR			-	-	-
Transportation Equipment	204-207	392	TD			-	-	-
Stores Equipment	204-207	393	PTD			-	-	-
Tools and Garage Equipment	204-207	394	PTD			-	-	-
Laboratory Equipment	204-207	395	PTD			-	-	-
Power Operated Equipment	204-207	396	TD			-	-	-
Communication Equipment	204-207	397	PTD			-	-	-
Miscellaneous Equipment	204-207	398	PTD			-	-	-
Other Tangible Property	204-207	399	DIRECT	PTD		-	-	-
Asset Retirement Costs for General Plant	204-208	399.1	PTD			-	-	-
Total General Plant					$ -	$ -	$ -	$ -
Total Electric Plant In-Service					$ -	$ -	$ -	$ -

(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
LESS:								
Depreciation and Amortization Reserve								
Steam Production Plant	219	108	PROD			-	-	-
Nuclear Production Plant	219	108	PROD			-	-	-
Hydraulic Production Plant	219	108	PROD			-	-	-
Other Production Plant	219	108	PROD			-	-	-
Transmission Plant (i)	219	108	TRANS			-	-	-
Distribution Plant	219	108	DIST			-	-	-
General Plant	219	108	GP			-	-	-
Amortization of Intangible Plant - Account 301	219	111	DIST			-	-	-
Amortization of Intangible Plant - Account 302	219	111	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	219	111	DIRECT	DIST		-	-	-
Mining Plant Depreciation	219	108	PROD			-	-	-
Amortization of Plant Held for Future Use	219	111	DIST			-	-	-
Capital Lease - Common Plant	219	108	DIRECT	PTD		-	-	-
Leasehold Improvements	200-201	108	DIRECT	DIST		-	-	-
In-Service: Depreciation of Common Plant (a)	200-201	108	DIRECT	PTD		-	-	-
Amortization of Other Utility Plant (a)	200-201	108	DIRECT	DIST		-	-	-
Amortization of Acquisition Adjustments	200-201	115	DIRECT	DIST		-	-	-
Depreciation and Amortization Reserve (Other)			DIRECT					
Total Depreciation and Amortization Reserve					$ -	$ -	$ -	$ -
Total Net Plant					$ -	$ -	$ -	$ -
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)								

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Assets and Other Debits (Comparative Balance Sheet)								
Cash Working Capital (f)	Calculation					-	-	-
Utility Plant								
(Utility Plant) Held For Future Use	200-201	105	DIST			-	-	-
(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD			-	-	-
Nuclear Fuel		120.2-120.6	PROD			-	-	-
Construction Work in Progress (CWIP)	200-201	107 & 120.1	DIST			-	-	-
Common Plant	356 & 356.1		DIRECT					
Acquisition Adjustments (Electric)	200-201	114	DIRECT	DIST		-	-	-
Total					$ -	$ -	$ -	$ -
Other Property and Investments								
Investment in Associated Companies	110-111	123.1	DIST	DIST		-	-	-
Other Investment	110-111	124	DIST			-	-	-
Long-Term Portion of Derivative Assets	110-111	175	DIST			-	-	-
Long-Term Portion of Derivative Assets - Hedges	110-111	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Current and Accrued Assets								
Fuel Stock	110-111	151	PROD			-	-	-
Fuel Stock Expenses Undistributed	110-111	152	PROD			-	-	-
Plant Materials and Operating Supplies	110-111	154	PTD			-	-	-
Merchandise (Major Only)	110-112	155	DIST			-	-	-
Other Materials and Supplies (Major only)	110-111	156	DIST			-	-	-
EPA Allowance Inventory	110-112	158.1	PROD			-	-	-
EPA Allowances Withheld	110-112	158.2	PROD			-	-	-
Stores Expense Undistributed	110-111	163	PTD			-	-	-
Prepayments	110-111	165	PTD			-	-	-
Derivative Instrument Assets	110-111	175	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets	110-112	175	DIST			-	-	-
Derivative Instrument Assets - Hedges	110-111	176	DIST			-	-	-
(Less) Long-Term Portion of Derivative Assets - Hedges	110-112	176	DIST			-	-	-
Total					$ -	$ -	$ -	$ -

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1		Functionalization Method		Total	Production	Transmission	Distribution/ Other
	Page Number	Account Numbers	Default	Optional				
Deferred Debits								
Unamortized Debt Expenses	110-111	181	PTDG			-	-	-
Extraordinary Property Losses	110-111	182.1	DIRECT	DIST		-	-	-
Unrecovered Plant and Regulatory Study Costs	110-111	182.2	DIRECT	DIST		-	-	-
Other Regulatory Assets	110-111	182.3	DIRECT	DIST		-	-	-
Preliminary Survey and Investigation Charges (Electric)	110-111	183	DIST			-	-	-
Preliminary Natural Gas Survey and Investigation Charges	110-111	183.1	DIST			-	-	-
Other Preliminary Survey and Investigation Charges	110-111	183.2	DIST			-	-	-
Clearing Accounts	110-111	184	DIST			-	-	-
Temporary Facilities	110-111	185	PTDG			-	-	-
Miscellaneous Deferred Debits	110-111	186	DIRECT	DIST		-	-	-
Deferred Losses from Disposition of Utility Plant	110-111	187	DIRECT					
Research, Development, and Demonstration Expenditures	110-111	188	DIST			-	-	-
Unamortized Loss on Reacquired Debt	110-111	189	PTDG			-	-	-
Accumulated Deferred Income Taxes	110-111	190	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Assets and Other Debits					$ -	$ -	$ -	$ -

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BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALES AGREEMENT

2008 Average System Cost Methodology (ASC) Utility Template

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1: Plant Investment / Rate Base

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Liabilities and Other Credits (Comparative Balance Sheet)								
Current and Accrued Liabilites								
Derivative Instrument Liabilities	112-113	244	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities	112-114	244	DIST			-	-	-
Derivative Instrument Liabilities - Hedges	112-115	245	DIST			-	-	-
(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-114	245	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Deferred Credits								
Customer Advances for Construction	112-113	252	DIST			-	-	-
Other Deferred Credits	112-113	253	DIRECT	DIST		-	-	-
Other Regulatory Liabilities	112-113	254	DIRECT	DIST		-	-	-
Accumulated Deferred Investment Tax Credits	112-113	255	DIST			-	-	-
Deferred Gains from Disposition of Utility Plant	112-113	256	DIRECT					
Unamortized Gain on Reacquired Debt	112-113	257	PTDG			-	-	-
Accumulated Deferred Income Taxes-Accel. Amort.	112-113	281	DIST			-	-	-
Accumulated Deferred Income Taxes-Property	112-113	282	DIST			-	-	-
Accumulated Deferred Income Taxes-Other	112-113	283	DIST			-	-	-
Total					$ -	$ -	$ -	$ -
Total Liabilities and Other Credits					$ -	$ -	$ -	$ -
Total Rate Base					$ -	$ -	$ -	$ -

Total Net Plant + (Assets and Others Debits) - (Liabilities and Other Credits)

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BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 1A: Cash Working Capital (f)

Account Description	Total	Production	Transmission	Distribution/ Other
Cash Working Capital Calculation:				
Total Production O&M	-	-	-	-
Total Transmission O&M (i)	-	-	-	-
Total Distribution O&M	-	-	-	-
Total Customer & Sales	-	-	-	-
Total Administrative and General O&M	-	-	-	-
Less Purchased Power, Public Purpose Charge, REP Reversal, Fuel Costs	-	-	-	-
Revised Total O&M Expenses	$ -	$ -	$ -	$ -
One-Eighth Revised Total O&M Expenses				
Allowable Functionalized Cash Working Capital	$ -	$ -	$ -	$ -

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Schedule 1A

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 2: Capital Structure and Rate of Return (b)

SUMMARY *(for use by ASC Forecast Model)*

Single-Jurisdiction Investor-Owned Utility Return Calculation:

Multi-Jurisdiction Investor-Owned Utility Return Calculation:

Consumer-Owned Utility Return Calculation:

Rate of Return :

Single-Jurisdiction Investor-Owned Utility Return Calculation

Step 1: Weighted Cost of Capital from Most Recent State Commission Rate Order
Note: Multi-jurisdictional utilities must begin on Page 2
Publicly-owned utilities must begin on Page 4

	Capitalization Structure		Effective Cost	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**
Debt				
Preferred Equity				
Common Equity				
Weighted Cost of Capital	$ -			

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%
Federal Income Tax Factor
*{(ROR – (Embedded Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital
(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation

Step 1:

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 1

	Capitalization Structure		Effective Cost		Jurisdictional	Effective Cost -	
Component	**Amount**	**Percent**	**Embedded**	**Weighted**	**Allocation**	**Weighted**	**State Allocation**
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 2

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Weighted Cost of Capital from Most Recent State Commission Rate Order in Jurisdiction 3

Component	**Amount**	**Percent**	**Embedded**	**Weighted**			
Debt					0		
Preferred Equity							
Common Equity							
Weighted Cost of Capital	$ -						

Jurisdiction	**Rate Base**	**Weighted cost**	**%**	**Weighted Return**		
Total						

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 2: Capital Structure and Rate of Return (b)

Multi-Jurisdiction Investor-Owned Utility Return Calculation *(continued)*

Step 2: Gross Up Equity Return for Federal Income Taxes

Federal Income Tax Rate (Currently 35%) 35%

Federal Income Tax Factor

*{(ROR – (Embedded Cost of Debt * (Debt ÷ (Total Capital))} * {(Federal Tax Rate ÷ (1- Federal Tax Rate)}*

Federal Income Tax Adjusted Weighted Cost of Capital

(Weighted Cost of Capital Plus Federal Income Tax Factor)

Step 3: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Weighted Cost of Capital				
Federal Income Tax Adjusted Return on Rate Base				

*(Total Rate Base * Federal Income Tax Adjusted Weighted Cost of Capital)*

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Schedule 2

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:	
End of Year Report Period:	
ASC Filing Date:	

Schedule 2: Capital Structure and Rate of Return (b)

Consumer-Owned Utility Return Calculation

Step 1: Weighted Cost of Debt

Debt Issue	Original Amount	Year Issued	Year Due	Interest Rate	Interest Expense
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
					$ -
Weighted Cost of Debt	$ -				$ -

Step 2: Calculate Return on Rate Base

	Total	Production	Transmission	Other
Total Rate Base from Schedule 1	$ -	$ -	$ -	$ -
Weighted Cost of Debt				
Return on Rate Base				

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BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Power Production Expenses:								
Steam Power Generation								
Steam Power - Fuel	320-323	501	PROD			-	-	-
Steam Power - Operations (Excluding 501 - Fuel)	320-323	500-509	PROD			-	-	-
Steam Power - Maintenance	320-323	510-515	PROD			-	-	-
Nuclear Power Generation								
Nuclear - Fuel	320-323	518	PROD			-	-	-
Nuclear - Operation (Excluding 518 - Fuel)	320-323	517-525	PROD			-	-	-
Nuclear - Maintenance	320-323	528-532	PROD			-	-	-
Hydraulic Power Generation								
Hydraulic - Operation	320-323	535-540.1	PROD			-	-	-
Hydraulic - Maintenance	320-323	541-545.1	PROD			-	-	-
Other Power Generation								
Other Power - Fuel	320-323	547	PROD			-	-	-
Other Power - Operations (Excluding 547 - Fuel)	320-323	546-550.1	PROD			-	-	-
Other Power - Maintenance	320-323	551-554.1	PROD			-	-	-
Other Power Supply Expenses								
Purchased Power (Excluding REP Reversal)	326	555	PROD		0	-	-	-
System Control and Load Dispatching	320-323	556	PROD			-	-	-
Other Expenses	320-323	557	PROD			-	-	-
BPA REP Reversal	327	555	PROD			-	-	-
Public Purpose Charges (a) (h)			DIRECT					
Total Production Expense					$ -	$ -	$ -	$ -
Transmission Expenses: (i)								
Transmission of Electricity by Others (Wheeling)	320-323	565	TRANS			-	-	-
Total Operations less Wheeling	320-323	560-567.1	TRANS			-	-	-
Total Maintenance	320-323	568-574	TRANS			-	-	-
Total Transmission Expense					$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Distribution Expense:								
Total Operations	320-323	580-589	DIST			-	-	-
Total Maintenance	320-323	590-598	DIST			-	-	-
Total Distribution Expense					$ -	$ -	$ -	$ -
Customer and Sales Expenses:								
Total Customer Accounts	320-323	901-905	DIST			-	-	-
Customer Service and Information	320-323	906-907	DIST			-	-	-
Customer Assistance Expenses (Major only)	320-323	908	DIRECT					
Customer Service and Information	320-323	909-910	DIST			-	-	-
Total Sales Expense	320-323	911-917	DIST			-	-	-
Total Customer and Sales Expenses					$ -	$ -	$ -	$ -
Administration and General Expense:								
Operation								
Administration and General Salaries	320-323	920	LABOR			-	-	-
Office Supplies & Expenses	320-323	921	LABOR			-	-	-
(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR			-	-	-
Outside Services Employed (g)	320-323	923	LABOR			-	-	-
Property Insurance	320-323	924	PTDG			-	-	-
Injuries and Damages	320-323	925	LABOR			-	-	-
Employee Pensions & Benefits	320-323	926	LABOR			-	-	-
Franchise Requirements	320-323	927	DIST			-	-	-
Regulatory Commission Expenses	320-323	928	DIST			-	-	-
(Less) Duplicate Charges - Credit	320-323	929	PTDG			-	-	-
General Advertising Expenses (g)	320-323	930.1	DIST	DIST		-	-	-
Miscellaneous General Expenses	320-323	930.2	DIST			-	-	-
Rents	320-323	931	DIST			-	-	-
Transportation Expenses (Non Major)	320-324	933	DIST			-	-	-
Maintenance								
Maintenance of General Plant	320-323	935	GPM			-	-	-
Total Administration and General Expenses					$ -	$ -	$ -	$ -

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Appendix 1

Schedule 3

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3: Expenses

Account Description	Form 1 Page Number	Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Total Operations and Maintenance					$ -	$ -	$ -	$ -
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)								
Depreciation and Amortization:								
Amortization of Intangible Plant - Account 301	336	404	DIST			-	-	-
Amortization of Intangible Plant - Account 302	336	404	DIRECT	PTD		-	-	-
Amortization of Intangible Plant - Account 303	336	404	DIRECT	DIST		-	-	-
Steam Production Plant	336	403	PROD			-	-	-
Nuclear Production Plant	336	403	PROD			-	-	-
Hydraulic Production Plant - Conventional	336	403	PROD			-	-	-
Hydraulic Production Plant - Pumped Storage	336	403	PROD			-	-	-
Other Production Plant	336	403	PROD			-	-	-
Transmission Plant (i)	336	403	TRANS			-	-	-
Distribution Plant	336	403	DIST			-	-	-
General Plant	336	403	GP			-	-	-
Common Plant - Electric	336	403	DIRECT					
Common Plant - Electric	336	404	DIRECT					
Depreciation Expense for Asset Retirement Costs	336	403.1	DIRECT					
Amortization of Limited Term Electric Plant	336	404	DIRECT					
Amortization of Plant Acquisition Adjustments (Electric)	200-201	406	DIRECT					
Total Depreciation and Amortization					$ -	$ -	$ -	$ -
Total Operating Expenses					$ -	$ -	$ -	$ -
(Total O&M + Total Depreciation & Amortization)								

BONNEVILLE POWER ADMINSTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:

End of Year Report Period:

ASC Filing Date:

FERC Form 1		Purchased Power - Base Period		Purchased Power - Base Period Minus 1		Purchased Power - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	326-327						
LF	326-327						
IF	326-327						
SF	326-327						
LU	326-327						
IU	326-327						
OS	326-327						
EX	326-327						
NA	326-327						
AD	326-327						
TOTAL		$ -	-	$ -	-	$ -	-

FERC Form 1		Sales for Resale - Base Period		Sales for Resale - Base Period Minus 1		Sales for Resale - Base Period Minus 2	
Statistical Classification	Page Number	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased	Settlement Total	MWh Purchased
RQ	310-311						
LF	310-311						
IF	310-311						
SF	310-311						
LU	310-311						
IU	310-311						
OS	310-311						
EX	310-311						
NA	310-311						
AD	310-311						
TOTAL		$ -	-	$ -	-	$ -	-

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3A Items: Taxes

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Funct. Method	Total	Production	Transmission	Distribution/ Other
FEDERAL							
Income Tax	262	409.1	DIST		-	-	-
Employment Tax	262	408.1	LABOR		-	-	-
Other Federal Taxes	262	408.1	DIST		-	-	-
TOTAL FEDERAL				$ -	$ -	$ -	$ -
STATE AND OTHER							
Property or In-Lieu (c)	262	408.1	PTDG		-	-	-
Unemployment	262	408.1	LABOR		-	-	-
State Income, B&O, etc.	262	409.1	DIST		-	-	-
Franchise Fees	262	408.1	DIST		-	-	-
Regulatory Commission	262	408.1	DIST		-	-	-
City/Municipal	262	408.1	DIST		-	-	-
Other	262	408.1	DIST		-	-	-
TOTAL STATE AND OTHER TAXES				$ -	$ -	$ -	$ -
TOTAL TAXES				$ -	$ -	$ -	$ -

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 3B Other Included Items (j)

Account Description	FERC Form 1 Page Number	FERC Form 1 Account Numbers	Functionalization Method Default	Functionalization Method Optional	Total	Production	Transmission	Distribution/ Other
Other Included Items:								
Regulatory Credits	114	407.4	DIRECT	PROD		-	-	-
(Less) Regulatory Debits	114	407.3	DIRECT	DIST		-	-	-
Gain from Disposition of Utility Plant	114	411.6	DIRECT	PROD		-	-	-
(Less) Loss from Disposition of Utility Plant	114	411.7	DIRECT	DIST		-	-	-
Gain from Disposition of Allowances	114	411.8	PROD			-	-	-
(Less) Loss from Disposition of Allowances	114	411.9	PROD			-	-	-
Miscellaneous Nonoperating Income	114	421	DIRECT	PROD		-	-	-
Total Other Included Items					$ -	$ -	$ -	$ -
Sales for Resale:								
Sales for Resale	310	447	PROD		-	-	-	-
Total Sales for Resale					$ -	$ -	$ -	$ -
Other Revenues:								
Forfeited Discounts	300	450	DIST			-	-	-
Miscellaneous Service Revenues	300	451	DIST			-	-	-
Sales of Water and Water Power	300	453	PROD			-	-	-
Rent from Electric Property	300	454	TD			-	-	-
Interdepartmental Rents	300	455	DIST			-	-	-
Other Electric Revenues	300	456	DIRECT	PROD		-	-	-
Revenues from Transmission of Electricity of Others (i)	330	456.1	TRANS			-	-	-
Total Other Revenues					$ -	$ -	$ -	$ -
Total Other Included Items					$ -	$ -	$ -	$ -

(Total Other + Total Sales for Resale + Total Other Revenue)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 4: Average System Cost

	Total	Production	Transmission	Distribution/Other
Total Operating Expenses (From Schedule 3)	$ -	$ -	$ -	$ -
Federal Income Tax Adjusted Return on Rate Base (From Schedule 2)	$ -	$ -	$ -	$ -
State and Other Taxes (From Schedule 3a)	$ -	$ -	$ -	$ -
Total Other Included Items (From Schedule 3b)	$ -	$ -	$ -	$ -
Total Cost	$ -	$ -	$ -	$ -

(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)

BONNEVILLE POWER ADMINISTRATION

RESIDENTIAL PURCHASE AND SALE AGREEMENT

2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Schedule 4: Average System Cost

Contract System Cost	
Production	$ -
Transmission	$ -
(Less) New Large Single Load Costs (d)	
Total Contract System Cost	$ -
Contract System Load (MWh)	
Total Retail Load	
(Less) New Large Single Load	
Total Retail Load (Net of NLSL) (d)	0
Distribution Loss (e)	0
Total Contract System Load	0
Average System Cost $/MWh	$0

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Distribution of Salaries and Wages (For Labor Ratio Calculation)

Description	Form 1 Page Number	Amount
Electric		
Operation		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Customer Accounts	354-355	
Customer Service and Information	354-355	
Sales	354-355	
Administrative and General	354-355	
TOTAL Operation		$0
Maintenance		
Production	354-355	
Transmission	354-355	
Distribution	354-355	
Administrative and General	354-355	
TOTAL Maintenance		$0
Operation and Maintenance		
Production (Total of lines 16 and 26)	354-355	0
Transmission (Total of lines 17 and 27)	354-355	0
Distribution (Total of lines 18 and 28)	354-355	0
Customer Accounts (From line 20)	354-355	0
Customer Service and Information (From line 20)	354-355	0
Sales (From line 21)	354-355	0
Administrative and General (Total of lines 22 and 29)	354-355	0
TOTAL Operation and Maintenance		$0

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
Labor Ratio Input:						
	Production	PROD	$ -	$ -	$ -	$ -
	Transmission	TRANS	-	-	-	-
	Distribution	DIST	-	-	-	-
	Customer Accounts	DIST	-	-	-	-
	Customer Service and Informational	DIST	-	-	-	-
	Sales	DIST	-	-	-	-
	Administrative & General	PTD	-	-	-	-
Total Labor			$ -	$ -	$ -	$ -
	LABOR RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
GP	**General Plant Ratio**					
	Land and Land Rights	PTD	$ -	$ -	$ -	$ -
	Structures and Improvements	PTD	-	-	-	-
	Furniture and Equipment	LABOR	-	-	-	-
	Transportation Equipment	TD	-	-	-	-
	Stores Equipment	PTD	-	-	-	-
	Tools and Garage Equipment	PTD	-	-	-	-
	Laboratory Equipment	PTD	-	-	-	-
	Power Operated Equipment	TD	-	-	-	-
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	Other Tangible Property	DIRECT	-	-	-	-
	Asset Retirement Costs for General Plant	PTD	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	GP RATIO		0%	0%	0%	0%

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
PTD	**Production, Transmission, Distribution Ratio**					
	Steam Production	PROD	$ -	$ -	$ -	$ -
	Nuclear Production	PROD	-	-	-	-
	Hydraulic Production	PROD	-	-	-	-
	Other Production	PROD	-	-	-	-
	Total Production Plant		-	-	-	-
	Transmission Plant	TRANS	-	-	-	-
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTD RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
PTDG	**Production, Transmission, Distribution and General Plant Rati**					
	PTD Total		$ -	$ -	$ -	$ -
	Intangible Plant - Organization	DIST	-	-	-	-
	Intangible Plant - Franchises and Consents	DIRECT	-	-	-	-
	Intangible Plant - Miscellaneous	DIRECT	-	-	-	-
	General Plant Total		-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	PTDG RATIO		0%	0%	0%	0%

		Ratio Used	Total	Production	Transmission	Distribution
TD	**Transmission and Distribution Plant Ratio**					
	Total Transmission Plant	TRANS	$ -	$ -	$ -	$ -
	Total Distribution Plant	DIST	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	TD RATIO		0%	0%	0%	0%

BONNEVILLE POWER ADMINISTRATION
RESIDENTIAL PURCHASE AND SALE AGREEMENT
2008 Average System Cost Methodology

UTILITY NAME:
End of Year Report Period:
ASC Filing Date:

Ratio Table

		Ratio Used	Total	Production	Transmission	Distribution
GPM	**Maintenance of General Plant Ratio**					
	Structures and Improvements	PTD	$ -	$ -	$ -	$ -
	Furniture and Equipment	LABOR	-	-	-	-
	Communication Equipment	PTD	-	-	-	-
	Miscellaneous Equipment	PTD	-	-	-	-
	TOTAL		$ -	$ -	$ -	$ -
	GPM RATIO		0%	0%	0%	0%

SUMMARY RATIO TABLE

Direct to Distribution	DIST	0.00%	0.00%	100.00%
Direct to Production	PROD	100.00%	0.00%	0.00%
Direct to Transmission	TRANS	0.00%	100.00%	0.00%
Direct Allocation	DIRECT	0.00%	0.00%	0.00%
General Plant	GP	0.00%	0.00%	0.00%
Maintenance of General Plant	GPM	0.00%	0.00%	0.00%
Labor Ratios	LABOR	0.00%	0.00%	0.00%
Production, Transmission, Distribution	PTD	0.00%	0.00%	0.00%
Production, Transmission, Distribution, General	PTDG	0.00%	0.00%	0.00%
Transmission, Distribution	TD	0.00%	0.00%	0.00%

IX. AVERAGE SYSTEM COST METHODOLOGY APPENDIX 1 ENDNOTES

a/ Contract System Costs shall reflect the costs and the revenues arising from conservation and/or retail rate schedules.

b/ The overall rate of return (ROR) to be applied to a Utility's Exchange Period rate base as shown in Appendix 1 shall be equal to its weighted cost of capital (WCC), including debt, preferred stock and equity, from its most recently approved Regulatory Body Rate Order. For multi-Jurisdictional Utilities, a Utility will first determine the WCC for each Jurisdiction. The Utility will then determine a region-wide WCC based on applying the WCC times the Regulatory Body approved rate base from the same rate order used for the WCC.

The ROE used in the WCC calculation will then be grossed up for Federal income taxes at the marginal Federal income tax rate using the following formula to determine the percentage increase in the ROE used for ASC determination:
FIT Adder = {(WCC – (Cost of Debt * (Debt / (Total Capital))} * {(Federal Tax Rate / (1-Federal Tax Rate)}

The sum of the FIT Adder plus the ROE equals the Federal income tax adjusted ROE (TAROE). The TAROE will replace the ROE in the WCC calculation to determine a Federal income tax adjusted weighted cost of capital (TAWCC). The TAWCC will be multiplied by the total rate base from Schedule 1 to determine the return component on Schedule 2.

For Utilities that do not use depreciation for Jurisdictional rate setting, the return will be equal to the weighted cost of debt times the rate base included in the ASC filing.

c/ A tax-exempt Utility may include in-lieu taxes up to an amount that is comparable, for each unit of government paid in-lieu taxes, with taxes that would have been paid by a non-tax exempt utility to that unit of government. In no event shall the Utility's regional total be greater than the actual amount paid or the amount used to determine the total revenue requirement. In-lieu taxes shall be functionalized according to the PTDG ratio.

d/ The cost of additional resources sufficient to serve any New Large Single Load (NLSL) that was not contracted for, or committed to, prior to September 1, 1979, is to be determined as follows:

1). To the extent that any NLSLs are served by dedicated resources at the cost of those resources, including applicable transmission;

2) In the amount that NLSLs are not served by dedicated resources, at BPA's New Resources (NR) rates as established from time to time pursuant to section 7(f) of the Northwest Power Act, and as applicable to the Utility, and applicable BPA transmission charges if transmission costs are excluded in the determination of BPA's NR rate, to the extent such costs are recovered by the Utility's retail rates in the applicable Jurisdiction; and

3) To the extent that NLSLs are not served by dedicated resources plus the Utility's purchases at the NR rate, the costs of such excess load shall be determined by multiplying the kilowatt-hours not served under subsections (1) and (2) above, by the cost (annual fixed plus variable cost, including an appropriate portion of general plant, administrative and general expense and other items not directly assignable) per kilowatt-hour of all resources and long term power purchases (five years or more in duration), as allowed in the regulatory Jurisdiction to establish retail rates during the Exchange Period, exclusive of the following resources and purchases: (a) purchases at the NR rate; (b) purchases at the PF Exchange rate, pursuant to section 5(c) of the Northwest Power Act; (c) resources sold to BPA, pursuant to section 6(c)(1) of the Northwest Power Act; (d) dedicated resources specified in endnote d(1) of this Methodology; (e) resources and purchases committed to the Utility's load as of September 1, 1979, under a power requirements contract or that would have been so committed had the Utility entered into such a contract; and (f) experimental or demonstration units or purchases therefrom. Transmission needed to carry power from such generation resources or power purchases shall be priced at the average cost of transmission during the Exchange Period.

The above three paragraphs shall determine the Base Period cost of resources used to serve NLSLs. BPA will escalate the Base Period cost of resources used to serve NLSLs to the Exchange Period using the following steps:

i. Escalate the components of the Base Period fully allocated resource costs to the Exchange Period using the general method for escalation of all Base Period costs.

ii. Adjust the projected resource costs by the projected transmission costs.

iii. Add the fully allocated costs for major resource additions/retirements to the Exchange Period fully allocated costs.

iv. The cost to serve NLSLs will change when the ASC changes due to resource additions/retirements.

v. The Exchange Period NLSL load will equal the Base Period NLSL load.

e/ The losses shall be the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. The distribution loss can be measured using one of the following 3 methods:

Method 1, Distribution Loss Study: Losses shall be established according to a study (engineering, statistical and other) that is submitted to BPA by the Utility which will be subject to review by BPA. This study shall be in sufficient detail so as to accurately identify average distribution losses associated with the Utility's total load, excluded loads, and the residential load. Distribution losses shall include losses associated with distribution substations, primary distribution facilities, distribution transformers, secondary distribution facilities and service drops.

Method 2, Revenue Grade Meters: If a Utility does not have a loss study, but it has sufficient revenue grade meters in its distribution system, BPA will permit the Utility to directly measure its distribution losses subject to BPA review and approval. A Utility that does not possess the capability to directly measure its distribution losses will be required to submit a distribution loss study every seven years.

Method 3, Default: If a Utility does not have a current loss study or grade meters, BPA will accept the following method for determining a Utility's distribution loss factor.

i. Calculate a 5-year average total system loss factor, using data from the Base Period plus the preceding 4 years. IOUs will use data from the FERC Form 1. COUs will use a comparable data source.

ii. From this 5-year total system loss factor, subtract the loss factor for BPA's transmission system.

iii. The resulting loss factor will be deemed to be the exchanging Utility's distribution loss factor for calculating Contract System Load and exchange loads under the REP.

f/ Cash working capital (CWC) is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. For determining the allowable amount of cash working capital in rate base for a Utility, BPA will allow no more than 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.

g/ Conservation costs are costs of energy audits and actual or planned load reduction resulting from direct application of a conservation measure (Northwest Power Act, section 3(19)(B)) by means of physical improvements, alterations, devices, or other installations which are measurable in units. Conservation costs funded by the Utility will be functionalized to Production in the Utility's Average System Cost. Conservation costs incurred to promote changes in consumer behavior including costs attributable to brochures, advertising, pamphlets, leaflets, and similar items will be functionalized by Direct Analysis with a default to Distribution/Other. Conservation surcharges imposed pursuant to section 4(f)(2) of the Northwest Power Act or other similar surcharges or penalties imposed on a Utility for failure to meet required conservation efforts will also be functionalized to Distribution/Other. Conservation and associated costs must be generally consistent with the Council's resource plan as determined by the Administrator.

h/ Public Purpose Charges collected by Utilities and distributed to independent third party non-profit organizations or state and local entities (recipient organizations) for the purposes of acquiring conservation and renewable resources shall be determined on a utility-by-utility basis through Direct Analysis. The ASCM will only allow the costs of conservation and renewable resource development, acquisition and implementation. Allowable costs include costs associated with energy audits and advertising and promotion of conservation and renewable resources.

In order to be included in Contract System Costs, the renewable resources acquired by the recipient must be included in the Utility's Integrated Resource Plan or similar document and, in the case of dispatchable resources, must be included in the Utility's resource stack. BPA will treat expenditures of Public Purchase Charge funds similar to Utility conservation costs.

i/ If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using FERC's seven factor test contained in Order 888, and its Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its Form 1 filing. However, if a Utility is not required to file a Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission. Alternatively, the Direct Analysis may use FERC's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

j/ All revenues associated with the production and transmission function of a Utility will be functionalized to production or transmission respectively.

Appendix 2
Chief Financial Officer Attestation

Exhibit A:
Statement of Review and Compilation of Work Performed

Exhibit B:
Financial Reporting Process and Attestation for IOUs and COUs

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Appendix 2
Chief Financial Officer Attestation

<<Customer's Name>>
Average System Cost Filing
For the Base Period Beginning ______________, 20XX
And Ending ______________, 20XX

I, ____, having reviewed the Average System Cost (ASC) Appendix 1 Filing (ASC Filing) attached with this attestation, and in accordance with Exhibit A, *Statement of Review and Compilation of Work Performed*, of this Appendix 2, hereby certify that:

1. The ASC Filing has been prepared in accordance with Bonneville Power Administration's current ASC Methodology.

2. The ASC Filing excludes the costs associated with: (a) the cost of additional resources in an amount sufficient to serve any New Large Single Load after September 1, 1979; (b) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after December 5, 1980; and (c) any costs of any generating facility which is terminated prior to initial commercial operation.

3. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing is based on <<Customer's Name>>'s audited financial statements, FERC Form 1 filings and/or Cost of Service Analysis (COSA), and other financial information, and fairly presents in all material respects the operating costs of the utility for ___________, 20XX through ___________, 20XX.

4. Based on my knowledge as <<Customer's Name>>'s Chief Financial Officer, the ASC Filing omits no material facts and contains no false statement regarding any material facts.

Respectfully submitted,

Chief Financial Officer
<<Customer's Name>>

Date:______________________

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Exhibit A to Appendix 2
Statement of Review and Compilation of Work Performed

<<Customer's Name>>
Cost of Service Analysis Report
for the Base Period ______________, 20XX
through ______________, 20XX

This document is intended to be used by Engineering and Consulting Firms to provide; 1) a statement of the review work that was performed to ensure the accuracy and correctness of the information contained in the COSA report, and 2) to provide an assurance statement that the information contained in the COSA report is presented fairly in all material respects. Independent accounting firms would present similar information in their COSA compilation reports. The Appendix 1 references below simply denote where the financial and load data will ultimately appear in the Appendix 1 filing.

<u>Section 1</u> – Statement of the Work performed and procedures that were followed in preparing the Cost of Service Analysis (COSA).

Examples of work performed cited in the Statement of Work should include:

1. Reconciliation of (1) results of financial statement expense information with (2) data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3).
2. Reconciliation of (1) tax expense and amounts paid in-lieu of taxes to state and local governmental bodies per the financial statement expense information with (2) the tax expense information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3A).
3. Reconciliation of (1) revenue credits and other included items used to reduce the rates of the utility's native load customers contained in financial statement income information with (2) the information contained in the COSA report (ASC Filing, Appendix 1 - Schedule 3B).
4. Reconciliation of (1) cash and short-term investment financial statement account information with (2) working capital data contained in the COSA report (ASC Filing, Appendix 1 - Schedule 1A).
5. Plant investment costs, accumulated depreciation on plant investments and net un-depreciated plant investment at year end date is reconciled to the plant investment information contained in the COSA report. Plant investment costs associated with New Large Single Loads; generating assets used to serve loads outside of the Pacific Northwest region; and generating facilities that were terminated prior to commercial operation should be identified in separate accounts (ASC Filing, Appendix 1 - Schedule 1).
6. Long-term debt information (date bonds issued, original issue amount, principal balance at year end date, and interest rate of each bond issued along with a

weighted average cost of long-term debt outstanding) is reconciled to the information contained in the COSA report (ASC Filing, Appendix 1 – Sch. 2).

7. Return on plant investment calculation (net plant investment per Item 3 above times the weighted average cost of long-term debt per Item 4 above) is reconciled to the information contained in the COSA report.
8. Items 1-3 and 5-7 above are aggregated to produce the total cost of service amounts (aggregate costs have to be less than the projected costs contained in the utility's rates) and divided by annual customer loads (Item 9 below) to arrive at the utility's base period ASC.
9. Annual customer load information (annual megawatt hours) per the statistical section of the annual report is reconciled to the COSA report information.
10. Description of analytical procedures performed to gain additional assurance over the COSA report information. Comparison of current year information with prior year information, trend analysis, financial ratio analysis, and comparison of customer load information by segment with prior year load information.
11. Description of additional compilation and review procedures performed in preparing the COSA information.

Section 2 – Report Assurance

Based upon the audited financial statements of <<Customer's Name>> for the year ending ____________, 20XX, along with other financial statement and utility operating information provided to us, we have reviewed <<Customer's Name>>'s COSA report for the twelve month period ending ________. Our review included sufficient compilation review procedures along with additional analytical procedures to allow us to conclude that the information contained in the COSA report is presented fairly in all material respects.

Respectfully submitted,

_________________________, <<Title>>
<<Company Name>> Auditing, Engineering or Management Consulting Firm

Date:__________________

Exhibit B to Appendix 2
Financial Documentation Requirements and Attestations for IOUs and COUs

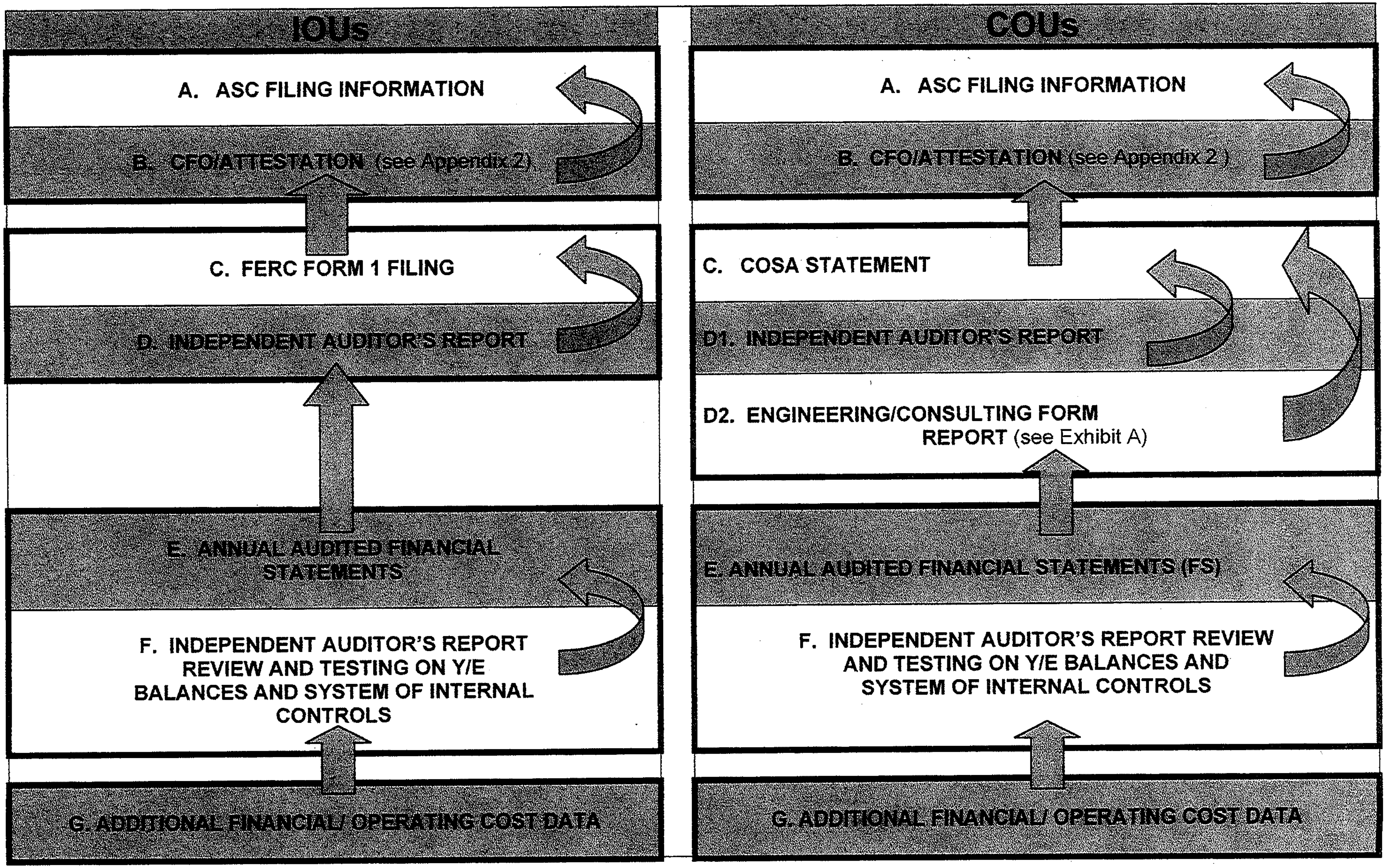

EXHIBIT D
SCHEDULING

1. **PURPOSE OF THIS EXHIBIT**

The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power and energy sold under this Agreement. All provisions apply to Purchasing-Selling Entities (PSEs), including their authorized scheduling agent. Transmission scheduling arrangements are handled under separate agreements/provisions with the designated transmission provider. Nothing in this exhibit is intended to relieve the Parties of any obligation they may have under North American Electric Reliability Council (NERC) or Western Systems Coordinating Council (WSCC) policy, procedure, or guideline.

2. **COORDINATION: GENERAL, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS**

2.1 **General Requirements**

2.1.1 The Parties may revise and replace this exhibit by mutual agreement. BPA shall also have the right to revise and replace this exhibit under the following circumstances after providing an opportunity for all affected Parties to discuss and comment on any proposed changes: (1) to comply with rules or orders issued by FERC, NERC, or WSCC or (2) to implement changes reasonably consistent with standard industry practice, but necessary for BPA to administer it's power scheduling function.

2.1.2 PSEs shall have staff available 24 hours a day for each day an active transaction or preschedule is in effect. PSEs must be prepared to verify transactions on an hourly basis if necessary.

2.1.3 PSEs shall complete the prescheduling and check out processes, and to verify Transactions and associated totals, per NERC tag, and BPA contract.

2.1.4 Inability to verify Transactions may result in schedule rejection or curtailment.

2.1.5 PSEs shall verify Transactions and totals after-the-fact (ATF) per both parties' ATF processes.

2.1.6 BPA is not obligated to accept Transactions that do not comply with the scheduling requirements in this exhibit or the contract.

2.1.7 Should a PSE attempt to preschedule a Transaction for power for which that PSE has an obligation to provide transmission and fails to properly reserve the transmission necessary to complete the

Transaction, the PSE will not be excused from its payment obligation, if any, under this Agreement.

2.1.8 All Transactions shall be stated in WSCC time zone and "hour ending" format.

2.1.9 All Schedules, except Dynamic Schedules, will be implemented on an hourly basis using the standard ramp as specified by WSCC procedures.

2.1.10 [Intentionally omitted]

2.1.11 Changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time, Control Area, or Scheduling Agents, etc.) must be submitted to BPA.

2.2. Prescheduling Requirements

2.2.1 Information Required For Any Preschedule

2.2.1.1 Unless otherwise mutually agreed, all Transactions will be submitted according to NERC instructions for E-tagging, as modified by WSCC.

2.2.1.2 When completing the NERC E-Tag insert the applicable BPA Contract number(s) in the "reference" column of the miscellaneous section of the tag.

2.2.1.3 Transactions going to or from COB (California-Oregon Border) must be identified as using Malin or Captain Jack, or COB Hub.

2.2.2 Preschedule Coordination

2.2.2.1 Final hourly preschedules (verbal submission of E-tag information) must be submitted for the next day(s) by 1000 of each Workday, unless otherwise agreed.

2.2.2.2 Typically, preschedules are for one to three days. By mutual agreement of the parties, final preschedules may be requested for longer time periods to accommodate special scheduling requirements.

2.2.2.3 Under certain operating conditions, either party may require submission of estimated daily preschedules for an ensuing period up to ten days in length, prior to the final preschedule.

2.3 **Real-Time Requirements**

2.3.1 PSEs may not make Real-Time changes to the scheduled amounts, including transmission arrangements unless such changes are allowed under individual contract provisions or by mutual agreement.

2.3.2 If Real-Time changes to the Schedule become necessary, and are allowable as described in section 2(c)(1) above, PSEs must submit such request no later than 30 minutes prior to the hour for which the Schedule change becomes effective.

2.3.3 Multi-hour changes to the Schedule shall specify each hour to be changed and shall not be stated as "until further notice."

2.3.4 Emergency scheduling and notification procedures (including mid-hour changes) will be handled in accordance with NERC and WSCC procedures.

2.4 **After-the-Fact Reconciliation Requirements**
PSEs agree to reconcile all Transactions, Schedules and accounts at the end of each month (as early as possible within the first ten calendar days of the next month). The parties will verify all Transactions per BPA contract, as to product or type of service, hourly amounts, daily, and monthly totals, and related charges.

3. DEFINITIONS AND ACRONYMS
Capitalized terms in this Exhibit shall have the meanings defined below, in context, or as used elsewhere in this Agreement.

3.1 **Control Area:** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection.

3.2 **Hour Ending:** Designation for one hour periods of time based upon the time which the period ends. For example: the one hour period between 1300 and 1400 is referred to as Hour Ending 1400.

3.3 **Prescheduling:** The process (electronic, oral, and written) of establishing and verifying with all scheduling parties, advance hourly Transactions through the following Workday(s). Preschedules apply to the following day or days (if the following day or days are not Workday(s).

3.4 **Purchasing-Selling Entity (PSE):** (NERC defined term) An entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

3.5 **Real-Time:** The hourly or minute-to-minute operation and scheduling of a power system as opposed to those operations which are prescheduled a day or more in advance.

3.6 **Schedule:** The planned Transaction approved and accepted by all PSEs and Control Areas involved in the Transaction.

3.7 **Transaction:** An agreement arranged by a PSE to transfer energy from a seller to a buyer.

3.8 **Workday:** Any day BPA, other regional utilities, and PSEs observe as a working day.

Contract No. 08PB-11971

NEW RESOURCE FIRM POWER BLOCK
POWER SALES AGREEMENT
executed by the
BONNEVILLE POWER ADMINISTRATION
and
PORTLAND GENERAL ELECTRIC COMPANY

Table of Contents

This NEW RESOURCE FIRM POWER BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and PORTLAND GENERAL ELECTRIC COMPANY (PGE). PGE is an investor-owned utility organized under the laws of the State of Oregon.

RECITALS

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision-making activities of BPA's power business from the administrative and decision-making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA and PGE agree:

1. **TERM**
This Agreement takes effect on the date signed by BPA and PGE (Effective Date), and shall continue in effect until 2400 hours on September 30, 2011.

2. **TERMINATION OF PRIOR AGREEMENT**
Effective on the Effective Date, the Firm Power Block Power Sales Agreement, Contract No. 00PB-12167 between BPA and PGE, is terminated.

3. **DEFINITIONS**
Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs), or its successors.

(a) "Alternate Supplier" means an entity, other than PGE, or a consumer of PGE serving its own load with an on-site resource, that provides electric power service directly to a retail electric power consumer that receives service over the distribution system of PGE under Voluntary Retail Access or Mandated Retail Access.

(b) "Amounts Taken" means an amount deemed equal to the amount of power scheduled by PGE under section 8 of this Agreement or an amount of power as measured at Points of Measurement, as appropriate.

(c) "Annexed Load" means the amount of load, including the increase in load associated with an annexation, that is added to PGE's distribution system after September 30, 2000, due to PGE acquisition by condemnation, purchase or other legal process, as authorized under applicable state law, of distribution facilities and the obligation to serve the retail electric power consumers connected to the facilities. Annexed Load amounts are shown in Exhibit A, Rate Commitments.

(d) "Contract Year" or "CY" means the period that begins each October 1 and which ends the following September 30. For instance, Contract Year 2008 begins October 1, 2007, and continues through September 30, 2008.

(e) "Diurnal" means the division of hours of the day between Heavy Load Hours (HLH) and Light Load Hours (LLH).

(f) "Firm Power" means electric power that PBL will make continuously available to PGE under this Agreement.

(g) "Mandated Retail Access" means the right, mandated either by Federal or state law, of retail electric power consumers to either acquire electric power service directly from one or more Alternate Suppliers of such electric power, or choose electric power service from a portfolio of power supply options, without PGE taking an ownership interest.

(h) "New Large Single Load" or "NLSL" means the definition established for NLSL in the Northwest Power Act, as implemented in a NLSL policy developed by BPA after this Agreement is executed.

(i) "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(j) "Party" or "Parties" means PBL and/or PGE.

(k) "Points of Measurement" means the interconnection points between BPA, PGE and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(l) "Points of Receipt" means the points of interconnection on the transmission provider's transmission system where Firm Power will be made available to PGE's transmission provider by PBL.

(m) "Power Business Line" or "PBL" means the administrative unit of the Bonneville Power Administration, United States Department of Energy, or its successor, which is acting by and for BPA in making this contract, and which is responsible for the management of marketing and sale of Federal power under BPA statutes.

(n) "Region" means the definition established for "Region" in the Northwest Power Act.

(o) "Returned Retail Load" means a retail electric power consumer load that returns to PGE for electric power service after receiving electric power service from an Alternate Supplier.

(p) "Total Retail Load" means all electric power consumption, including electric system losses, within a utility's distribution system as measured at Points of Measurement, adjusted as needed for unmetered loads or generation, nonfirm or interruptible loads agreed to by the Parties, transfer loads of other utilities served by PGE and PGE's transfer loads located in other control areas, and losses on PGE's transmission system. No distinction is made between load that is served with Firm Power and load that is served with electric power from other sources.

(q) "Transmission Business Line" or "TBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(r) "Voluntary Retail Access" means retail access that is not Mandated Retail Access and under which the retail electric power consumer has the ability to either acquire electric power service directly from one or more Alternate Suppliers of such electric power, or choose electric power service from a portfolio of power supply options, without PGE taking an ownership interest.

4. APPLICABLE RATES

The New Resource Firm Power (NR) rate schedule, including the GRSPs, or their successors, apply to Firm Power purchases under this Agreement.

5. NEW RESOURCE FIRM POWER BLOCK PRODUCT

(a) **Purchase and Sale of Block Product**
PBL shall sell and make available and PGE shall purchase under the applicable NR rates each hour the Firm Power amounts as established in section 5(b) below.

(b) **Establishment of Block Power Amounts**
PGE may, upon written notice to BPA, request Firm Power service from BPA. Any such notice shall specify, for each month of the term of the purchase, an equal amount of Firm Power in all hours of each such month. Upon mutual agreement by BPA and PGE of the terms and conditions for such Firm Power service, the Parties shall amend this Agreement to reflect such amounts in the table below.

Contract Year 2009	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh	0	0	0	0	0	0	0	0	0	0	0	0
HLH MWh	0	0	0	0	0	0	0	0	0	0	0	0
LLH MWh	0	0	0	0	0	0	0	0	0	0	0	0

6. LOAD LOSS

(a) **Limitation on Damages**
Up to 60 days after the end of each Contract Year, PBL may determine if PGE purchased less Firm Power, due to load loss established in section 5 of Exhibit C, Net Requirements, in any month during the previous Contract Year than it was contractually obligated to purchase under this Agreement (Monthly Purchase Deficiency). If PBL makes such a determination it shall calculate the reasonable market value of each Monthly Purchase Deficiency taking into account the differing market values within each month during such Contract Year. PGE shall pay PBL damages for such Contract Year equal to the amount by which the sum of the product of the Monthly Purchase Deficiencies and the amount PBL would have charged if the power had been taken under this Agreement, exceeds the sum of the product of the Monthly Purchase Deficiencies and the reasonable market value in each month. PBL may require through a written notice to PGE that PGE provide a reasonable forecast of its expected load loss amounts for a Contract Year.

(b) **Returned Retail Loads**
PGE shall notify PBL of any Returned Retail Load and provide PBL with metering information for such loads prior to PBL providing any power to serve such loads. PGE agrees not to request from PBL service under section 5(b) of the Northwest Power Act for a Returned Retail Load which would commence earlier than one year after the date the Returned Retail Load began receiving service from the Alternate Supplier.

7. **RETAIL ACCESS IMPLEMENTATION**
At least 180 days before PGE allows Voluntary Retail Access or before the effective date of Mandated Retail Access, the Parties shall amend the terms of this Agreement, if and to the extent necessary, to reflect the following PGE obligations:

(a) PGE shall ensure that PBL has access to information adequate to plan, schedule, and bill for service rendered under this Agreement; and

(b) PGE shall ensure that any retail electric power consumer, that receives all or a portion of its power supply from an Alternate Supplier, acquires all services necessary to support such service, including without limitation energy imbalance service.

8. **SCHEDULING**
All Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit E, Scheduling. The procedures for scheduling described in Exhibit E, Scheduling are the standard utility procedures followed by PBL for power transactions between PBL and other utilities or entities in the Region that require scheduling.

9. DELIVERY

(a) **Transmission Service for Firm Power**
This Agreement does not provide transmission services for, or include the delivery of, Firm Power to PGE. PGE shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Firm Power (Wheeling Agreement). The Parties agree to take such actions as may be necessary to facilitate the delivery of Firm Power to PGE consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(b) **Liability for Delivery**
PGE waives any claims against PBL arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. PBL shall not be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership.

(c) **Points of Receipt**
PBL shall make Firm Power available to PGE under this Agreement at Points of Receipt solely for the purpose of scheduling transmission to points of delivery on PGE's distribution system. PGE shall schedule, if scheduling is necessary, such Firm Power solely for use by its firm retail electric power consumer load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to PGE 18 months after PGE provides notice that it desires to purchase power from BPA, as required by section 5(b) of this Agreement.

If required by the Wheeling Agreement when PBL designates such Points of Receipt, PBL will provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under PGE's Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount reasonably necessary for PBL to provide Firm Power. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of nonfirm Points of Receipt to provide Firm Power to PGE, but notwithstanding section 9(b) above, PBL shall reimburse PGE for any additional costs incurred by PGE due to its compliance with such request.

(d) **Transmission Losses**
PBL shall provide PGE the losses, between the Points of Receipt and the point of interconnection between the BPA Control Area and the Control Area in which PGE resides, for Firm Power, at no additional charge. Losses will

be provided at Points of Receipt as established under section 9(c), and under the terms and conditions as defined in the transmission provider's tariff.

10. MEASUREMENT

Amounts Taken are deemed equal to the amount of power scheduled by PGE under section 8 of this Agreement or an amount of power as measured at Points of Measurement, as appropriate.

11. BILLING AND PAYMENT

(a) **Billing**

PBL shall bill PGE monthly, consistent with applicable BPA rates, including the GRSPs and the provisions of this Agreement, for the Firm Power, Unauthorized Increase Charges, payments pursuant to section 5, and other services provided to PGE in the preceding month or months under this Agreement. PBL may send PGE an estimated bill followed by a final bill. PBL shall send all bills on the bill's issue date either electronically or by mail, at PGE's option. If electronic transmittal of the entire bill is not practical, PBL shall transmit a summary electronically, and send the entire bill by mail.

(b) **Payment**

Payment of all bills, whether estimated or final, must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. If payment has been made on an estimated bill before receipt of a final bill for the same month, PGE shall pay only the amount by which the final bill exceeds the payment made for the estimated bill. PBL shall provide PGE the amounts by which an estimated bill exceeds a final bill through either a check or as a credit on the subsequent month's bill. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. PGE shall pay by electronic funds transfer using BPA's established procedures. PBL may terminate this Agreement if PGE is more than three months behind in paying its bills under this Agreement and PGE cannot demonstrate an ability to make the payments owed.

(c) **Disputed Bills**

In case of a billing dispute, PGE shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If PGE is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the

Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by BPA.

12. NOTICES

Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Either Party may change its address for notices by giving notice of such change consistent with this section.

If to PGE:	If to PBL:
Portland General Electric Company 121 SW Salmon Street, 17th Floor Portland, OR 97204 Attn: Jim Lobdell Vice President for Power Operations and Resource Strategy Phone: 503-464-2723 FAX: 503-464-2222 E-Mail: jim_lobdell@pgn.com	Bonneville Power Administration P.O. Box 3621 Portland, OR 97208-3621 Attn: Charles W. Forman – PSW-6 Account Executive Phone: 503-230-3432 FAX: 503-230-3242 E-Mail: cformanjr@bpa.gov

13. COST RECOVERY

(a) Nothing included in or omitted from this Agreement creates or extinguishes any right or obligation, if any, of BPA to assess against PGE and PGE to pay to BPA at any time a cost underrecovery charge pursuant to an applicable transmission rate schedule or otherwise applicable law.

(b) BPA may adjust the rates for Firm Power set forth in the applicable power rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs, or successor GRSPs.

14. UNCONTROLLABLE FORCES

PBL shall not be in breach of its obligation to provide Firm Power and PGE shall not be in breach of its obligation to purchase Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that impairs that Party's ability to perform its contractual obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(a) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Firm Power to PGE's facilities or distribution system, including but not limited to unplanned maintenance outages;

(b) any unplanned curtailment or interruption, failure or imminent failure of PGE's distribution facilities, including but not limited to unplanned maintenance outages;

(c) any planned transmission or distribution outage that affects either PGE or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(d) strikes or work stoppage, including the threat of imminent strikes or work stoppage;

(e) floods, earthquakes, or other natural disasters; and

(f) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets, shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force also agrees to notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

Both Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

15. GOVERNING LAW AND DISPUTE RESOLUTION

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Final actions subject to section 9(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. PGE reserves the right to seek judicial resolution of any dispute arising under this Agreement that is not subject to arbitration under this section 15. For purposes of this section 15, BPA policy means any written document adopted by BPA as a final action in a record of decision that establishes a policy of general application, or makes a determination under an applicable statute. If either Party asserts that a dispute is excluded from arbitration under this section 15, either Party may apply to the Federal court having jurisdiction for an order determining whether such dispute is subject to arbitration under this section 15.

(b) Any contract dispute or contract issue between the Parties arising out of this Agreement, except for disputes that are excluded through section 15(a) above, shall be subject to binding arbitration. The Parties shall make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

(c) Any arbitration shall take place in Portland, Oregon, unless the Parties agree otherwise. The CPR Institute for Dispute Resolution's arbitration procedures for commercial arbitration, Non-Administered Arbitration Rules (CPR Rules), shall be used for each dispute; *provided, however*, that: (1) the Parties shall have the discovery rights provided in the Federal Rules of Civil Procedure unless the Parties agree otherwise; and (2) for claims of $1 million or more, each arbitration shall be conducted by a panel of three neutral arbitrators. The Parties shall select the arbitrators from a list containing the names of 15 qualified individuals supplied by the CPR Institute for Dispute Resolution. If the Parties cannot agree upon three arbitrators on the list within 20 business days, the Parties shall take turns striking names from the list of proposed arbitrators. The Party initiating the arbitration shall take the first strike. This process shall be repeated until three arbitrators remain on the list, and those individuals shall be designated as the arbitrators. For disputes involving less than $1 million, a single neutral arbitrator shall be selected consistent with section 6 of the CPR Rules.

(d) Except for arbitration awards which declare the rights and duties of the Parties under this Agreement, the payment of monies shall be the exclusive remedy available in any arbitration proceeding. Under no circumstances shall specific performance be an available remedy against BPA. The arbitration award shall be final and binding on both Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof.

(e) Each Party shall be responsible for its own costs of arbitration, including legal fees. The arbitrators may apportion all other costs of arbitration between the Parties in such manner as they deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

16. STATUTORY PROVISIONS

(a) **Annual Financial Report and Retail Rate Schedules**
PGE shall provide PBL with a current copy of its annual financial report and its retail rate schedules, as required by section 5(a) of the Bonneville Project Act, P.L. 75-329.

(b) **Insufficiency and Allocations**
If BPA determines, consistent with section 5(b) of the Northwest Power Act and other applicable statutes, that it will not have sufficient resources on a planning basis to serve its loads after taking all actions required by applicable laws then BPA shall give PGE a written notice that BPA may restrict service. Such notice shall be consistent with BPA's insufficiency and allocations methodology, published in the Federal Register on March 20, 1996, and shall state the effective date of the restriction, the amount of PGE's load to be restricted, and the expected duration of the restriction. BPA shall not change that methodology without the written agreement of all affected customers. Such restriction shall take effect no sooner than five years after notice is given to PGE. If BPA imposes a restriction under this provision then the amount of Firm Power that PGE is obligated to purchase pursuant to section 5 shall be reduced to the amounts available under such restricted service.

(c) **New Large Single Loads**

(1) **General**
All existing NLSLs are listed in section 5 of Exhibit A, Rate Commitments. PGE shall provide reasonable notice to PBL of any expected increase in load that is likely to qualify as a new NLSL. PGE may either serve a NLSL with Firm Power or with power from another source. For purposes of this section 16(c), "Consumer" means an end-user of electric power or energy.

(2) **Determination of a Facility**
PBL, in consultation with PGE, shall make a reasonable determination of what constitutes a single facility, for the purpose of identifying a NLSL, based upon the following criteria:

(A) whether the load is operated by a single Consumer;

(B) whether the load is in a single location;

(C) whether the load serves a manufacturing process which produces a single product or type of product;

(D) whether separable portions of the load are interdependent;

(E) whether the load is contracted for, served or billed as a single load under PGE's customary billing and service policy;

(F) consistent application of the foregoing criteria in similar fact situations; and

(G) any other factors the Parties determine to be relevant.

PBL shall show an increase in load associated with a Consumer's facility which has been determined to be a NLSL in section 5 of Exhibit A, Rate Commitments. PBL shall have the unilateral right to amend Exhibit A to reflect such determinations when made.

(3) **Determination of Ten Average Megawatt Increase**
An increase in load shall be considered a NLSL if the energy consumption of the Consumer's load associated with a new facility, an existing facility, or expansion of an existing facility during the immediately past 12-month period exceeds by 10 average megawatts or more the Consumer's energy consumption for such new facility, existing facility or expansion of an existing facility for the consecutive 12-month period one year earlier, or the amount of the contracted for, or committed to load of the Consumer as of September 1, 1979, whichever is greater.

(4) **CF/CT Loads**
PGE has no loads that were contracted for, or committed to, as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

(5) **Annexed Load**
If an Annexed Load is added to PGE's distribution system, and such Annexed Load includes a NLSL, then PGE shall notify PBL that it has acquired a NLSL, pursuant to section 16(c)(1) above. Similarly, if a portion of PGE's load becomes an Annexed Load of another utility and such portion of load includes a NLSL, then such NLSL shall become a NLSL of such other utility.

(d) **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. BPA agrees that PGE, together with other customers in the Region, shall have priority to BPA power, consistent with such provisions.

(e) **Prohibition on Resale**
PGE shall not resell NR Firm Power except to serve PGE's Total Retail Load or as otherwise permitted by Federal law.

(f) **Use of Regional Resources**

(1) Within 60 days prior to the start of each Contract Year, PGE shall notify PBL of any firm power from a generating resource, or a contract resource during its term, that has been used to serve firm consumer load in the Region that PGE plans to export for sale outside the Region in the next Contract Year. PBL may during such Contract Year request additional information on PGE resources if PBL has information that PGE may have made such an export and not notified PBL. PBL may request and PGE shall provide within 30 days of such request, information on the planned use of any or all of PGE's generating and contractual resources. PGE shall have no obligation to notify PBL under this subsection (f) if and for so long as the Firm Power amounts as established in section 5(b) above are equal to zero.

(2) PGE shall be responsible for monitoring any firm power from generating resources and contract resources it sells in the Region to ensure such firm power is delivered to be used to serve firm consumer load in the Region.

(3) If PGE fails to report to PBL in accordance with section (1) above, any of its planned exports for sale outside the Region of firm power from a generating resource or a contract resource that has been used to serve firm consumer load in the Region, and PBL makes a finding that an export which was not reported was made, then PBL may terminate this Agreement upon 30 days written notice to PGE. If PBL concludes that the failure to report is inadvertent and unlikely to reoccur PBL shall not terminate this Agreement and may instead elect to decrement the amount of Firm Power by up to two times the amount of the export that was not reported. When applicable such decrements shall be established consistent with section 4(c) of Exhibit C.

(4) For purposes of this section, an export for sale outside the Region means a contract for the sale or disposition of firm power from a generating resource, or a contract resource during its term, that has been used to serve firm consumer load in the Region in a manner that such output is not planned to be used solely to serve firm consumer load in the Region. Delivery of firm power outside the Region under a seasonal exchange agreement that is made consistent with BPA's section 9(c) policy will not be considered an export. Firm power from a generating resource or contract resource used to serve firm consumer load in the Region means the firm generating or load carrying capability of a generating resource or contract resource as

established under Pacific Northwest Coordination Agreement resource planning criteria, or other resource planning criteria generally used for such purposes within the Region.

(g) **BPA Appropriations Refinancing Act**
The Parties agree that the BPA Refinancing Section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110 Stat. 1321, 1350, as stated in the United States Code on the date this Agreement is signed by the Parties, is incorporated by reference and is a material term of this Agreement. The Parties agree that this provision and the incorporated text shall be included in subsequent agreements between the Parties, as a material term through at least September 30, 2011.

17. STANDARD PROVISIONS

(a) **Amendments**
No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. BPA may assign this Agreement to another Federal agency to which BPA's statutory duties have been transferred. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. BPA shall consider any request for assignment consistent with applicable BPA statutes. PGE may not transfer or assign this Agreement to any of its retail customers.

(c) **Information Exchange and Confidentiality**
The Parties shall provide each other with any information that is reasonably required, and requested by either Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party, including metering data for each load that qualifies as a NLSL. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without

obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

(d) **Entire Agreement**
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits**
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers**
Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies**
Any reference in this Agreement to BPA policies, including without limitation BPA's NLSL Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by PGE to such policy, nor shall it be construed to be a waiver of the right of PGE to seek judicial review of any such policy.

(i) **Severability**
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Rate Covenant**
PGE agrees that it will establish, maintain, and collect rates or charges for power and energy and other services, facilities and commodities sold, furnished or supplied by it through any of its electric utility properties which, in the judgment of PGE, shall be adequate to provide revenues sufficient to enable PGE to make the payments required under this Agreement.

18. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the party for whom they sign.

PORTLAND GENERAL ELECTRIC COMPANY	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By ____________________	By ____________________ Account Executive
Name ____________________ *(Print/Type)*	Name Charles W. Forman *(Print/Type)*
Date ____________________	Date ____________________

Exhibit A
RATE COMMITMENTS

1. **PURCHASE DURATION**

PGE shall purchase all of the Firm Power as established in section 5 of the body of this Agreement for the term specified in such section 5.

2. **SPECIAL NR LOAD TREATMENT**

(a) **Annexed Loads**

PGE agrees to serve any Annexed Loads with resource amounts added consistent with section 4 of Exhibit C, Net Requirement except as follows: Annexed Load amounts that were served by PBL under section 5(b) of the Northwest Power Act immediately prior to becoming an Annexed Load will be provided service under rates, terms, and conditions that, within the constraints of BPA's applicable policies, are as comparable as possible to what such Annexed Load would have received if the load had not become an Annexed Load. When PGE has an Annexed Load this exhibit shall be revised to include estimated monthly HLH and LLH MWs in a table below.

(b) **Returned Retail Load**

PGE may request service from PBL to serve Returned Retail Load in time periods where the amount of Firm Power as established in section 5 of the body of this Agreement has been reduced due to load loss. The Returned Retail Load Amount served by PBL under this Agreement may not exceed the difference between the original amount and the amount established in section 5 of Exhibit C. The Parties shall revise this exhibit to establish monthly HLH and LLH MWs for such service in a table below. The table shall identify whether the amounts in the table are deemed to be actual for billing purposes or whether the table is an estimate with bills based on metered amounts. PBL shall provide service within 180 days of the request at rates BPA has established or establishes as applicable to such loads. The rate treatment for such loads shall continue through Contract Year 2006. Rate treatment after Contract Year 2006 shall be determined in a future rate case.

(c) **Load Previously Served By PGE Northwest Power Act Sections 5(b)(1)(A) and/or 5(b)(1)(B) Resources**

PGE may request service from PBL to serve load that would otherwise be served by PGE's Northwest Power Act sections 5(b)(1)(A) resources and 5(b)(1)(B) generating resources and long-term contract resources that are removed consistent with section 4(d) of Exhibit C, Net Requirements. The Parties shall revise this exhibit to establish monthly HLH and LLH MWs for such service in a table below. The amounts are deemed to be actual for billing purposes. PBL shall provide service within 180 days of the request at rates BPA has established or establishes as applicable to such loads. Rate treatment for such loads shall be determined in each rate case.

3. **NEW LARGE SINGLE LOADS**

(a) PGE has an existing NLSL(s). The NLSLs are listed below.

Customer information is commercially sensitive and PGE does not have permission to release detailed information about large customers. PGE submits the following:

Customer A. The customer is served by distribution facilities in PGE's service area. Load incremented over 10 aMW in a 12 month period in 1997. In 2006 the NLSL for this customer totaled 22,950 MWhs. In addition, the following customer, currently being served by an ESS, may be an NLSL if they return to PGE service in the future.

Customer B. The customer is served by distribution facilities in PGE's service area. Load incremented over 10 aMW in a 12 month period in 2003. The customer is served by distribution facilities in PGE's service area. Note: This customer is currently not on PGE's cost of service rate and is purchasing energy from an Energy Service Supplier. The customer's annual election period for the following year is in November. As this customer is not currently taking service from PGE they are not an NLSL customer.

(b) PGE shall serve any NLSLs with resource amounts added consistent with section 4 of Exhibit C, Net Requirements. When PGE has a NLSL this exhibit shall be revised to include estimated monthly HLH and LLH MWs in a table below.

4. **REVISIONS**
The Parties may update this exhibit by mutual agreement.

Exhibit B
BILLING

1. **NEW RESOURCE FIRM POWER ENTITLEMENTS**

   (a) The HLH and LLH amounts shown in section 5(b) of the body of this Agreement multiplied by the number of hours in an applicable daily Diurnal period establishes PGE's daily NR HLH and LLH Energy Entitlements.

   (b) The HLH amount shown in section 5(b) of the body of this Agreement establishes PGE's NR Demand Entitlement.

2. **DEFINITIONS**
   "Deemed Schedule" means the greater of the scheduled amount or the minimum hourly purchase amount established in section 5 of the body of this Agreement.

3. **HOURLY ENERGY TEST**

   (a) The Unauthorized Increase Charge for energy shall be applied to the portion of the Deemed Schedule that exceeds the NR Demand Entitlement.

   (b) For LLH, the Unauthorized Increase Charge for energy shall be applied to the portion of the Deemed Schedule that exceeds the amounts shown, for LLH in section 5(b) of the body of this Agreement. The minimum hourly LLH purchase obligation is the amount shown in section 5(b) of the body of this Agreement.

   (c) Amounts Taken in excess of the Deemed Schedules are subject to the Unauthorized Increase Charge.

4. **DAILY ENERGY TEST**
   The Unauthorized Increase Charge for energy shall be applied to the portion of the total daily HLH Deemed Schedules from PBL that exceeds the daily NR HLH Energy Entitlement, less any energy that is subject to the Unauthorized Increase Charge as determined under section 3(a) of this exhibit. PGE's minimum daily HLH energy purchase obligation is the PGE's NR HLH Energy Entitlement.

5. **MONTHLY DEMAND TEST**
   The Unauthorized Increase Charge for demand shall be applied to the amount by which the largest Amounts Taken or Deemed Schedule on any HLH during the month exceeds the NR Demand Entitlement.

6. **NLSL POWER ENTITLEMENTS**

   (a) The amount of energy served by PBL under section 3 of Exhibit A during each applicable Diurnal period establishes PGE's Monthly NR HLH and LLH Energy Entitlements for NLSLs.

(b) The amount of demand served by PBL under section 3 of Exhibit A that is made available on Generation System Peak is PGE's Measured Demand for NLSLs.

7. **UNAUTHORIZED INCREASE CHARGE**
Amounts Taken from PBL in excess of Firm Power shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and PGE will not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement.

8. **REVISIONS**
This exhibit may be revised upon mutual agreement by the Parties.

Exhibit C
NET REQUIREMENTS

1. ESTABLISHING NET REQUIREMENTS

(a) Initial Net Requirement

(1) Total Retail Load Forecast
The tables below shows the PBL approved forecast of PGE's Total Retail Load. The Parties agree that this forecast shall not be subject to arbitration under section 15 of the body of this Agreement.

Total Retail Load												
Contract Year 2009	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh	1573642	1700060	1893907	1959716	1681181	1755092	1592000	1570870	1539506	1685105	1682050	1539299
HLH (MWh)	1022735	1005463	1175016	1200586	1065388	1093651	1021169	952087	996554	1065852	1064148	968671
LLH (MWh)	550907	694597	718891	759130	615793	661441	570831	618782	542953	619253	617,902	570628
Peak (MW)	2825	3122	3475	3762	3444	3121	2917	2799	2958	3274	3346	2848

(2) Initial Net Requirement
PGE's net requirement amounts are derived by taking the forecast of PGE's Total Retail Load and subtracting from it the resource amounts that are committed to serve PGE's Total Retail Load under section 2(c) of this exhibit and the amount of load served by known non-PGE resources, if any, as established in section 3 of this exhibit.

NET REQUIREMENTS												
Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh	0	0	0	0	0	0	0	0	0	0	0	0
HLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
LLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
Peak (MW)	0	0	0	0	0	0	0	0	0	0	0	0

(b) Annual Update of Net Requirement

(1) Updated Forecast of Total Retail Load
At least 60 days prior to the start of each Contract Year, PGE shall provide PBL an updated monthly forecast of PGE's Total Retail Load in sufficient detail to fill in the table below. Up to 30 days before the start of the Contract Year PBL may notify PGE that PBL has determined that the forecast submitted when considered as a whole is not reasonable and that PBL will substitute a forecast of Total Retail Load that it considers reasonable to fill in the table below. The only issue arising under this section 1(b)(1) that is subject to arbitration under section 15 of body of this Agreement is whether PBL's forecast

when considered as a whole was reasonable. Such arbitration shall not include the interpretation or application of BPA's policies to such load forecast. However the Parties may mutually agree to mediate disputes regarding PBL's forecast. Prior to the start of the Contract Year this exhibit shall be revised to update the forecast in the table below.

Total Retail Load												
Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

(2) **Review of Net Requirements Amounts**
PGE's updated net requirement amounts are derived by taking the PGE forecast of Total Retail Load established in section 1(b)(1) above and subtracting from it the resource amounts that are committed to serve PGE's Total Retail Load under section 2(c) and the amount of load served by known non-PGE resources, if any, as established in section 3 of this exhibit. The updated net requirement amounts shall be shown in the table below.

NET REQUIREMENTS												
Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

2. **CUSTOMER RESOURCES**
The amounts listed in the tables in this section are only for determining PGE's net requirement under this Agreement and do not imply any specific resource operation, nor are the amounts intended to interfere with PGE's decisions on how to operate its specific resources.

(a) **Declared Output of Specific PGE Resources**
PGE commits the firm output from the following resources (or an equivalent amount from another source) to serve its Total Retail Load.

(1) **Resource Name**
PGE's resources and the characteristics of the resources are identified in the chart below. Power amounts associated with resources are listed in the attachment to this exhibit. The column labeled "Table" in the chart below corresponds to the tables listed in the attachment.

Table	Resource Name	Resource Type	5b1A/ 5b1B	Number of Units	Peak Cap MW	Customer % Share	% Ded to TRL	Resource Addition
7	TW Sullivan	Hydro	5b1A	13	17	100%	100%	
1	Round Butte	Hydro	5b1A	3	225	66.67%	100%	
2	Pelton	Hydro	5b1A	3	73	66.67%	100%	
3	Oak Grove	Hydro	5b1A	2	44	100%	100%	
4	North Fork	Hydro	5b1A	2	58	100%	100%	
5	Faraday	Hydro	5b1A	6	46	100%	100%	
6	River Mill	Hydro	5b1A	5	25	100%	100%	
11	Priest Rapids Share	Hydro	5b1A	10	932	6.51%	100%	
10	Wanapum Share	Hydro	5b1A	10	1038	7.87%	100%	
9	Rocky Reach Share	Hydro	5b1A	10	1475	12.00%	100%	
8	Wells Share	Hydro	5b1A	11	824	20.00%	100%	
12	Portland Hydro	Hydro	5b1B	2	36	100%	100%	
16	Boardman	Coal	5b1B	1	380	65.00%	100%	
17	Colstrip 3	Coal	5b1B	1	128	20.00%	100%	
18	Colstrip 4	Coal	5b1B	1	128	20.00%	100%	
20	Beaver Units 1 – 7	Gas	5b1A	7	521	100%	100%	
21	Beaver Unit 8	Gas	5b1B	1	28	100%	100%	
22	Coyote Springs	Gas	5b1B	2	243	100%	100%	
23	Port Westward	Gas	5b1B	2	427	100%	100%	
13	Biglow Canyon Phase 1	Wind	5b1B	76	125	100%	100%	
29	Biglow Canyon Phase 2	Wind	5b1B		150	100%	100%	
30	Biglow Canyon Phase 3	Wind	5b1B		175	100%	100%	
	WWP Capacity Nov-Mar	Contract	5b1B	1	18	100%	100%	
	WWP Capacity Nov-Mar	Contract	5b1B	1	-18	100%	100%	
	WWP Capacity Apr-Oct	Contract	5b1B	1	26	100%	100%	
	WWP Capacity Apr-Oct	Contract	5b1B	1	-26	100%	100%	
	EWEB Capacity-Summer	Contract	5b1B	1	1.5	100%	100%	
	EWEB Capacity-Summer	Contract	5b1B	1	-1.5	100%	100%	
	EWEB Capacity-Winter	Contract	5b1B	1	1.5	100%	100%	
	EWEB Capacity-Winter	Contract	5b1B	1	-1.5	100%	100%	
	EWEB StCreek Cap On	Contract	5b1B	1	3	100%	100%	
	EWEB StCreek Cap Off	Contract	5b1B	1	2	100%	100%	
	EWEB StCreekCapWOn	Contract	5b1B	1	-1	100%	100%	
	EWEB StCreekCapWOff	Contract	5b1B	1	-3	100%	100%	
	EWEB StCreekCapSOn	Contract	5b1B	1	-.26	100%	100%	
	EWEB StCreekCapSOff	Contract	5b1B	1	-.76	100%	100%	
	Dispatch Standby Test	Contract	5b1B	1	.09	100%	100%	
	Beaver Test	Contract	5b1A	1	.2	100%	100%	
	Beaver WECC Test	Contract	5b1A	1	.15	100%	100%	
	Wells On-Peak	Contract	5b1A	1	12	100%	100%	
	Wells Off-Peak	Contract	5b1A	1	10	100%	100%	
25	Canadian Entitlement	Contract	5b1A	1	-16	100%	100%	
	Mt Tabor Hydro	Contract	5b1A	1	.07	100%	100%	
	Lake Oswego Hydro	Contract	5b1A	1	.03	100%	100%	
	PPL Streetlighting	Contract	5b1A	1	1	100%	100%	
24	Covanta Marion	Contract	5b1B	1	10	100%	100%	
	Chelan In Summer	Contract	5b1A	1	7	100%	100%	
	Chelan Out Summer	Contract	5b1A	1	-5	100%	100%	
	Glendale In	Contract	5b1B	1	4	100%	100%	
	Glendale Out	Contract	5b1B	1	-4	100%	100%	
14	ESI Vancycle	Contract	5b1B	1	8	100%	100%	
	Mid-C Spill	Contract	5b1A	1	-2	100%	100%	
	Tribes Mid-C	Contract	5b1B	1	51	100%	100%	

	Confederated Tribes*	Contract	5b1B	1	14	100%	100%	
	Peak Tolling Agreement	Contract	5b1B	1	12	100%	100%	
	PPM Klondike II	Contract	5b1B	1	15	100%	100%	
	PPM Klondike II	Contract	5b1B	1	12	100%	100%	
	TransAlta PPA	Contract	5b1B	1	92	100%	100%	
	Morgan Stanley	Contract	5b1B	1	15	100%	100%	
	Morgan Stanley	Contract	5b1B	1	12	100%	100%	
	Sempra Energy	Contract	5b1B	1	44	100%	100%	
	Sempra Energy	Contract	5b1B	1	11	100%	100%	
	Sempra Energy	Contract	5b1B	1	5	100%	100%	
	PPM Energy	Contract	5b1B	1	28	100%	100%	
	PPM Energy	Contract	5b1B	1	11	100%	100%	
	Morgan Stanley	Contract	5b1B	1	11	100%	100%	
	Sempra Energy	Contract	5b1B	1	18	100%	100%	
	Sempra Energy	Contract	5b1B	1	28	100%	100%	
	Sempra Energy	Contract	5b1B	1	22	100%	100%	
	Avista Corp.	Contract	5b1B	1	4	100%	100%	
	Seattle City Light	Contract	5b1B	1	4	100%	100%	
27	Cove Replacement PPL	Contract	5b1A	1	-1	100%	100%	
	Cove Obligation USBR	Contract	5b1A	1	-.4	100%	100%	
	Colstrip Pumping Load	Contract	5b1B	1	-1	100%	100%	
	Thermal Station Flat	Contract	5b1B	1	-1	100%	100%	
	Thermal Station On-Peak	Contract	5b1B	1	-1	100%	100%	
	Thermal Station Off-Peak	Contract	5b1B	1	-1	100%	100%	
	Glendale – Beaver	Contract	5b1B	1	-1	100%	100%	
	Glendale - Coyote	Contract	5b1B	1	-1	100%	100%	
	PPM Energy	Contract	5b1B	1	-28	100%	100%	
	PPM Energy	Contract	5b1B	1	-11	100%	100%	
	Morgan Stanley	Contract	5b1B	1	-11	100%	100%	
	Sempra Energy	Contract	5b1B	1	-14	100%	100%	
	Sempra Energy	Contract	5b1B	1	-28	100%	100%	

*Pelton Reregulation

(b) **Unspecified Resource Amounts Committed To Serve Total Retail Load**

PGE shall use its best efforts to meet the obligations to provide unspecified resources established in the provisions below. PGE agrees that if such power is acquired from PBL as anything other than a separately negotiated purchase of Surplus Firm Power, the power provided will be subject to the Unauthorized Increase Charge.

(1) **Unspecified Resources for Balancing Net Requirements**

PGE agrees to provide power from unspecified resources to serve Total Retail Load in amounts, and in periods, equal to its Total Retail Load not served through PGE's power purchases committed to load under this Agreement, through resource amounts committed in section 2(a) above, through unspecified resource amounts established in sections 2(b)(2) and 2(b)(3) below, or through amounts in section 3 below. The amount in the table below shall be updated annually to show the amount, if any, that the forecast established in section 1(b)(1) of this exhibit exceeds the sum of the following: the power amount established in section 4 of the body of this exhibit (as updated consistent with section 5 of this exhibit); and resource amounts committed for the upcoming Contract Year in sections 2(a), 2(b)(2), 2(b)(3), and 3 of this exhibit.

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh	9232	118216	201692	330852	201516	239400	590539	606538	281543	44897	36479	13317
HLH (MWh)	-	-	-	-	-	-	-	-	-	-	-	-
LLH (MWh)	-	-	-	-	-	-	-	-	-	-	-	-
Peak (MW)	722	925	1201	1572	1083	1083	1527	1500	1212	1071	1132	730

(2) **Specific Amounts Committed for Contract Term**
In addition to the resource amounts established in section 2(a) above PGE agrees to serve its Total Retail Load with unspecified resources in the amounts listed in the table below.

None at this time.

(3) **Amounts Committed for 9(c) Decrements**
Below are the amounts of unspecified resources added consistent with BPA's 9(c) Policy and the requirements of section 4(c) of this exhibit.

None at this time.

(c) **Total Resource Amounts Committed to Serve Total Retail Load**
PGE commits the resources listed in sections 2(a) and 2(b) above to serve Total Retail Load amounts served by PGE and not served with Firm Power through this Agreement. The total amount of PGE's resources are shown in the table below. These amounts shall be updated whenever sections 2(a) or 2(b) above are modified, consistent with section 4 of this exhibit.

Sum of Resources												
Contract Year 2009	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh	1573642	1700060	1893907	1959716	1681181	1755092	1592000	1570870	1539506	1685105	1682050	1539299
HLH (MWh)	1022735	1005463	1175016	1200586	1065388	1093651	1021169	952087	996554	1065852	1064148	968671
LLH (MWh)	550907	694597	718891	759130	615793	661441	570831	618782	542953	619253	617,902	570628
Peak (MW)	2825	3122	3475	3762	3444	3121	2917	2799	2958	3274	3346	2848

(d) **PGE Resources Not Used to Serve Total Retail Load**

Generating Resource Name	Resource Type	5b1A/ 5b1B	Number of Units	Peak Cap MW	Customer % Share	% Ded to TRL	Resource Addition

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total (MWh)												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

3. NON-PGE GENERATING RESOURCES

Known non-PGE resources greater, if any, than 1 MW that provide power to serve PGE's Total Retail Load or such resources that otherwise connect to PGE's distribution system are listed below.

Generating Resource Name	Resource Type	Nameplate or Capacity
Portland Wastewater (Table 31)	Hydro	1.7

The amounts in the table below establish the total amount of non-PGE resources that the Parties agree are to be applied to serve PGE's Total Retail Load to calculate PGE's net requirement. These amounts may only be modified consistent with section 4 of this exhibit.

Contract Year 2009	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
HLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
LLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
Peak (MW)	0	0	0	0	0	0	0	0	0	0	0	0

4. CHANGES TO RESOURCE AMOUNTS

(a) **Annual Right to Add New Renewable Resources**
PGE may add new renewable resources to section 2(a) of this exhibit according to the terms of this provision. PGE shall request the addition of such resources at least 60 days before the start of the Contract Year the resources will be added. The request shall identify the resources, the length of time that the resources shall be applied to PGE's Total Retail Load and power amounts from the resources for each month of the request. PBL will revise section 2 of this exhibit prior to the start of the Contract Year if PBL agrees that the resource meets BPA's standards to qualify for BPA's Conservation and Renewables Discount, subject to any applicable limits established in BPA's policy on net requirements under section 5(b) of the Northwest Power Act. PGE shall resume purchasing Firm Power under this Agreement when its commitment to apply the renewable resource ends. The rate treatment for such power shall be the same PGE would have received for such power if PGE had not chosen to apply a resource under this provision.

(b) **Resource Additions for a BPA Insufficiency Notice**
In lieu of the unspecified resource amounts established in 2(b)(1), PGE shall add resources to sections 2(a) or 2(b)(2) to replace amounts of Firm Power BPA notifies PGE will not be provided due to a notice under section 16(b) of the body of this Agreement.

(c) **Decrements for 9(c) Export**
PBL may determine consistent with BPA's policy implementing section 9(c) of the Northwest Power Act and section 3(d) of P.L. 88-552 (9(c) Policy) that an export of a PGE resource requires a reduction in the amount of Federal power that PBL sells under this Agreement. If PBL determines such a reduction is required it will notify PGE of the amount and duration of the reduction. PBL shall revise this exhibit to include such amounts as unspecified resources for the duration of the export requiring such reduction under section 2(b)(3). Determinations by PBL to reduce the amount of Federal power sold are not subject to arbitration under section 15 of the body of this Agreement. When a decrement under the BPA 9(c) Policy occurs within the Contract Year, (1) the monthly amounts in 1(b)(2) shall be reduced by how much the monthly amounts added to 2(b)(3) exceed the corresponding monthly amounts in 2(b)(1), and (2) the Firm Power provided by PBL shall also be reduced within the Contract Year consistent with such changes to 1(b)(2), through the terms of section 5 below.

(d) **Permanent Resource Removal**
The resource amounts established in section 2 of this exhibit may be removed permanently by PGE consistent with statutory discontinuance for permanent removal in BPA's policy on net requirements under section 5(b) of the Northwest Power Act. If PBL determines PGE has met PBL's standards for a permanent removal, the exhibit will be revised to show the agreed resource changes. Additional power purchases under this Agreement as a result of such a resource removal are subject to the terms established in section 4(d) of Exhibit A, Rate Commitments. Determinations by PBL on the permanent removal of a resource are not subject to arbitration under section 15 of the body of this Agreement.

(e) **Changes to Non-PGE Resources**
PGE shall annually update the information established for non-PGE resources in section 3 at least 60 days before the start of each Contract Year, if circumstances reasonably warrant such a change. Subject to agreement of the Parties, the exhibit shall be revised to show the updated information prior to the start of the applicable Contract Year.

(f) **Resource Additions for NLSL and Annexed Loads**
In lieu of the unspecified resource amounts established in section 2(b)(1), PGE may add an amount of resources to sections 2(a) or 2(b)(2) above to serve the full amount of Annexed Loads established in Exhibit A, Rate Commitments and NLSLs added after this Agreement is executed.

(g) **Annual Retail Load Loss and Resource Removal**
PGE may reduce the resource amounts established in sections 2(a) and 2(b) above by up to the amount of load loss PGE reasonably expects in the upcoming Contract Year consistent with the requirements of this section. PGE shall notify PBL at least 60 days prior to the applicable Contract Year, identifying the total monthly Diurnal MWh amounts of load loss. Reductions in resource amounts shall apply first to unspecified resources established in sections 2(b)(1) and 2(b)(2) of this exhibit. Additional reductions shall apply to specific resources in section 2(a) of this exhibit identified by PGE in the notice. The Parties shall revise this exhibit prior to the start of the Contract Year to make the changes in the resources and shall establish those changes in tables below which shall identify the specific changes that were made to the resources. The resource changes shall only apply for one Contract Year. Prior to the start of the subsequent Contract Year this exhibit shall be revised to add back the resources shown in tables below to the applicable provisions in section 2 of this exhibit, except for amounts PGE requests to remove under this provision for the following Contract Year. Resources removed under this provision continue to be subject to the 9(c) Policy.

(h) **Revisions for Changes in Resource Output**
Up to 60 days prior to the start of a Contract Year PGE may request changes to the monthly distribution of the capabilities of specific resources listed in section 2 of this exhibit. PGE must demonstrate to PBL's satisfaction that an adjustment is appropriate. PBL will only consider such adjustments within like diurnal periods. When PBL decides to grant a request to revise resource amounts PBL shall revise section 2 of this exhibit to show the changes to the resource.

5. REDUCTION OF BLOCK PURCHASE AMOUNTS

The monthly amounts of Firm Power provided under this Agreement shall be reduced in any month when the monthly net requirement amount established in section 1(b)(2) above is less than the corresponding monthly amount established in section 5 of the body of this Agreement. The reduction shall equal the difference between those monthly values. The monthly amounts shall also be reduced when resource amounts not already used to calculate the monthly values in section 1(b)(2) are added pursuant to section 4(c) above during the Contract Year. Reduced amounts are subject to payments as established in section 5 of the body of this Agreement. If such a reduction occurs this exhibit will be revised to include a table below with the updated values. When a table is included below it shall supersede the table in section 5 of the body of this Agreement.

6. RESOURCE DECLARATIONS

The resource capabilities set forth in sections 2(a) and (b) of this exhibit are dedicated to serving PGE's firm load pursuant to section 5(b) of the Northwest Power Act. In addition to the resource capabilities set forth in such sections that may be removed pursuant to other sections of this Agreement, BPA consents that the resource capabilities set forth in section 2(b)(1) and (2) above may be discontinued from use in serving PGE's firm load upon the termination or expiration of this Agreement. The resources established in sections 2(d) and 3 above are not used to serve PGE's firm load under section 5(b) of the Northwest Power Act and will not be required to be so used after the termination or expiration of this Agreement.

7. **REVISIONS**

When required PGE shall submit a revised Exhibit C, Net Requirements, to PBL at least 60 days prior to each Contract Year. As long as PGE's submittal is consistent with the requirements of this exhibit PBL shall accept it as submitted. If PGE fails to submit revisions when necessary, or if the information provided is inconsistent with the requirements of this exhibit, PBL shall update this exhibit prior to the beginning of the Contract Year with the information PBL believes is required.

Attachment A to PGE's Net Requirements Exhibit C - Table 2(a)(1)

Table 1: Round Butte

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	300	300	300	300	300	300	300	300	300	300	300	300
Energy (MWh)	53,401	57,896	57,844	61,994	56,701	68,210	60,216	54,037	51,487	47,812	47,143	47,779

Table 2: Pelton

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	108	108	108	108	108	108	108	108	108	108	108	108
Energy (MWh)	24,096	25,999	26,014	27,039	24,720	29,648	28,064	23,707	22,609	21,102	20,819	21,050

Table 3

Table 3: Oak Grove

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	45	45	45	45	45	45	45	45	45	45	45	45
Energy (MWh)	13,303	16,679	20,391	24,662	20,527	23,570	23,897	21,714	19,254	16,768	14,940	23,676

Table 4: North Fork

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	54	54	54	54	54	54	54	54	54	54	54	54
Energy (MWh)	9,723	21,730	28,500	29,478	25,518	26,575	27,158	25,516	17,049	9,075	6,742	8,084

Table 5: Faraday

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	43	43	43	43	43	43	43	43	43	43	43	43
Energy (MWh)	9,544	20,771	26,643	27,411	24,117	25,598	26,030	24,704	16,502	8,822	6,622	7,948

Table 6: River Mill

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	23	23	23	23	23	23	23	23	23	23	23	23
Energy (MWh)	5,348	11,279	14,422	14,783	13,120	14,113	14,259	13,598	9,166	4,996	3,704	4,448

Table 7: TW Sullivan

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	17	17	17	17	17	17	17	17	17	17	17	17
Energy (MWh)	10,676	10,533	10,556	10,029	9,096	10,207	9,882	10,222	10,467	10,198	10,686	10,943

Table 8: Wells Share Douglas

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	177	177	177	177	177	177	177	177	177	177	177	177
Energy (MWh)	47,247	53,732	61,810	70,019	62,945	51,635	61,274	77,894	78,015	76,145	67,268	42,232

Table 9: Rocky Reach Share Chelan

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	156	156	156	156	156	155	155	156	156	156	156	156
Energy (MWh)	46,411	52,416	60,091	69,718	62,226	51,341	65,471	69,730	78,060	76,420	65,823	41,520

Table 10: Wanapum Share Grant

2008-09	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	170	170	170	170	170	170	170	170	170	170	170	170
Energy (MWh)	53,681	63,709	74,628	79,043	71,519	60,396	69,049	83,254	87,871	80,407	49,203	45,858
2008-09												
(Cap.) MW	0	0	0	0	0	0	0	0	0	0	0	0
Energy (MWh)	0	0	0	0	0	0	0	0	0	0	0	0

Attachment A to PGE's Net Requirements Exhibit C - Table 2(a)(1)

Table 11: Priest Rapids Share Grant

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	156	156	156	156	156	156	156	156	156	156	156	156
Energy (MWh)	52,431	55,191	59,913	60,781	54,865	51,883	61,784	68,156	71,324	68,974	55,129	49,877

Table 12: Portland Hydro

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	36	36	36	36	36	36	36	36	36	36	36	36
Energy (MWh)	4,066	10,368	12,606	11,714	10,047	10,565	10,788	8,967	5,094	2,027	1,500	1,682

Table 13: Biglow Canyon, Phase 1

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	125	125	125	125	125	125	125	125	125	125	125	125
Energy (MWh)	32,727	13,358	25,213	16,906	27,592	37,861	36,650	41,242	47,253	53,223	47,128	38,362

Table 14: ESI Vansycle

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	25	25	25	25	25	25	25	25	25	25	25	25
Energy (MWh)	5,028	5,808	6,574	6,052	5,265	7,299	7,188	6,039	6,389	5,287	5,629	5,213

Table 15: Klondike

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	75	75	75	75	75	75	75	75	75	75	75	75
Energy (MWh)	15,976	13,319	12,229	14,194	14,055	18,231	21,151	24,076	26,482	26,723	25,046	19,472

Table 16: Boardman

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	380	380	380	380	380	380	380	380	380	380	380	380
Energy (MWh)	253,765	245,579	253,765	250,475	226,235	250,475	16,160	0	226,237	250,475	250,475	242,395

Table 17: Colstrip 3

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	148	148	148	148	148	148	148	148	148	148	148	148
Energy (MWh)	100,643	97,396	100,643	101,413	91,599	101,413	9,814	9,814	98,141	101,413	101,413	98,141

Table 18: Colstrip 4

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	148	148	148	148	148	148	148	148	148	148	148	148
Energy (MWh)	100,643	97,396	100,643	101,413	91,599	101,413	9,814	9,814	98,141	101,413	101,413	98,141

Table 19: TransAlta/Centralia

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	100	100	100	100	100	100	100	100	100	100	100	100
Energy (MWh)	68,500	66,290	68,500	68,500	61,871	68,500	66,290	68,500	66,290	68,500	68,500	66,290

Table 20: Beaver Units 1-7

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	505	505	505	505	505	505	505	505	505	505	505	505
Energy (MWh)	0	0	0	0	0	0	0	0	0	83,768	156,435	144,161

Table 21: Beaver Unit 8

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	24	24	24	24	24	24	24	24	24	24	24	24
Energy (MWh)	0	0	0	0	0	0	0	0	0	0	641	0

Attachment A to PGE's Net Requirements Exhibit C - Table 2(a)(1)

Table 22: Coyote

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	242	242	242	242	242	242	242	242	242	242	242	242
Energy (MWh)	159,652	157,436	166,350	177,116	158,491	172,325	75,597	0	0	157,847	160,116	157,852

Table 23: Port Westward

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	427	427	427	427	427	427	427	427	427	427	427	427
Energy (MWh)	270,679	264,990	277,169	280,505	250,469	203,142	0	0	0	258,773	279,273	265,393

Table 24: Covanta Marion

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	13	13	13	13	13	13	13	13	13	13	13	13
Energy (MWh)	7,194	6,962	7,194	7,229	6,529	7,229	6,996	7,229	6,996	7,229	7,229	6,996

Table 25: Canadian Entitlement Allocation Extension

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Energy (MWh)	-11,530	-11,158	-11,530	-11,615	-10,491	-11,615	-11,822	-12,216	-11,822	-12,216	-12,216	-11,822

Table 26: Contract & Market Purchases

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Energy (MWh)	364,923	465,792	558,660	544,267	397,384	457,113	887,526	922,583	581,931	240,400	227,677	183,286

Table 27: PGE to PPL Cove Replacement

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Energy (MWh)	-676	-660	-676	-676	-628	-676	-660	-676	-660	-676	-676	-660

Table 28: Contract Sales

2008-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Energy (MWh)	-136,872	-129,795	-136,104	-81,166	-73,090	-79,704	-78,514	-75,019	-72,261	-80,003	-82,358	-78,777

Table 29: Biglow Canyon Phase 2

2009-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	150	150	150	150	150	150	150	150	150	150	150	150
Energy (MWh)	37,235	15,198	28,686	19,235	31,393	43,023	41,699	46,923	53,762	60,554	53,620	43,646

*projected 100% operation Sept. 2009

Table 30: Biglow Canyon Phase 3

2010-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	175	175	175	175	175	175	175	175	175	175	175	175
Energy (MWh)	40,968	16,722	31,562	21,163	34,540	47,336	45,880	51,628	59,153	66,625	58,996	48,022

*projected 100% operation Oct. 2010

Table 31: Portland Wastewater

2010-11	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
(Cap.) MW	2	2	2	2	2	2	2	2	2	2	2	2
Energy (MWh)	1,264	1,224	1,264	1,264	1,142	1,264	1,224	1,264	1,224	1,264	1,264	1,224

*projected 100% operation Oct. 2010

Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS

1. **No additional products and/or special provisions at this time.**

2. REVISIONS
   This exhibit shall be revised by mutual agreement of the Parties to reflect additional products and/or special provisions during the term of this Agreement.

Exhibit E
SCHEDULING

1. **PURPOSE OF THIS EXHIBIT**

The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power and energy sold under this Agreement. All provisions apply to Purchasing-Selling Entities (PSEs), including their authorized scheduling agent. Transmission scheduling arrangements are handled under separate agreements/provisions with the designated transmission provider. Nothing in this exhibit is intended to relieve the Parties of any obligation they may have under North American Electric Reliability Council (NERC) or Western Electricity Coordinating Council (WECC) policy, procedure, or guideline.

2. **COORDINATION: GENERAL, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS**

(a) **General Requirements**

(1) The Parties may revise and replace this exhibit by mutual agreement. BPA shall also have the right to revise and replace this exhibit under the following circumstances after providing an opportunity for all affected Parties to discuss and comment on any proposed changes: (1) to comply with rules or orders issued by FERC, NERC, or WECC; or (2) to implement changes reasonably consistent with standard industry practice, but necessary for BPA to administer its power scheduling function.

(2) PSEs shall have staff available 24 hours a day for each day an active transaction or preschedule is in effect. PSEs must be prepared to verify transactions on an hourly basis if necessary.

(3) PSEs shall complete the prescheduling and check out processes, and verify Transactions and associated totals per NERC E-Tag and BPA contract.

(4) Inability to verify Transactions may result in schedule rejection or curtailment.

(5) PSEs shall verify Transactions and totals after-the-fact (ATF) per both parties' ATF processes.

(6) BPA is not obligated to accept Transactions that do not comply with the scheduling requirements in this exhibit or the contract.

(7) Should a PSE attempt to preschedule a Transaction for power for which that PSE has an obligation to provide transmission and fails to properly reserve the transmission necessary to complete the

Transaction, the PSE will not be excused from its payment obligation, if any, under this Agreement.

(8) All Transactions shall be stated in the time zone specified by WECC and shall be in "hour-ending" format.

(9) All Schedules, except Dynamic Schedules, will be implemented on an hourly basis using the standard ramp as specified by WECC procedures.

(10) Any power that is allowed to be resold at wholesale under this Agreement may only be resold if all characteristics of the product (e.g., Points of Receipt, shape, hours) are maintained in the resale.

(11) Changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time, Control Area, or Scheduling Agents, etc.) must be submitted to BPA.

(b) **Prescheduling Requirements**

(1) **Information Required for Any Preschedule**

(A) Unless otherwise mutually agreed, all Transactions will be submitted according to NERC instructions for E-tagging, as modified by WECC.

(B) When completing the NERC E-Tag insert the applicable BPA Contract number(s) in the "reference" column of the miscellaneous section of the tag.

(C) Transactions going to or from California-Oregon Border (COB) must be identified as using Malin or Captain Jack, or COB Hub.

(2) **Preschedule Coordination**

(A) Final hourly preschedules (verbal submission of E-tag information) must be submitted for the next day(s) by 1000 of each Workday, unless otherwise agreed.

(B) Typically, preschedules are for 1 to 3 days. By mutual agreement of the parties, final preschedules may be requested for longer time periods to accommodate special scheduling requirements.

(C) Under certain operating conditions, either party may require submission of estimated daily preschedules for an ensuing period up to 10 days in length, prior to the final preschedule.

(c) **Real-Time Requirements**

(1) PSEs may not make Real-Time changes to the scheduled amounts, including transmission arrangements, unless such changes are allowed under individual contract provisions or by mutual agreement.

(2) If Real-Time changes to the Schedule become necessary, and are allowable as described in section 2(c)(1) above, PSEs must submit such request no later than 30 minutes prior to the hour for which the Schedule change becomes effective.

(3) Multi-hour changes to the Schedule shall specify each hour to be changed and shall not be stated as "until further notice."

(4) Emergency scheduling and notification procedures (including mid-hour changes) will be handled in accordance with NERC and WECC procedures.

(d) **After-the-Fact Reconciliation Requirements**
PSEs agree to reconcile all Transactions, Schedules and accounts at the end of each month (as early as possible within the first 10 calendar days of the next month). The parties will verify all Transactions per BPA contract, as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

3. **DEFINITIONS AND ACRONYMS**
Capitalized terms in this Exhibit shall have the meanings defined below, in context, or as used elsewhere in this Agreement.

(a) **Control Area:** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection.

(b) **Hour Ending:** Designation for one hour periods of time based upon the time which the period ends. For example: the 1-hour period between 1300 and 1400 is referred to as Hour Ending 1400.

(c) **Prescheduling:** The process (electronic, oral, and written) of establishing and verifying with all scheduling parties, advance hourly Transactions through the following Workday(s). Preschedules apply to the following day or days (if the following day or days are not Workday(s)).

(d) **Purchasing-Selling Entity (PSE):** (NERC defined term). An entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(e) **Real-Time:** The hourly or minute-to-minute operation and scheduling of a power system as opposed to those operations which are prescheduled a day or more in advance.

(f) **Schedule:** The planned Transaction approved and accepted by all PSEs and Control Areas involved in the Transaction.

(g) **Transaction:** An agreement arranged by a PSE to transfer energy from a seller to a buyer.

(h) **Workday:** Any day BPA, other regional utilities, and PSEs observe as a working day.

DAVID F. WHITE

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September 17, 2008

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol St. N.E., #215
P. O. Box 2148
Salem, OR 97308-2148

Attention: Administrative Hearings Division

Re: Docket UM 926: Application for Approval of the Residential Purchase and Sale Agreement by and between Bonneville Power Administration and Portland General Electric Company for the Payment of Residential Exchange Program Benefits for FY 2009 though 2011 and the New Resource Firm Power Block Sales Agreement by and between Bonneville Power Administration and Portland General Electric Company

Dear Administrative Hearings Division:

Pursuant to ORS 757.663, Portland General Electric Company ("PGE") hereby requests that the Commission require it to sign the proposed (1) Residential Purchase and Sale Agreement ("RPSA") by and between PGE and Bonneville Power Administration ("BPA")and (2) the New Resource Firm Block Power Sales Agreement by and between PGE and BPA (the "NR Block Agreement", and collectively, the "BPA Contracts"). The BPA Contracts are enclosed as Attachments 1 and 2 to this letter and are described in more detail below. BPA has offered the proposed BPA Contracts for execution by PGE no later than September 30, 2008. PGE recommends that the Commission issue an order requiring PGE to sign the proposed contracts. We will be available for questions at the public meeting scheduled for September 23, 2008.

I. RPSA

The proposed RPSA provides the contractual terms under which PGE's small farm and residential customers will receive benefits under the Residential Exchange Program ("REP") with BPA. The REP is an exchange of power, with BPA purchasing power from an exchanging utility at the utility's average system cost ("ASC") and the exchanging utility purchasing power from BPA at the PF Exchange rate. However, it has been BPA's practice that no actual power sales have taken place under the REP. Instead, the REP benefits are provided as monetary benefits that pass through to PGE's residential and small farm customers in the form of a rate credit.

The formula for determining the level of REP benefits is established by statute and is set forth in the RPSA. The amount of REP benefits is based on three factors: the PF Exchange rate (which BPA determines in its power rate proceedings), PGE's average system cost for transmission and generation of power (the "ASC"), and PGE's eligible residential and small farm load. The level of REP benefits is determined by the difference between the PF Exchange rate and PGE's ASC, multiplied by the eligible load.

BPA is currently engaged in the WP-07 Supplemental wholesale power rate case ("WP-07S") which will establish a PF Exchange rate for FY 2009 (October 1, 2008, through September 31, 2009). Concurrent with the WP-07S proceeding, BPA has revised its ASC methodology and has conducted an expedited review of PGE's ASC. Under the terms of the RPSA, PGE will be required to make annual ASC filings that will establish the ASC under the RPSA and be used to establish the level of REP benefits. In addition, BPA has stated its intent to commence a power rate case that will establish the PF Exchange Rate for FY 2010 and 2011.

PGE has actively participated in WP-07S, the ASC Methodology proceeding, and all BPA proceedings that affect the level of REP benefits our customers receive. We recognize the importance of these benefits for our customers and will continue to advocate for BPA rates, policies and decisions that provide our customers with a fair and equitable share of the benefits of the federal hydro system.

BPA has stated that it will issue the WP-07S record of decision on September 22, 2008. By October 1, 2008 PGE will submit our FY 2009 ASC to BPA for a full review. We expect BPA's full review to be completed sometime in April 2009.

A. Term

The term of the RPSA will commence on October 1, 2008, and will end on September 30, 2011, unless terminated sooner. RPSA, §1.

B. In Lieu Transactions

Upon written notice to PGE, BPA may "in lieu" of purchasing power offered by PGE acquire an equivalent amount of electric power from other sources to replace power sold by BPA to the utility as part of the exchange. RPSA, §7. However, the cost of the "in lieu" power must be less than the utility's ASC. The result is a reduction in REP benefits by the difference between the in lieu price and PGE's ASC, multiplied by the amount of "in lieu" power. Under the proposed RPSA, BPA may not initiate an in-lieu transaction until it has adopted an In-Lieu Policy following appropriate notice and comment. RPSA, §7.2.

C. Balancing Account

If PGE's ASC is less than the applicable PF Exchange rate, the payment that would be owed to BPA in that circumstance is tracked and added to the balancing account. RPSA, §12.2. While there is an account balance, BPA will distribute no REP benefits but will first use REP benefits otherwise due to eliminate any balance in the account. PGE does not expect that this provision will adversely affect PGE's customers given that PGE's projected ASC is well above the expected PF Exchange rate.

D. Adjustments to Monetary Payments

In the current WP-07S proceeding, BPA is determining for each investor-owned utility, including PGE, the amount of alleged "overpayments" of REP benefits from October 1, 2001, through September 30, 2008. During this period IOUs received REP settlement benefits under settlement agreements which the Ninth Circuit Court of Appeals determined in 2007 exceeded BPA's authority and were not supported by the record before BPA at the time. The RPSA provides that monetary payments of REP benefits may be adjusted to account for such alleged overpayments (called "Lookback Amounts") in the past. In the draft record of decision in the WP-07S proceeding, BPA has proposed to recover (through offsetting against future REP benefits otherwise due) each IOU's Lookback Amount within seven years where possible. PGE and other IOUs have strenuously objected to this approach and argued for a 20-year recovery period to coincide with the Regional Dialogue Contracts.

PGE has vigorously argued against BPA's authority to assess such Lookback Amounts and its ratemaking determination of such amounts. The RPSA has a reservation of rights clause that provides that, by entering into the RPSA, neither BPA nor PGE waive any of its rights, arguments, or claims.

II. NR Block Agreement

The NR Block Agreement is proposed to be effective for the same term as the RPSA (October 1, 2008, through September 30, 2011) to meet requests for power sales contracts made by IOUs pursuant to 5(b) of the Northwest Power Act. Section 5(b) provides that whenever requested, BPA shall offer to sell to a requesting IOU power to meet its firm power load net of the utility's own resources used to serve such load. Power that BPA sells to an IOU under section 5(b) is priced at BPA's new resource firm power rate. The non-price terms of the NR Block Agreement are similar to the terms of the Firm Block Power Sales Agreement, which PGE executed in connection with the 2000 Settlement Agreement with BPA. PGE does not currently anticipate purchasing BPA power under the NR Block Agreement.

III. PGE's Recommendation

PGE respectfully requests that the Commission order it to execute the proposed RPSA and NR Block Agreement. While the exact level of REP benefits is unknown, PGE's customers are expected to receive substantial benefits under the REP. BPA currently estimates that PGE's customers will be entitled to $66.9 million in REP benefits in FY 2009 and will receive $51.4 million in benefits after reduction due to the recovery of a portion of PGE's Lookback Amount. The terms of the RPSA do not adversely affect PGE's ability to challenge BPA's legal authority and ratemaking decisions with respect to PGE's Lookback Amount. The RPSA will permit our customers to continue to receive REP benefits in the future.

The NR Block Agreement also may provide benefits to our customers. While PGE currently does not plan to purchase power from BPA at the NR rate, it would be prudent for PGE to execute the proposed NR Block Agreement. Signing the contract will permit PGE to purchase power from BPA under Section 5(b) in the future if the NR rate warrants such purchases. PGE may elect to purchase power under the NR Block Agreement but is not required to do so.

For the reasons stated above, the Commission should order PGE to execute the BPA Contracts.

Very truly yours,

David F. White, On Behalf of
Portland General Electric Company

DFW/cp

cc: UM 926 Service List
Enclosures

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