INDEX

TESTIMONY OF

RODNEY BOLING AND WILLIAM DOUBLEDAY

Witnesses for Bonneville Power Administration

SUBJECT: Residential Exchange Average System Cost and Load Forecasts

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rodney Boling and my qualifications are contained in WP-02-Q-BPA-07.

A. My name is William Doubleday and my qualifications are contained in WP-02-Q-BPA-17.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the data sources and assumptions that BPA used to develop its forecasts of: (1) Average System Cost (ASC); and (2) residential loads for utilities that may participate in the Residential Exchange Program. Another purpose is to describe BPA's assumptions regarding the use of "in lieu" transactions in implementing the Residential Exchange Program.

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 the Residential Exchange Program. Section 3 describes the assumptions and procedures supporting BPA's forecasts of ASC and exchanging utilities' residential loads. Section 4 discusses BPA's "in lieu" resource assumptions and the effect of such assumptions on the net cost of the Residential Exchange Program.

Section 2: Description of the Residential Exchange Program

Q. What is the Residential Exchange Program?

A. The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839, created the Residential Exchange Program 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, the Bonneville Power Administration's (BPA) 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) power rate. The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the Residential Exchange Program. The Northwest Power Act requires that the net benefits of the Residential Exchange Program be passed on directly to the residential and small farm customers of the participating utilities.

Q. Does the Residential Exchange Program involve a conventional purchase and sale of power?

A. No. Under the normal implementation of the Residential Exchange Program, 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 the power "purchased" by BPA and the less expensive power "sold" to the participating utility. As discussed in section 4 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. What is the current status of the Residential Exchange Program?

A. Residential Exchange Termination Agreements have been negotiated with all but one of the previously active exchanging utilities. The only remaining utility with an "active" Residential Purchase and Sale Agreement (RPSA) is Montana Power Company, which receives no Residential Exchange Program benefits. Montana Power continues to be in "deemer" status.

Q. Please explain deemer status.

A. When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. By doing so it avoids making actual monetary payments to BPA. The amount that the utility would otherwise pay BPA is tracked in a "deemer account." At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA. The current RPSA provides that "[u]pon termination of this agreement, any debit balance in such separate account shall not be a cash obligation of the Utility, but shall be carried forward to apply to any subsequent exchange by the Utility for the Jurisdiction under any new or succeeding agreement."

Q. Do any other utilities have deemer balances?

A. Yes. Avista Corporation (Avista) and Idaho Power Company (IPC) both terminated their RPSAs in 1993 and have deemer balances.

Q. How does BPA determine exchanging utilities' ASCs?

A. Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers. Basically, 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). A utility's system load is the firm energy load used to establish retail rates. While BPA has used the ASC Methodology for its ASC determinations, it should be noted that the ASC Methodology can be revised. Regional investor-owned utilities (IOUs) have advocated the revision of the ASC Methodology to eliminate the changes made in 1984. In the event that the ASC Methodology were revised in such a manner, forecasted exchange benefits would increase significantly.

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

A. BPA uses a "jurisdictional approach," which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. This data provides the starting point for BPA's determination of the ASC of each utility participating in the Residential Exchange Program. Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs.

Q. *What is the schedule for filing and reviewing a utility's ASC?*

A. As required by the 1984 ASC Methodology, "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the Utility shall file a preliminary Appendix 1, setting forth the costs proposed by the Utility and shall deliver to BPA all information initially provided to the State Commission." The filing includes all testimony and exhibits filed in the retail rate proceeding. Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. BPA then has 210 days to review the filing and issue a report signed by the Administrator. During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. BPA makes adjustments as necessary.

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

A. The gross cost of the Residential Exchange Program is the total dollar amount that BPA pays for the power it "purchases" from participating utilities, including utilities in deemer status. In the case of an in lieu transaction, as discussed in section 4 below, the gross cost of the Residential Exchange Program 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 Program is the difference between gross cost and gross revenue, plus the Program implementation costs.

Q. Do you expect the Residential Exchange Program to continue during the rate period?

A. BPA assumes that the Residential Exchange Program will continue to exist during the rate period. However, BPA's Subscription Strategy proposes a settlement of the Program for IOUs that includes a power sale and a financial component. Because BPA does not know whether eligible utilities will continue participation in the Residential Exchange Program or agree to a settlement of the Residential Exchange Program, BPA must establish a rate that applies to the continued implementation of the Program.

Section 3. Forecast of Average System Cost and Loads for Exchanging Utilities

Q. How has BPA forecasted a utility's ASC in the past?

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 you have employed for this rate filing?

A. Yes, in part. Because of the Residential Exchange Termination Agreements noted above, BPA no longer receives cost and load data from utilities through ASC filings as was previously required and provided under the RPSAs. BPA has therefore used a variety of data sources and approaches to determine ASCs.

Q. What general approach was used to determine ASCs?

A. BPA's first step was to identify which of BPA's many public agency and IOU customers might have ASCs that would be high enough to ensure positive Exchange benefits and should therefore be evaluated in detail. Utilities that executed Residential Exchange Termination Agreements that extend through 2011 were eliminated. BPA then determined a proxy for the new PF Exchange rate. Utilities' ASCs would need to exceed this rate in order to receive positive Exchange benefits. In developing the proxy rate, BPA noted that the section 7(b)(2) rate test triggered in BPA's 1996 rate case and the 1996 PF Exchange rate was 32.7 mills/kWh. BPA then reviewed some of the fundamental elements of the 1996 section 7(b)(2) rate test to determine whether it was likely that the trigger for the PF-02 rate period would be similar and therefore the PF Exchange rate would be similar. BPA noted that BPA's generation costs after revenue credits had remained relatively flat since the 1996 rate case; that exchanging utilities' ASCs were increasing over time; and that the value of reserves credit for the direct service industrial customers (DSIs) had diminished. These factors suggested that the new trigger amount and the new PF Exchange rate would likely be at least as high as the previous trigger amount and 1996 PF Exchange rate. Based on ASCs that were current or forecasted at the time the Residential Exchange Termination Agreements were negotiated, BPA assumed that Puget Sound Energy (Puget), Portland General Electric Company (PGE), the Pacific Power and Utah Power Divisions of PacifiCorp, and Montana Power Company (MPC) might have relatively high ASCs. In addition, as discussed in greater detail below, BPA used simplifying assumptions to estimate whether Avista and IPC were likely to be candidates for Exchange benefits during the rate period.

Q. Were any public utilities evaluated in detail?

A. Yes. Clark County Public Utility District (PUD), Snohomish County PUD, and the City of Idaho Falls were considered possible candidates to have relatively high ASCs. Each utility has generating resources and had a relatively high ASC at the time it negotiated a Residential Exchange Termination Agreement.

Q. *What model did BPA use to forecast ASCs for PacifiCorp (the Pacific Power and Utah Power Divisions), Puget, PGE, and MPC?*

A. BPA developed a Microsoft Excel-based model to replace the ASC forecasting function that was performed by a computer mainframe model in BPA's 1996 rate case. BPA developed a new model for a number of reasons. The mainframe model was expensive to maintain and to run. The model was also difficult for parties in BPA's rate case to understand and replicate. Desktop computer technology improved to where it was possible to build spreadsheet-based models that could perform many of the applications of the mainframe model.

Q. *Please compare the new model with the former mainframe model.*

A. The ASC forecasting methodology of the new model is consistent with the old model. The new model 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. The new model, however, is simpler to operate than the old model. The new model, unlike the old model, does not calculate gross cost, gross revenue, and net cost as they are applied to the Residential Exchange Program. This function is now calculated by an Exchange cost model linked to the Rate Analysis Model (RAM), which simplifies the iterative process required to achieve stable PF rates and Exchange costs. *See* Wholesale Power Rate Development Study (WPRDS), WP-02-E-BPA-05, Section 3.2.1.3.

Q. *What plant and expense data were used to forecast ASCs for the rate period?*

A. The starting point expense data used as the basis for forecasting rate period ASCs are essentially the same data used in BPA's 1996 rate case. Plant replacement factors have been adjusted to reflect the most current five years of plant retirement activity and expenses have been adjusted using current escalators. In addition, given possible industry restructuring and uncertain market conditions, BPA assumed for ASC forecasting purposes that utility load growth will be satisfied with purchased power. Such purchases are assumed to be at 28.1 mills/kWh, BPA's forecast of five-year flat block purchases, plus a transmission charge. The testimony of Oliver, *et al.*, WP-02-E-BPA-20, describes the derivation of the five-year flat block purchase forecast. This forecast is appropriate because exchanging utilities will make long-term purchases to meet load growth. BPA based the transmission charge on the PTP Rate (currently $1.00 per kW-month), which was assumed to increase to $1.48 per kW-month in BPA's next Transmission Business Line (TBL) rate case. The $1.48 rate was assumed to be constant through Fiscal Year (FY) 2010. BPA then assumed an energy loss rate of 2 percent and flat delivery. Converting these adjustments to an energy-only charge resulted in a rate of 2.07 mills/kWh. BPA then assumed that the foregoing energy losses were valued at 28.1 mills/kWh, resulting in a cost of transmission with losses of 2.63 mills/kWh in FY 2002.

Q. Has BPA adjusted any base period expenses?

A. Yes. BPA has adjusted PGE's Contract System Costs based on the functionalization of certain benefits from PGE's merger with Enron as directed by the Oregon Public Utilities Commission (OPUC) in Order Number 97-196. OPUC's order specified that $105 million in benefits relating to use of PGE's name and other intangibles be distributed with interest over eight years beginning in 1997. The order further specified that $36 million in cost of service savings be distributed with interest over four years beginning in 1998. Based on the ratio of exchangeable plant in service to total plant in service (the "PTDG ratio") taken from PGE's ASC filing that was suspended when PGE's Residential Exchange Termination Agreement was negotiated, BPA assumed that 60 percent of such merger benefits would reduce Contract System Costs. This results in a $9.7 million reduction to PGE's Contract System Costs during the first three years of BPA's rate period, FY 2002-2004.

Q. What simplifying assumptions were used to estimate ASCs for Avista and IPC?

A. The test years of the most recent ASC filings for Avista and IPC are 1983 and 1984, respectively. With such old data, BPA estimated a proxy ASC for 1997. BPA determined prior ASCs as a percentage of average residential revenue per kilowatthour (kWh) sold for the test years and applied those percentages to average residential revenue per kWh sold for 1997. The post-1997 ASCs for Avista and IPC were escalated at 2.5 percent annually. This escalation rate is equal to the simple average annual rate of growth in ASC for MPC, PGE, Puget, Pacific Power, and Utah Power, for the FY 1999–2010 period.

Q. How were system and residential loads forecasted for the IOUs?

A. Load forecasts for PacifiCorp and PGE were based on data submitted by the utilities and used in BPA's 1996 rate case. Load forecasts that did not extend through FY 2010 were escalated at average annual rates of growth during the utility's forecast period. Load forecasts for MPC and Puget are based on utility forecasts submitted to BPA in March 1998. Loads for IPC were estimated from publicly available data in early 1998. Residential loads for Avista were estimated by reviewing current total utility load data and residential loads that had been provided by Avista for FY 1995.

Q. How were ASCs and residential loads forecasted for Clark County PUD, Snohomish County PUD, and the City of Idaho Falls?

A. Because these utilities terminated their RPSAs so long ago, it is unwise to project such obsolete cost data ahead 10 or more years just to determine ASCs for the first year of BPA's rate period. Instead, with the cooperation of utility staff, BPA staff estimated current ASCs for Clark and Idaho Falls using BPA's Excel-based ASC evaluation template. Such ASCs were then escalated at 2.2 percent annually through FY 2010. This escalation factor is lower than the escalation factor applied to Avista's and IPC's ASC described above. The escalator applied to Avista and IPC is significantly influenced by the assumption that load growth is satisfied by purchases at 28.1 mills/kWh. Clark and

Idaho Falls have access to BPA's preference power at rates lower than BPA's five-year flat block purchase forecast for their net requirements. To estimate the effect of lower purchased power costs on ASC, BPA determined the simple average annual rate of growth in ASC for MPC, PGE, Puget, Pacific Power and Utah Power for the FY 1999-2010 period, substituting PF-96 for the higher 28.1 mills/kWh price that was used to estimate the IOUs' ASCs. Using the lower PF-96 rate for load growth-driven purchased power yielded the lower escalation rate for Clark and Idaho Falls. Both Clark and Idaho Falls provided current load forecasts.

Q. What approach was used to estimate and forecast Snohomish PUD's ASC?

A. Using 1997 annual report data, Snohomish PUD's ASC was estimated to be 30.87 mills/kWh. Snohomish's ASC effective October 1, 2001, is estimated to be 30.07 mills/kWh. This reduction is largely based on assumptions of reduced purchased power costs. Snohomish's ASC was then escalated at the same annual rate, 2.2 percent, that was applied to Clark and Idaho Falls.

Section 4. "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 Residential Exchange Program.

A. BPA counsel has advised that 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 Residential Exchange] 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" that would otherwise occur under the Residential Exchange Program, and is designed to provide a mechanism to limit the net costs of the Program. 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. Are all exchanging utilities likely to be subject to in lieu transactions?

A. No. BPA must determine which utilities are candidates for in lieu transactions. In lieu transactions are only appropriate for utilities with ASCs that exceed the PF Exchange rate. BPA therefore does not propose to in lieu utilities with ASCs below BPA's PF Exchange rate. In addition, where a utility's ASC is only slightly higher than the PF Exchange rate, it is inappropriate to assume an in lieu transaction because forecast error and the costs of implementation could make the in lieu transaction uneconomic. In lieu transactions therefore are financially sound only for utilities with ASCs significantly above the PF Exchange rate. Finally, in lieu transactions are financially sound only when the cost of the in lieu resource is significantly below the utility's ASC.

Q. You note that the determination of which utilities would be subject to in lieu transactions rests primarily on three factors: a utility's ASC, the cost of the in lieu resource, and the PF Exchange rate. Please summarize the determination of the exchanging utilities' ASCs.

A. BPA's forecast of exchanging utilities' ASCs is discussed in section 3 above. Complete documentation of the exchanging utilities' ASCs is contained in the Documentation for WPRDS, WP-02-E-BPA-05A.

Q. Please describe BPA's assumptions regarding the source and cost of in lieu resources.

A. BPA assumed that in lieu resources could be acquired by market purchases. The cost of such purchases is appropriately reflected by BPA's forecast of five-year flat block purchases, adjusted to reflect shaped delivery. *See* Oliver, *et al.*, WP-02-E-BPA-20. Shaped delivery is based on PF-02 billing determinants. Average energy prices from this forecast are 29.0 mills/kWh. Since this market forecast is for undelivered energy, BPA assumed 3.40 mills/kWh for delivery based on the forecast of the transmission contribution to the PF Exchange Program rate. *See* WPRDS, WP-02-E-BPA-05.

Q. What has BPA assumed regarding the timing of in lieu transactions?

A. Because in lieu transactions are governed by the terms of the RPSAs, BPA had to make assumptions regarding the relevant provisions of the RPSAs during the rate period. BPA has not yet negotiated new RPSAs for the period beginning in FY 2002. BPA assumed that contract provisions for new RPSAs would not unduly limit BPA's statutory right to implement in lieu transactions. For example, the previous RPSAs included seven-year notice provisions for implementing in lieu transactions based on the time needed to construct a new generating resource. Given the changes in the utility industry since 1981 and the ability of utilities to acquire power much more quickly, BPA assumed that the notice period to begin an in lieu transaction would be short enough to allow in lieu transactions to begin in FY 2002 after the negotiation of new RPSAs.

Q. How did BPA determine which exchanging utilities would be subject to in lieu transactions?

A. As described above, BPA developed forecasted ASCs for the exchanging utilities. BPA then compared the ASCs with a proxy for the new PF Exchange rate, which was determined to be at least as high as the 1996 PF Exchange rate. BPA then compared the simple average of utilities' forecasted new ASCs over the rate period to the 1996 PF Exchange rate (32.7 mills/kWh), and determined that only four exchanging utilities were likely candidates for in lieu transactions: MPC, Puget, PGE, and PacifiCorp's Utah Power Division. MPC's ASC is forecasted to be 33.12 mills/kWh in 2002, increasing to 41.13 in 2010. Puget's ASC is forecasted to be 39.01 mills/kWh in 2002, increasing to 47.01 in 2010. PGE's ASC is forecasted to increase from 38.68 to 46.04 mills/kWh over the nine-year period. Utah Power's ASC is forecasted to increase from 37.93 to 43.27 mills/kWh.

BPA then conducted preliminary runs of RAM reflecting the participation of the four IOUs. While Puget, PGE, and PacifiCorp's Utah Power Division have ASCs significantly higher than the preliminary RAM PF Exchange rate, MPC's average ASC for the rate period was 35 mills/kWh, which was relatively close to the preliminary rate. Because of MPC's deemer balance, which would have to be worked off before MPC could receive positive Exchange benefits, MPC's small residential load (approximately 60 aMW), and the risk of forecast error and administrative costs making the in lieu transaction uneconomic, BPA does not propose to in lieu MPC.

Q. *What part of the utilities' residential loads does BPA forecast will be subject to in lieu transactions?*

A. BPA proposes that in lieu transactions will occur beginning FY 2002 for 50 percent of the Exchange loads of Puget, PGE, and PacifiCorp's southern Idaho jurisdiction of its Utah Power Division. This averages 1202 aMW over the rate period. BPA assumed that the loads of all three utilities would be subject to in lieu in order to spread the impact of in lieu transactions among the three state jurisdictions of Washington, Oregon, and Idaho instead of placing the impact in a single jurisdiction.

Q. *Why does BPA propose to in lieu only 50 percent of the utilities' residential loads instead of a larger amount?*

A. As described above, in lieu transactions are only appropriate for utilities with ASCs that exceed the PF Exchange rate. The proposed PF Exchange Program rate of 37.11 mills/kWh is reasonably close to the utilities' ASCs in the early years of the rate period. BPA is less inclined to assume a larger in lieu amount where there are only small differences between ASCs and the PF Exchange rate. In addition, BPA has limited the in lieu amount to 50 percent to account for risk and uncertainty regarding forecasted ASCs, to reduce possible adverse effects to the utilities of receiving large in lieu power deliveries on relatively short notice, and to ensure that some amount of benefits of Federal power would be provided to the residential and small farm consumers of the exchanging utilities.

Q. *Please explain your concerns regarding risks related to forecasted ASCs.*

A. BPA is unsure whether, over the lengthy ASC forecast period, there will continue to be a significant difference between the expected price of in lieu power and the ASCs of likely candidates for in lieu transactions. BPA is looking ahead more than two years until the start of the rate period, five years during the rate period, and then, for purposes of the section 7(b)(2) rate test, an additional four years. While BPA's forecasts have been conducted in the best manner possible, BPA is not developing its forecasts from current ASC reports. As noted above, due to settlement of most exchanging utilities' RPSAs, BPA does not have information that is as accurate as was previously available to BPA. In addition, ASCs are also subject to variation for reasons beyond BPA's control such as market forces and industry restructuring.

Q. Please explain the possible adverse effects on utilities that were considered in determining not to in lieu greater than 50 percent of the utilities' loads.

A. Puget, PGE, and the southern Idaho jurisdiction of PacifiCorp's Utah Division could be placed in a surplus condition under an actual delivery of PF power upon relatively short notice. That is, the sale of power to an IOU under an in lieu transaction could provide the utility with more resources than would be necessary to meets its loads, thereby rendering the utility surplus. Disposing of such surplus could impose costs on the utilities and their customers if the revenue received for any resulting surplus sales should prove to be less than was paid for the power purchased from BPA. Utilities' sales of their surplus might also require marketing Northwest resources outside the region. Based on data taken from the 1997 Pacific Northwest Loads and Resources Study (Whitebook), in lieu sales equal to 50 percent of the utilities' exchangeable loads would approximately equal the utilities' deficits and would help minimize the effect of displacing the utilities' resources.

Q. Were the adverse effects of reduced Exchange benefits considered in determining the in lieu amount?

A. Yes. Absent a settlement, implementation of the Residential Exchange Program is the manner in which residential and small farm customers of regional IOUs receive benefits of Federal power. In lieu transactions, while fiscally prudent for BPA, reduce Residential

Exchange benefits. Assuming 100 percent in lieu transactions, for example, would completely eliminate Residential Exchange benefits where in lieu resource costs are less than the PF Exchange rate. This would eliminate nearly all benefits of Federal power received by the residential and small farm customers of regional investor-owned utilities. In addition, the current proposal highlights certain potential effects on exchange benefits that have not been previously recognized by BPA.

Q. How would Residential Exchange benefit payments to PGE, Puget, and Utah Power be affected by 50 percent in lieu transactions with those utilities?

A. The anticipated effect of such transactions would be influenced by the forecast that in lieu resource costs will be considerably lower than the PF Exchange rate. Given this relationship, the effect then depends on the contract provisions that are assumed to be in place during the rate period to implement in lieu transactions.

Q. How would the 50 percent in lieu assumption be implemented under an RPSA that has in lieu provisions substantially similar to provisions in the 1981 RPSA?

A. Under the 1981 RPSA, a utility had two options if BPA intended to implement an in lieu transaction. The utility could purchase actual power from BPA at the PF Exchange rate in the amount of the in lieu transaction, or it could refuse the power and reduce its ASC to the cost of the in lieu resource for the amount of the in lieu transaction (in this case, 50 percent). Under current conditions, where in lieu resources are projected to cost considerably less than the PF Exchange rate, utilities would have no rational incentive to purchase power from BPA at greater than market prices. The utility would opt instead to reduce its ASC to the in lieu resource cost. By reducing its ASC to resource cost for, in BPA's proposal, 50 percent of its exchange load, the utility might continue to receive exchange benefits for the remaining 50 percent of its exchange load. The 1981 RPSA is silent, however, regarding the effect on total benefits associated with the reduced ASC portion of exchange load.

Q. *What are some contract options to address the treatment of that portion of exchange load that has an ASC reduced below the PF Exchange rate?*

A. One approach would have the "negative benefits" of the in lieued portion of exchange load be offset against the positive benefits associated with the remaining exchange load. This approach could result in net negative benefits to a utility. This situation could occur if the difference between the utility's ASC and PF Exchange rate (positive benefits) is less than the difference between the PF Exchange rate and the in lieu resource cost (negative benefits). This option could create anomalous results. For example, a utility could be required to pay money to BPA. Also, a 100 percent in lieu transaction could be of less benefit to BPA than a 50 percent in lieu transaction.

Q. *What alternative contract provisions could address this situation?*

A. It is reasonable to assume that a new RPSA would allow a utility to terminate its participation in the Residential Exchange Program for the in lieued portion of its exchange load where such load had its ASC reduced to the in lieu resource cost and where such cost was less than the PF Exchange rate. This would allow a utility to receive benefits for its remaining non-in lieued exchange load. Based on BPA's proposal of a 50 percent in lieu of PGE, Puget and Utah Power, each utility's exchange benefit would be reduced by approximately one-half. This would avoid the possibility of zero, or even negative, benefits to a utility in a situation where some of the utility's exchange load is still actively exchanging.

Q. *Does this conclude your testimony?*

A. Yes.