2007 Wholesale Power Rate Case Initial Proposal

Direct Testimony

Book 2

November 2005

BPA Exhibit No.	Witness
WP-07-E-BPA-13	Bolden, Keep, Wedlund, Bermejo, Lindland
WP-07-E-BPA-14	Normandeau, Lovell, Wagner, Conger, Lennox
WP-07-E-BPA-15	Doubleday, Keep, Brodie, Homenick
WP-07-E-BPA-16	Boling, Doubleday, McClain
WP-07-E-BPA-17	Gustafson, Clark, Wilson, Bermejo
WP-07-E-BPA-18	King, Gustafson

Table of Contents

Second Book of Testimony

BPA FILE NO.	SUBJECT	WITNESSES
WP-07-E-BPA-13	Rate Design, Energy and Demand Rate, Targeted Adjustment Clause, Flexible PF, Operating Reserves Credit	Gery Bolden, Byron G. Keep Spencer G. Wedlund, Sarah K. Bermejo, Shelley M. Lindland
WP-07-E-BPA-14	Risk Mitigation Testimony	Michael R. Normandeau, Byrne E. Lovell, Arnold L. Wagner, Sid Conger, Jr., Alexander Lennox
WP-07-E-BPA-15	Cost of Service Analysis and Rate Design Changes and Adjustments	William J. Doubleday, Byron G. Keep, Paul A. Brodie, Ronald J. Homenick
WP-07-E-BPA-16	Residential Exchange Average System Cost and Load Forecasts	Rodney E. Boling, William J. Doubleday, Paul W. T. McClain
WP-07-E-BPA-17	Policy on DSI Solutions; 7(C)(2) Industrial Margin Study; Floor Rate Test; Value of DSI Supplemental Contingency Reserves	Greg C. Gustafson, Harry W. Clark, Scott K. Wilson, Sarah K. Bermejo
WP-07-E-BPA-18	Low Density Discount	Larry D. King , Greg C. Gustafson

This is the table of contents for this volume of testimony
Tables of contents for the other two volumes follow this sheet

Table of Contents

First Book of Testimony

BPA FILE NO.	SUBJECT	WITNESSES
WP-07-E-BPA-08	Financial Strategy and Risk Tolerance	Kimberly A. Leathley, Roy B. Fox, Valerie A. Lefler
WP-07-E-BPA-09	Load Resource	Jon A. Hirsch, Timothy C. Misley, Janet Ross Klippstein, Harry W. Clark, Roger P. Schiewe
WP-07-E-BPA-10	Revenue Requirement	Ronald J. Homenick, Dana M. Jensen, David M. Steele
WP-07-E-BPA-11	Market Price Forecast	Robert J. Petty, Rob W. Anderson, Arnold L. Wagner, Rodney E. Boling
WP-07-E-BPA-12	Risk Analysis	Arnold L. Wagner, Michael R. Normandeau, Byrne E. Lovell, Sid Conger, Jr., Randy B. Russell, Kenneth J. Marks, Steven R. Kerns

This is the table of contents for this volume of testimony
Tables of contents for the other two volumes follow this sheet

Table of Contents

Third Book of Testimony

BPA FILE NO.	SUBJECT	WITNESSES
WP-07-E-BPA-19	Revenue and Purchased Power Expenses Forecast	Spencer G. Wedlund, Jr., Jon A. Hirsch, Janet Ross Klippstein, Arnold L. Wagner
WP-07-E-BPA-20	Generation Inputs for Ancillary Services	Sarah K. Bermejo, Rebecca M. Berdahl, Thomas R. Murphy, Gery Bolden, Ronald J. Homenick
WP-07-E-BPA-21	Segmentation of US Army Corps of Engineers and Bureau of Reclamation Transmission Facilities	Rebecca M. Berdahl, David L. Gilman, Ron Homenick
WP-07-E-BPA-22	General Transfer Agreement (GTA) Delivery Charge	Leslie J. Pompel, Scott D. Wiley
WP-07-E-BPA-23	Slice Revenue Requirement and Rate	Carie E. Lee, Gery Bolden, Ronald J. Homenick, Byron G. Keep, John L. Hairston, Janet Ross Klippstein, Stephanie F. Konesky
WP-07-E-BPA-24	Conservation Programs and Conservation Rate Credit	John B. Pyrch, Karen L. Meadows, Mark E. Johnson, Ken M. Keating, Debra J. Malin, Allan E. Ingram
WP-07-E-BPA-25	Facilitation for Regional Renewable Resource Development and the Green Energy Premium	Allan E. Ingram, Debra J. Malin, Elliott E. Mainzer
WP-07-E-BPA-26	Firm Power Products and Services (FPS) Rate Schedule	Elliot E. Mainzer, Gery Bolden, Carol A. Miller, Phillip McLeod
WP-07-E-BPA-27	Section 7(b)(2) Rate Test Study	Byron G. Keep, William J. Doubleday, Paul A. Brodie, Michael Mace

This is the table of contents for this volume of testimony
Tables of contents for the other two volumes follow this sheet

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INDEX

TESTIMONY OF

GERARD BOLDEN, BYRON G. KEEP, SPENCER G. WEDLUND,

SARAH K. BERMEJO, AND SHELLEY M. LINDLAND

Witnesses for Bonneville Power Administration

SUBJECT: RATE DESIGN

Page

Section 1. Introduction and Purpose of Testimony 1

Section 2. Demand Rate 2
Definition of the Demand Rate 2
Method for Computing the Demand Rate 3
Differences From the 2002 Rate Case 6

Section 3. Load Variance 7
Definition and Purpose of Load Variance 7
Application of the Load Variance Rate 7
How the Load Variance Rate Is Calculated 9

Section 4. Discontinuation of Stepped-Up Multi-Year (SUMY) Block Charge 11

Section 5. Development of Energy Rates 12

Section 6. Unauthorized Increase Charge and Excess Factoring Charge 13

Section 7. Targeted Adjustment Charge (TAC) 13

Section 8. Operating Reserve Credit (ORC) 14
Background 14
Application of the Proposed Operating Reserve Credit (ORC)
Cost Methodology 18

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TESTIMONY OF

GERARD BOLDEN, BYRON G. KEEP, SPENCER G.WEDLUND,

SARAH K. BERMEJO, and SHELLEY M. LINDLAND

Witnesses for Bonneville Power Administration

SUBJECT: RATE DESIGN

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Gerard Bolden. My qualifications are contained in WP-07-Q-BPA-05.

A. My name is Byron G. Keep. My qualifications are contained in WP-07-Q-BPA-22.

A. My name is Spencer G. Wedlund. My qualifications are contained in WP-07-Q-BPA-51.

A. My name is Sarah K. Bermejo. My qualifications are contained in WP-07-Q-BPA-03.

A. My name is Shelley M. Lindland. My qualifications are contained in WP-07-Q-BPA-31.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor the rate design portions of Bonneville Power Administration's (BPA) Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05, and associated portions of the Wholesale Power Rate Schedules and GRSPs (WP-07-E-BPA-07).

Q. How is your testimony organized?

A. Our testimony is organized in eight sections. The first section outlines the purpose of our testimony. Section 2 describes BPA's Demand Rates, including subsections on the definition of the Demand Rate, the method for computing the Demand Rates, and differences from the currently effective WP-02 Demand Rate. Section 3 describes BPA's Load Variance Rate, with subsections on the definition and purpose of the Load Variance Rate, application of the Load Variance Rate, how the Load Variance Rate is

calculated, and the differences from the WP-02 Load Variance Rate. Section 4 describes the steps involved in developing BPA's energy rates and differences from the WP-02 rate case. Section 5 discusses discontinuation of the Stepped Up Multi-Year Block Rate. Section 6 describes a minor change to the Unauthorized Increase Rates and the Excess Factoring Rates. Section 7 describes the Targeted Adjustment Charge. Section 8 addresses the Operating Reserves Credit.

Section 2. Demand Rate

Definition of the Demand Rate

Q. Please define the Demand Rates.

A. The Demand Rates are a $/kilowatt- (kW-) month rates that, multiplied by the appropriate billing determinants, result in charges that compensate BPA for three components of firm power service: (1) the cost of firming bulk energy, including firm energy provided in flat amounts as under the Block product; (2) the cost of service BPA calls "factoring" in which energy is distributed among hours to match a load shape; and (3) the cost of readiness to meet actual load under peaking conditions. BPA will apply the same demand rates to appropriate demand billing factors for different products such as Full Service, Partial Service, and Block products. *See*, WP-07-E-BPA-05.

Q. Is BPA proposing any changes to the billing factors for the Demand Rates?

A. No. BPA is not proposing any change to the billing factors for the Demand Rates. The contracts and products that the Demand Rates in the PF and NR rate schedules apply to have not changed since the WP-02 rate case. The product of the Demand Rates and the demand billing factors are the demand charges.

Q. Why is a Demand Rate appropriate in conjunction with a Heavy Load Hour (HLH) and Light load Hour (LLH) energy rates?

A. BPA is proposing to continue the use of a single HLH energy rate for each month of the year even though each hour in the year may have a different energy value. Developing

8760 hourly energy rates would not be feasible; therefore, to reflect the costs associated with higher value hours, BPA is developing a demand charge to be applied in conjunction with the monthly energy rate. Under this pricing scheme, a flat load with a 100 percent load factor pays a lower effective rate than a shaped load with a less than 100 percent load factor. This sends an appropriate price signal because generally flatter loads are less expensive to serve. The Priority Firm (PF) and New Resources (NR) rate design with its monthly HLH Energy Rates and its separate monthly Demand Rates compensate BPA for the services described above.

Method for Computing the Demand Rate

Q. Is BPA proposing to change the method for computing the Demand Rates?

A. Yes. BPA proposes a minor modification to computing the Demand Rates. This modification is further explained below.

Q. Describe the method used for computing the Demand Rates.

A. For every quarter of the three-year rate period, the method uses hourly values minus quarterly averages of each HLH price from BPA's forecast of market prices. The method computes a total dollar value, which is the sum of all the positive differences between hourly values and the average of the HLH values for each quarter of the rate period. There are 12 of these total values.

Q. What is the source of data for the market forecast used to compute the Demand Rate?

A. The hourly market-clearing price forecasts from the Market Price Forecast, Study Documentation, WP-07-E-BPA-03A, Section 2, were used to derive the Demand Rate. The Market Price Forecast Study uses the AURORA model to estimate a market-clearing price. New capacity is built in the AURORA model and the costs of these new resources are recovered through energy prices. No explicit demand value is computed. AURORA computes 8760 hourly energy prices for each year of the rate period. In lieu of setting 8760 hourly energy rates, BPA continues to use Demand and HLH/LLH

energy rates to achieve cost recovery and send the desired price signal to customers to flatten the load placed on BPA. Therefore, a demand value must be derived from hourly energy prices.

Q. What does the AURORA model do?

A. AURORA simulates serving peak loads at hourly prices that are higher than the annual average. In the AURORA model, all loads would pay these higher than average hourly prices for every kilowatt-hour (kWh) served during the high priced hours. For a more detailed description of AURORA, *see,* the Market Price Forecast Study, WP-07-E-BPA-03.

Q. What modifications were made to the AURORA output of hourly energy prices to approximate the value of Demand?

A. Some hourly prices were limited because a few hours showed extreme values, such as a single hour in a month at $400/MWh. The limit was used if an hourly value was more than twice as much as the value two hours earlier. If so, that hourly value was set equal to the value from the same hour of the same day of the previous week. We believe this limit was necessary because such extreme values were anomalies and should not be used in calculating the Demand Rates.

Q. What component of AURORA hourly energy prices is used to approximate the value of demand?

A. The component used to approximate the value of demand is the sum of the differences of the projected HLH energy values and the quarterly average HLH prices derived from the AURORA model.

Q. Why is it appropriate to use this difference in computing the Demand Rate?

A. It is appropriate to use the sum of the positive differences in hourly HLH energy prices above the average quarterly HLH price for each quarter of the three year rate period, because the sum of the differences reflects an additional cost of serving firm loads each

hour. Since BPA is not proposing hourly rates, a Demand Rate is needed to reflect firming costs and hourly price differentials. A Demand Rate plus energy rates will tend to mimic the effect that hourly pricing would have on the customer's effective mills/kWh rate. Higher prices result in hours with higher loads. Providing the services of firming, factoring and serving peak load may cause BPA to purchase, or forego sales in the surplus energy market during hours with highest prices. Therefore, this proposal uses projected hourly prices from AURORA to develop Demand Rates that are applied to the demand billing factors for the product being purchased to cover the cost of serving hourly loads. This method allows BPA to recover the cost of serving loads based on an hour of highest demand, without the need to develop hourly energy rates for every hour of the rate period.

Q. How were the Demand Rates developed from the hourly prices that are above a quarterly average price?

A. The sum of the positive HLH price differences is calculated for each quarter of the three-year rate period and is converted to an average Demand Rate in $/kW-month for the three years. This three-year average rate is shaped using AURORA average monthly on-peak prices across the year resulting in 12 monthly Demand Rates. The entire process is described in detail in section 2.2.1.2 of the WPRDS, WP-07-E-BPA-05.

Q. Why is it appropriate to have a different Demand Rate for each month?

A. It reflects the shape of forecasted market prices in each month. For example, more value is attributed to months where BPA faces higher prices that may result in higher costs to serve load. Less value is attributed to months where BPA faces lower prices that may result in lower costs to serve load.

Q. What is the Demand Rate?

A. The three-year annual average Demand Rate using this methodology is $1.06/kW-month. Monthly Demand Rates are shown in the Wholesale Power Rate Schedules,

WP-07-E-BPA-07. The derivation of the Demand Rate can be found in the WPRDS Documentation Section 4.6.1, WP-07-E-BPA-05B.

Differences from the 2002 Rate Case

Q. Please describe how the proposed method is different from the method used to calculate the WP-02 Demand Rates.

A. The WP-02 rate case used the average of the deltas of hourly prices above an annual average price for each year of the rate period. Those five yearly differences were converted to a $/kW-month rate for each year. Those five yearly rates were averaged to get an average annual demand charge for the five year rate period. That average annual rate was capped at an annual rate of $2.00/kW-month to reduce the impact on customers of a large increase in demand charges. That capped rate was then shaped by month to the average HLH price for each of 12 months to derive a demand charge for each month. The first difference in this proposal is that we first compute the HLH average price not the annual average of all prices. The second difference is the use of quarterly average prices to derive the differences of hourly prices above average instead of differences from the average annual price.

Q. Why were these changes in the method made?

A. Calculating the average HLH price instead of the average annual energy price was done because the purpose for the Demand Rate is to collect the additional costs of serving load during the HLH period when prices are higher. A quarterly average price is used instead of an annual average price because it removes the seasonality component which is more appropriately captured in the HLH Energy Rates.

Q. Is BPA proposing any other changes in the application of the Demand Rate?

A. BPA is proposing that the cost recovery adjustment charge (CRAC) not apply to Demand or Load Variance Rates because the method used to determine these proposed rates set them close to a market value. Energy rates are set to recover a total Revenue

Requirement after accounting for expected revenues from Demand and Load Variance Rates. Since energy rates are set on a cost basis that is net of Demand and Load Variance revenues, BPA believes the CRAC should only apply to energy rates. The description of the CRAC is found in Section 2 of the WPRDS, WP-07-E-BPA-05.

Section 3. Load Variance

Definition and Purpose of Load Variance

Q. Please define Load Variance.

A. In the context of core Subscription products Load Variance is defined as the variability in total monthly energy consumption within the BPA customer's system. Variability in monthly energy consumption may be caused by weather, economic business cycles, load growth, or load loss. It does not include the variance in load caused by a customer's actions to annex new load, variance in load due to retail access, or variance caused by service to New Large Single Loads (NLSLs). Such load will receive Load Variance coverage once it is served by BPA under the applicable firm power rate. BPA offers to stand ready to serve this variability under the Full Service and Actual Partial Service Products. The Load Variance product under Full and Actual Partial Service purchases entitles customers' firm power purchases from BPA to follow actual consumption. This differs from Block products where the amounts to be purchased are fixed in advance.

Application of the Load Variance Rate

Q. How will the Load Variance Rate be applied?

A. The Load Variance Rate will be applied to a customer's Total Retail Load as defined in the GRSPs, *see*, WP-07-E-BPA-07. This includes variations in load for load acquired through annexations, retail access gain or loss, and NLSLs once such load becomes part of the Total Retail Load (TRL). The product of the Load Variance Rate and the TRL billing factor yields the Load Variance Charge.

1 *Q. Is this a change from current rates?*

2 A. No.

3 *Q. Why is the Load Variance Rate applied to Total Retail Load?*

4 A. The Load Variance Rate is applied to TRL because under the core Subscription products
5 BPA's service applies to the entire TRL even if the customer dedicates some resource
6 amounts to serve its load. If the Load Variance Rate were applied only to net load,
7 customers would pay unequally for the same service. For example, consider Utility A
8 and Utility B having exactly the same loads. Utility A has no resources and purchases
9 the Full Service product. Utility B has declared a 50 megawatt flat resource and is an
10 Actual Partial Service customer. The load of both utilities has an expected load of 100
11 average megawatts (aMW) for the month. Suppose cold weather causes the actual loads
12 of each utility to be 110 aMW. In both cases, BPA is covering an extra 10 aMw of load.
13 To apply the Load Variance Rate to total purchases instead of TRL, Utility B would
14 receive the same benefit as Utility A for less than 60 percent of the cost, e.g., 110 aMW
15 – 50 aMW = 60 aMW multiplied by the Load Variance Rate compared to 110 aMW
16 multiplied by the Load Variance Rate. For this reason the Load Variance Rate is applied
17 to TRL.

18 *Q. If payment of the Load Variance Rate does not give a customer a right to purchase more*
19 *power to meet annexed loads, how could a customer add such loads to its system for*
20 *service under the BPA contract?*

21 A. A customer may request BPA to serve new load under its Subscription contract.
22 Increases in the customer's load due to annexations and retail access load gain that occur
23 after June 30, 2005, will be subject to a Targeted Adjustment Rate (TAC) to their
24 applicable firm power rate. *See,* Section 7 of this testimony. NLSLs will be served at
25 the New Resources (NR-07) rate. Once these types of loads are added to the customer's
26

TRL, they will receive Load Variance coverage. BPA does not currently forecast any loads under the TAC or NR rate.

Q. Is the Load Variance Rate applicable to or available for Subscription core products other than Full Service and Actual Partial Service?

A. No. Full and Actual Partial Service are the only core Subscription products that flex to meet actual consumption. Block product entitlement and billing amounts are fixed in advance and are not altered to reflect after-the-fact measured power consumption. The Block Plus Shaping Capacity and Block Plus Factoring product combinations allow for some shaped distribution of block energy among hours but do not change the monthly HLH and LLH contracted block energy amounts in relation to any actual measured load of the customer.

Q. Is BPA proposing any other changes in the application of the Load Variance Rate?

A. Yes. BPA is proposing to exclude the application of any CRACs to the Load Variance Rate for the same reasons described in Section 2 of this testimony regarding the Demand Rate.

How the Load Variance Rate Is Calculated

Q. How was the Load Variance Rate determined for this initial proposal?

A. The Load Variance Rate is established based on the estimated cost of serving load growth and load forecast error. The Load Variance Rate was determined by estimating these two costs separately then adding them together.

Q. How was the cost of serving load growth determined?

A. The cost of serving load growth was determined by multiplying the amount of expected load growth over the rate period by the additional price of meeting load growth.

Q. How was the amount of load growth determined?

A. The amount of load growth was calculated by subtracting forecasted monthly Full and Partial Requirements HLH and LLH loads in FY 2007 from the sum of monthly Full and

Partial Requirements HLH and LLH loads forecast for FY 2008 and FY 2009. This resulted in two sets of numbers, load growth for HLHs and load growth for LLHs.

Q. How was the additional cost of meeting load growth determined?

A. The cost of meeting load growth is the difference between market prices and power rates. Since this analysis is prospective, the projected priority firm HLH and LLH energy rates were subtracted from AURORA projections of HLH and LLH market prices. The HLH energy rate was increased by an amount that reflects the Demand Rate for comparison to market prices.

Q. How was the per unit cost of serving HLH and LLH load growth determined?

A. After determining the amount of load growth and the per unit cost of meeting load growth, the resulting HLH and LLH per unit cost was multiplied by the corresponding monthly HLH and LLH monthly load growth amounts to obtain an estimate of total cost of serving load growth for HLH and LLH, respectively.

Q. What was the resulting cost of serving load growth?

A. The cost of serving load growth was determined to be 0.24 mills/kWh. *See*, WPRDS Documentation, WP-07-E-BPA-05, Table 4.3.

Q. How was the forecast error component of the Load Variance Rate determined?

A. The cost of the load forecast error component of the Load Variance Rate was determined by multiplying the amount of expected forecast error by the per-unit cost of forecast error.

Q. How was the amount of expected load forecast error determined?

A. To quantify forecast error, BPA used historical differences over the last 36 months of the current rate period. From August 2002 through July 2005, the actual Full and Partial Requirements HLH and LLH loads differed from the forecasted loads by 2.8 percent. The load forecast, of Full and Partial service customers, for each month in the rate period is multiplied by this percentage to obtain the load forecast error.

Q. Was the monthly unit cost of serving HLH and LLH load forecast error determined in the same way as the unit cost of serving monthly load growth?

A. Yes, the same HLH and LLH energy rates were subtracted from the AURORA projections of monthly average HLH and LLH energy prices. The difference between these figures is the HLH and LLH monthly per unit cost of serving load forecast errors.

Q. Why did BPA use a different procedure for costing load forecast error than it used during the previous rate proceeding?

A. In the previous rate proceeding BPA assumed the cost of meeting load forecast errors was best approximated by pricing options since the projected cost of power purchases was fairly close to the rate proposal. Now, because of the large positive disparity between market prices and proposed power rates, that method for pricing this product is no longer considered reasonable.

Q. Is the total cost of load forecast errors calculated using the same procedure used to calculate the cost of load growth?

A. Yes. The monthly amounts of HLH and LLH load forecast errors are multiplied by the unit cost of meeting monthly HLH and LLH load forecast errors to obtain the total cost of load forecast errors.

Q. What was the load forecast error component of the Load Variance Rate?

A. The total cost of load forecast errors is divided by the forecast Total Retail Load of Full and Partial service customers to obtain 0.29 mills/kWh.

Q. What is the Load Variance Rate?

A. The total Load Variance Rate is 0.53 mills/kWh (the sum of 0.24 and 0.29 mills/kWh).

Section 4. Discontinuation of Stepped Up Multi-Year (SUMY) Block Charge

Q. Why is BPA proposing to discontinue the SUMY Block Charge?

A. The SUMY Block Charge is being discontinued because the option to change block

energy purchases from month-to-month and year-to-year is no longer being offered; therefore, this rate option is no longer necessary.

Section 5. Development of Energy Rates

Q. What changes are proposed in the WP-07 Rate Design for HLH and LLH energy rates?

A. BPA is using the same approach to establish energy rates for FY 2007-FY 2009 that was used in the WP-02 rate case. Rates are shaped to a forecast of market-based marginal costs for the rate period and then adjusted so that the total revenue requirement is neither over-collected nor under-collected. As in BPA's current rate period, rates for FY 2007-2009 are diurnally differentiated.

Q. Is BPA proposing any other changes related to Energy Rates?

A. Yes. BPA is proposing to denote six NERC holidays as LLH periods for the FY 2007-2009 rate period. This is a change from WP-02, which did not include these NERC holidays as part of the LLH period. *See*, WP-07-BPA-05A.

Q. What are the holidays added to the LLH period?

A. They are New Year's Day, Memorial Day (observed), July 4th, Labor Day, Thanksgiving, and Christmas Day. If New Year's Day, July 4th, or Christmas Day falls on a Sunday, then the next day (Monday) would be defined as all LLH..

Q. Why is BPA proposing this change?

A. This change will make BPA definition of HLH and LLH periods consistent with NERC and many of our customers and suppliers who do business in the surplus energy market. This also eliminates the need for two definitions of HLH and LLH periods in BPA's billing system.

Q. Is BPA proposing to revise the HLH and LLH definitions in the transmission rates?

A. Yes. In order to make the definitions in BPA's transmission rate schedules consistent with its power rate schedules and with NERC, BPA is proposing to revise the HLH and LLH definitions included in the 2006 Transmission and Ancillary Service Rate

Schedules, General Rate Schedule Provisions, Section III, definitions 16 and 21. We are proposing that this revision be effective beginning October 1, 2006 (FY 2007). Transmission and Ancillary Service Rate Schedules that use HLH and LLH definitions are (1) the Network Integration Rate and (2) the Ancillary Services and Control Area Services (ACS) Rate (Energy Imbalance Service and Generation Imbalance Service). As well, the HLH and LLH definitions are also used under the General Rate Schedule Provision for the Power Factor Penalty Charge.

Section 6. Unauthorized Increase Charge and Excess Factoring Charge

Q. Is BPA proposing a change to the Unauthorized Increase and Excess Factoring Charges?

A. Yes. BPA is proposing to delete the reference to the California Power Exchange (CalPX) in both the Unauthorized Increase Charges for demand or energy and the Excess Factoring Charges.

Q. Why is BPA proposing this change?

A. BPA is proposing this change since the CalPX is no longer an applicable index. In 2001 CalPX trading was suspended and the CalPX filed for bankruptcy protection. Consequently, it has not been used as an index to determine the above rates.

Section 7. Targeted Adjustment Charge (TAC)

Q. Is BPA proposing any changes to the Targeted Adjustment Charge?

A. Yes. BPA is proposing to exempt unanticipated incremental load that is less than 1 aMW in a year from the TAC and, in addition, to use any monthly surplus available from the Federal System to serve portions of a TAC load.

Q. Why is BPA proposing to exempt loads of 1 aMW or less?

A. BPA is proposing to exempt these small loads because BPA's experience with applying the TAC during the current rate period to small loads leads us to conclude that the administrative and contract modification costs outweigh the cost of serving these loads

at the posted PF rates. Furthermore, we do not schedule power in less than 1 MW increments and there is no market from which to purchase these small amounts. BPA is proposing to meet this type of load through its on-going balancing purchases.

Q. Why is BPA proposing to use monthly FBS surplus to meet loads that would face the TAC?

A. BPA recognizes that even though it may be deficit on an annual basis in any year there may be some surplus Federal power available in some months. Therefore, BPA is proposing to allow that energy to be used to lower the cost of a customer's TAC. The most current BPA White Book will be used to make the determination of monthly available Federal surplus, accounting for all current contracts. It will not be used to decrease the size of a load for the purpose of evaluating whether the load is exempt from a TAC. *See*, Section 2.13 of WP-07-E-BPA-05.

Section 8. Operating Reserve Credit (ORC)

Q. What is the purpose of this section of testimony?

A. The purpose of this section of testimony is to describe the BPA's Power Business Line (PBL) proposal to modify the credit that is based on the PBL revenue received from the Transmission Business Line (TBL) related to the provision of generation inputs for Operating Reserves. There are two reasons for this modification. First, PBL intends to correct a revenue under-recovery problem that has arisen within the current WP-02 rate period concerning the application of the Operating Reserves revenue credit. Second, by correcting the under-recovery issue, BPA intends to correct a rate inequity that has developed among firm power requirements customers. Finally, this testimony sponsors those parts that deal with Operating Reserves credit calculations. *See*, Section 2.3 of the WPRDS, WP-07-E-BPA-05, and Section 4.3 of WP-07-E-BPA-05B.

Background

Q. Please describe Operating Reserves.

A. Operating Reserves are described by the Western Electricity Coordinating Council (WECC) as the reserve generating capacity (or rights to interrupt delivery of generation) necessary to allow an electric system to recover from generation failures. Operating Reserves are the unloaded generating capacity, interruptible load, or other on-demand rights accessible within 10 minutes of a power system disturbance that are capable of sustained performance for up to one hour. Operating Reserves include both Spinning Reserves and Supplemental Reserves. The primary distinction between these reserve services is that Supplemental Reserves are not required to be on line, while Spinning Reserves are available instantly to provide additional energy as required to cover system disturbances. *See*, Sections 4.1.1.1 and 4.1.1.2 of WP-07-E-BPA-05.

Q. Why are Operating Reserves needed?

A. Operating Reserves are needed to cover system disturbances in the BPA control area. According to the Northwest Power Pool (NWPP), a system disturbance occurs when generation is lost due to unit trips, a transmission path between generator and the network point of interconnection is lost, a plant suffers internal equipment problems, or a generating unit fails to start.

Q. How were revenues associated with Operating Reserves recovered from the TBL treated in the WP-02 rate calculations?

A. PBL forecasted an amount of revenues from generation inputs PBL believed it would sell to TBL for provision of Operating Reserves in the BPA control area, and deducted this forecasted amount from the revenue requirement used to set both the firm requirements energy rate and the Slice rate.

Q. What assumptions were made in the WP-02 rate proceeding regarding self-supply and third-party supply of Operating Reserves to the BPA control area?

A. In that proceeding, it was assumed that federal generation would meet the entire Operating Reserve obligation of the BPA control area since transmission customers

were not self or third-party supplying Operating Reserves at the time. Given that assumption, PBL credited the expected revenues from providing generation inputs to TBL for Operating Reserves against PBL's total revenue requirement prior to computing all PF rates. Therefore all firm power rates were lowered.

Q. What change arose during the WP-02 rate period regarding PBL's assumption about self-supply and third-party supply?

A. In 2003, transmission customers started to take advantage of the option to elect to either purchase from TBL, self-supply or acquire third-party supply of Operating Reserves on an annual basis.

Q. What impact did this change have on PBL's assumption about the revenue forecast for generation inputs PBL supplies to TBL for provision of Operating Reserves?

A. Because several transmission customers elected to either self-supply/third-party supply their Operating Reserves, the assumed amount of PBL-supplied generation inputs for Operating Reserves was reduced by approximately one-third. Because the generation inputs supplied by PBL decreased, the associated revenue from the TBL was also reduced, resulting in an approximate $10 million per year shortfall from the WP-02 power revenue forecast and an under-recovery of the power revenue requirement. Second, self-supply/third-party supply creates a rate inequity.

Q. How does this result in a rate inequity?

A. The rate inequity results from a rate benefit that is spread to all firm power requirements customers, which was determined assuming no self- or third-party supply. When some customers elected to self- or third-party supply Operating Reserve, PBL under-collected revenues. This under-recovery resulted in a higher FB/SN CRAC and Slice true-up than would otherwise have been needed. In other words, some customers caused an under-recovery but all firm power requirements customers paid for the under-recovery.

Q. Please describe PBL's proposal to address the under recovery of Operating Reserves revenue and the inequity that exists among firm power requirements customers?

A. In order to address the risk of under-recovery associated with the option to self- or third-party supply Operating Reserves and the resulting rate inequity between firm power requirements customers, PBL is proposing to not have an Operating Reserves credit in the base rate calculation. PBL is proposing to provide an Operating Reserve Credit (ORC) to only those firm power requirements customers that elect to purchase Operating Reserves from TBL that are supported by generation inputs supplied by PBL. The customer's monthly power bill will reflect this credit if appropriate. The ORC better reflects actual revenues PBL receives for generation inputs provided to TBL and ensures cost recovery consistent with the power revenue requirement and eliminates the inequity among firm power requirements customers that currently exists. *See*, Section 4.1.3 of WP-07-E-BPA-05.

Q. How does the proposal fix the rate inequity?

A. It allows those firm power requirement customers that share in paying the cost of the Operating Reserves provided by the TBL that are supported with generation inputs from PBL to share in the PBL's revenue benefit. Therefore, should any of PBL's firm power requirements customers purchase Operating Reserves from TBL that are supported with generation inputs from PBL, including Slice customers, they will receive the credit on their monthly power bill.

Q. Do firm power requirements customers remain free to choose whether to self- or third-party supply Operating Reserves?

A. Yes. Our proposal is intended to develop a power rate design to adjust to the fact there will continue to be some firm power requirements customers that choose to self- or third-party supply Operating Reserves.

Q. How does the proposal treat Operating Reserve revenue generated from sales of Operating Reserves to transmission customers that are not firm power requirements customers of PBL?

A. Revenue from supplying Operating Reserves to transmission customers that are not firm power requirements customers of PBL is treated similarly to revenue generated by sales of capacity on PBL's trading floor. PBL will spread such revenue across its firm power requirements rates in the form of a revenue credit, except to the Slice rate.

Q. What other issues should be considered regarding Operating Reserve revenues?

A. WECC parties are discussing many issues and proposals, which may be implemented during this FY 2007-2009 rate period, to address outstanding Operating Reserves issues throughout the Western Interconnection. Due to the multitude and complexity of issues, WECC formed separate task forces that are chartered to address specific issues related to Operating Reserves. The proposals resulting from these efforts may significantly affect control area operator Operating Reserve requirements in both the amount and quality of service needed. Other industry efforts are underway suggesting a complete overhaul to ancillary and reserve markets. In combination, these changes present many issues that may impact revenues PBL receives from TBL. It is important that PBL establish an equitable power rate design that may allow adjustment to these changes.

Application of the Proposed Operating Reserve Credit (ORC) Cost Methodology

Q. How is the proposed ORC determined and what is the credit amount?

A. The ORC is determined from the total PBL revenue forecasted to be recovered from TBL associated with generation inputs provided by PBL divided by the total forecasted PF loads associated with customers obtaining Operating Reserves from TBL that are supported with those generation inputs. This computation yields a credit amount of $0.89/MWh. *See*, Section 4.7 of WP-07-E-BPA-05B.

1 *Q. How will the proposed ORC be applied?*

2 A. The ORC will be reflected on individual customer power bills for firm power
3 requirements customers that are purchasing Operating Reserves from TBL using
4 generation inputs provided by PBL. The billing determinant for customers within the
5 BPA control area is proposed to be the customer's total retail load since this is the
6 amount used to establish the Operating Reserve requirement. The billing determinant
7 for customers outside of the BPA control area is proposed to be all monthly kWh of
8 federal energy purchases by the customer for each month. For the Slice product, BPA
9 will apply the ORC to the Slice portion of the customers bill using a methodology
10 comparable to that employed for the other PF products.

11 *Q. How would this change in rate design affect the calculation of IOU REP Settlement*
12 *benefits?*

13 A. It does not affect the calculation. The IOU Residential Exchange Program (REP)
14 Settlement is basically valued as the market price minus the lowest cost PF rate, which
15 represents the value the Preference Customers receive from the system. Customers that
16 receive the ORC will pay the PF rate and pay TBL for Operating Reserves. Payment to
17 the TBL for Operating Reserves is the source of funding for the ORC. In contrast,
18 customers that self or third-party supply do not pay TBL for Operating Reserves that are
19 supported by generation inputs provided by PBL. Since the IOUs do not, and are not
20 expected to, purchase Operating Reserves associated with the IOU REP settlement, they
21 then should be treated like the customers who self-supply/third-party supply Operating
22 Reserves and should not receive the ORC.

23 *Q. Are there any other issues to be resolved with the ORC calculation?*

24 A. Yes. The assumptions for self-or-third party supply of Operating Reserves obligations
25 need to be confirmed by the TBL for proper application to this rate calculation.

26 *Q. Is BPA open to other proposals to address this inequity?*

A. Yes. BPA is open to looking at other proposals to address the revenue under-recovery problem and the resulting rate inequity that has been identified.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY OF

MICHAEL NORMANDEAU, BYRNE E. LOVELL, ARNOLD L. WAGNER,

SID CONGER, AND ALEX LENNOX

Witnesses for Bonneville Power Administration

SUBJECT: RISK MITIGATION

Page

Section 1. Introduction and Purpose of Testimony 1

Section 2. Treasury Payment Probability Methodology 2

Section 3. Risk Mitigation Tools in the ToolKit Model 3

Section 4. Financial Reserves 4

Section 5. Planned Net Revenues for Risk (PNRR) 6

Section 6. Cost Recovery Adjustment Clause (CRAC) 8

Section 7. The NMFS FCRPS BiOp (NFB) Adjustment 12

Section 8. Dividend Distribution Clause (DDC) 14

Section 9. Modified Net Revenue 16

Section 10. Additional Risk Mitigation Tools and Efforts 19

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TESTIMONY OF

MICHAEL NORMANDEAU, BYRNE E. LOVELL, ARNOLD L. WAGNER,

SID CONGER, AND ALEX LENNOX

Witnesses for Bonneville Power Administration

SUBJECT: Risk Mitigation

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Michael Normandeau and my qualifications are contained in WP-07-Q-BPA-43.

A. My name is Byrne Lovell and my qualifications are contained in WP-07-Q-BPA-32.

A. My name is Arnold Wagner and my qualifications are contained in WP-07-Q-BPA-50.

A. My name is Sid Conger and my qualifications are contained in WP-07-Q-BPA-10.

A. My name is Alex Lennox and my qualifications are contained in WP-07-Q-BPA-30.

Q. What is the purpose of your testimony?

A: The purpose of our testimony is to describe the risk mitigation tools used in this rate case and the calculation of the probability of BPA making U.S. Treasury (Treasury) payments on time and in full during the three-year rate period for this rate proceeding. This testimony also examines additional Risk Mitigation Tools and efforts to reduce the cost of risk mitigation in rates.

Q. How is your testimony organized?

A. Our testimony includes 10 sections including this introductory section. Section 2 summarizes the methodology for calculating the probability of making all Treasury payments in full and on time. Section 3 surveys the risk mitigation tools used in the ToolKit model. Section 4 discusses financial reserves. Section 5 goes over Planned Net Revenues for Risk (PNRR). Section 6 is devoted to the Cost Recovery Adjustment

Clause (CRAC). Section 7 describes the NFB Adjustment to the CRAC. Section 8 explains the Dividend Distribution Clause (DDC). Section 9 details the calculation of Modified Net Revenue (MNR). Section 10 highlights other possible risk mitigation measures that are not quantitatively assessed in this proposal.

Section 2. Treasury Payment Probability Methodology

Q. What is the Treasury Payment Probability (TPP)?

A. TPP is the probability (expressed as a percentage) that BPA will be able to make all of its planned payments to Treasury in a rate period in full and on time. TPP is the means by which BPA tests the financial strength of its rate proposal. Payments to Treasury, in particular principal payments, are by law subordinate to all of BPA's other payment obligations. Therefore, if BPA meets its Treasury payment obligations, it will have met all its other financial obligations as well. For this reason, TPP serves as the key prospective measure of BPA's ability to recover all its costs.

Q. How does BPA calculate the TPP?

A. BPA calculates TPP using a *Monte Carlo* modeling approach in which 3,000 separate scenarios or *games* are generated. Each game covers the three years in this rate period. In each game a test is performed to see if BPA is able to make its U.S. Treasury payment during each year of the rate period. The TPP is the percentage of those 3,000 games in which BPA makes its U.S. Treasury payment on time and in full in all three years.

Q. What tool does BPA use to calculate the TPP?

A. BPA uses a model called the ToolKit to evaluate PBL's ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to generation.

Q. How has BPA modified the ToolKit Model since the WP-02 rate case?

A. The version of ToolKit used in the WP-07 proceeding is similar to the version used in the WP-02 proceeding in terms of its overall form and function. ToolKit reads in two files of risk data, one produced by the RiskMod model that reflects operating risks, and one from the Non-Operating Risk Model (NORM). However, BPA has modified the Visual Basic for Applications (VBA) code of ToolKit to account for changes in rate design and to account for new or modified obligations (for example, IOU REP Settlement benefits.) *See,* WP-07-E-BPA-04 on Risk Analysis for discussion of the RiskMod and the NORM and for more details on changes to the ToolKit.

Q. What TPP percentage is BPA targeting with its WP-07 Initial Proposal?

A. In this Initial Proposal, BPA is implementing its long-standing TPP standard of 95 percent. That standard, adopted in 1993 as part of BPA's 10-Year Financial Plan, applies to a two-year rate period. Because the FY 2007 – 2009 rate period is a three-year period, BPA must convert the 95 percent TPP for two-year rate periods into the equivalent TPP percentage for a three-year rate period. The three-year equivalent TPP is 92.6 percent.

Q. How does BPA measure TPP for comparison to its TPP standard?

A. BPA measures TPP in the rate-setting process used by an individual business line. The TPP standard is a rate-setting standard, and since BPA now sets rates separately for power and transmission functions, the TPP test must be made separately also. BPA believes that if each business line is meeting the TPP standard, then the Agency as a whole is ensuring timely payment of its Treasury obligations sufficiently to comply with the thrust of the TPP standard. The WP-07 initial proposal is measured against the three-year equivalent (92.6%) of the 95% standard defined in the 10-Year Financial Plan for two-year rate periods.

Section 3. Risk Mitigation Tools in the ToolKit Model

Q. What risk mitigation tools is BPA using to achieve the 92.6 percent TPP standard?

A. BPA identified a list of potential risk management tools to be used as part of a comprehensive risk management plan in Risk Analysis Study, WP-07-E-BPA-04. The tools that are included in the ToolKit analysis for the Initial Proposal are starting financial reserves, the temporary availability of other Agency reserves, Planned Net Revenues for Risk (PNRR), a Cost Recovery Adjustment Clause (CRAC), and a Dividend Distribution Clause (DDC). These tools address the uncertainties BPA is facing for the fiscal years FY 2007 - 2009 period, particularly hydro conditions, market prices, operating and non-operating costs, and fish and wildlife costs while assuring that PBL reserves do not accumulate to unnecessarily high levels.

Q. Does BPA's Initial Proposal contain other risk mitigation tools that are not modeled in ToolKit?

A. Yes. BPA is proposing the NFB Adjustment (National Marine Fisheries Service [NMFS] Federal Columbia River Power System [FCRPS] Biological Opinion [BiOp] Adjustment), but is not modeling the adjustment or the risks it will mitigate. The NFB Adjustment is an upward adjustment to the CRAC Maximum Planned Recovery Amount (Cap) for any year in the rate period if unforeseen fish and wildlife costs or financial impacts of operational changes arise from a predetermined set of circumstances related to the litigation over the 2004 BiOp. BPA is not modeling the impacts of this risk tool or the risks it covers because the possible outcomes of the litigation and their probabilities are unknowable. *See,* Section 7 for further discussion of the NFB Adjustment.

Q. Will the risk mitigation package apply to Slice purchases?

A. No. The Slice product is not subject to the proposed risk mitigation package because Slice customers cover their proportional share of risk by paying actual costs and they receive their proportional share of actual secondary revenues.

Section 4. Financial Reserves

Q. Please explain the term "starting financial reserves."

A. Starting financial reserves comprise cash in the BPA Fund and cash equivalents in the form of a deferred borrowing balance at the start of the first fiscal year of the rate period. Since BPA is setting rates only for power in this rate case, it is only referring to those financial reserves attributable to the generation function.

Q. Please explain how financial reserves are modeled as a risk mitigation tool.

A. Financial reserves are BPA's central risk mitigation tool. During years of low secondary revenue or other financial exigencies, reserves can be drawn down to provide funds for paying operating expenses and the Treasury, and during years of high net revenue reserves can be replenished. The first step in BPA's calculation of TPP is modeling starting financial reserves for the rate period.

Q. What is BPA assuming for FY 2007 starting reserves?

A. At the time of this analysis, shortly after the FY 2005 3rd Quarter Review, the actual starting reserve level for FY 2007 was unknown because of the uncertainty regarding PBL cash flow during the remainder of FY 2005 and FY 2006. To account for this uncertainty, BPA has modeled 3,000 games for FY 2005 and FY 2006 to produce 3,000 separate starting reserve values for FY 2007. The result showed an expected value of PBL starting reserves for FY 2007 of $381 million.

Q. Does this mean BPA will have PBL reserves of $381 million at the start of FY 2007?

A. No. The actual amount of starting reserves for FY 2007 is unknown. BPA is using the ToolKit model, along with RiskMod and NORM, to compute a distribution of 3,000 different starting reserve values for FY 2007. The expected value of our distribution of starting reserves is $381 million; the distribution ranges from a low of $50 million (reflecting a deferral of part of the Treasury payment for FY 2006) up to $665 million.

Q. Does BPA's Initial Proposal rely solely on reserves attributed to PBL?

A. Not exactly. BPA evaluated whether any Agency reserves not attributed to generation could be considered to be available for helping to mitigate power risks without violating

the Agency's TPP standard. BPA concluded such reserves were available. When TBL completed its rate case for FY 2006 – 2007, its rates passed BPA's three tests: 1) they demonstrated cost recovery on an accrual basis; 2) they demonstrated cost recovery on a cash basis, and 3) they satisfied the requirement of the 10-Year Financial Plan that the TPP be at least 95 percent for a two-year rate period. In fact, the TBL TPP was higher than 95 percent: TBL's reserves were greater than the amount needed to meet the 95 percent TPP standard. Staff determined that if TBL reserves were reduced by $55 million in FY 2007, TBL's reserves would still be sufficient to meet the TPP standard. As a result, $55 million of reserves not attributed to PBL in FY 2007 can be considered for rate-setting purposes to be available to PBL to mitigate its risks. Since TBL has not set rates for FY 2008 and 2009 the $55 million of reserves is only available to PBL in FY 2007. As a result, PBL must plan that any temporary use of these reserves in FY 2007 would be completely made up for by the end of FY 2008, in such a way that TBL rates in FY 2008 – 2009 will not be increased. *See,* Leathley, *et al.,* WP-07-E-BPA-08. The starting and ending reserves calculated in this proposal are solely those attributed to PBL.

Section 5. Planned Net Revenues for Risk (PNRR)

Q. What is the role of PNRR?

A. PNRR is a component of the revenue requirement that is added to bolster reserves to mitigate the impacts of operating and non-operating risks. *See*, Section 3.3.1 of the Risk Analysis Study, WP-07-E-BPA-04. PNRR is included when the projections of revenues, expenses, financial risks, and risk mitigation measures without any planned increases in reserves fail to meet the 92.6 percent TPP standard. Increasing the PNRR component of revenue requirements forces the rate level up, which generates additional revenue and higher reserves, which then improves our ability to make U.S. Treasury payments in years when hydro, market price, and other risks depress our financial performance. PNRR is essentially an adjustment to financial reserves that makes reserves a more

effective risk mitigation tool. PNRR is not needed if reserves plus other risk mitigation measures are adequate to meet BPA's TPP standard.

Q. What is the relationship between PNRR and the other risk mitigation tools BPA will be using?

A. The amount of PNRR included in revenue requirements is determined only after the impacts of other risk mitigation measures, such as the starting reserves and CRAC, have first been assessed. PNRR as a way to increase reserves is the backstop in BPA's risk mitigation portfolio: whatever risk is not mitigated by other tools and projected reserves will be mitigated by increases in reserves generated by PNRR.

Q. Please summarize how the ToolKit calculates the amount of PNRR needed.

A. With a set of risk mitigation measures, such as a particular CRAC design, or distribution of starting reserves, and the risks as modeled in RiskMod and NORM, ToolKit measures the TPP. To begin the process of measuring the TPP in ToolKit, a set of rate assumptions is prepared that does not take into account any risk mitigation measures. These rate assumptions generate sufficient revenues to meet PBL's revenue requirements for the FY 2007–2009 period under average conditions – that is, average water, average thermal plant performance, planned spending levels, expected market prices, etc. The operating and non-operating risk distributions produced by RiskMod and NORM, respectively, are then added to this base, which results in a distribution of 3,000 net revenue values that are read by ToolKit. ToolKit then translates these net revenue values to cash flows for the generation function through the Accrual-to-Cash adjustment to develop a distribution of annual ending reserve values. Then ToolKit examines the ending reserve values to determine whether the Treasury payment was met often enough. For each of the 3,000 games, ToolKit checks to see if each year in the FY 2007–2009 rate period ended with at least $50 million, the amount of reserves needed for liquidity in the first part of BPA's fiscal year (the *liquidity reserve level,* formerly called the working capital amount).

ToolKit counts the number of games in which all three years ended with at least $50 million in reserves, and divides that by the number of games, that is, 3,000, to compute the three-year TPP.

If this calculated TPP is below the 92.6 percent TPP standard, it is necessary to add PNRR to the revenue requirement. Through a process of trial-and-error, amounts of PNRR are added until the TPP standard is met. For this proposal, $97 million PNRR was required to meet the TPP standard, given the other features of the risk mitigation package described in this testimony.

Section 6. Cost Recovery Adjustment Clause (CRAC)

Q. Please describe the CRAC.

A. This rate proposal includes a CRAC; a temporary upward adjustment to the power rates if forecast Accumulated Modified Net Revenues (AMNR) fall below the thresholds shown on Table A, Attachment 1. The adjustment will be made by a percentage increase in light load hour (LLH) and heavy load hour (HLH) energy rates. *See,* Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05. In addition, the upwardly adjusted energy rates will be used in the calculation of benefits under the REP Settlement Agreements with the IOUs and any benefits paid to the region's aluminum companies.

Q. What is AMNR?

A. AMNR is the equivalent of Accumulated Net Revenue (ANR) defined in the FY 2002 – 2006 rate period. ANR is the sum of the annual modified net revenue (MNR) calculations since the end of FY 1999. We are replacing ANR with AMNR for the sake of clarity. This is the same AMNR used in the DDC calculations. See Section 9 below for more details on MNR.

Q. Why is the trigger based on accumulated modified net revenues rather than reserves?

A. The CRAC triggers on the basis of AMNR because accumulated modified net revenues are subject to financial audit, thus allowing independent verification of actual results. In

addition, net revenues are easier than reserves to segregate between generation and transmission functions because of financial systems design and financial reporting practices.

Q. Please explain the timing of the CRAC adjustment.

A. Before the end of FY 2006, FY 2007, and FY 2008, BPA will determine if the forecast of AMNR at the end of the year is below the applicable CRAC threshold for the next fiscal year. If AMNR is below the applicable threshold, BPA will adjust energy rates for the next fiscal year. The adjustment will be a percentage increase to the applicable posted rates. This initial proposal does not call for a forecast of AMNR to be made in FY 2009, since the next year, FY 2010, is outside the rate period.

Q. How were the CRAC thresholds derived?

A. The threshold was originally discussed in terms of starting reserves levels because they are easier to relate to BPA's risks. BPA determined that approximately $500 million was an appropriate threshold level because it represented an appropriate compromise between a lower threshold that would trigger less frequently but require higher PNRR, and a higher threshold with higher total CRAC revenues but a lower level of PNRR. The threshold for FY 2007 was reduced by $30 million to reduce the expected value of the FY 2007 rate slightly. This brings the FY 2007 expected value rate a little closer to the expected values of the rates for FY 2008 and FY 2009, which are lower than the FY 2007 expected value rate. In the risk studies BPA performed for FY 2007, in 238 of the 3,000 games (approximately 8 percent of the games) PBL net revenues were more than $500 million below the expected value due to the impact of operating risks. Allowing reserves levels to drop below $500 million would make it very difficult to achieve the TPP target.

Q. How did BPA choose $300 million as the maximum recovery amount?

A. BPA chose $300 million to achieve a balance between rate stability from the current rate

period to the next rate period as well year-to-year variability within the FY 2007 – 2009 rate period.

Q. What would be the effect of changing the maximum recovery amount of the CRAC?

A. The maximum recovery amount could be set higher or lower depending on what risk mitigation tools are available and how much PNRR is acceptable in base rates. A lower cap on the CRAC would require BPA to increase PNRR to achieve the 92.6 percent TPP target. Lowering the cap would result in higher expected-value rates and less year to year rate volatility because the increase in PNRR is paid in all years, while CRAC revenues are only collected when needed. Raising the cap would result in lower expected value of the rate over three years and greater year to year rate volatility.

Q. How is the total amount to be recovered through the CRAC adjustment determined?

A. The total amount to be recovered through the CRAC adjustment is the smaller of the amount by which AMNR is below the threshold and the maximum recovery amount shown in Attachment 1, Table A.

Q. How is the amount of rate increase calculated?

A. The CRAC amount will be recovered from two sources, the PF energy rates subject to the CRAC, which would increase revenues, and a decrease in the IOU REP Settlement benefits, unless those benefits have reached the caps or floors. See section six of Petty, *et al.,* WP-07-E-BPA-11 for additional information about the IOU REP Settlement calculation.

Q. How do the IOU REP Settlement benefits cap and floor affect this calculation?

A. The calculation of the IOU REP Settlement benefits complicates the determination of the CRAC amount collected because the IOU REP Settlement benefits are constrained by a cap and floor. As a result, an increase in the PF rate may or may not translate into a reduction in the IOU REP benefit level for that fiscal year. If the calculation of the IOU REP Settlement benefits is below the floor after the CRAC adjustment to the PF rate, the

benefits cannot be reduced any further. Likewise, if the calculation of IOU REP Settlement benefits is significantly above the cap even after any CRAC adjustment to the PF rate, this increase will not result in a change to the benefit levels. If there is no reduction in IOU REP Settlement benefits, then the entire CRAC amount would be collected through PF energy loads subject to the CRAC. For a discussion on how the IOU benefit caps and floors impact the CRAC calculation, *see,* Section 3.5.3 of the Risk Analysis Study, WP-07-E-BPA04.

Q. Will BPA include the aluminum DSI benefits in the calculation of the CRAC?

A. No. To the extent BPA elects to provide financial benefits to the aluminum DSIs, BPA will adjust the benefits paid to the aluminum DSIs in the event there is a CRAC adjustment to energy rates. However, BPA will not know before the beginning of the next fiscal year what the applicable aluminum DSIs financial benefit level will be in order to calculate the contribution to the CRAC amount. Aluminum DSIs may opt to shut down operations due to rate increases or other economic factors. Because of this operational uncertainty, BPA cannot rely upon the contribution of these DSIs. Therefore, the aluminum DSIs' benefits will be affected by the CRAC, but changes in the aluminum DSIs' benefits due to the CRAC will not be included in the calculations of the CRAC amount or the CRAC percentage increase in covered rates.

Q. Please explain the CRAC Revenue Basis.

A. The CRAC Revenue Basis is the total LLH and HLH generation revenue for products and benefits that are subject to the CRAC, based on the then most current revenue forecast for the relevant BPA fiscal year.

Q. How will the CRAC percentage be applied to customer bills?

A. The CRAC percentage will be applied as a mills/kWh rate to the customer's HLH and LLH energy charges. The CRAC adjustments will be shown as separate line items on each customer's bill. *See,* the testimony of Bolden, *et al*., WP-07-E-13-BPA for an

explanation about why the CRAC will not apply to demand or load variance charges.

Q. Will there be a true-up of the CRAC?

A. No. The CRAC adjustment to the rates is made based on the CRAC percentage calculated prior to the start of the fiscal year with no true-up. Any over-collection or under-collection due to changes between the third quarter review and the end of the fiscal year will be addressed in the next fiscal year's analysis of the need for a CRAC.

Q. Is the CRAC robust enough to mitigate all of BPA's risk?

A. No. The CRAC is designed to collect up to $300 million a year. In order for BPA to reach the 92.6 percent TPP standard, BPA included PNRR in the risk package.

Section 7. The NMFS FCRPS BiOp (NFB) Adjustment

Q. What do the acronyms in this name mean?

A. National Marine Fisheries Service [N] Federal Columbia River Power System [F] Biological Opinion [B] Adjustment

Q. Are fish and wildlife issues being modeled in ToolKit in a similar fashion to the 13 distinct Fish and Wildlife Alternatives assumed in the May 2000 rate case?

A. No. Prior to the May 2000 rate case there was an agreement among Federal Agencies involved in fish recovery that BPA would model the uncertainty about fish recovery plans by using a set of 13 alternatives that would be assumed to be equally likely. The 13 alternatives do not apply to the current rate period.

The financial impacts of fish and wildlife programs and measures remain a major uncertainty for the agency, especially due to ongoing litigation issues around the 2004 Biological Opinion. Therefore BPA has developed a separate risk mitigation tool for dealing with specific fish and wildlife uncertainties. *See,* Leathley, *et al.,* WP-07-E-BPA-08.

Q. Please describe the NFB Adjustment and how it will work.

A. The NFB adjustment is an adjustment to the CRAC cap designed to mitigate the

potentially large financial impact of court-ordered changes in the operation of the hydro system and with the fish and wildlife program costs. An NFB Adjustment results in an upward adjustment to the annual CRAC Maximum Recovery Amount (Cap) for any one year in the rate period. The NFB Adjustment will not affect rates unless the AMNR is below the CRAC Threshold and the CRAC Amount (before comparison to the CRAC cap) is greater than $300 million for that year. For instance, if there is an NFB Adjustment and AMNR is above the CRAC Threshold for that year, there will be no rate impact in that year from the NFB Adjustment because there will be no CRAC. On the other hand, if AMNR is more than $300 million below the CRAC Threshold for that year, the NFB Adjustment will allow BPA to recover more than the original $300 million cap, and the CRAC rate will be higher than it would have been without the NFB adjustment. This tool is described in detail in Section 6 of this testimony and also in the Risk Analysis Study, WP-07-E-BPA-04.

Q. Why is the NFB Adjustment necessary?

A. It is necessary because the risk analysis does not account for the uncertainty surrounding the outcome of the FCRPS Biological Opinion (BiOp). It is very difficult to predict the results of the litigation over the BiOp and their potential impacts on BPA's costs and revenues. BPA does not have a defined set of alternative costs and operations for fish to model as it did in the May 2000 power rate proposal. There are large numbers of possibilities, and probabilities cannot be estimated for any particular scenario. Because the uncertainty is so open-ended, BPA believes it is necessary to have an open-ended adjustment mechanism to help ensure that cost recovery is assumed no matter what fish and wildlife program BPA is obligated to implement.

Q. What conditions are required for the NFB Adjustment to trigger?

A. The NFB Adjustment will "trigger" if changes to the anadromous fish portion of the Fish and Wildlife program reduce PBL's modified net revenue below what they would

otherwise be, 'but only when those impacts result from changes in FCRPS Endangered Species Act (ESA) compliance as required by a court order (including court-approved agreements), an agreement related to litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA. Financial impacts include foregone revenues, power purchase costs, direct program expenses, fish credits, Corps of Engineers and Bureau of Reclamation Operations and Maintenance, and capital repayment. Financial impacts will be calculated net of estimated 4(h)(10)(C) credits. The triggering events, such as court orders, may occur at any time during a fiscal year. The assessment of the financial impacts of any such events will take place shortly before the end of the fiscal year in which the changes take effect.

Q. Can the NFB Adjustment trigger more than once during the rate period?

A. Yes. It can trigger for each year of the rate period.

Q. How will the NFB Adjustment address changes in the BiOp that affect more than one year?

A. The NFB Adjustment analysis will be made separately for each year. If one change to the BiOp affects costs or revenues in more than one year in the rate period, the separate, annual NFB Adjustment analyses will capture the impacts for each year individually.

Section 8. Dividend Distribution Clause (DDC)

Q. Please describe the DDC.

A. This initial rate proposal includes a DDC; a temporary downward adjustment to power rates if forecasted Accumulated Modified Net Revenues (AMNR) is above the thresholds shown in Table B, Attachment 1. The adjustment will be made by a percentage decrease in LLH and HLH energy rates. In addition, the downwardly adjusted energy rates will be used in the calculation of benefits under the REP Settlement Agreements with the IOUs and any benefits paid to the region's aluminum DSIs.

1 *Q. What is the purpose of the DDC?*

2 A. The DDC is designed to prevent the accumulation of PBL reserves to unnecessarily high
3 levels; that is, levels above the amount needed for mitigating all of PBL's financial risks.
4 The DDC will return financial reserves to customers when PBL's AMNR are forecast
5 around the 3rd Quarter Review to be greater than the AMNR equivalent of $800 million
6 in PBL reserves for the end of each fiscal 2006, 2007 or 2008.

7 *Q. How does the DDC work?*

8 A. The DDC is a temporary reduction in posted power rates if forecasted AMNR is above
9 the thresholds shown in Table B, Attachment 1. The amount to be returned to customers
10 will be the difference between the forecasted ending AMNR for the current fiscal year
11 and the DDC threshold. The adjustment will be made by a percentage decrease in LLH
12 and HLH energy rates. In addition, the downwardly adjusted energy rates will be used in
13 the calculation of benefits under the REP Settlement Agreements with the IOUs and any
14 benefits paid to the region's aluminum DSIs.

15 *Q. Is there an annual cap on the amount of the DDC?*

16 A. There is not a cap on the maximum dollar amount to be returned under the DDC, but the
17 DDC cannot be so large that the rate for LLH energy is reduced to less than $1 per MWh.

18 *Q. Why is the trigger based on accumulated modified net revenues rather than reserves?*

19 A. The DDC triggers on the basis of AMNR for the same reasons that the CRAC triggers in
20 this manner. *See,* Section 6, Page 8 for additional information about AMNR.

21 *Q. Please explain the timing of the DDC.*

22 A. Before the end of FY 2006, 2007, and 2008, BPA will determine if the forecast of
23 AMNR at the end of the year is above the applicable DDC threshold for the next fiscal
24 year. If AMNR is above the threshold, BPA will adjust energy rates for the next fiscal
25 year. The adjustment will be a percentage decrease to the applicable posted rates. This
26 initial proposal does not call for a forecast of AMNR to be made in FY 2009, since the

next year, FY 2010, is outside the rate period.

Q. How does the DDC interact with the CRAC?

A. They are both triggered by a comparison of forecasted AMNR against their thresholds. The threshold for the FY 2007 DDC is $330 million higher than for the FY 2007 CRAC, and the thresholds for the FY 2008 and FY 2009 DDC are $300 million higher than for the corresponding CRACs, so they cannot both trigger for the same year. It is possible for neither to trigger.

Q. How will the DDC percentage be applied to customer bills?

A. The DDC adjustment will be applied as a mills/kWh rate to the customer's HLH and LLH energy charges. The DDC adjustment will be shown as separate line items on the customer's bill. The DDC applies only to energy charges for the same reason the CRAC applies only to energy charges.

Section 9. Modified Net Revenue

Q. Have changes been made to the manner in which BPA calculates Modified Net Revenue (MNR)?

A. No. The calculation of MNR that is described in the GRSPs is the same as the calculation used during the FY 2002-2006 rate period. The calculation of MNR starts with actual net revenues. It excludes actual EN debt service for the year and the effect of adopting Financial Accounting Standard (FAS) 133, Accounting for Derivative Instruments and Hedging Activities. It includes the rate case forecast of EN debt service as identified in the rate proceeding. The calculation is shown below.

Net Revenue
- FAS 133
+ Actual EN Debt Service
- Rate Case EN Debt Service
= Modified Net Revenue

BPA is considering a variation of this calculation that may more closely reflect changes in PBL's financial reserves. This variation is offered for discussion in this proceeding and for possible use in the final proposal.

Q. Please describe the alternative method for calculating MNR.

A. As with the current method, this calculation starts with actual net revenue and excludes the effect of adopting FAS 133. Instead of removing total EN debt service for a given year, the revised calculation would remove only a portion, known as EN Debt Retirement or EN retired debt. EN Debt Retirement is associated with Debt Service Reassignment, and is related to the portion of the PBL's EN debt service obligation that has been extinguished. *See,* Homenick, *et al.*, WP-07-E-BPA-10 for a description of Debt Service Reassignment. The annual calculation will include the par value of EN bonds that are forecasted to be extended under the Debt Optimization (DO) program for that year. The amount of DO bonds in FY 2006, 2007, and 2008 will be identified in the Final Proposal Revenue Requirement Study Documentation. The alternative calculation is shown below.

Net Revenue
- FAS 133
+ EN Debt Retirement
- DO Bonds
= Modified Net Revenue

The inclusion of DO bonds would be conditioned on DO actions actually occurring during the year. If DO actions are not taken, the amount of DO bonds would not be included in the MNR calculation. An example illustrating the alternative method for calculating MNR is shown in Table 1.

Table 1:
MNR Calculation for FY 200x
For Illustration Purposes Only
($ in thousands)

	Current Calculation	Alternative Calculation	
Net Revenue	200,000	200,000	Net Revenue
- FAS 133	(50,000)	(50,000)	- FAS 133
+ Actual EN DS	477,000	225,000	+ EN Retired Debt
- Rate Case EN DS	(550,000)	(300,000)	- DO Bonds
MNR	77,000	75,000	MNR

Notes
(1) This example is highly simplified. It includes only one variation from the "rate case" forecast. Actual results in this illustration include $2 million in additional expense due to changes in interest rates on variable rate debt.
(2) This illustration assumes that $300 million of the EN debt service can be refinanced through Debt Optimization and that 75% ($225 million) would be reassigned to TBL through Debt Service Reassignment.

Q. Why is BPA considering a change to the MNR calculation?

A. By using a rate case forecast of total EN debt service, the FY 2002-2006 calculation excludes the effect of changing interest rates on variable rate debt, basis risk on the current two swaps associated with variable rate debt, the effect of financing transactions completed during the rate period that were not forecast in the rate case, and the effects of unanticipated cash receipts or payments for various reasons. The revised calculation would capture these and other potential results that vary from the rate case forecast. The actual impact on the MNR calculation is entirely dependent on actual results absent the debt optimization bonds.

Q. Why is it not used in the Initial Proposal?

A. The alternative calculation was proposed late in the process for developing the initial proposal. While the concept is fairly simple, implementation may be complex. MNR is used in contexts outside of rate-making. MNR is applied to agency and FCRPS finances as a whole. It appears in BPA's regular financial reports and in the FCRPS annual report.

BPA did not have sufficient time to fully consider the implications of changing the method for calculating MNR while still meeting the schedule for this proceeding. Nevertheless, this alternative shows some promise so it is offered for consideration during this rate proceeding.

Q. Why does the ANR calculation start with FY 1999 rather than a more recent year?

A. Since the proposed methodology is the same as in the FY 2002-2006 rate period, the starting point was left the same. BPA could change the starting point to a more recent FY, such as FY 2005. The choice of the starting point will not affect the methodology or the likelihood of triggering the CRAC.

Section 10. Additional Risk Mitigation Tools and Efforts

Q. What other risk mitigation efforts are currently underway but are not included in this analysis?

A. BPA is currently pursuing a number of liquidity tools that could reduce the need for higher financial reserves required to achieve the 92.6 percent TPP. These tools remain under development and are not included in the Initial Proposal. *See* Leathley, *et al*., WP-07-E-BPA-08.

Q. Why are these items not included in the Risk Mitigation Package for the WP-07 Initial Proposal?

A. At this time, BPA does not have a sufficient level of confidence to include the liquidity tools under development in the risk mitigation package for the Initial Proposal. Should one or more of these tools become available between the Initial and Final Proposal, then the tool may be included in the risk mitigation analysis performed for the Final Proposal.

Q. What would be the effect on the Risk Mitigation Package if a liquidity tool was available for the Final Proposal?

A. It depends on what type of liquidity tool is available and what the limitations (if any)

would be on accessing that tool. Generally speaking, a liquidity tool should make the cost of risk mitigation lower.

Q. What other tools has BPA considered in developing the proposed risk mitigation package?

A. BPA staff and customers have worked on a number of different alternatives over the past year. A number of alternatives are discussed in the Risk Analysis Study, WP-07-E-BPA-04. Other alternatives, in particular a mid-year or an end-of-year hydro surcharge mechanism has been discussed but not yet fully modeled. *Id.*

Q. Why was the proposed package chosen over the other modeled alternatives?

A. Each alternative when compared to the other produces different possible outcomes for PBL reserves, posted and effective rates, and TPP. Some packages produce relatively low posted rates but tend to have greater rate volatility. Other packages have relatively high posted rates but produce a lower effective rate. BPA ultimately chose a package for the Initial Proposal that balanced rate levels (posted and effective), with some PNRR and a DDC that returned excess reserves after good financial outcomes. Any number of different alternatives could generally reach the same objectives outlined in the policy testimony (Leathley, *et al.,* WP-07-E-BPA-08) but with different TPP, rate and reserve outcomes. *See* the Risk Analysis Study, WP-07-E-BPA-04 for additional information on the risk mitigation packages.

Q. Does this conclude your testimony?

A. Yes.

Attachment 1

Table A: CRAC Annual Thresholds and Caps

[Dollars in Millions]

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold	Approx. Threshold as Measured in PBL Reserves	Maximum CRAC Recovery Amount (Cap)*
2006	2007	-$193	$470	$300
2007	2008	-$36	$500	$300
2008	2009	-$45	$500	$300

* The Maximum CRAC Recovery Amount (Cap) may be modified to account for adjustments made to the Cap by the NFB Adjustment (if triggered) calculated at the end of FYs 2006, 2007, and 2008.

Table B: DDC Thresholds

[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold	Approx. Threshold as Measured in PBL Reserves
2006	2007	$137	$800
2007	2008	$264	$800
2008	2009	$255	$800

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INDEX

TESTIMONY OF

WILLIAM J. DOUBLEDAY, BYRON G KEEP, PAUL A. BRODIE,
AND RONALD HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: COST OF SERVICE ANALYSIS AND RATE DESIGN CHANGES AND ADJUSTMENTS

		Page
Section 1.	Introduction and Purpose of Testimony	1
Section 2.	Cost of Service Analysis (COSA)	2
	a. Program Case and 7(b)(2) Case	2
	b. Changes to RAM2007 COSA Logic	5
Section 3:	Rate Design Changes and Adjustments	5
	a. Modeling the Low Density Discount (LDD)	5
	b. Modeling the Conservation and Renewables Discount	6
	c. Modeling Rate Mitigation for Customers with Seasonal Loads	6
Section 4:	Rate Development Modeling	7
	a. Rate Design Step	8
	b. Subscription Step	8
	c. Slice Separation Step	8
	d. Modeling the Slice Product	9

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TESTIMONY OF

WILLIAM J DOUBLEDAY, BYRON G KEEP, PAUL A BRODIE,

AND RONALD HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: COST OF SERVICE ANALYSIS AND RATE DESIGN CHANGES AND ADJUSTMENTS

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Byron G. Keep and my qualifications are contained in WP-07-Q-BPA-22.

A. My name is Paul A. Brodie and my qualifications are contained in WP-07-Q-BPA-07.

A. My name is Ron Homenick and my qualifications are contained in WP-07-Q-BPA-17.

Q. Please describe the purpose of your testimony.

A. The purpose of our testimony is to sponsor a portion of BPA's Wholesale Power Rate Development Study (WPRDS), WP-07-E-BPA-05, Chapter 3. This testimony addresses BPA's Cost of Service Analysis (COSA), rate design adjustments, and the modeling of BPA's rate development.

Q. How is your testimony organized?

A. Our testimony is organized in four sections. Section 1 outlines the purpose of our testimony. Section 2 describes BPA's COSA, including subsections on the Program Case and the 7(b)(2) Case, and changes to BPA's Rate Analysis Model (RAM) COSA logic. Section 3 describes changes to BPA's rate design and ratemaking adjustments, with subsections on: (a) modeling the Low Density Discount (LDD); (b) modeling the Conservation Rate Credit (CRC); and (c) modeling rate mitigation for customers with

seasonal loads. Section 4 describes the modeling of BPA's rate development, with subsections on: (a) modeling the Rate Design Step; (b) modeling the Subscription Step; (c) modeling the Slice Separation Step; and (d) modeling the Slice product cost.

Section 2: Cost of Service Analysis (COSA)

a. Program Case and 7(b)(2) Case

Q. What are the Program Case and the 7(b)(2) Case?

A. The section 7(b)(2) rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers. *See* Section 7(b)(2) Rate Test Study, WP-07-E-BPA-06 and testimony of Keep, *et al.*, WP-07-E-BPA-27. The two sets of rates are: (1) a set for the rate test period (FY 2007-2009) and the ensuing four years (FY 2010-2013) assuming that section 7(b)(2) of the Northwest Power Act is not in effect (this set is known as the Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (this set is known as the 7(b)(2) Case rates). The 7(b)(2) Case rates are modeled the same as the Program Case rates except for the five assumptions listed in section 7(b)(2).

Q. What is the purpose of the COSA section in the RAM?

A. The COSA allocates the test period generation revenue requirements that are determined in the Revenue Requirement Study, WP-07-E-BPA-02, to BPA's customer classes. The COSA apportions or "allocates" the test period generation revenue requirements among classes of service based on the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Q. How were generation revenue requirements assigned to the resource pools in the Cost of Service Analysis (COSA)?

A. Consistent with past practice, costs were assigned to the resource pools primarily by direct identification and consistent with the rate development requirements of the Northwest Power Act. Exceptions are net interest expenses and planned net revenues, which were first split between conservation and the remainder of generation by the use of equivalent annual costs (annual mortgage-type payments). The generation portions were then divided among Federal Base System (FBS) Hydro, Fish and Wildlife, and BPA generation programs based on average net investment.

Q. Is the assignment of generation revenue requirements to the resource pools reflected in the Program Case and 7(b)(2) Case?

A. Yes. The assignment of generation revenue requirements to the resource pools is reflected in the Program Case revenue requirements for all years of the 7(b)(2) rate test (FY 2007–2013) and in the 7(b)(2) Case revenue requirements for all years of the 7(b)(2) rate test (FY 2007–2013).

Q. Were the 7(b)(2) Case revenue requirements developed on the same basis as in previous rate cases?

A. Yes. The 7(b)(2) Case revenue requirements reflect the Program Case revenue requirements with the required exclusions of costs associated with the Residential Exchange Program (or any related settlements thereof), energy conservation, and the resources acquired under the authority of the Northwest Power Act. Repayment studies for the 7(b)(2) Case revenue requirements also exclude those costs.

Q. How was risk mitigation addressed in Program Case revenue requirements?

A. During the FY 2007-2009 rate period, Program Case revenue requirements include $96 million per year of Planned Net Revenues for Risk (PNRR) in addition to the funds provided by the difference between noncash expenses included in revenue requirements

and the cash requirements for amortization of bonds and appropriations and irrigation assistance. In the Program Case generation revenue requirements, there are years in which net revenues are necessary in addition to risk mitigation to satisfy cash requirements for planned amortization and irrigation assistance payments. *See* WPRDS Documentation, WP-07-E-BPA-05A, Section 2.2, Table COSA06.

Q. *How did BPA determine PNRR in the COSA tables of the Rate Analysis Model (RAM2007)?*

A. The PNRR value found in the COSA06 tables is the result of an iterative process between the RAM2007, the RiskMod model, and the ToolKit model (including the NORM model results). The iteration is initiated with a seed value for PNRR in COSA06 of the RAM2007. The resultant rates and revenue requirement data are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value and annual ending cash reserve amounts for new COSA06 tables. The iterations are complete when the difference between the new PNRR value and the previously calculated value is less than $1 million per year.

Q. *During the iteration process mentioned above, which rates from RAM2007 are used in the RiskMod?*

A. RAM2007 produces rates in its Rate Design Step, its Subscription Step, and its Slice Product Separation Step, all of which are, in turn, used in the RiskMod. [[[is it accurate to add this?...I just thought the answer ought to directly reference RiskMod]]] These three major rate calculation steps are more fully discussed in section 4 of this testimony. A PNRR iterative process is done using the final non-Slice Product rates produced by the last of the major ratemaking steps, the Slice Product Separation Step.

Q. *Why is it appropriate to use the Slice Product Separation Step rates as the basis for determining the PNRR level?*

A. In the Rate Design and Subscription Steps, the PF Preference rate pool includes the loads

of all PF Preference products. The Slice Product Separation Step separates the Slice product firm loads and allocated costs from the non-Slice product PF preference loads and costs. Purchasers of the PF Slice product assume the risks mitigated by PNRR. The PNRR that BPA adds to its revenue requirement is recovered by BPA's non-Slice product rates. Therefore, the non-Slice product PF Preference rate calculated in the Slice Product Separation Step is the appropriate PF rate to use in the risk iteration process that will determine the level of PNRR. For additional RiskMod, NORM, and ToolKit information, *See* Normandeau, *et al.,* WP-07-E-BPA-14, and Wagner, *et al.,* WP-02-E-BPA-12.

Q. *How was risk mitigation addressed in the 7(b)(2) Case revenue requirements?*

A. As in previous rate cases, the 7(b)(2) Case revenue requirements reflect the same treatment of risk mitigation as in the Program Case. During the FY 2007–2009 rate period, the 7(b)(2) Case revenue requirements produce annual cash flows that are identical to those of the Program Case revenue requirements. In the outyears, the 7(b)(2) Case revenue requirements are based on total expenses and any net revenues needed to satisfy cash requirements for amortization and irrigation assistance payments, as was done in the Program Case revenue requirements.

b. Changes to RAM2007 COSA Logic

Q. *Have changes been made to the Cost of Service Analysis (COSA) section of RAM2007 for this rate case?*

A. Yes. In the current rate case, seven years of cost information are included in the COSA tables.

Q. *Why are seven years of cost data included in the current COSA?*

A. The Rate Design Step within RAM2007 used to model the three-year rate period and calculate the posted three-year average rates is also used to calculate Program Case rates in the 7(b)(2) rate test. The 7(b)(2) rate test period is the three-year rate period plus the

ensuing four years. RAM2007 can calculate rates for each individual year for the 7(b)(2) rate test and can also calculate average rates for the three-year rate period.

Section 3: Rate Design Changes and Adjustments

a. Modeling the Low Density Discount (LDD)

Q. Is the LDD modeled differently in RAM2007 than it was modeled in RAM2002?

A. Yes. In order to avoid adverse impacts on retail rates of BPA's purchasers with low system densities, BPA applies the LDD, to the extent appropriate, to BPA's rates for such purchasers. BPA expects that the costs and the benefits associated with the LDD are limited to the PF Preference rate class. In RAM2002, the costs associated with the LDD were added to the revenues to be collected by energy in the Rate Schedule Charge Calculation Table for the PF Preference rate at the very end of the ratemaking process. In the RAM2007, the costs associated with the LDD were allocated to the PF rate pool in the initial cost allocation step at the beginning of the ratemaking process. In this way, the costs associated with the LDD are now allocated at the same time in the modeling as all other costs and the final rate calculation is simplified.

b. Modeling the Conservation Rate Credit Costs

Q. Are the Conservation Rate Credit (CRC) costs modeled in RAM2007 differently than the Conservation and Renewables Discount (C&R Discount) costs were modeled in RAM2002?

A. Yes. In RAM2002, the costs associated with the C&R Discount were added to the revenues to be collected by energy for the applicable rates in the individual Rate Schedule Charge Calculation Tables at the very end of the ratemaking process. In RAM2007, the costs associated with the CRC are included in BPA's revenue requirement and enter the ratemaking process at the very beginning by including the CRC costs within the conservation line of each year's COSA Table. *See* COSA 06 tables, WPRDS, WP-07-EBPA-05A. In this way, the costs associated with the CRC are now allocated at the

same time in the modeling as all other costs and the final rate calculation is simplified.

c. Modeling Rate Mitigation for Customers with Seasonal Loads

Q. Is seasonal and irrigation rate mitigation modeled differently in RAM2007 than it was modeled in RAM2002?

A. Yes. Rate mitigation is targeted to PF Preference rate class customers with heavy summer seasonal loads that faced adverse rate impacts from BPA's rate design. The costs and the benefits associated with this rate mitigation are limited to the PF Preference class. In RAM2002, the costs associated with the rate mitigation were added to the revenues to be collected by energy rates in the Rate Schedule Charge Calculation Table for the PF Preference rate at the end of the ratemaking process. In RAM2007, the costs associated with the rate mitigation were allocated to the PF rate pool in the initial cost allocation step at the beginning of the ratemaking process. In this way, the costs associated with the rate mitigation are now allocated at the same time in the modeling as all other costs and the final rate calculation is simplified.

Section 4: Rate Development Modeling

Q. Have changes been made to BPA's rate development modeling for this rate case?

A. Yes. In BPA's 2002 Rate Case, BPA used the 2002 Rate Analysis Model (RAM2002) that consists of 5 large Excel spreadsheets that work together by the use of Visual Basic macros. BPA now proposes to use the 2007 Rate Analysis Model (RAM2007), a single automated Excel spreadsheet.

Q. Why did BPA develop RAM2007?

A. The need for greater efficiency and flexibility in rate analysis prompted BPA rate staff to develop RAM2007. While the RAM2002 model was developed specifically for the 5-year FY 2002-2006 rate period and the associated 9-year 7(b)(2) test period, RAM2007 was originally developed as a long-term rate forecast model with the ability to forecast rates over a 10-year period. In addition, whereas RAM2002 was designed to accurately

model the 2002 Rate Case assumptions, RAM2007 will accommodate different scenarios and will forecast 7(b)(2) Rate Test triggers and rates for the FY 2007-09, FY 2010-11, and FY 2012-13 rate periods (assuming BPA goes to two-year rate periods).

Q. How is RAM2007 organized?

A. RAM2007 has three main steps: a Rate Design Step, a Subscription Step, and a Slice Separation Step.

Q. Is this step-wise rate making similar to that used in RAM2002?

A. Yes. RAM2002 developed rates in a two step process. In 2002, Program Case rates for the 7(b)(2) Rate Test were calculated in the Rate Design Step using all costs including a forecast of gross exchange costs for the IOUs. BPA then conducted a Subscription Step to calculate rates assuming the IOUs had signed their Subscription contracts.

a. Rate Design Step

Q. Please briefly describe the Rate Design Step in RAM2007.

A. The RAM2007 Rate Design Step follows BPA's rate directives by determining the costs associated with the three resource pools (FBS resources, Residential Exchange resources, and new resources) used to serve load and then allocating those costs to the rate pools (PF, IP, and NR). After the initial allocation of costs, the Northwest Power Act requires that some rate adjustments be made, such as those described in section 7(b) and section 7(c) of the Act. RAM2007 performs these rate adjustments including the 7(b)(2) rate test in its Rate Design Step. The Rate Design Step within RAM2007 concludes with the calculation of the "Rate Design Step" rates. At this point in the modeling, all posted rates are still preliminary except for the PF exchange rate which is set and is then used to calculate the net cost of any public utility exchange.

b. Subscription Step

Q. Please briefly describe the Subscription Step in RAM2007.

A. RAM2007 includes a Subscription Step to calculate rates that will include the costs of the

investor-owned utility (IOU) Residential Exchange Program (REP) settlement. The Subscription Step takes the results of the Rate Design Step and adjusts them by first subtracting any net cost of the traditional REP for the IOUs that have been included in the Rate Design Step rates, and then adding the costs of the IOU REP settlement.

c. Slice Separation Step

Q. Please proved a brief description of the Slice Separation Step.

A. In the Rate Design and Subscription steps, costs were allocated to the various rate pools, including the PF preference rate pool that contained all firm PF preference load. The Slice Separation Step separates out the PF Slice product revenues and firm loads from the overall PF preference rate pool, leaving the costs that must be covered by the remaining non-Slice product PF preference load through posted PF preference energy, demand, and load variance charges.

d. Modeling the Slice Product

Q. How is the Slice product modeled in RAM2007?

A. RAM2007 includes a Slice Costing worksheet that estimates the cost per month of a 1-percent Slice of the BPA system. This worksheet lists the components of the Slice revenue requirement, including the net cost of system augmentation, and excluding the cost of balancing power purchases and PNRR. The cost per month of the Slice product is an estimate and will be trued up to actuals in real time. *See* Lee, *et al.,* WP-07-E-BPA-23.

Q. Does this conclude your testimony?

A. Yes.

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INDEX

TESTIMONY OF

RODNEY E. BOLING, WILLIAM J. DOUBLEDAY AND PAUL W.T. MCCLAIN

Witnesses for Bonneville Power Administration

SUBJECT: RESIDENTIAL EXCHANGE AVERAGE SYSTEM COST AND LOAD FORECASTS

Page

Section 1. Introduction and Purpose of Testimony.....1

Section 2. Description of the Residential Exchange Program (REP).....2

Section 3. Forecast of Average System Costs for Potential Exchanging Utilities.....4
Preliminary ASC Evaluations.....4
Computer Models.....7
ASC Data Issues.....9
Base ASC Results.....14
ASC Forecasts.....14

Section 4. Forecast of Exchanging Utility Loads.....17

Section 5. "In Lieu" Power Purchases and Sales.....18

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TESTIMONY OF

RODNEY E. BOLING, WILLIAM J. DOUBLEDAY, AND PAUL W.T. MCCLAIN

Witnesses for Bonneville Power Administration

SUBJECT: RESIDENTIAL EXCHANGE PROGRAM AVERAGE SYSTEM COST AND LOAD FORECASTS

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rodney E. Boling and my qualifications are contained in WP-07-Q-BPA-06.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Paul W.T. McClain and my qualifications are contained in WP-07-Q-BPA-37.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the data sources and assumptions BPA used to develop its forecasts of Average System Costs (ASC) and residential loads for utilities that may participate in the Residential Exchange Program (REP). In addition, we sponsor the ASC section of the Wholesale Power Rate Development Study (WPRDS). *See,* WPRDS, WP-07-E-BPA-05, Section 2.19. Another purpose is to describe Bonneville Power Administration's (BPA) assumptions regarding the use of "in lieu" transactions in implementing the REP.

Q. How is your testimony organized?

A. Our testimony is organized in five sections. Section 1 outlines the purpose of our testimony. Section 2 describes the REP. Section 3 describes the assumptions and procedures supporting BPA's forecasts of ASCs. Section 4 addresses BPA's forecasts

of potential exchanging utilities' residential loads. Section 5 discusses BPA's "in lieu" resource assumptions and the effect of such assumptions on the net cost of the REP.

Section 2. Description of the Residential Exchange Program (REP)

Q. What is the Residential Exchange Program?

A. The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) created the REP to provide residential and small farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the Northwest Power Act, BPA's Administrator "purchases" power from each participating utility at that utility's ASC. The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's Priority Firm Exchange (PF Exchange) rate. The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities.

Q. Does the REP involve a conventional purchase and sale of power?

A. No. Under normal implementation of the REP, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction where BPA provides the participating utility cash payments that represent the difference between power "purchased" by BPA and the less expensive power "sold" to a participating utility. As discussed in Section 5 below, however, actual power sales may occur under "in lieu" transactions where BPA purchases power from a source other than the utility and sells actual power to the utility.

Q. How does BPA determine exchanging utilities' ASCs?

A. Each exchanging utility's ASC is determined by the Administrator in accordance with the 1984 ASC Methodology (ASCM). The 1984 ASCM is an administrative rule developed by BPA in consultation with its customers. Essentially, a utility's ASC is the

sum of a utility's production and transmission-related costs (Contract System Costs) divided by the utility's system load (Contract System Load). For purposes of establishing its ASC, a utility's system costs and system loads are those costs and loads used by the utility to establish its retail rates. The ASC filing from a utility is detailed in an "Appendix 1," which is the required format under the ASCM.

Q. *How does BPA determine production and transmission-related costs?*

A. Because only production and transmission costs are considered exchange costs, all costs must be functionalized to determine if they are production or transmission-related costs, or not. Functionalization is a process that allocates costs to production, transmission, or distribution. For the majority of the costs, the allocation is clear. In other cases, the ASCM directs BPA to functionalize costs based on certain ratios, e.g., based on pro-rata labor costs assigned to the three functions. The process of functionalization, and our application with respect to various costs, is discussed in Sections 3.3 and 3.5.

Q. *What is the source of the cost data BPA uses to determine a utility's ASC?*

A. The 1984 ASCM directs BPA to use a "jurisdictional approach," which relies upon cost data approved by state public utility commissions in the case of investor-owned utilities and utility governing bodies in the case of public utilities for retail rate-making. Such data provide the starting point for BPA's determination of the ASC for each utility participating in the REP. Costs, assets, liabilities, and revenues that public utility commissions or utility governing bodies have not approved for retail rate-making are excluded from Contract System Costs.

Q. *Please explain the terms "gross cost," "gross revenue," and "net cost" as they are applied to the REP.*

A. The gross cost of the REP is the total dollar amount that BPA pays for the power it "purchases" from participating utilities. In the case of an in-lieu transaction as discussed in Section 5, the gross cost of the REP includes the cost of an in-lieu resource. The

gross revenue is the total dollar amount that BPA receives from participating utilities for its subsequent "sale" of power to them at the PF Exchange rate. The net cost of the REP is the difference between gross cost and gross revenue, plus costs to administer the REP.

Q. What is the current status of the REP?

A. As part of BPA's Subscription process, BPA entered into REP Settlement Agreements with BPA's investor-owned utility customers (IOUs) in 2000. These agreements replaced implementation of the traditional REP. Based on contracts and contract amendments signed in May 2004, the IOUs will continue to receive benefits under the REP Settlement Agreements for FY 2007-2011.

Some public utilities signed REP Termination Agreements that are effective through FY 2011 and therefore will not participate in the REP during FY 2007-2011. All other previously exchanging public utilities signed REP Termination Agreements through FY 2001 and, with one exception, have not executed new Residential Purchase and Sale Agreements (RPSAs) since that time. Clark Public Utilities (Clark) is currently seeking REP benefits. Clark and BPA recently executed an RPSA, and Clark filed a revised Appendix 1 on October 7, 2005, in accordance with the 1984 ASCM.

Q. If the IOUs will not receive benefits under the traditional REP during the FY 2007-2011 period, why has BPA forecasted IOU ASCs and REP loads in the current Wholesale Power Rate Development Study (WPRDS)?

A. BPA forecasted ASCs and REP loads for IOUs and some public utilities because BPA uses such information to develop the PF Preference, NR, IP, and PF Exchange rates. This is explained in the testimony of Keep, *et al*., WP-07-E-BPA-27, and in the WPRDS, WP-07-E-BPA-05, Section 2.19.

Section 3. Forecast of Average System Costs for Potential Exchanging Utilities

Preliminary ASC Evaluations

Q. How has BPA previously forecasted a utility's ASC?

A. An exchanging utility's ASC forecast was typically based on the costs included in its last approved ASC report signed by the Administrator. Such costs were then adjusted to account for inflation, power purchases, and resource additions, and were then applied to forecasted loads for future periods to calculate the forecasted ASC.

Q. Is this the method employed for the WP-07 rate proceeding?

A. No. Because of the IOU REP Settlement Agreements and public utility REP Termination Agreements already noted, BPA no longer receives cost and load data from those utilities through ASC filings. BPA therefore used a variety of data sources and approaches to determine ASCs for these utilities.

Q. What were the sources of data used to determine base ASCs for the utilities?

A For the IOUs, BPA used 2004 FERC Form 1s. Because public utilities are not required to file a FERC Form 1, BPA used the latest published annual report as the source for relevant public utilities. When BPA calculated ASCs, the most recent available annual reports were for 2003 or 2004, or both.

Q. What initial approach was used to identify those utilities that might have ASCs high enough to receive REP benefits?

A. BPA first limited the scope of its research by assuming utility ASCs would need to exceed the current Cost Recovery Adjustment Clause (CRAC) adjusted PF Exchange rate to be eligible to receive REP benefits. The current CRAC-adjusted PF Exchange rate is 46.65 mills/kWh and, for this WP-07 initial proposal, serves as a reasonable proxy for the FY 2007-2009 PF Exchange rate.

Q. What CRAC adjustments are included in the FY 2006 PF Exchange rate?

A. The PF Exchange rate, without the transmission component, was adjusted by the sum of three CRAC percentages: (1) the Load-Based CRAC at 24.40 percent for October 2005 through March 2006, and 28.51 percent for April 2006 through September 2006; (2) the

Financial-Based CRAC at 4.41 percent for FY 2006; and (3) the Safety Net CRAC at 1.75 percent for FY 2006.

Q. Did BPA evaluate the ASCs of public utilities with existing REP Termination Agreements?

A. Yes. Nine public utilities affiliated with the Pacific Northwest Generating Cooperative (PNGC) previously executed REP Termination Agreements that extend through 2011. After evaluation, however, the PNGC utilities' ASCs did not appear to be sufficiently high to calculate.

Q. Why were the PNGC utilities' ASCs not calculated?

A First, PNGC utilities will not receive REP benefits through 2011. Second, the PNGC utilities have a long-term power sales contract under which they sell power to Turlock Irrigation District. This sale is tied to the output of PNGC's share of the Boardman Coal Plant, operated by Portland General Electric Company (PGE). In past ASC filings, the cost of Boardman was the primary cause of the PNGC utilities' high ASCs. Absent specific information regarding the Turlock contract, BPA assumed that revenue from the power sale to Turlock would equal the cost of the PNGC utilities' annual share of the Boardman power plant. PNGC utilities currently purchase requirements power from BPA to meet their total retail loads, which should keep their ASCs below the PF Exchange rate.

Q. Did BPA evaluate the IOUs in detail?

A. Yes, BPA evaluated all six regional IOUs in detail. BPA evaluated IOU costs and loads, and developed individual ASCs, because such information is used to develop the PF Preference and PF Exchange rates. *See*, Keep, et al., WP-07-E-BPA-27, and WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. Were any public utilities evaluated in detail?

A. Yes. Six public utilities were evaluated in detail. For purposes of this proceeding, they will be referred to as utilities No. 1 through No. 5 in order to safeguard these utilities' confidential load forecasting information. The sixth utility is Clark, which signed an RPSA agreement and submitted an ASC Filing with BPA, thereby making public any potentially confidential information it may have had. All six are considered candidates to have relatively high ASCs because they own thermal resources or are exposed to market volatility, or both.

Computer Models

Q. What computer model was used to forecast ASCs in BPA's WP-02 proceeding?

A. We used a Microsoft Excel-based model that adjusts costs to account for price changes and inflation, replaces and depreciates production plant based on historical activity, and accounts for power purchases and sales. This model does not calculate gross cost, gross revenue, and net cost as they are applied to the REP. This function is calculated by an REP cost model linked to the Rate Analysis Model (RAM), which simplifies the iterative process required to achieve stable PF rates and REP costs.

Q. Is BPA using the same computer model in the WP-07 proceeding?

A. No. BPA is using two models to forecast ASCs in the current proceeding, a "Cookbook Model." *See,* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.12.1, *and* "ASC Forecast Model," Table 4.12.2. The ASC Forecast Model is similar to the model used in the WP-02 proceeding. Both models use base ASC values and both escalate costs using inflation escalators.

Q. Why were the computer models changed from the WP-02 proceeding?

A. The WP-02 proceeding's forecasted ASCs were based on approved ASCs or recent data at that time, i.e., from the late-1990s. BPA compared its current base ASC calculations with the WP-02 ASC forecasts and noted a significant increase in ASCs. A simple

escalation of the WP-02 ASCs would not capture changes in market conditions that are evident in the current electric utility environment.

Q. What process was employed in this proceeding to forecast utilities' ASCs?

A. We used a two-step process. First, we established base ASCs, that is, estimates of utilities' ASCs today. BPA developed base ASCs for each utility using the most recent published historical cost and load data (2003 or 2004), and populated the data in the Cookbook Model. Such data were analyzed and functionalized in accordance with the 1984 ASCM as would have been done in a formal ASC review proceeding. BPA then forecasted ASCs from the base ASCs for the remainder of the rate period, and for four subsequent years for purposes of the 7(b)(2) rate test. Prospective ASCs were forecasted using the ASC Forecast Model.

Q. What is the Cookbook Model?

A. The Cookbook Model is an Excel model that was used by BPA and the exchanging utilities when there was an active REP. *See*, WPRDS Documentation, WP-07-E-BPA-05B, Section 4.12. The Cookbook Model follows the FERC System of Accounts and allows for detailed review of costs, assets, and liabilities. This analysis was important in the review of separate and discrete transactions accounted for in deferred assets, deferred liabilities, and taxes.

Q. What is the ASC Forecast Model?

A. The ASC Forecast Model is also an Excel model. It was developed to calculate forecasts of ASCs after BPA had established base ASCs. The ASC Forecast Model is discussed in detail in Section 3.4. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19. The ASC Forecast Model is similar to the model used in BPA's WP-02 proceeding to calculate forecasted ASCs.

ASC Data Issues

Q. What data sources were used to develop each utility's base ASC?

A. The primary source of data for the IOUs was the utilities' 2004 FERC Form 1s. The FERC Form 1 is an annual required submittal by IOUs to FERC of financial, operating, and load information for the previous calendar year. The information is the final audited value recorded in the utility's accounting system. Public utilities' base ASCs were developed using the latest published annual report available for each utility. Both the FERC Form 1s and the annual reports include actual load information by customer class.

Q. Why did BPA use these data sources to develop base ASCs?

A. When implementing the REP, BPA determines ASCs from an Appendix 1 filing based on costs and loads approved in either a regulatory proceeding or by a governing body for retail rate-making. Except for Clark, there are no utilities currently participating in the REP; consequently, no Appendix 1s have been submitted recently to BPA. BPA therefore used the best available and current data sources noted above to develop the base ASCs.

Q. Is the FERC Form 1 a sufficient substitute for a utility's Appendix 1 filing for forecasting base ASCs?

A. As noted above, the information provided by the FERC Form 1 is the best available substitute for a filed Appendix 1.

Q. Were any adjustments made to the data of any utility?

A. Yes. BPA adjusted PacifiCorp's data to account for its Pacific Northwest (PNW) loads and resources.

Q. Please explain why the adjustments were made.

A. Adjustments were made because PacifiCorp operates in multiple states, and the state utility commissions have jointly developed a system of cost allocation between the states known as the Inter-Jurisdictional Cost Allocation System. This system allocates

PacifiCorp's total electric operations proportionately to each of the states in which it has load and regulated prices. This allocation system is necessary to ensure that PacifiCorp will have cost recovery mechanisms in all of its jurisdictions that are assumed to be equitable among the jurisdictions.

Q. What did BPA use to make the appropriate allocations to PacifiCorp's PNW jurisdictions?

A BPA used PacifiCorp's "Oregon Jurisdiction, Results of Operations, March 2002" filing (Results of Operations filing) before the Oregon Public Utility Commission (OPUC). The Results of Operations filing compares allowed rate of return to the actual rate of return using actual results of operation for the utility with approved rates. This filing includes all of PacifiCorp's costs and the allocation of such costs to each state, based upon the Inter-Jurisdictional Cost Allocation System.

Q. Is this the current version of the Jurisdictional Allocation System?

A At the time of this analysis, the 2002 PacifiCorp filing with the OPUC was BPA's most current source document for the Inter-Jurisdictional Cost Allocation System. BPA understands that PacifiCorp's state commissions are currently reviewing the Inter-Jurisdictional Cost Allocation System, and if any changes are documented before the final studies are run BPA will endeavor to incorporate the changes into its analysis.

Q. Does the Results of Operations filing contain all cost allocation factors?

A. Yes. The jurisdictional allocation factors are extensive and cover all costs, assets, liabilities, and revenues contained in the Results of Operations filing.

Q. How did BPA use the allocation factors to develop its forecast of PacifiCorp's ASC?

A. PacifiCorp's rate filings use the same FERC system of accounts as does BPA's ASCM, and as does the FERC Form 1. BPA first entered total utility cost data from the FERC Form 1 into the Cookbook Model, which included costs that would be allocated to states outside the PNW region. BPA then transferred the PNW allocation factors to the

corresponding accounts in the Cookbook Model. The total costs in each account were then multiplied by the PNW allocation factors to produce PNW state-specific costs.

Q. Did BPA use the 1984 ASCM to develop individual utility base ASCs?

A. Yes, BPA used the ASCM for its base ASC determinations.

Q. What changes in the utility industry necessitated developing new ASCs rather than escalating ASCs from the WP-02 proceeding?

A. A primary area of change has been in wholesale power markets, where increases in both purchased power costs and wholesale revenues impact the analysis. Other related areas of change are growth of regulatory assets and liabilities, and growth of derivative assets and liabilities associated with hedge transactions.

Q. Why were purchased power and wholesale revenues a concern in developing base ASCs?

A. The 1984 ASCM did not anticipate the development of energy commodity markets where utilities would have open market operations. The 1984 ASCM treats purchased power as power needed to meet a utility's loads. In addition, the ASCM is based on an assumption of limited wholesale sales. In electric utility operations today, purchase and sale of firm power is often extensive, and often largely unrelated to system needs. Further, the ASCM is based on a presumption of regulatory jurisdiction guidance regarding netting purchase costs and sales revenues. In BPA's WP-07 initial proposal ASC forecasts, there is no guidance from a utility commission on the netting of purchased power and wholesale revenues.

Q. How did BPA reflect purchased power and wholesale revenues in its base ASC determinations?

A. Absent guidance from regulatory commissions regarding how costs and revenues are allocated to a utility's rates, all purchased power was functionalized to Production and included in ASC. Wholesale market revenues were included and functionalized to Production. BPA assumed that a utility would not always receive full value for its

wholesale transactions, so BPA reduced annual wholesale market revenues by 20 percent.

Q. What are regulatory assets?

A. Regulatory assets are deferrals of costs that have been incurred by the utility but have either not been placed in rates or have not been fully amortized through rates. The costs are generally large in nature and relate to the operation of the utility. Examples of such assets include deferred power costs and pension benefits.

Q. How are regulatory assets treated under the 1984 ASC Methodology?

A. Regulatory assets are a subset of Deferred Debits (FERC Accounts 183 and 186). In the past, these accounts were relatively small and therefore either functionalized to distribution or functionalized on a preset ratio that is detailed in the 1984 ASCM. In some cases, the utility would note specific assets and assign a functionalization. In such cases, BPA would examine the functionalization and make a determination regarding the utility's proposed cost assignment.

Q. Why were regulatory assets reviewed in detail?

A. The total value of regulatory assets has grown over time. In addition, there are more transactions and accounts that have been made into regulatory assets. Accordingly, it became necessary to review regulatory assets in greater detail than what was called for by the 1984 ASC Methodology.

Q. Why were these costs booked as assets and not passed through in rates when they were incurred?

A. In a rate-setting process, forecasted costs are usually established at a level to absorb normal variations in operations. Costs incurred between rate-setting processes are considered either new or large enough to be outside the normal operations of the utility. During periods of high market prices, for example, a utility may incur very high purchased power costs. The utility generally would seek an accounting order to defer

such costs for future rate treatment.

Q. How did BPA treat regulatory assets in forecasting ASCs?

A. For each utility, all details of each sub-account were reviewed. This review included the name and brief description of the account listed, and any explanation included in the financial notes. The ASCM describes this level of review as a "direct analysis" of costs.

Q. Does the 1984 ASCM allow a direct analysis of costs?

A. Yes. The ASCM provides that a direct analysis of costs is a valid way to functionalize costs. A direct analysis reviews the nature and cause of a cost to help determine whether a utility's proposed functionalization is correct.

Q. What are derivative accounts?

A. Derivative accounts represent the present value of future financial instruments. An example is a hedge against future gas or power prices. Derivatives are also used to hedge the risk of changes in interest rates. Utilities are required to book assets and liabilities related to derivatives on their balance sheets.

Q. Why were derivative accounts reviewed in detail in this proceeding?

A. BPA's review of utility costs noted that derivative accounts were often large, and had a similarly large impact on utility rate base and ASC. Therefore, it was necessary to review them in detail.

Q. Does the 1984 ASCM address the treatment of derivatives?

A. No. The commodities market in energy, including financial hedge instruments, was not a significant part of utility operations when the 1984 ASCM was established. In BPA's development of base ASCs, derivative accounts were reviewed by direct analysis.

Q. What was the result of BPA's direct analysis of derivative accounts?

A. For a number of reasons, BPA functionalized derivative accounts to distribution which reduces a utility's ASC. The main reasons for this interpretation of the ASCM are: (1) the financial documents reviewed did not indicate the type of hedge instrument(s)

used; (2) there was no indication what type of transactions the hedge account was representing; (3) there was no indication whether an account was one or several different future transactions; (4) there was no explanation of when the hedge transaction was to be exercised, or of the duration of the transaction; and (5) there was no information regarding regulatory commission treatment of the assets.

Base ASC Results

Q. What are BPA's base ASCs for regional utilities?

A. Base ASCs for the relevant regional utilities are contained in the WPRDS, WP-07-E-BPA-05, Section 2.19.

ASC Forecasts

Q. What was the starting point for the prospective forecasts of ASCs for the relevant utilities?

A. The prospective forecasts started with the base ASCs for each utility, which were developed using the Cookbook Model described above. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. What was the basis for these ASC forecasts?

A. BPA forecasted a utility's load and resource balance (system resource requirements including losses, and resource position), sales for resale revenues, purchased power costs, non-fuel costs, and fuel costs. The ASC Forecast Model used inflation and cost escalators, gas price forecasts, and market price forecasts to escalate base ASC costs through year 2013.

Q. How was a utility's load and resource balance determined?

A. BPA first forecasted a utility's load including distribution losses. Changes in a load forecast were used to forecast purchased power and any available amounts of energy that could be sold into the market as wholesale sales. The ASC Forecast Model tests any annual change in requirements, and either adds purchases to meet new requirements or

reduces wholesale sales. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19. The model forecasted future resource costs based on each utility's 2004 resources, and any known resource additions or reductions.

Q. Were wholesale sales treated differently for the IOUs than for the public utilities?

A. Yes. BPA assumed that the IOUs would continue "for-profit" trading floor operations, and that prior-period purchased power and wholesale sales would continue in the future. The public utilities, while they may have a trading floor, were assumed not to acquire generating resources to support a "for profit" trading floor. BPA assumed the public utilities would meet load growth through use of current surplus resources, or would purchase power in the market at forecasted market prices. Any public utility resource surplus after meeting load growth was assumed to generate revenues from wholesale sales.

Q. How were a utility's wholesale sales amounts and purchased power amounts determined in the forecast period?

A. BPA assumed that a utility's wholesale sales potential and purchased power amounts are a function of the utility's surplus or deficit as determined by its load and resource balance.

Q. How were a utility's wholesale sales revenues and purchased power costs determined?

A. BPA determined wholesale sales revenue as the product of any utility surplus and average forecasted market price. Wholesale sales revenue was then decremented by 20 percent to account for the utility's inability to extract full value from surplus power sales. Deficits were met with market purchases at forecasted market prices.

Q. Were inflation escalators used in the ASC Forecast Model?

A. The model uses inflation escalators that are part of BPA's WP-07 initial proposal. The inflation escalators can be found in the WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. How were inflation rates used to develop the ASC forecasts?

A. Inflation rate forecasts were used to escalate non-fuel costs annually. For an explanation of the calculation and escalation of non-fuel costs, *see* WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. What was the source for gas price forecasts used in the model?

A. The gas price forecasts are the same forecasts used in BPA's WP-07 initial proposal. *See,* Market Price Forecast Study, WP-07-E-BPA-03.

Q. How were gas price forecasts used to develop ASC forecasts?

A. Annual gas price forecasts were used to forecast fuel costs for gas-fired resources. For an explanation of this calculation. *Id*.

Q. Were BPA's gas forecasts used to develop all utilities' ASCs?

A. No. The ASC forecast for Clark uses gas prices that Clark included in both its rates and its ASC filing for the years FY 2006 through 2008. For the remaining years of the study, the gas forecast for Clark is the same as was used for the other utilities.

Q. How were coal fuel costs escalated?

A. Coal fuel costs estimated for each utility in 2004 were escalated at 0.5 percent per year. BPA used this moderate escalation factor because the majority of coal plants used to serve loads in the PNW are lower-cost mine mouth operations where the utility controls the production and cost of the coal. In addition, coal costs have not historically risen substantially over time.

Q. How were market price forecasts for electricity used to develop ASC forecasts?

A. Market price forecasts for electricity were used to determine the annual cost of additional purchased power needed by a utility due to increases in loads. Market price forecasts were also used to determine the value of surplus sales. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. What was the source for the electric market price forecasts?

A. BPA used market price forecasts contained in the Market Price Forecast Study. *See,*

Market Price Forecast Study, WP-07-E-BPA-03.

Q. Do the forecasts of utility costs and ASCs include costs associated with construction of new power plants?

A. No. BPA assumed that load growth would be met with purchased power or with reduced wholesale sales. For an explanation of how this is modeled, *see,* WPRDS, WP-07-E-BPA-05, Section 2.19.

Q. Will BPA update gas price forecasts and electric market price forecasts if these forecasts are updated in other BPA studies?

A. Yes, and BPA will endeavor to update the ASC forecasts in order to incorporate changes to the underlying drivers of these forecasts including changes to the gas price forecast.

Section 4. Forecast of Exchanging Utility Loads

Q. Please describe the load forecasts BPA developed for REP purposes in this proceeding.

A. Both system load forecasts and residential load forecasts were developed for this proceeding.

Q. What is system load?

A. System load is a utility's total retail load (TRL), or the metered load that is billed to a utility's retail customers. TRL includes residential, commercial, and industrial loads.

Q. How were system load forecasts developed?

A. System load forecasts were obtained from a BPA forecast of loads used in the WP-07 proceeding.

Q. Were any adjustments made to the actual and forecasted system loads used in the ASC calculations?

A. Yes. BPA added distribution losses to both actual and forecasted loads, consistent with the 1984 ASCM. BPA assumed five percent distribution loss factors for both actual and forecasted system loads, which increased the system loads. Distribution losses depend on system load density, and on the age of a utility's system. The range for loss factors is

generally 3.5 percent to five percent.

Q. What were the results of the system load forecasts?

A. The results of the system load forecasts are shown in the ASC Forecast Model. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19, *and* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.12.2.

Q. What is residential load?

A. Residential load is the metered residential and small farm load for each utility.

Q. How were residential and small farm load forecasts developed?

A. Actual loads reported in FERC Form 1s and in annual reports were used. When adequate detail was available, irrigation loads were included with actual residential loads. A residential percentage factor was calculated by dividing the actual residential load by the total system load. System loads in the ASC Forecast Model were multiplied by the residential percentage factor to determine forecasted residential loads. The residential percentage factor was assumed to not change over the study period.

Q. What were the results of the residential and small farm load forecasts?

A. The results of the residential and small farm load forecasts are shown in the ASC section of the WPRDS. *See,* WPRDS, WP-07-E-BPA-05, Section 2.19, *and* WPRDS Documentation, WP-07-E-BPA-05B, Table 4.12.2.

Section 5. "In Lieu" Power Purchases and Sales

Q. Please explain the meaning of "in lieu" in terms of the "purchase and sale" of power under the REP.

A. Under section 5(c)(5) of the Northwest Power Act, BPA

> "may acquire an equivalent amount of electric power from other sources to replace power sold to [a] utility as part of [the REP] if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility."

This acquisition of power from other sources is "in lieu" of the "purchase" from the

utility that would otherwise occur under the REP. This purchase right is designed to provide a mechanism to limit the net costs of the REP. An in-lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable RPSA.

Q. Will BPA establish any guidelines prior to conducting any in-lieu transactions?

A. Yes. In-lieu transactions are financially sound only when the cost of the in-lieu resource is forecasted to be below the utility's ASC. BPA has determined that the sources of power available for an in-lieu purchase will be defined in an In-Lieu Power Policy. *See,* Administrator's Record of Decision on Residential Purchase and Sale Agreements with Pacific Northwest Investor-Owned Utilities, October 4, 2000, at 68 (RPSA ROD). BPA agreed to develop an In-Lieu Power Policy prior to implementing any in-lieu transactions.

Q. What is the forecasted cost of in-lieu transactions?

A. BPA must develop a forecasted cost of an in-lieu transaction when BPA implements such a transaction. Such forecasted cost is based on an assessment of total transaction costs. *Id*. at 69. The assessment of the cost of an in-lieu transaction may be based on the cost of power in the wholesale power market. For example, the cost of flat-block purchases from the market is found in Petty, *et al*.,WP-07-E-BPA-11, Section 6. In addition to this basic cost, the current prototype RPSA provides that the full cost of the in-lieu transaction must also reflect the cost of transmission and losses to integrate the power into the BPA system, if incurred; the costs of the power shaped to meet diurnally differentiated monthly amounts of residential load; the costs of additional operating reserves, if necessary; the product of the transmission component of ASC multiplied by the amount of in-lieu power; and the costs that BPA incurs to deliver the in-lieu power to the point of delivery.

The FY 2007 average energy price for undelivered energy from BPA's market

forecast is 52.07 mills/kWh. *Id*. This forecast does not include transmission costs, which are included in utility ASCs. With the addition of a 3.4 mills/kWh transmission component (which was determined in the WP-02 proceeding), the resulting 55.47 mills/kWh forecast exceeds the forecasted ASCs of all utilities, except Clark, that might participate in the REP. The review period for Clark's ASC filing is currently suspended. BPA and Clark will either reach settlement on the filing, or the filing will be reopened and reviewed in accordance with the 1984 ASCM. For all utilities, the high forecasted market price, in conjunction with additional costs required by the RPSA to more precisely estimate the cost of in-lieu power, indicate that BPA will not conduct any in-lieu transactions.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY OF

GREG C. GUSTAFSON, HARRY W. CLARK, SCOTT K. WILSON,
AND SARAH K. BERMEJO

Witnesses for Bonneville Power Administration

SUBJECT: POLICY ON DSI SOLUTIONS; 7(C)(2) INDUSTRIAL MARGIN STUDY; FLOOR RATE TEST; VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

		Page
Section 1.	Introduction and Purpose of Testimony	1
Section 2.	Policy on DSI Solutions	2
Section 3.	Rationale for the Industrial Margin	5
Section 4.	Data Base for the Margin Study	6
Section 5.	Methodology	7
Section 6.	The Margin	9
Section 7.	Floor Rate Test	11
Section 8.	Value of DSI Supplemental Contingency Reserves	12

TESTIMONY OF

GREG C. GUSTAFSON, HARRY W. CLARK, SCOTT K. WILSON,

and SARAH K. BERMEJO

Witness for Bonneville Power Administration

SUBJECT: POLICY ON DSI SOLUTIONS; 7(C)(2) INDUSTRIAL MARGIN STUDY; FLOOR RATE TEST; VALUE OF DSI SUPPLEMENTAL CONTINGENCY RESERVES

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Greg C. Gustafson. My qualifications are contained in WP-07-Q-BPA-14.

A. My name is Harry W. Clark. My qualifications are contained in WP-07-Q-BPA-09.

A. My name is Scott K. Wilson. My qualifications are contained in WP-07-Q-BPA-53.

A. My name is Sarah K. Bermejo. My qualifications are contained in WP-07-Q-BPA-03.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to explain BPA's policy on service to the Direct Service Industries (DSIs), sponsor the 7(c)(2) Industrial Margin Study portion of the Wholesale Power Rate Development Study (WPRDS), and explain the derivation of the typical industrial margin used to set the Industrial Firm Power (IP-02) rate. The testimony also describes how the floor rate was derived. In addition, this testimony explains how the value of DSI supplemental contingency reserves was determined, sponsors the Supplemental Contingency Reserves Adjustment portion of the 2007 General Rate Schedule Provisions (GRSPs), and sponsors the Value of DSI Supplemental Contingency Reserves portion of the WPRDS.

Q. How is your testimony organized?

A. This testimony is in eight sections. Section 1 is this introduction. Section 2 explains

BPA's policy on service to the DSIs. Section 3 explains why we are calculating the industrial margin. Section 4 describes the database used in calculating the industrial margin. Section 5 describes the methodology used to calculate the margin. Section 6 describes the margin calculation. Section 7 describes the derivation of the floor rate and applies the floor rate test. Section 8 describes how the value of DSI supplemental contingency reserves was derived.

Section 2. Policy on DSI Solutions

Q. In the DSI Service ROD, BPA agreed to provide aluminum smelters up to 560 aMW and Port Townsend Paper Corporation 17 aMW of either power or financial benefits during FY2007-2009. Please describe the terms of this service.

A. In the DSI Service ROD, the Administrator proposed to offer 560 aMW of service benefits to the aluminum smelters, capped at $59 million, and 17 aMW to Port Townsend Paper Corporation for the FY2007-2011 period. *See,* BPA Service to DSI Customers for Fiscal Years 2007-2011, Administrator's Record of Decision, signed June 30, 2005. The DSI Service ROD describes the offer to the aluminum smelters as a surplus power sale but with an option for BPA to convert the power sale to a financial transaction if a power sale would exceed the $59 million benefit cap. The DSI Service ROD also states that BPA will work together with the local public utilities to provide these benefits to the DSI customers. Under this service plan, DSI aluminum smelters would not be purchasing power under the IP rate schedule.

Q. Why is BPA developing an IP rate if it does not plan to make any sales under that rate schedule?

A. There is a strong likelihood that smelters will not be able to purchase power under the IP rate and continue production on an economically viable basis, given the highly competitive conditions in the global aluminum market. However, there is no absolute certainty in that regard. Therefore, it is prudent for the Administrator to establish a DSI

rate pursuant to the directives set forth in Section 7(c) of the Northwest Power Act as has been the practice in prior rate cases. 16 U.S.C. § 839e(c)(1). At this point, however, BPA has no expectation that the rate will be used for discretionary sales to aluminum smelters under Section 839(d)(1) of the Northwest Power Act. 16 U.S.C. § 839(d)(1). Beyond that, BPA does anticipate the need for an IP rate in connection with provision of service to Port Townsend Paper Corporation. The DSI Service ROD states that BPA will offer a 17 aMW surplus power sales contract to the local utility for delivery to Port Townsend Paper Corporation at a price approximately equivalent to the lowest-cost PF rate "or the IP rate if viable." A posted IP rate, then, is also needed so that its viability can be assessed.

Q. Does BPA expect to have the DSI contracts finalized and signed in time to include the cost of DSI service benefits in the final rates?

A. Yes. BPA expects to have the DSI contracts finalized and signed in time to be reflected in the final rate proposal. The current schedule calls for initial negotiations, contract drafting, public review, final negotiations and signing to be completed by mid-March, which is before BPA will need to prepare the studies for the final rate proposal.

Q. What is BPA assuming in its Initial Proposal regarding the cost of providing DSI service pursuant to the service plan described in the DSI Service ROD?

A. BPA will provide the aluminum smelters with 560 aMW of financial benefits based on the difference between forward market electricity prices and a PF-equivalent lowest-cost flat rate up to a maximum of $12.00/MWh or $58.9 million/year and a FPS sale of 17 aMW to the Port Townsend Paper Corporation via its local PUD at a PF-equivalent lowest-cost flat rate.

Q. What is BPA assuming in its Initial Proposal regarding uncertainty about actual payments to DSIs?

A. The DSI benefits included in the Revenue Requirement for the Final Rate Proposal will

be the same as the actual benefit payments for FY 2007. Accordingly, there is only uncertainty in the amount of aluminum smelter benefits that will actually be paid in FY 2008 and 2009, relative to the benefits for that period included in the Revenue Requirement for the purpose of setting rates.

Q. BPA did not include aluminum price and smelter-specific operating cost risk when modeling aluminum smelter benefit risk. Why not?

A. In the past, using modeling based on aluminum prices and estimates of smelter-specific costs has not provided a reliable indication of whether a given smelter would continue or curtail operations in any particular market scenario. Experience has shown that smelters have actually operated when such comparisons would imply they should not have been operating, presumably because each smelter has different operating strategies that are not accounted for in the market price/smelter cost analysis. Thus, BPA has no reliable basis for assessing any Northwest aluminum smelter's reaction to changes in market fundamentals. In short, it is not possible for BPA to evaluate market risk faced by smelter operations unless the assumptions underlying that evaluation truly reflect the basis for operational decisions.

Q. BPA assumes that the aluminum smelters will continue to operate during FY 2007-2009 at electricity prices equal to the flat PF rate developed in this rate filing. What is the basis for this assumption?

A. During FY 2004-2005 two Northwest smelters operated at reduced capacity with power purchases between $32/MWh and $34/MWh (flat average annual IP-02 rate). For this reason, BPA assumed aluminum smelters may continue to operate during FY 2007-2009 at electricity prices equal to a flat PF rate that is less than or equal to these power purchase prices.

Q. BPA's results do not indicate what combination of specific smelters will or will not run for a given benefit level. Why is such information unnecessary?

A. In the DSI Service ROD, the Administrator determined that any unused service benefits can be reallocated to the other operating DSIs. Thus, if one smelter cannot operate economically, BPA assumes other smelters that continue to operate will acquire the freed-up service benefits via this reallocation. Please refer to the DSI Service ROD for more detail on the potential reallocation of service benefits for DSI service.

Q. BPA assumes that the aluminum smelters will maximize their benefits and adjust their output level to minimize per aMW effective electricity prices, taking into account any BPA benefits. Can pot line energy use be varied in this manner?

A. The Northwest aluminum smelters have, in the past, demonstrated strategies that include operating partial potlines from 10 aMW up to full potlines using over 100 aMW. BPA has no reason to think the aluminum smelters cannot do the same thing in the future.

Q. BPA assumes that all smelters will shut down at electricity prices of $70.00/MWh or more. Please explain the logic behind this assumption.

A. In previous responses the difficulty of modeling individual smelter reactions to changes in market fundamentals was noted. At some level of increasing power prices, we recognize that aluminum smelting becomes uneconomic regardless of all other considerations. Under nearly all market conditions, Northwest smelters cannot operate on an economic basis at electricity prices of $70/MWh or more. Thus, the Risk Analysis Study establishes $70/MWh as the point at which there is a substantial certainty that Northwest smelters will be unable to continue operations. *See,* Risk Analysis Study, WP-07-E-BPA-04.

Section 3. Rationale for the Industrial Margin

Q. What is the section 7(c)(2) industrial margin?

A. Section 7(c)(1)(B) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) provides that Bonneville shall set a rate for direct industrial service "at a level which the [Bonneville Power] Administrator determines to be

equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Section 7(c)(2) of the Northwest Power Act further provides that:

> "The determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account:
> (A) the comparative size and character of the loads served;
> (B) the relative costs of electric capacity, energy transmission, and related delivery facilities provided and other service provisions; and
> (C) direct and indirect overhead costs, all as related to the delivery of power to industrial customers…"

Thus, the rates established pursuant to this provision are set by adding a typical retail margin, taking into account the factors stated above, to the applicable wholesale rate. The purpose of the 7(c)(2) Industrial Margin Study is to calculate the typical retail margin.

Section 4. Data for the Margin Study

Q. Have there been any changes in how the margin study data were collected?

A. No. The data were collected by the Public Power Council (PPC) in the same way as in the 2002 rate case. This was done to assure confidentiality of the data submitted by the utilities.

Q. Which utilities were eligible to provide data for use in the margin study?

A. The margin study includes only utilities with at least one industrial customer with a peak demand of at least 3.5 megawatts. Thirty-four public body and cooperative customers meeting this requirement responded to BPA's request for data.

Q. What definition of "industrial customer" was used in compiling these data?

A. Consistent with past margin studies, "industrial customer" was defined as a customer that

receives firm electric service and is engaged primarily in manufacturing, processing, refining, and/or mining.

Q. How many utilities were included in the margin study?

A. Of the 34 responses, sufficient data to determine a margin were received from 30 public body and cooperative customers. These responses provided the cost information necessary to calculate the industrial margin.

Q. What specific types of data did each utility provide?

A BPA requested that utilities provide their most recent cost of service analyses (COSA) used in establishing their existing industrial customer rates. BPA also requested information from any power contracts that a utility may have with an industrial customer for providing electrical service under other than traditional industrial tariffs (such as market-based or market-access pricing). The data base consists of complete COSAs or various forms of summary data received from the utilities, margin information provided by the utilities, plus information from rate schedules, and contracts currently in effect.

Q. What information was contained in the COSAs?

A. COSAs generally contain expenses that are individually identified and categorized based upon the functionalization and allocation used by the utilities. The functionalization is the separation of costs into categories of cost causation, including production, transmission, distribution, taxes, and overhead. The allocation of costs is the separation of the functionalized costs to customer classes such as residential, commercial, and industrial.

Section 5. Methodology

Q. How did you derive individual utility margins?

A. Basically, BPA followed the same methodology as used in the margin studies conducted for the 1996 and 2002 rate cases. Where COSAs were provided, we derived individual utility industrial margins by analyzing the cost categories the utilities allocated to their

industrial consumers. BPA relied on utility data used to prepare the COSA, and the same information was used in determining how costs were functionalized among the various cost categories and allocated to their industrial customers. In other words, BPA generally accepts each utility's functionalization and allocation methods. The only exception was in the case of a utility functionalizing programmatic conservation costs to the "Other" cost category. These costs were placed in the "Production" cost category for purposes of calculating this utility's industrial margin, consistent with the treatment of this cost in past margin studies.

In sum, BPA's task was to determine what utility costs should appropriately be considered as part of the typical margin and which should not. The cost categories excluded from the margin calculation were those related to the production, transmission, or distribution functions.

Q. How did you assign the costs to the cost categories?

A. For utilities that provided complete COSAs, the costs included in the studies are typically purchased power, production, operations and maintenance (O&M), transmission O&M, distribution O&M, depreciation, debt service, capital expenses, administrative and general expenses, in-lieu taxes, conservation costs, and other overhead costs. We assigned the costs listed above to five cost categories based on the utilities' allocation of costs to their industrial customers in the following categories: Production, Transmission, Distribution, Revenue Taxes, and Other Overhead Costs. Generally, this is fairly straightforward. For example, we assigned all purchased power costs to the production cost category. Transmission O&M was assigned to the Transmission category. However, some costs are not directly associated with a Production, Transmission, Distribution, or Other Overhead category. For example, administrative and general (A&G) costs, depreciation expenses, or capital expenses as a category of costs needed to be apportioned to four of the five categories of costs. We apportioned these costs to the

Production, Transmission, Distribution, and Other category based on the relative proportion of O&M costs already functionalized by the utility to these cost categories. Thus, if total O&M allocated to the industrial class is $100, of which $40 is functionalized to transmission, we assigned 40 percent of A&G to the Transmission cost category. Return on working capital was apportioned based on the proportion of working capital assigned to those same cost categories, and revenue or income credits were apportioned based on relative shares of revenue requirement. The following cost categories were always assigned directly to the Other category: customer service, public service expenditures, and programmatic conservation costs. All revenue taxes, when identified, were assigned to the Revenue Tax category.

Next, the various categories of costs were totaled and then divided by the total kilowatthour (kWh) sales during the utility's test period to arrive at a mills per kWh (mills/kWh) figure for each category. All of the costs included in the Production, Transmission, Distribution, Revenue Taxes, and Other cost categories were totaled and divided by total sales. The result is the amount per kWh of each of the five categories that contributes to the overall rate.

Q. How did you allocate costs for the utilities that did not provide complete COSAs?

A. In a few cases BPA did not receive complete COSAs from utilities. Instead the data consisted of utility statements or summaries regarding contract margins or other overhead costs. In these instances, where the utility specifically identified the amount of margin or other overhead costs associated with a particular contract, BPA accepted it.

Appendix A of the Wholesale Power Rate Development Study, WP-07-BPA-E-05, contains summary spreadsheets displaying costs apportioned to each of these five categories for each utility participating in the margin study.

Section 6. The Margin

Q. What cost categories are included in the margin calculation?

A. BPA is using the same cost categories used in the 1996 and 2002 rate cases. Costs included in the typical industrial margin are those direct and indirect overhead costs that are not associated with the production, transmission, or distribution of electricity. Costs included in the margin calculation are those costs typically associated with such activities as customer service, programmatic conservation costs, and public service expenditures.

Q. Why is it appropriate to exclude costs functionalized to power and transmission from the margin?

A. This is the same methodology that BPA employed in 1985, 1996, and 2002. We are excluding these costs now for the same reason. The seasonally and diurnally adjusted rates in the proposed IP-07 schedule are based on a combination of the industrial margin and the proposed Priority Firm Power (PF-07) rates. The costs of providing generation will be recovered through the PF-07 rate. However, transmission costs will be determined in the transmission rate case and will be charged to customers by the BPA Transmission Business Line. Since generation and transmission costs will be recovered through BPA's power and transmission rates applicable to the DSIs, it would be inappropriate to include them in the industrial margin as well.

Q. Why is it appropriate to exclude revenue taxes from the margin?

A. We continued the method used in the 1996 and 2002 rate cases. The Northwest Power Act directs the Bonneville Administrator to base the DSI margin on the "typical" retail margins included in rates by BPA's public body and cooperative customers. In the last two rate cases, the Administrator determined that revenue taxes are not "typical" in two respects. First, revenue taxes are not "typical" because a majority of the states in Bonneville's service territory do not levy revenue taxes. Second, a majority of BPA's wholesale customers do not pay revenue taxes. We found no reason to deviate from the policy of excluding revenue taxes from the margin calculation.

Q. How did you calculate the "typical" margin?

A. First, we calculated the individual utility margins. We then weighted the individual margins to arrive at the overall margin.

Q. What weighting technique did you employ?

A. We multiplied each margin by the total annual energy consumed by each utility's large industrial customers. Thus, we weighted each margin by the amount of energy sold by the utility to its industrial customers, thereby giving greater weight to the utilities with more sales. We then added all the individually weighted margins and divided by the sum total energy for all utilities. We derived an overall typical margin of 0.57 mills/kWh.

Section 7. Floor Rate Test

Q. What is the floor rate test?

A. Section 7(c)(2) of the Northwest Power Act provides that the rate developed pursuant to that section "shall in no event be less than the rates in effect for the contract year ending on June 30, 1985." This is the so-called "floor rate test." Simply stated, the floor rate test requires that BPA recover revenues from its DSI customers in the test period equal to or greater than the revenues it would recover in the test period using the applicable IP rate in effect on June 30, 1985.

Q. How is the floor rate test calculated?

A. The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 2007-2009) DSI billing determinants. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills per kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills per kWh basis. *See,* Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05A, Section 2.3, Table RDS23. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to

revenues at the floor rate. If expected IP-07 rate revenues match or exceed floor rate revenues, then the IP rate is the applicable rate. If not, then rates must be adjusted accordingly.

Q. Are you proposing any changes to the way the floor rate is calculated?

A. No. We calculated the floor rate in the same manner as was done in the 2002 rate case.

Section 8. Value of DSI Supplemental Contingency Reserves

Q. Please state the purpose of this section of your testimony.

A. The purpose of this testimony is to explain BPA Power Business Line's (PBL) proposal for valuing and, if necessary, procuring Supplemental Contingency Reserves (Supplemental Reserves) from its DSI customers. In the event that PBL decides to purchase Supplemental Reserves from a DSI, the value of the reserves will be negotiated on a case-by-case basis within the limits established in this rate case, and such credit or payment will be reflected as a billing adjustment on the power bill.

Q. Why does BPA need to have access to Supplemental Reserves?

A. BPA needs access to an alternate source of Supplemental Reserves in order to comply with the Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC) provisions that ensure secure and reliable operation of the bulk electric systems in the Western Interconnection. *See,* Section 4.1.1.2 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05.

Q. Does BPA procure other kinds of reserves from the DSIs?

A. Yes, BPA also procures Stability Reserves from the DSIs.

Q. Why would BPA's Power Business Line procure Stability Reserves from a DSI?

A. Generally, BPA would procure Stability Reserves from a DSI to comply with WECC MORC provisions that ensure secure and reliable operation of the bulk electric systems in the Western Interconnection.

Q. Is BPA proposing a different approach to procuring Supplemental Reserves in this rate case?

A. No. BPA will post a range (subject to change in BPA's final proposal), from $0 to $6.96/kW-month that reflects the credit or payment an individual DSI may receive for supplying Supplemental Reserves, should BPA elect to procure such reserves. The customer-specific negotiated price will fall within this range. The maximum price will be expressed in the GRSPs as a $/kW-month rate.

Q. How is PBL proposing to establish the rate that would be applicable to any purchases of Supplemental Reserves from a DSI?

A. PBL is proposing a flexible rate with a cap that will permit BPA to negotiate a price according to the quality of reserves provided. The maximum amount PBL may pay for Supplemental Reserves from a DSI will be capped in the schedule at $6.96/kW-month. The proposed cap is established to be equivalent to the maximum price at which PBL would sell generation inputs to the TBL for operating reserves. This amount, in turn, is based on an embedded cost methodology, which is discussed more fully in other testimony. *See,* Bermejo, *et al.,* Section 3 of WP-07-E-BPA-20.

Q. Will a flat credit be given for Supplemental Reserves under the IP rate schedule to all DSIs?

A. No. If reserves were needed, PBL may separately negotiate with any interested and operating DSIs. The price paid by BPA will be determined, within the cap established in the schedule, based on the quality of Supplemental Reserves provided.

Q. Is the methodology for calculating the value of Supplemental Reserves the same methodology that has been used in prior rate cases?

A. Yes. The same methodology was used in the WP-02 rate case.

Q. Why does PBL propose to cap the DSI Supplemental Reserves rate at the embedded cost of generation inputs for operating reserves that PBL proposed to charge TBL?

A. BPA has proposed a price that TBL would pay PBL for generation inputs for operating reserves. This price is based upon the embedded costs of FCRPS generation. Generation inputs for operating reserves have essentially the same electrical characteristics as the highest-quality Supplemental Reserves that PBL might purchase from the DSIs.

Q. What quantity of Supplemental Reserves is PBL forecasting to purchase from the DSIs?

A. PBL is currently forecasting to purchase zero Supplemental Reserves from the DSIs. Under most conditions, the BPA FCRPS power system is capable of providing its own Supplemental Reserves. However, many proposed changes at the North American Electric Reliability Council (NERC), WECC, and the Northwest Power Pool (NWPP) provisions, standards, and criteria for reserves present uncertainties to PBL's future need for these reserves. Thus, the amount of reserves needed is unknown.

Q. What are the uncertainties with respect to the quantity of Supplemental Reserves PBL is forecasting to purchase from the DSIs?

A. As described above, many proposed changes for reserves at NERC, WECC and the NWPP create uncertainties that make the amount of reserves needed difficult to forecast. Furthermore, DSIs may find it advantageous to provide reserves directly to TBL or other power marketers or TBL may acquire the generation component of Supplemental Reserves from PBL if competitive markets for such services emerge. In that event, DSI-provided reserves could only have value to BPA if they were purchased by the TBL because of FERC's prohibition on self-supply by a merchant affiliate. There is also uncertainty as to the number of DSIs that would be willing and able to provide Supplemental Reserves given the criteria outlined in this testimony. For all of these reasons, there is no basis to conclude that any specific level of Supplemental Reserves will be purchased from the DSIs by PBL.

Q. Is BPA forecasting any DSI sales through the IP rate?

A. No. As described above, BPA is not forecasting any DSI sales through the IP rate.

However, rate directives in the Northwest Power Act applicable to the DSIs require that the value of the reserves credit be established in the rate case. PBL prefers to have the flexibility to purchase Supplemental Reserves from the DSIs without initiating a separate section 7(i) process. In addition, BPA may negotiate and purchase Supplemental Reserves, if needed, from the DSI through three way contracts that will be in place for delivery of DSI service benefits.

Q: Does that conclude your testimony?

A: Yes.

INDEX

TESTIMONY OF

LARRY D. KING AND GREG C. GUSTAFSON

Witnesses for Bonneville Power Administration

SUBJECT: LOW DENSITY DISCOUNT

		Page
Section 1.	Introduction and Purpose of Testimony	1
Section 2.	Description of the Low Density Discount (LDD)	1
Section 3.	Proposed Changes to the LDD	2
	Section 3.1. Changes to the "Retail Rate to PF Rate" Eligibility Criterion	3
	Section 3.2. Changing "Consumers" in the C/M Ratio to "Meters"	7
	Section 3.3. Clarification of the Application of the LDD to Slice	10

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TESTIMONY OF

LARRY D. KING and GREG C. GUSTAFSON

Witnesses for Bonneville Power Administration

SUBJECT: LOW DENSITY DISCOUNT

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Larry King and my qualifications are contained in WP-07-Q-BPA-24.

A. My name is Greg Gustafson and my qualifications are contained in WP-07-Q-BPA-14.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the Low Density Discount (LDD); the Bonneville Power Administration's (BPA) proposed changes to the LDD; and to sponsor the LDD portions of the Wholesale Power Rate Development Study (WP-07-E-BPA-05, Section 2.10), rate schedules, and General Rate Schedule Provisions (WP-07-E-BPA-07, Section II.K).

Q. How is your testimony organized?

A. Following this introductory Section 1, Section 2 of this testimony describes the LDD. Section 3 describes BPA's proposed changes to the LDD methodology, including subsections on: changes to the "retail rate to PF rate" eligibility criterion; changing "consumers" in the customers/4mile-of-line (C/M) ratio to "meters"; and clarification of the application of the LDD to Slice.

Section 2: Description of Low Density Discount (LDD)

Q. What is the LDD?

A. In order to avoid adverse impacts on retail rates of BPA's customers with low system densities, BPA applies a discount, to the extent appropriate, to BPA's rates for such customers. The LDD applies to the PF Preference, PF Exchange, and New Resources

rates. An LDD benefit is determined for the following components of the foregoing rate schedules adjusted for cost recovery adjustment and dividend distribution clauses, as applicable: (1) Generation System Peak (GSP) demand, (2) Heavy Load Hour (HLH) energy purchases, (3) Light Load Hour (LLH) energy purchases, and (4) load variance charges.

Q. Please describe how the LDD is currently calculated in BPA's 2002 Rate Schedules and GRSPs.

A. As in BPA's current proposal, a customer must first satisfy five eligibility criteria in order to qualify for the LDD (S*ee,* 2002 Rate Schedules and GRSPs, WP-02-E-BPA-07). For qualifying Purchasers, the level of the LDD is determined by the Purchaser's K/I (Total Retail Load to depreciated investment in electric plant) ratio and their C/M (customers per pole mile of distribution line) ratio.

An eligible Purchaser receives the sum of the discounts determined from the K/I and C/M ratios, not to exceed 7 percent. If the eligible Purchaser's revised discount varies from its current discount by more than one-half of 1 percent, BPA progressively phases-in or phases-out the revised discount in annual increments of one-half of 1 percent until the eligible Purchaser receives its then-final revised discount.

An additional discount of one-half of 1 percent applies to eligible Purchasers with very low densities. This additional discount requires a C/M ratio of 3 or less and a K/I ratio of 26 or less. The sum of the discounts based on the two ratios and the additional one-half of 1 percent cannot exceed 7 percent.

Once the percentage discount is determined, the discount is applied each month only to the above-noted charges associated with the specified components for power purchased from BPA under the PF Preference, PF Exchange, and New Resources rates. The LDD reduces the Purchaser's monthly power bill by the applicable discount.

Q. What is the estimated annual cost of the LDD in the FY 2007-2009 rate period?

A. As stated in the Wholesale Power Rate Development Study (WP-07-E-BPA-05, Section 2.10), the estimated annual cost of the LDD for the FY 2007-2009 rate period is $24 million.

Q. Is this consistent with the estimate of LDD costs used in the RAM2007 model to determine FY 2007-2009 PF rates?

A. No, we found a discrepancy. The estimate used in the rate calculation process ($18 million/year) was based on rates from the FY 2002 rate schedule. This discrepancy will be corrected in BPA's final studies to be consistent with the final proposed rates.

Section 3: Proposed Changes to the LDD

Q. Is BPA proposing any changes to the LDD?

A. Yes. BPA is proposing three primary changes: (i) changing the "retail rate to PF rate" eligibility criterion; (ii) changing the term "consumers" in the C/M ratio to "meters"; and (iii) clarifying how BPA determines LDD benefits for qualifying Slice customers. BPA's proposed methodology for calculating the LDD is explained in detail in BPA's Wholesale Power Rate Schedules, GRSPs, WP-07-E-BPA-07, Section II.K

Section 3.1. Changes to the "Retail Rate to PF Rate" Eligibility Criterion

Q. Please describe the current "retail rate to PF rate" eligibility threshold criterion.

A. Section 2 of BPA's 2002 GRSPs establishes five eligibility criteria that Purchasers must satisfy in order to receive an LDD. One of these criteria is that "the Purchaser's average retail rate for the reporting year must exceed the Purchaser's average cost of BPA power purchases under the applicable rate for the qualifying period by at least 10 percent." The retail rate to PF rate eligibility threshold was first established in BPA's 1987 rate case. The 1987 rate case established that a Purchaser's average retail power rate must exceed the average BPA Priority Firm rate by at least 10 percent. The rationale for this eligibility threshold was that if a utility could not meet this criterion then it was not

suffering adverse impacts on its retail rates due to a low system density that the LDD is intended to mitigate.

Q. Please describe BPA's proposed changes to this criterion.

A. BPA proposes to change the first sentence of Section 2.c. of the LDD Eligibility Criteria to state: "the Purchaser's average retail rate for the reporting year must exceed BPA's average Priority Firm power rate for the most closely corresponding fiscal year by at least 25 percent."

Increase in "Retail Rate to PF Rate" Eligibility Threshold

Q. In Section 2.c of the LDD Eligibility Criteria, why has BPA proposed that the Purchaser's average retail rate must exceed BPA's average Priority Firm power rate by at least 25 percent, instead of 10 percent?

A. Prior to the separation of BPA's power and transmission rates in 1996, a BPA Purchaser's average retail rate had to exceed the average Priority Firm power rate by 10 percent to qualify for a LDD. The Priority Firm power rate included transmission costs prior to rate schedules established in 1996. When BPA separated power and transmission rates, BPA left the retail rate to PF rate eligibility threshold unchanged at 10 percent and BPA no longer included transmission costs in the calculation of the average PF rate for purposes of LDD qualification. This approach effectively and inadvertently resulted in a lower retail rate to PF rate eligibility threshold. BPA proposes to restore the retail rate to PF rate eligibility threshold to the general level that existed prior to the separation of power and transmission rates by setting a new percentage by which retail rates must exceed the average PF rate (power only) that is approximately equivalent to the 10 percent threshold that existed prior to the rates established in 1996.

BPA used the PF-96 and NT-96 rates and billing determinants applied to recent loads of LDD Purchasers to simulate Purchasers' costs of power and transmission and determined that the appropriate threshold, relative to power-only PF costs, is 25 percent.

Specifically, BPA applied the PF-96 and NT-96 rates to the corresponding billing determinants using October 2002 through September 2004 load data for 57 BPA Purchasers receiving an LDD in 1996. This analysis yielded BPA annual power costs equal to 88 percent of combined annual power and transmission costs. If power-only costs represent 88 percent of power-plus-transmission costs, then the percentage by which a Purchaser's retail rate must exceed the average PF rate (power only) that is equivalent to the 10 percent threshold that existed prior to 1996 is 25 percent (1.1 / .88 = 1.25). The 88 percent number is the median annual power cost percentage of power plus transmission costs for the 57 Purchasers for two years (BPA's FYs 2003 and 2004). The median was used rather than the mean because the median avoids a potential problem where a few relatively large or small observations can result in a substantial change in the resulting measure of central tendency. In this instance, however, the mean and median were equal when calculated to the nearest 0.1 percent.

Q. Why did BPA use FY 2003 and FY 2004 load data to determine the power cost percentage of combined power and transmission costs?

A. At the time these data were processed they represented the two most recently completed BPA fiscal years, were readily available electronically, and were of good quality. These data also represent a reasonable range of economic and weather-driven load conditions and better represent current and expected FY 2007-2009 BPA power and transmission purchase patterns than data for the 1996 through 2002 period. Data prior to October 2002 would reflect the impacts of the severe drought of 2001, the requests for conservation in 2000-2001 and the power market failures of the same years, as well as the load buy-downs that were substantial in BPA's FY 2002. Based on these considerations, BPA concluded that using its two most recently completed fiscal years would provide a reasonable basis for determining the percentage that power costs constitute of total power plus transmission costs.

Changes to the Average Cost of BPA Power Purchases

Q. Why has BPA changed the definition of the denominator in the retail rate threshold calculation from "the Purchaser's average cost of BPA power purchases" to "BPA's average Priority Firm power rate"?

A. Using the average Priority Firm power rate simplifies administration of the LDD program by avoiding the need to calculate Purchaser-specific average costs of BPA power purchases. It also provides all Purchasers with the same class-average PF rate basis for qualifying for an LDD regardless of whether they take service under Slice/block, block, full or partial requirements contracts; regardless of the Purchaser-specific shape of their BPA power purchases; and regardless of whether or not the Purchaser has non-PF BPA purchases such as the Irrigation Rate Mitigation product in the current rate period. This change returns to the definition used prior to the current rate period and therefore is consistent with BPA's intent to return to a retail rate threshold that is equivalent to the 10% threshold that existed prior to 1996.

Period for Determining BPA's Average Priority Firm Power Rate

Q. Why has BPA proposed changing the time period for determining BPA's average Priority Firm power rate in the LDD eligibility criteria from "the qualifying period" to "the most closely corresponding fiscal year"?

A. The phrase "during the qualifying period" could be interpreted as the period of time that a Purchaser would qualify for and receive the LDD, meaning the upcoming BPA fiscal year, or it could be interpreted as the reporting year for which the Purchaser provides utility data. BPA wanted to eliminate this potential ambiguity and also wanted to simplify the calculation of the average PF rate. Using "the most closely corresponding BPA fiscal year" eliminates the potential ambiguity. It also eliminates the need to compile data and calculate the average BPA rate for three months of one fiscal year and nine months of the following fiscal year. This means that the average BPA rate that is

calculated will be within a single rate period. This will reduce the administrative costs of calculating the average BPA rate.

Definition of "Average Retail Rate"

Q. Please describe BPA's proposed definition of "average retail rate."

A. BPA proposes to define "average retail rate" as total retail electricity revenue ($) divided by total retail electricity sales (kWh), both as reported on the LDD data requirements reporting form submitted by the Purchaser.

Q. Why is BPA proposing to add this definition of average retail rate?

A. In the past BPA assumed the term "average retail rate" was sufficiently clear and that a specific definition in the GRSPs was not needed. During the current rate period, a BPA customer that is not receiving the LDD questioned the definition. This customer suggested that a different definition was reasonable and should be used to determine its eligibility for an LDD. BPA decided that providing a specific definition in the GRSPs would avoid possible disputes and clearly establish the basis for calculating the average retail rate. The proposed definition is consistent with the way BPA has determined the average retail rate in its administration of the LDD.

Section 3.2. Changing "Consumers" in the C/M Ratio to "Meters"

Q. Please describe the current "consumers/mile-of-line" eligibility threshold criterion.

A. BPA's 2002 GRSPs use the C/M ratio two ways in determining LDD benefits. First, Section 2 of the GRSPs establishes five eligibility criteria that purchasers must satisfy in order to receive an LDD. One criterion is established in Section 2.e, which states "the Purchaser's C/M ratio must be less than 12." This standard limits LDD benefits only to utilities with fewer than 12 consumers per mile-of-line. Second, Section 3, Table C of the GRSPs uses the C/M ratio to establish the level of the C/M ratio portion of the LDD benefit.

The C/M ratio is determined annually using data supplied by the Purchaser. In

April of each year, BPA provides Purchasers with a letter and an LDD data request form. Purchasers are to provide the requested data by June 30 of the same year. BPA uses these data to determine Purchasers' eligibility for and level of LDD that will be effective for the upcoming BPA fiscal year. The C/M ratio is calculated by dividing the maximum number of consumers within the distribution system in any one month of the reporting year by the number of pole miles of distribution line. "Consumer" means every billed consumer regardless of usage, excluding specified separately metered services. Distribution lines are defined as lines that deliver electric energy from a substation or metering point, at a voltage of 34.5 kV or less, to the point of attachment to the consumer's wiring.

Q. Please describe BPA's proposal to change the term "consumers" to "meters."

A. Rather than reporting "consumers," eligible LDD Purchasers will report the maximum number of revenue producing meters connected to the distribution system in any one month of the reporting year. This maximum month meter count would exclude meters for separately billed water heating and security lights.

Q. Why has BPA changed the definition from "consumers" to "meters"?

A. Density is the essence of the LDD. A uniform and sound basis for calculating density is essential to ensure equity among Purchasers receiving the LDD, to ensure that the LDD is provided only to BPA's Purchasers with low system densities, and to support efficient and effective administration of the LDD.

The definition of "consumer" in the 2002 GRSPs prevents BPA from applying a uniform definition. The current LDD reporting criteria and the resulting annual Purchaser reporting of what constitutes a "consumer" has caused confusion and inconsistency in the determination of LDD benefits. Purchasers eligible for LDD benefits have been reporting numbers of consumers differently based on, for example, the number of meters, the number of consumers, or the number of members (for

cooperatives). How the data are reported can impact LDD eligibility and the discount level. Examples of reporting inconsistencies are:

- A condominium complex or apartment house occupied by numerous owners or tenants, separately metered, may be reported as a single "consumer."
- A retail consumer who has different, separately metered service locations, but who receives one consolidated electric bill, may be reported as a single "consumer."
- An agricultural operation with several different, separately metered service locations, including residential, irrigation, stock wells and agricultural processing accounts may be reported as a single "consumer."
- A manufactured housing court with different, separately metered pads, may be reported as a single "consumer."

BPA does not routinely collect data from LDD recipients on the number of active meters. In order to assess the potential impacts of the proposed change from consumers to meters, BPA informally asked a number of current LDD recipients if they currently report meters or some other measure of consumers, and whether changing to meters from consumers would impact them. Forty-six LDD recipients provided the following information: 29 reported meters or a number close to the number of meters, 11 reported consumers, and 6 reported members. Five LDD recipients indicated they would be impacted by a change from consumers to meters.

BPA also compared "number of consumers" data from the LDD annual data reports submitted for calendar year 2003 with data Purchasers submitted to the US Energy Information Administration (EIA) for calendar year 2003. The EIA data reported by Purchasers should closely approximate the number of meters assuming that Purchasers report data as requested by EIA. Comparison of LDD submittal and EIA data indicates that a majority of LDD recipients currently report active meters or a number close to it

when asked for the number of consumers. Forty-six of 55 LDD recipients reviewed reported a consumer number sufficiently close to the EIA (meter) number that switching from consumers to meters is expected to have no impact on these Purchasers' LDD. Assuming no change in the K/I component of Purchasers' LDD's, and given the LDD phase-in rule, BPA estimates that 8 of the remaining Purchasers would see a 0.5 percentage point LDD reduction in FY 2007. Three Purchasers would see an additional 0.5 percentage point LDD reduction in FY 2008. The 2003 data indicate that changing from C/M to meters/mile-of-line (M/M) may result in one Purchaser with an M/M ratio exceeding the qualifying threshold of 12 meters per mile. BPA finds these estimated impacts reasonably consistent with the results of its informal survey of LDD recipients and believes them to be reasonably representative of impacts that will result from a change from consumers to meters.

In summary, BPA believes the change from "consumers" to "meters" more accurately reflects a utility's density, provides a uniform basis for calculating the ratio, ensures greater equity among Purchasers, and provides eligible Purchasers a clear, understandable, verifiable and administratively reasonable reporting standard. Furthermore, it is an easier standard for BPA to implement and supports the overall objective of ensuring that the LDD goes only to Purchasers that have low system densities.

Section 3.3. Clarification of the Application of the LDD to Slice

Q. Please describe how the LDD benefit is determined for eligible Slice customers.

A. To be eligible for the LDD, customers purchasing the Slice Product must meet the eligibility criteria specified in Section 2 of the LDD GRSPs. The LDD benefit for eligible Slice Product Purchasers is determined by calculating a dollars/MWh discount rate. A discount rate is determined for each one-half percent discount bracket, from 0.5 percent to 7 percent, as needed. The GRSPs state "[t]his quantity [requirements power] is

defined in the Slice Contract as Critical Slice Amount." Since not all Block and Slice related agreements calculate the Critical Slice Amount, BPA has been calculating its equivalent by multiplying the annual Critical Inventory Amount by the Purchaser's Selected Slice Percentage. The result is divided by twelve to determine the monthly LDD benefit.

Q. Why is application of the LDD for the Slice Product purchases different from non-Slice products?

A. Unlike BPA's other power products, the Slice Product entitles Purchasers to an amount of power based on a fixed percentage of the power generated by the Federal Columbia River Power System (FCRPS) for the payment of a fixed percentage of the Slice Revenue Requirement. Since the amount of power purchased by a Slice Product Purchaser is a function of the generation output of the FCRPS (which includes some secondary power) and the Purchaser's contract limits, deliveries of the Slice Product are not limited to the firm power portion of a purchaser's net requirements as it is with BPA's other products. Therefore, the traditional LDD methodology is not applicable to the Slice Product. As a result, in the WP-02 rate proceeding BPA developed a separate methodology for Slice Product Purchasers that calculated the LDD benefits based only on that portion of the Slice Product used to serve the Purchaser's net requirement. This methodology is analogous to the manner in which LDD benefits are calculated for BPA's other power products that are sold on a MW or MWh basis.

Q. Does BPA propose any changes to the manner in which it determines the LDD for Slice Purchasers?

A. Yes. BPA proposes to change Section Q.7 in the 2002 GRSPs. BPA is proposing to estimate the Slice Product Purchaser's LDD based on the "Critical Inventory Amount" and "Selected Slice Percentage" rather than the "Critical Slice Amount," and later true-up the LDD based on the Purchaser's "Requirements Slice Output" as defined in the Slice

Contract.

Q. Please explain BPA's logic for changing from the "Critical Slice Amount" to the product of the "Critical Inventory Amount" and the "Selected Slice Percentage."

A. For purposes of the LDD, the current GRSPs define the requirements portion of the Slice Product purchase as the Critical Slice Amount. BPA is proposing this change because the Critical Slice Amount is not a calculated term in all Block and Slice related contracts. In order to assure consistency across customers for purposes of determining the LDD benefit, the GRSPs should not reference a term that is not common to all Block and Slice related contracts.

BPA is substituting the Critical Slice Amount with the product of the Critical Inventory Amount and the Purchaser's Selected Slice Percentage because they are equivalent and are referred to in all Block and Slice related contracts.

Q. Why does BPA believe it is necessary to change the way it determines the LDD benefit for Slice Purchasers?

A. BPA is proposing to true-up the LDD so it applies to only the requirements portion of the Slice Product. The product of the Critical Inventory Amount and the Selected Slice Percentage can include secondary power in some months and is therefore not always representative of the Purchaser's actual net requirement (as adjusted for Block purchases). Therefore, some adjustment is necessary so that the LDD applies only to the requirements portion of the Slice Product.

The Slice Contract defines the requirements portion of the product as Requirements Slice Output. This is established in the Slice Contract to be "in each month the portion of Slice Output energy that is equal to the lesser of: (1) the Critical Slice Amount [which is numerically equal to the Critical Inventory Amount times the Selected Slice Percentage]. . . ; (2) the forecasted Net Requirement . . . , less the amount of any Block Power purchase . . . ; or (3) the actual Net Requirement . . . less the amount of any

Block Power purchase . . . ." However, because the Requirements Slice Output is an after-the-fact calculation, BPA has concluded for the purposes of the application of the LDD to the Slice Product that the LDD should be based upon the Requirements Slice Output. This change will place the application of the LDD to the Slice Product on a more consistent and similar basis as other products because the Requirements Slice Output establishes the requirements load portion of the Slice Product.

Q. How will the proposed calculation be used in determining LDD benefits compared to how it is used in the current rate period?

A. BPA will calculate the estimated monthly LDD benefit by multiplying (1) the applicable dollars/MWh discount rate by (2) the product of the annual Critical Inventory Amount and the Purchaser's Selected Slice Percentage as determined in Exhibits M and G of the Block and Slice power sales agreements, respectively. The monthly estimated LDD is one-twelfth this amount. The only difference between the current methodology and the proposed methodology is that the proposed methodology is the estimated rather than final LDD benefit.

Q. Please summarize BPA's proposal for how it will true-up LDD benefits for qualifying Slice Product Purchasers.

A. The actual LDD benefit will be determined in the following fiscal year. The actual monthly LDD benefit will be determined by multiplying the applicable dollars/MWh discount rate by the monthly Requirements Slice Output as defined in the Block and Slice Contract and summing the monthly amounts into an annual amount. Any difference between the actual and estimated LDD benefit will be reflected on the Purchaser's Individual Charges or Individual Credits as specified in the Block and Slice Contract.

Q. Does BPA currently collect the data necessary to determine the Requirements Slice Output for individual Slice Product Purchasers?

A. Not at this time. Implementing this change would require Slice Product

Purchasers eligible for the LDD to provide BPA with the data necessary to calculate and verify the Requirements Slice Output each October for the previous fiscal year so the Individual Credit or Individual Charge could be calculated along with the annual Slice True-up.

Q. Does this conclude your testimony?

A. Yes.