I. INTRODUCTION

Q. What is your name and business address?

A. My name is Alan P. Buckley. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive SW, Olympia, Washington, 98504-7250.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Senior Policy Strategist. I am responsible, among other duties, for the analysis of power supply issues relating to the Commission's jurisdictional electric utilities.

Q. Would you describe your education and relevant employment experience?

A. I received a B.S. degree in Petroleum Engineering from the University of Texas at Austin in 1981. In 1987, I received a Masters of Business Administration degree in Finance from the University of California at Berkeley Haas School of Business. From 1981 through 1986, I was employed by British Petroleum Company in San Francisco as a Petroleum Engineer working primarily on large Alaskan North Slope exploration and drilling projects. From 1987 through 1988, I was employed as a Rates Analyst for Pacific Gas and Electric Company, also in San Francisco. Beginning late 1988 until late 1992, I was employed by R.W. Beck and Associates, an engineering and management consulting firm in Seattle, Washington, conducting cost-of-service and other rate studies, carrying out power supply studies, analyzing mergers, and analyzing the rates of the Bonneville Power Administration and the Western Area Power Administration.

I came to the Commission in December, 1993. I have held a number of positions here, including Utilities Analyst, Electric Program Manager, and the position that I presently hold. I have provided testimony in numerous proceedings before the Commission, in addition to testifying in proceedings at the Federal Regulatory Commission and the Bonneville Power Administration.

Q. What is the purpose of your testimony in this docket?

A. I provide analyses of Avista's proposed power supply expenses and present Staff's recommended adjustments to those expenses. In addition, I analyze the Company's proposed Power Cost Adjustment mechanism and present Staff's recommendations for that proposal.

Q. **Did you prepare any exhibits in this docket in support of your testimony?**

A. Yes, I have prepared Exhibit ___ (APB-1) through Exhibit ___ (APB-6).

Q. Have you provided a table of contents for your testimony?

A. Yes. My testimony is organized as follows:

1) Introduction;
2) Summary of Recommendations and Adjustments;
3) Review of Past Commission Orders;
4) Water Year Adjustment;
5) Mid- Columbia Adjustment;
6) Colstrip Availability Adjustment;
7) PGE Capacity Contract Adjustment;
8) Potlatch Adjustment;
9) Rathdrum Adjustment;

10) Wood Power Amortization Adjustment;

11) Capacity Purchase Adjustment;

12) Fuel Cell Gas Adjustment;

13) Dispatch Credit Adjustment;

14) Purchase Power and Sales Issues;

15) Centralia Power Supply Expense;

16) Market Transaction Adjustment; and

17) Power Cost Adjustment Mechanism.

II. SUMMARY OF STAFF'S RECOMMENDATIONS AND ADJUSTMENTS

Q. Can you please summarize Staff's recommendations and adjustments?

A. Yes. The results of Staff's recommendations and adjustments are presented in Exhibit ____ (APB-1) through Exhibit ____ (APB-4). Exhibit ____ (APB-1) is Staff's restated Power Supply Proforma Year Expenses as a result of its recommendations and adjustments. Those items changed are indicated by the box outline. These adjustments result in an approximately $13.6 million system decrease in proforma year net power supply expenses (as compared to the Company's net power supply expense amount indicated in Exhibit 152), in addition to the rate base adjustment recommended by Staff witness, Mr. Parvinen. Exhibit ____ (APB-2) is Staff's adjusted Summary of Secondary Sales, Purchases, and Thermal Generation based on Staff Dispatch Model, using a rolling 40-year average for hydro generation and adjusting the availability of Colstrip Units 3 and 4. Exhibit ____ (APB-3) is a summary showing the power supply expense-related treatment of the PGE contract buydown revenue based on Staff's recommendations and adjustments. Exhibit ___

(APB-4) is the Staff's Dispatch Model run output. Staff's recommendations and adjustments are as follows:

1) Staff recommends continued use of a 40-year rolling average for determining hydro generation;

2) Staff adjusted the availability of Colstrip 3 and 4 units to a more representative value;

3) Staff adjusted the revenue associated with the PGE Capacity Sale to reflect the long-term revenues associated with the sale buydown;

4) Staff recommends that PGE Contract Buydown Revenue be used to: a) buy out the remaining balance of the Rathdrum Combustion Turbine (CT) lease; b) fully amortize the balance of the Wood Power contract buyout costs; c) provide the Company with full recovery of Potlatch purchase power contract costs; and d) offset certain rate base items identified by Staff witness Mr. Parvinen;

5) Staff adjusted the cost of the Potlatch Purchase Power contract downward to reflect a more realistic estimate of long-term costs for that amount of power;

6) Staff adjusted the Rathdrum CT lease payments to zero, to reflect the buyout of the Rathdrum CT lease. Ratepayers continue to pay incremental costs and continue to capture benefits from selling into the market;

7) Staff adjusted the Wood Power Amortization expenses to zero to reflect the full amortization of the amount using PGE Contract buydown revenues;

8) Staff adjusted the Capacity Purchase expenses to zero to reflect a lack of support and potential double counting;

9) Staff adjusted the Fuel Cell Gas expenses to zero to reflect the lack of demonstrated benefits to ratepayers;

10) Staff adjusted short-term sales revenues and short-term purchase expenses to reflect the ability of the Company's system to shape energy into optimal load hours;

11) Staff made no adjustments to rate base or power supply expenses as a result of the proposed Centralia sale. Staff witness Mr. Martin discusses the treatment of any gains from the sale;

12) Staff adjusts power supply revenues to reflect a conservative estimate of market transaction activity;

13) Staff recommends that the Commission not approve the Company's proposed Power Cost Adjustment mechanism; and

14) Staff recommends that the Company initiate a process through which customer input can be obtained and Commission policies addressed, with the goal of developing an acceptable power cost adjustment mechanism.

III. REVIEW OF PAST COMMISSION ORDERS

Q. Can you provide a general summary of past Commission orders affecting Avista power supply issues?

A. Yes. The last adjustment to general rates, power supply related or otherwise, was in 1990 as a result of what initially was a single issue filing related to the WNP-1 Exchange Agreement with the Bonneville Power Administration (Docket No. UE-900093). That proceeding resulted in a Commission adopted Stipulation that resolved many contested issues that arose as a result of the Company's filing. Prior to that proceeding, electric rates were adjusted in 1987, again as the result of a Settlement Agreement resolving a number of issues surrounding the Company's investment in WNP-3 (Cause No. U-86-99). The last fully litigated electric general rate increase was completed in April, 1986 in Cause No. U-85-36. The most relevant issue in that proceeding was the Commission's decision regarding the use of a rolling 40-year average for purposes of deriving normalized power supply expenses. Power supply issues in both of the settlements were essentially limited to the single issues that initiated the proceedings.

Another past order of particular significance to this proceeding is the Commission's First Supplemental Order Denying Petition in Docket No. U-88-2363-P. In that proceeding, Avista sought an accounting order permitting the implementation of a Power Cost Adjustment mechanism. The Commission denied the petition, concluding that the proposed mechanism was not consistent with the public interest. I reviewed this order carefully in light of the Company's power cost adjustment proposal in this proceeding.

I also reviewed several other orders of interest, concentrating on those that have addressed issues raised by Avista's filing in this proceeding. In the Third Supplemental Order in Docket No. U-89-2955-T, the Commission revisited the water year issue. In the Third Supplemental Order in Docket No. UE-901184-P, the Commission reaffirmed its position regarding hydro adjustments. In the Eleventh Supplemental Order in Docket Nos. UE-920433, et al., the Commission set forth strong language upholding the use of a 40-year rolling average for the water year. In that Order, as well as in the subsequent Nineteenth Supplemental Order, the

Commission also addressed a company's burden to show the prudence of its new resource acquisitions. All of these orders were reviewed as part of Staff's analyses in this proceeding.

<u>IV. WATER YEAR ADJUSTMENT</u>

Q. Can you summarize your adjustment related to the use of the Commission's well established 40-year rolling water year average methodology as opposed to the Company's proposal?

A. Yes. I decreased power supply test year proforma expenses by approximately $5.9 million to reflect the use of a 40-year rolling average for determining "normalized" hydro conditions. The adjustment is in three parts – first, an adjustment to Short-Term Sales, second, an adjustment to Short-Term Purchases, and finally, an adjustment to the Fuel expenses associated with Kettle Falls, Colstrip, Centralia, and the Rathdrum Turbine.

Q. Can you summarize the Company's proposal in regard to the number of water years to be used?

A. Yes. The Company used 60 years of streamflow data (1928 to 1988) to derive monthly hydroelectric generation and regional surplus amounts for input into the Dispatch Model. The Company made several adjustments to the regional surplus data to better reflect actual uncertainties in the runoff and operation of the reservoirs.

Q. What is the basis of your adjustment?

A. The use of a 40-year rolling average reflects the Commission's decision in Docket No. UE-920433, <u>et al.</u> (WUTC v. Puget Sound Power & Light Co.), as well as other proceedings that have addressed this issue. In Docket No. UE-920433, Puget proposed the use of a 50-year historical average to estimate normal hydro conditions. Also in that proceeding, Avista actively participated as an intervenor and submitted its own testimony arguing that a 50-year average was more reliable than a 40-year rolling average.

Q. What did the Commission conclude in Docket No. UE-920433 regarding the appropriate average to use?

A. In adopting Staff's recommendation to use a 40-year rolling average, the Commission stated clearly that the parties had spent far too much time revisiting this issue and that they had done nothing more than repeat arguments and evidence presented in previous cases (Eleventh Supplemental Order at 43). The parties were further put on notice that the use of the 40-year rolling average "will remain the Commission's position on this issue unless and until a clear and convincing argument supports a superior alternative."

Q. Did the Company's direct case in this proceeding make such a showing?

A. No. During cross examination Mr. Norwood contended that Exhibit T-151 contains the additional testimony that addresses the 60-year water record. (Tr. 183 - 184) Mr. Norwood's testimony, however provides only a general explanation of why the Company used 60 years of streamflow data and does not present any new analysis to justify a departure from the Commission's well established position.

Q. Did the Company provide any other studies or analyses to support its use of a 60 year average?

A. No. In response to Staff Data Request 26 (Exhibit 160), asking the Company to provide trend or pattern analyses supporting Mr. Norwood's statements, only copies of Company exhibits from Docket No. UE-920433 were provided together with a cite to

Staff witness Winterfeld's testimony in Cause No. U-85-36. When asked to provide all studies, analyses, or documents supporting the use of a 60-year average in this proceeding, the Company provided only copies of testimony or exhibits from past proceedings in which the arguments had already been rejected. (Exhibit 161) One of the items, in fact, was from a filing that was later withdrawn. On cross-examination, Mr. Norwood stated that he was not aware of the Commission's language regarding the water year issue in Docket No. UE-920433. (Tr. 182) As a party submitting testimony on the matter in that proceeding, however, the Company certainly should have been aware of the Commission's position on the matter. Finally, on cross examination Mr. Norwood attempted to raise uncertainties regarding cumulative errors and changes in operations brought about by the 1995 Biological Opinion, and he claimed that the 40-year method does not accomplish what it was presented to accomplish. (Tr. 185) None of these claims have been supported by testimony, studies, or analyses as required by the Commission.

Q. Did you or other Staff present additional studies or analyses?

A. No. Staff believes the Commission's Order in Docket No. UE-920433 clearly states the Commission's position in absence of a "clear and convincing argument" necessary to support an alternative methodology.

Q. What is the effect of using a 40-year rolling average?

A. As stated earlier, its use results in an approximate $5.9 million adjustment to power supply proforma expense. The adjustment is determined by rerunning the Company's Dispatch Model using the latest 40 years of water data. Changing the number of water years used results in a decrease in Short-Term Purchases of approximately $3.8

million and an increase in Short-Term Sales of approximately $0.14 million. In addition, changes in hydro production over the study period also lead to changes in Dispatch Model utilization of thermal resources which results in adjustments to fuel expenses associated with Kettle Falls, Colstrip, Centralia, and the Rathdrum Turbine.

V. MID-COLUMBIA ADJUSTMENT

Q. Can you summarize your adjustment related to the Mid-Columbia projects?

A. Yes. I adjusted the Purchased Power proforma expense amounts related to the Wanapum and Priest Rapids projects by an increase of $9,000 and a decrease of $231,000, respectively. The result is a total net expense decrease relating to these two Mid-Columbia projects of $222,000.

Q. Can you describe the basis for your adjustments?

A. Yes. In developing the Company's pro-forma cost estimates for purchases from the Wanapum and Priest Rapids projects, the Company used "unofficial" power cost forecasts from Grant County dated October, 1998. In response to Staff data requests asking for subsequent "official" estimates received by the Company, updated forecasts were provided to Staff which showed a slight increase in Wanapum costs and a larger decrease in Priest Rapids costs. (Exhibits 165 & 166) I adjusted power supply test year to the average of 2000 and 2001.

Q. Is the use of the later cost forecast appropriate?

A. Yes. In adjusting proforma power supply expenses for a June, 2000 to July, 2001 "test year," the use of the later forecast is appropriate.

VI. COLSTRIP AVAILABILITY ADJUSTMENT

Q. Can you summarize your adjustment related to Colstrip availability?

A. Yes. I decreased the Purchased Power proforma expense amounts related to the Colstrip 3 and 4 units by $428,400. The adjustment has three components – the first is an adjustment to Short-Term Sales, the second is an adjustment to Short-Term Purchases, and finally I made an adjustment to the Fuel expenses associated with Colstrip.

Q. Can you describe the basis for your adjustment?

A. Yes. In reviewing the outage reports for the Colstrip 3 and 4 plant, there appeared to be an anomaly in the availability of the units in 1993 as compared to the recent years prior to and after 1993. The Company's response to Staff Data Request 160 (Exhibit 162) shows a significant outage of Unit 3 in 1993 due to transmission system problems. This single event was the principal cause for the unit 3 equivalent availability figure of just under 64% during 1993. This compares to a more typical range of 85% to 95% for both units during the years prior to and after 1993.

Q. How was your adjustment determined?

A. For ratemaking purposes, I believe that it is appropriate to use the most representative value for unit outages. These values should not reflect anomalies in the data. For the combined Colstrip 3 and 4 units, I used the four-year average from 1994 through 1998 in my Dispatch Model run. This also results in a value that best represents the most current operating practices. Using the 1994 to 1998 time period results in an average equivalent availability for the combined units of about 86%. This figure is still below the actual values obtained during the previous two years leading up to 1993. The annual equivalent availability was then converted to a monthly factor for input into the Dispatch Model.

Q. Can you explain the results of the Dispatch Model as a result of the new monthly factors?

A. Yes. The new monthly factors for the Colstrip 3 and 4 units results in an increase in Short-Term Sales of $80,000, a decrease in Short-Term Purchases of about $537,000, and an increase in Colstrip fuel expense of $188,500. This totals to a $428,500 reduction in Proforma Power Supply Expense.

VII. PGE CAPACITY CONTRACT ADJUSTMENT

Q. Can you summarize your adjustment related to the Portland General Electric Capacity Contract?

A. Yes. I have revised the annual revenue associated with the Portland General Electric Capacity sale downward to reflect the buying down of the contract to a rate more representative of the current market for capacity. The revision results in a decrease in annual proforma revenues from $18 million to $1.8 million. In addition to this adjustment, I am making several recommendations regarding the proposed treatment for ratemaking purposes of the $143.4 million cash payment made to the Company as part of the contract buyout. In addition to decreasing the proforma power supply revenues, my recommendations include: a) using the proceeds to buy-out the remaining balance of Rathdrum CT Lease; b) using the proceeds to fully amortize the remaining balance of the Wood Power contract buyout; c) providing the Company with full recovery of the Potlatch purchase power contract costs; and d) reducing certain Company rate base items. (Exhibit___ (APB-3)) These adjustments will be detailed in subsequent sections of my testimony and in the testimony of Staff witness Mr. Parvinen.

Q. Can you describe the basis for your proforma power supply expense adjustment and other related recommendations?

A. Yes. In December, 1998 the Company received a net-of-expenses $143.4 million dollar payment related to the monetization of the PGE Capacity contract. Generally stated, this money was received as a result of PGE buying down a 24-year contract between the Company and Portland General for 150 MW of capacity. The original contract provided approximately $18 million in revenue per year. In exchange for net $143.4 million cash payment made to the Company, the contract rate was reduced to a level resulting in annual revenue of approximately $1.8 million. My recommended adjustments are an attempt to reflect actual contract amounts in the proforma power supply expenses, and appropriately treat for ratemaking purposes the monies received as a result of the PGE Capacity Sale buy-down.

Q**. What did the Company present in its direct case relating to this transaction?**

A. No mention of the transaction was made. The Company's direct case did not contain one single word relating to the contract buyout or the receipt of net $143.4 million. Nor was the transaction memorialized in any of the workpapers provided by the Company. In describing the PGE Capacity contract proforma amounts the Company simply states that:

> Proforma revenue decreases because contract rates decrease from $10,400/MW/mo in the test period to $10,080/MW/mo in the first 6 months of the proforma and $9.920/MW/mo in the last 6 months of the proforma period.

(Exhibit 195, Book 1, p. 7) This "oversight" is disturbing. Finally, I believe it important to understand the magnitude of this transaction. The Company has received a cash payment of net $143.4 million (about $96 million for Washington jurisdiction). This compares to the Centralia gain that has been the subject of much debate that is in range of $19 million for the Company's Washington jurisdiction.

Q. Why is the failure to identify this transaction disturbing?

A. It appears that the Company made no effort to bring the transaction to the attention of the Commission. It was not until Staff's review of the Company's 1998 Form 10K in this proceeding that the transaction was "discovered" in a footnote to one of the pages, at which time Staff followed up with a data request to the Company. Staff has included the non-confidential portion of Volume 3 from the Company's response to Staff Data Request 288 as Exhibit____ (APB-5). A prior Staff data request (Exhibit 170) asking the Company to provide any documents, studies, and analyses regarding the PGE Firm Capacity Sale resulted only in Staff's receipt of a copy of the old agreement, sections from a 1993 IRP, and any analysis estimating the costs to serve the old sale. The lack of disclosure in either the Company's direct case, supporting workpapers, or initial discovery requests concerns Staff. Particularly troublesome is that the Company made proforma adjustments to the PGE contract test year expenses (mid-2000 through mid-2001) knowing that actual contract rates would be significantly different over the next 14 years. The fact that the transaction was not completed until late 1998 does not excuse omitting the new contract rates, and making a proposal before to the Commission for treatment of the cash payment. In fact, in a

May 11, 1998 internal memo, Company staff members recommended to Gary Ely, Jon Eliassen, and Ron Peterson that:

> At a minimum the Commissions and staffs should be informed of the contract buy-down and our proposed accounting and ratemaking treatment.

(Exhibit ____ (APB-5), p. 24)

Q. Did the Company follow the action recommended in the internal memo?

A. Not to my knowledge. However, Staff had been sent a letter informing the Commission of an earlier Wood Power purchase power contract buyout that represented approximately $9.5 million in <u>costs</u> to the Company.

Q. Would knowledge of the transaction have made any difference?

A. Yes, I believe so. The Commission in recent years has addressed several filings in regard to contract buyouts, as well as sales of generating and other assets. The intent has been to address the proper treatment of these transactions for both accounting and ratemaking treatment. Such actions regarding the PGE transaction could have resulted in resolution of this matter.

Q. Can you describe the Company's response to Staff inquiries regarding this transaction?

A. Yes. The Company explained that for ratemaking purposes the Company is passing on revenue under the new arrangement equal to the revenues under the old capacity arrangement. The Company also states that deferred revenues resulting from the transaction are being amortized over 16 years – from 1999 to 2014, or $8,865,000 annually. Finally, the Company makes the claim that in order to pass through the entire $18 million in benefits of the sale, it is "recognizing" an additional revenue credit for ratemaking purposes of $7,335,000 ($18,000,000-$8,865,000-$1,800,000) with $1,800,000 being the expected contract revenues under the new arrangement. The Company provided no explanation of the decision not to inform the Commission of the transaction.

Q. Does Staff believe the Company's treatment of the transaction is sufficient?

A. No. While the Company's treatment appears to meet a "no harm" standard that the Company presented to the Federal Energy Regulatory Commission, its treatment provides no benefit of the transaction to ratepayers. The Company's treatment in this case does not recognize any interest (or time value of money) benefits that occur as a result of the cash payment, or benefits that could be obtained by other treatments of the cash such as those suggested by Staff. For example, in the May 11, 1998 internal memo, Company staff identified a potential for a benefit net present value of $32 million. (Exhibit ___ (APB-5), p. 23) I believe that ratepayers are entitled to receive the benefits of this transaction and recommend that the series of adjustments to the identified power supply expense items and rate base be accepted.

Q. Are there other reasons why ratepayers should receive the bulk of benefits from this transaction?

A. Yes. Another aspect of the transaction involves the tie-in between the PGE Capacity Contract and the prudence of the Company's acquisition of the Rathdrum CT. My specific recommendation regarding the Rathdrum CT will be detailed later in my testimony. For now, it is important to note that in any analysis or discussion of the need for and benefit of the Rathdrum CT, the revenues associated with the PGE Capacity Sale have always been cited as a demonstration of the cost-effectiveness of the project. This connection is evident in the numerous filings and analyses that were provided in response to Staff Data Request 71 (Exhibit 171). Staff's recommendation regarding the PGE Capacity Sale buy-down revenue not only returns the benefits of the transaction to the ratepayers, but also resolves some of the issues related to several power supply expense items that would otherwise be potentially contentious issues in this rate case. This includes the prudence of the Rathdrum CT that has previously been tied to the PGE Capacity Sale. Finally, by providing the benefits of the transaction to ratepayers in this proceeding, Staff acknowledges that at some time during the life of the contract the sale may be priced at below market rates. By obtaining the benefits that are available now, this issue is resolved and the Company is not at risk for these revenues.

Q. Has the Company made any statements regarding the treatment of benefits?

A. Staff takes the Company's complete silence as evidence that the Company had planned on retaining the immediate benefits of the transaction. In another Company document marked "PGE Buydown Opportunity 3/16/88" (Exhibit ____ (APB-5) p. 38), the Company even went so far as to identify possible uses of the money. Those uses include the purchase of additional generation, purchase of a gas and/or electric company, use in higher return investments, or to invest in safe returns. Interestingly, in the same document the Company recognizes that:

> In the past, all margins from these types of sales have been flowed through to retail customers.

In the same paragraph it states:

> A good cause can be made to retain a portion of the margins from this contract. This restructuring would provide that opportunity.

Again the Company made no filing at the Commission, or provided any notice of the transaction at all to Staff, the Commission, or other interested parties.

Q. Recognizing that you will be detailing the individual adjustments later in your testimony, can you review the entire set of adjustments you are recommending regarding this transaction?

A. Yes. The specific amounts related to these adjustments will be introduced in each of the sections discussing the adjustments. First, the sales revenue associated with the PGE Capacity sale should be adjusted downward by $16,200,000 to reflect the true contract rate. Second, the power supply expense associated with the "Rathdrum Lease Payment" should be zeroed out and a portion of the PGE buydown cash should be applied to pay off the Rathdrum Lease balance. Third, I propose that the Wood Power Buyout amortization expense item be zeroed out with another portion of the PGE buydown cash to be applied to the remaining balance. Fourth, I propose that a portion of the PGE cash be used to credit the Company for recovery of all Potlatch purchase power revenues not recovered as a result of my proposed adjustment to that expense item. These recommendations are summarized in Exhibit ___ (APB-3). Finally, Staff recommends that the remaining balance of the cash payment be applied to certain rate base items. Staff witness Mr. Parvinen will detail those recommendations.

Q. Does the Company receive any of the benefits from the transaction?

A. Yes. First, the adjustments proposed by Staff will resolve several potentially contentious areas of uncertainty in the recovery of certain costs. Second, Staff is not proposing to calculate interest on the net cash balance between the receipt date and the beginning of the rate period (October 1, 2000) at which point the remaining balances are determined. The Company therefore receives the benefits of a substantial interest amount during that 21-month period. If the Commission does not wish the Company to receive benefits as a result of its actions, an interest amount could be applied to the year-end 1998 cash payment amount of $143.4 million prior to approving the recommended credits against that balance. Twenty-one months of interest would be approximately $12.6 million, based on Staff's proposed authorized return of 8.82 percent.

Q. Are there other issues related to this transaction?

A. Yes. Although Staff is not asking for a specific remedy regarding the issue of notice, we are asking the Commission to order the Company in all future instances to notify the Commission, in writing, of the nature of any such transactions as well as any proposed accounting treatment at the time of the transaction. Finally, it should be pointed out that by adjusting the PGE Capacity Sale revenue to reflect the actual contract rate, Staff recognizes that the last two years of the sale remain at the original amount, at approximately $19 million. Staff is not at this time recommending a levelized approach to these revenues that would capture those amounts for ratepayers today.

VIII. POTLATCH PURCHASE ADJUSTMENT

Q. Can you summarize your adjustment related to the Potlatch Purchase Power Contract?

A. Yes. For purposes of determining normalized power supply expenses, I adjusted downward the expenses associated with the Potlatch Purchase Power contract. I applied an energy rate of 29.7525 mills to the same annual proforma energy amount used by the Company. The $14.105 million adjusted cost of the purchase results in a decrease in annual proforma expense of approximately $8.5 million. In addition to the expense adjustment, I am recommending that $11.4 million of the PGE Capacity Sale cash payment be credited to the Company to reflect the difference between the adjusted rate and the actual contract rate from the beginning of the rate period (October 1, 2000) until the end of the contract period (December 31, 2001). I am recommending that the Company be allowed to recover these costs to be held whole for costs associated with this contract. As an added benefit to the Company, I have not applied a net present value to the up-front payment for the differential cost of my adjustment.

Q. **Can you describe the basis for your proposed adjustment?**

A Yes. The Potlatch sales and purchase contracts have been an issue with this Commission in the past. In response to Company filings in Idaho regarding the approval of an electric service and purchase agreement with Potlatch, Staff expressed concerns over revenue and cost allocations and the detrimental effect on Washington ratepayers. As a result, Staff proposed a new jurisdictional allocation methodology that would minimize the adverse revenue requirement impacts to Washington that would otherwise result if the more traditional approach is used. That methodology continues through to the Company's filing in this proceeding.

Q. **Is this the issue that your proposed adjustment addresses?**

A. No. My adjustment reflects the anticipated termination of what Staff believes would be, in effect, an over-market priced purchase if allowed as a proforma power supply expense for the purposes of setting rates in this proceeding. The Potlatch purchase power and electric service contracts end December 31, 2001. The average price imbedded in the power supply proforma year expense amount is $4.80 per MWh (48 mills/kWh). Staff believes that it would be improper to imbed such a high rate into base rates knowing that the contract terminates at the end of December, 2001.

Q. **What period does the Company's proforma power supply expenses reflect?**

A. The Company has chosen the power supply rate period of July 1, 2000 to June 30, 2001 to "match as closely as possible the first twelve-month period that the retail rate change from this rate case would be in effect." The decision on what power supply proforma period to use is somewhat arbitrary. In this proceeding, the beginning of the retail rate change has already slipped to October 1, 2000, a change of three months. The Potlatch contracts would then terminate only four months after the end of the first retail rate change. Given the historically long period between general rate cases, Staff believes that the adjustment of the Potlatch purchase contract to a more representative market rate would best reflect actual power supply costs over a representative period.

Q. **Is removing both the entire Potlatch purchase and electric service revenues an option to protect Washington ratepayers?**

A Yes. However, I believe that such an action is unnecessary if the Commission adopts Staff's proposed adjustment. For simplicity I am assuming that both the electric service and purchase agreements continue in some form, with an adjustment to the purchase power rate.

Q. **Why have you not made a corresponding adjustment to the electric service rate?**

A. The Potlatch electric service agreement contains a clause that already results in changes to the rate. These changes are based on the price of short-term sales and purchase prices obtained from the Dispatch Model.

Q. **Can you summarize why this adjustment is appropriate?**

A. Yes. The Company has a recent history of infrequent general rate cases setting base rates. Therefore, this would likely cause the over-market costs of the Potlatch contract to be imbedded in rates long after the energy cost was reduced through a new contract or other resource. The size and cost allocation problem associated with this purchase and the related service agreement prompts Staff to look for a reasonable solution. In Staff's opinion, the outlook for market prices in the near future is well below the aforementioned 48 mill/kWh amount. The magnitude and the effect on power supply expenses makes this contract different than other contracts that may end or begin in the period surrounding the rate period. Finally, it is important to recognize that Staff is not recommending that the Company be harmed by this adjustment. The reduction of $8.5 million in long-term annual power supply expenses to ratepayers is made by providing the Company with full recovery of its Potlatch purchase contract expenses from the beginning of the rate period to the contract termination date, without present value discounting in the proposed treatment of the $143.4 million PGE contract buyout.

VIIII. RATHDRUM LEASE ADJUSTMENT

Q. Can you summarize your adjustment related to the Rathdrum Lease Payments?

A. Yes. I have removed the $5,756,000 proforma power supply expense associated with the annual Rathdrum Lease Payment. This adjustment reflects the recommendation that a portion of the PGE Capacity Sale cash payment be applied to pay-off the balance of the Rathdrum lease, effective at the beginning of the rate period (October 1, 2000). The Company's response to Staff Data Request 72 (Exhibit 172) indicates a lease balance, as of October 1, 2000, of $55,277,777. To the extent that the actual lease balance differs from this figure, the actual balance amount should be used. The remaining revenues and expenses associated with Rathdrum are unchanged, with the exception of fuel costs derived from the Dispatch Model. The Rathdrum CT remains in the Company's resource portfolio for the purposes of determining power supply expense amounts. The combination of these adjustments and recommendations resolves all of Staff's concerns with respect to the acquisition of the Rathdrum facility, and will enable ratepayers to continue to receive the full benefits of the Rathdrum CT in the future.

Q. **Can you describe the basis for your adjustment and other recommendations?**

A. Yes. The Company acquired the Rathdrum Combustion Turbine in 1995 using off-balance sheet lease financing. In the Company's filing in this proceeding, the lease is being treated as an operating lease for book purposes and as a financing lease for tax purposes. The Company has made no filing in this jurisdiction regarding the proper ratemaking treatment of the Rathdrum Lease. In addition, the Company has made no filing in regard to the prudence of acquiring Rathdrum. During informal discussions with Staff prior to this proceeding, the Company has continuously alluded to the "benefits" of the PGE Capacity Sale and has relied upon that sale to justify the acquisition of Rathdrum. In its direct case in this proceeding, the Company did not provide a showing of prudence. The only documents that appear to address the need for the Rathdrum CT are copies from past Integrated Resource Plans.

The Company's response to Staff Data Request 71 (Exhibit 171) contains several documents that analyzed the economics of the facility. In several of those documents the Company's own Business Analysis Department has used the label "PGE Capacity Sale - Rathdrum, Idaho Site" as one of the identifying headings in the analyses presented to support the Rathdrum CT. Staff believes the tie-in between the two projects justifies the use of PGE buydown revenues to resolve the uncertainties surrounding Rathdrum.

Q. **How do your proposed adjustments and recommendations address your concerns?**

A. Staff recognizes that the Rathdrum CT may be economically favorable, based on the original terms of the PGE Capacity Sale, and thus benefits the ratepayers. The economic benefit of any new arrangement is less certain. Staff's proposed adjustments and recommendations renders moot both the prudence and lease treatment issues related to the Rathdrum CT. Using a portion of the cash proceeds from the PGE Capacity Sale to buy-out the remaining lease balance eliminates the proforma power supply expense item related to the Rathdrum CT. Ratepayers will continue to bear the operating risk of the facility and will retain the benefits of the Company's operation of the project.

X. WOOD POWER AMORTIZATION ADJUSTMENT

Q**.** **Can you summarize your adjustment related to the Wood Power Contract Buyout?**

A. Yes. I have removed the Company's $1,188,000 proforma power expense relating to the annual Wood Power Amortization. This adjustment reflects the recommendation that a portion of the PGE Capacity Sale cash payment be applied to pay-off the balance of the unamortized Wood Power contract buy-out balance effective the beginning of the rate period (October 1, 2000). I have calculated the balance to be approximately $5,046,868 as of October 1, 2000, based on the Company's workpapers.

Q. **Can you describe the basis for your adjustment and recommendation?**

A. Yes. The Company has proposed to amortize the $9.5 million cost of the contract termination over eight years beginning January, 1997. Although the Company did file for specific ratemaking treatment in Idaho, it did not do so in Washington. The Company provided a letter to the Commission explaining the transaction, including the proposed treatment to amortize the cost to a purchase power expense account over eight years. In that letter, the Company also stated that the unamortized balance would be included in rate base for reporting purposes. However, since the Company has not filed in Washington for any ratemaking treatment related to this transaction, no regulatory asset has been created. Staff's recommendation to apply a portion of the PGE Capacity Sale cash payment to the Company's unamortized balance based on the eight-year amortization resolves any ratemaking treatment issues relating to the Wood Power contract termination costs. Staff had planned to recommend that any rate base associated with this transaction in the Company’s filing should be removed and the Company credited the approximate $5 million balance (calculated as of October 1, 2000) against the PGE Capacity Sale cash payment. However, in recent discussions the Company has confirmed that in its filing in this proceeding, the Company neglected to include the unamortized balance in rate base. Therefore, no rate base adjustment to the Company's case is necessary. As an incentive to continue exploring ways to provide additional benefits to the ratepayers and the Company, Staff is recommending recovery of the amortized balance through a credit of a portion of the PGE buydown revenue. This amount would otherwise go to reduce other generation rate base per Mr. Parvinen's testimony.

XI. CAPACITY PURCHASE ADJUSTMENT

Q. Can you summarize your adjustment related to Capacity Purchase expenses?

A. Yes. I have removed $955,000 of proforma power supply expense associated with what the Company has labeled Capacity Purchases.

Q. Can you describe the basis for your adjustment to the Capacity Purchase expense amount?

A. Yes. This adjustment is justified for two separate reasons. First, the Company has failed to demonstrate need for the specific levels of capacity represented by the proforma expense amount. The only purported justification for the amount in the Company's Workpapers (Exhibit 195, Book 1, PS-2) is a statement that "similar capacity purchases are expected for the proforma period and therefore, no adjustment to test period actuals have been made." In its initial and supplemental response to Staff Data Request 61 (Exhibit 185), the Company provided only an explanation of 1998 purchases, some historical data, copies of test year agreements, and a discussion of the capacity purchase policy of the Company. The Company has not identified any specific purchases that require additional firming made possible by the capacity purchases. In addition, after removing almost all short-term sales and purchase amounts from the test year, the Company proposes to maintain capacity purchases at levels that no doubt supported the removed amounts. The Company has failed to demonstrate that the almost $1 million of capacity purchases are necessary for the much lower purchase power levels that result from the remaining “system” transactions. Finally, the Company has provided no analyses that address the ability of its own system (i.e., the Clark Fork River Projects or the Rathdrum CT) to meet its capacity requirements.

Q. **You stated that there were two reasons that you are proposing this adjustment. What is the second reason?**

A. As discussed later in my testimony, Staff is proposing an adjustment related to market transactions. That adjustment is based on the historical amounts of short-term sales and purchases made by the Company. Upon review this information, I noted that short-term capacity purchases are included in the historical figures that I used to derive Staff's Market Transaction adjustment. To allow the capacity purchase amount as a separate line item would result in a double counting of these expenses if the Commission chooses to adopt Staff's recommendation regarding a Market Transaction adjustment.

Q. **Doesn't this mean that if the Commission adopts Staff's Market Transaction adjustment, that the Company will, in effect, recover some costs associated with capacity purchases?**

A. Yes, it does. I did not net the annual capacity purchases out of the sales and purchase data that I used to determine a Market Transaction adjustment. I do believe such an additional adjustment is justified based on my earlier testimony on demonstrated need.

However, for purposes of remaining conservative in Staff's Market Transaction adjustment, I did not make that additional adjustment.

XII. FUEL CELL GAS ADJUSTMENT

Q. **Can you summarize your adjustment related to the Fuel Cell Gas adjustment?**

A. Yes. I have removed $71,000 from the proforma power supply expenses related to gas provided by the Company's Gas Department for use in a fuel cell pilot project. Staff believes that the expenses and costs associated with the project may be much broader, and encourages the Company on rebuttal to make the necessary adjustments to remove any costs not recovered in the tariffed rates under which the customer involved in this pilot takes service.

Q. **Can you describe the basis for your recommended adjustment?**

A. Yes. The Company has not identified long-term benefits that the ratepayers will derive from this pilot project. The distinction between ratepayers and the Company is important. The Company has not provided any documents or analyses showing value to ratepayers that justifies this expense being incorporated into the Company's base electric rates.

Q. **Can you expand on your statement that the costs associated with the fuel cell pilot may be broader?**

A. Yes. Although this adjustment is a small one, I believe that additional adjustments may be appropriate. Exhibit 163, the Company's response to Staff Data Request 73, provides a copy of the customer contract, a report and discussion on the project and various pilot options, and an internal memo regarding the economics of the project. None of these documents addresses the ultimate benefit to ratepayers or addresses the final costs of the pilot project. One of the documents shows that the host is billed under Rate Schedule 21 rates of $0.04023 per kWh, but the fuel cell generates electricity at a cost of about $0.08 per kWh, not including capital cost recovery. Given the information provided by the Company, and the questionable potential for future direct ratepayer benefits, Staff recommends that, at a minimum, the fuel costs of $71,000 associated with the project be removed. In addition, the Company should be ordered to provide a clear showing of benefits to ratepayers, or in the absence of such benefits, make the appropriate additional adjustments to make ratepayers whole.

XIII. DISPATCH CREDIT ADJUSTMENT

Q. **Can you summarize your adjustment related to what you have called the Dispatch Credit?**

A. Yes. I made two adjustments relating to what I have called a Dispatch Credit. The Dispatch Credit reflects the fact that the Company's Dispatch Model does not carry out weekly, daily, or hourly dispatching of the Company’s resources. I have made a negative adjustment to Account 555 – Purchased Power of approximately $1.4 million, and positive adjustment to Account 447 – Sales of approximately $0.2 million.

Q. **Can you describe the basis for your recommended adjustment?**

A. Yes. The adjustment to Purchase Power reflects the decrease in Short-Term Purchase costs due to redispatching Company resources into the more expensive high-load hours, thus moving purchases into the lower cost low-load hours. The adjustment to Short-Term Sales represent the opposite, moving sales into the high priced high-load hours and production into lower priced hours. These adjustments attempt to reflect how the Company’s actual generation resources are operated, particularly storage projects and other dispatchable resources such as the Rathdrum CT that can dispatch into the market based on incremental costs.

Q. **Why doesn't the Company's Dispatch Model capture these benefits?**

A. The Company's model is a monthly model. This means that it only dispatches the resources based on monthly energy requirements, the "availability" of the resource, the price of energy on the market, and the incremental cost of the resource. (Exhibit 158) A particular resource is used either to meet load or to sell into the market if the market price is greater than the incremental price of the resource. A resource is dispatched only to its limit based on average monthly availability and average prices. No load variations across the month, week, day, or hour are recognized. Thus, the model cannot optimize a resource's available energy across the most cost-effective hours to minimize costs or maximize revenues.

Q. **On cross-examination Company witness Mr. Norwood stated that it was incorrect to characterize the Company's Dispatch Model as not being able to shape or redispatch the Company's resources on a daily or weekly basis. (Tr. 177-178) Can you comment on Mr. Norwood's remarks?**

A. Yes. I believe Mr. Norwood's response is more related to the calculation of available energy for each hydro project using what are called "H over K" curves or curves that convert water to energy based on flow and head. Applying hourly flow data to these curves affects the total amount of energy produced in whatever time period is being used; in the Company's case it is a total for each month. This summation is carried out once per water year. The use of the Northwest Power Pool hourly flow data to sum available energy from the hydro projects is not the system operation characteristic that

Staff is attempting to capture with this adjustment. Rather, Staff is attempting to capture the ability of the Company to operate the hydro generation facilities in a manner that optimizes value. Both of the main Clark Fork projects have storage capabilities and operation flexibility that have significant added value as compared to generation solely based on water flows alone. The Company identified this flexibility in filings related to its hydro relicensing effort.

Q. **How did you derive your proposed adjustment?**

A. I started by looking at three different methodologies. The first is to model the Company's resources using a production cost model that can dispatch on an hourly basis. A single average water year could be used to analyze the extent that generation or other dispatchable resources would optimize costs on a normalized basis.

Q. **Did you carry out this analysis?**

A. No. Due to time and workload constraints I was not able to take this analysis beyond the conceptual phase. Staff recommends that the Commission encourage the Company to investigate power supply model options that can better reflect the actual operations of the Company's resources. This may include the use of hourly production cost models for power supply normalization and ratemaking purposes.

Q. **Can you describe your second approach?**

A. Yes. The second approach was to look for ways to evaluate the benefits of the Company's hydro generation facilities, particularly the larger Clark Fork River projects, without using production cost models. I reviewed material from an economic task force that I participated in during the early stages of the relicensing effort. One of the task force assignments was to analyze the relative value of being able to operate the facilities with storage capabilities, as compared to run-of-the-river operations. This is relevant because I believe the Company's Dispatch Model operates similar to a run-of-river project. Run-of-the-river projects have no shaping capability, similar to a resource in the model which is simply dispatched based on the amount of monthly energy that it has available.

Q. **Did the analysis result in any benefits being identified?**

A. Yes. In the Cabinet Gorge and Noxon Rapids Hydroelectric Project's "Final Environmental Impact Statement," the Company stated:

> However, operating Noxon Rapids and Cabinet Gorge as run-of-river projects would significantly reduce Avista's flexibility to provide special services such as load following, load shaping, and spinning reserves to meet customer demands. Additionally, the production value of the projects would be reduced by 15 to 20 percent.

(pp. 2-36)

Q. Did you calculate a Dispatch Credit based on the Company's statement?

A. No, I did not. Regardless of how one views the matter, 15% to 20% of the value of these projects is a very large number. Without the detailed analysis supporting those numbers, however, I did not want to introduce an estimate based on those amounts. Nevertheless, the Company's statement acknowledges the value of the flexible operation capability of those projects.

Q. **How did you derive your recommended adjustment for this proceeding?**

A. I made what I believe are simple, conservative, and easy to understand assumptions regarding changes in both short-term sales and purchases. These changes represent the operational flexibility of the Company's resources and are derived from the output of Staff's Dispatch Model run. First, I assumed an initial equal distribution across the period for both sales and purchase energy amounts. Then, for sales I assumed that the operational flexibility of the system could allow the Company to move 50% of the low-load hour sales into high-load hours. For purchases, I moved 50% of the high-load hour amounts into low-load hours. For purposes of determining an adjustment amount I applied a low-load hour/high-load hour price differential to the sales and purchases amounts. I used 4.4 mills, obtained by averaging monthly low-load and high-load hour energy rates contained in the Bonneville Power Administration's Rate Case Federal Notice. I believe these estimates provide reasonable values for a Dispatch Credit.

XIV. PURCHASE POWER AND SALES ISSUES

Q. Can you describe your concerns regarding the Company’s long-term purchases and sales?

A. Yes. The Company’s proforma power supply expenses include both costs and revenues associated with longer-term wholesale transactions. Many of these transactions are significant, from 25 to 100 average megawatts. Staff’s concern regarding these transactions is the Company’s failure to provide documentation supporting many of its resource acquisitions, or identifying the benefits of some of its sales. The Company, not Staff, has the burden to make a demonstration of prudence for resource acquisitions, including purchase power agreements. The Company must show that the selection of the resource was necessary and reasonable and that the costs of acquisitions are appropriate. The Commission has made this clear in previous cases, most notably in its Eleventh Supplemental Order in Docket No. UE-920433.

Q. Did the Company make such a showing for its wholesale power transactions?

A. Staff does not believe that the Company has met the full burden for several of the transactions. For several of the resources, the Company provided only general statements that the resource was needed to meet system obligations, and often referenced only a single page from an appendix to a past Integrated Resource Plan. The Company further stated that no additional studies or analyses are available. The claimed necessity for several of the transactions is puzzling.

Q. **Can you give an example?**

A. Yes. For example, the Company acquired a two-year low cost purchase from MIECO, stating that the purchase was needed "to meet system obligations." (Exhibit 178) Subsequently, the Company made a two-year sale to Portland General which, according to the Company, was effectively a sale of the MIECO two-year purchase purportedly made to meet system obligations. (Exhibit 179) These activities appear to be similar (though longer-term) to the trading type activities that the Company claims are too risky to include in the ratemaking process.

Q. Does the Company provide an explanation of benefits for any of the wholesale transactions?

A. Yes, in certain instances. For example, for the Clark 5-Year sale (Exhibit 167), the Company did provide a demonstration of the costs and benefits associated with completing the transaction. Another example is the showing of benefits achieved as a result of the Duke Index Purchase/Sale and the Idaho Index Purchase/Montana Index Sale arrangement. (Exhibits 163 & 164) This arrangement takes advantage of Avista's ability to take and deliver power at various locations due to its transmission position.

Q. Is Staff recommending an adjustment relating to the wholesale transactions?

A. No. Other than adjustments for those specific transactions identified elsewhere in my testimony, Staff is not recommending any adjustments. Staff recognizes that most of these transactions are relatively short-term, as compared to the more traditional long-term wholesale arrangements, and the net effect of removing each transaction or adjusting sales and purchase prices would be small.

XV. CENTRALIA POWER SUPPLY EXPENSE

Q. Can you describe Staff's power supply recommendations regarding the sale of the Centralia properties?

A. Yes. As of the time of preparing Staff's direct case, Avista has not made a final decision on the disposition of Centralia properties. The Company's witness stated on cross-examination that the Company intends to pursue the sale. Staff's recommendation this proceeding regarding the rate base and power supply expense associated with Centralia is independent of its actual disposition. Staff recommends that the present rate base and power supply proforma year expenses (adjusted per Staff's case) associated with Centralia remain as is until the Company makes a sufficient showing regarding the long-term cost of replacing Centralia power. Staff Witness Mr. Martin discusses the disposition of the gain from the Centralia sale in the event that the sale occurs.

Q. Can you describe the basis for your recommendation?

A. Yes. Staff's recommendation relies on Exhibit C-194, which is the Company's confidential response to Staff Data Request 241. Staff has also relied upon the confidential response to Records Request 9, made during cross examination. The

Company's confidential response has been attached as Staff Exhibit C-___ (APB-C6). Staff Data Request 241 asks the Company to provide all impacts on the results of operations for ratemaking purposes, assuming the sale of Centralia properties occurs prior to the start of the test year. The overall result of the calculation is a significant increase in revenue requirement due to the sale caused in large part by an increase in net power supply expense from removing Centralia and including a short-term 200 MW purchase from TransAlta, the proposed purchasers of Centralia. Staff's recommendation is based on an incomplete analysis of alternative replacement power options.

Q. Can you please elaborate?

A. Yes. Exhibits C-194 and Exhibit C-___ (APB-C6) show that the Company has agreed to a contract with TransAlta for Centralia replacement power. The purchase is for 200 megawatts per hour for the period July 1 through March 31 of each year, running from the sale consummation date through December 2003. The sale is essentially a flat-block sale during the period July 1 through March 31. The information provided by the Company in Exhibit C-___ (APB-C6) provides only a cursory analysis of how the TransAlta purchase compares to Centralia costs, and also contains two internal e-mails discussing Mid-C energy prices. The Company conducted no studies analyzing the actual size or shape of replacement power that might be needed to replace Centralia based on the Company's existing resource portfolio. The Company conducted no analysis of alternatives, other than looking at Mid-C prices. To summarize, there was no analysis of any least cost options. Under cross examination (Tr. 222-223), Company witness Mr. Norwood testified:

Q. Did the company carry out any analysis to determine what the least cost or most optimal long-term replacement resource would be absent Centralia?

A. Obviously there was a need for replacement power, assuming the sale went through, and a fairly sizable need, so what we did was we assessed the marketplace to determine the –basically, the best product to replace Centralia. So there was no formal assessment, other than the analysis done by our wholesale marketing people to assess the market.

Q. Did the company engage in any kind of bid process to acquire the replacement power represented by this contract?

A. No, we did not.

Staff believes that the acquisition of the TransAlta purchase does not meet the Commission's prudence standards for resource acquisitions. Ratepayers should be held harmless for the Company's short-term acquisition of Centralia replacement power. Staff also recommends that the Commission order the Company to put on a full demonstration of prudence for any long-term resource acquired to replace the energy previously provided by the Centralia facility in the event it is necessary to acquire any power at all.

XVI. MARKET TRANSACTION ADJUSTMENT

Q. Can you summarize your proposed adjustment relating to what the Company has labeled market transactions?

A. Yes. I have increased short-term sales revenues (from the Company's proforma test year levels) of approximately $5.15 million annually, reflecting an estimated normalized value for short-term energy transactions. This amount represents trading or market transaction margins that Staff believes the Resource Optimization Department could make by using all of the Company's resources, following the

Company's Corporate Financial Risk Policy. The adjustments represent energy trading activities beyond what is included as Dispatch Model input or output.

Q. **Can you summarize the Company's position regarding "market transactions"?**

A. Yes. Avista has claimed that all energy transactions that are not included as input or captured in the Company's monthly Dispatch Model determination of a sales or purchase amount are "risky" transactions. The Company has, therefore, removed these transactions for retail ratemaking purposes. The Company testifies that:

> These transactions are speculative in nature and are unrelated to purchases made to serve retail load, and are also unrelated to sales of surplus power from the Company's generating system.

(Exhibit T-151, p.20) The Company provides an AVISTA version of what it considers the distinguishing characteristics of so called "commercial transactions." Based on the Company's test year and Dispatch Model results, this represents a removal of approximately $11.8 million of net revenues.

Q. **How does this amount compare to your proposed adjustment?**

A. My adjustment reflects what I believe to be a conservative expectation of net revenues that could be achieved in an average year from trading activities consistent with acceptable risk exposure. The $5.15 million amount also reflects what I believe to be a reduction in margins for market transactions as compared to the Company's 1998 test year.

Q. Could actual revenues from these types of transactions be different?

A. Absolutely. Actual revenues could range from a loss to a significant profit. This is why Staff is proposing a lower, more conservative amount than what could be suggested by the data. Hopefully, the lower amount used by Staff will provide some symmetry in the event that a particular year's trading activity results in a loss. In addition, Staff's recommended adjustment reflects transactions that do not appear to be overly risky and does not represent a recommendation that the Company enter into truly speculative transactions for the benefit of ratepayers.

Q. Can you comment on what the Company has called speculative or commercial trading transactions and their characteristics?

A. Yes. The Company's stated position is that every energy transaction not included in its modeling effort is a "risky" transaction and, therefore, should not be included for ratemaking purposes. The Company also believes that there is significant uncertainty in the volume of the transactions as well as their profitability, so they should be excluded for ratemaking purposes.

Q**.** **Can you comment on the Company's risk management policy?**

A. Exhibit 188 consists of pages from the Corporate Financial Risk Policy provided by the Company in response to Staff Data Request 29. Section 6 of that document covers the Resource Optimization Risk Policy. In the initial Business Focus discussion the document states:

> The primary focus of the Resource Optimization is to acquire power resources on behalf of its customers, and to operate those resources, both owned and contracted in a manner which optimizes the value of the resources to customers and shareholder. These activities include selling surplus at maximum value. This includes hedging transactions and other energy trading activities that occur as a result of the prudent management of resources and result in additional value to customers and shareholders.

Section 6 goes on to describe policies related to what risk is addressed, the limits of risk, the products that are authorized, how trader performance is benchmarked, and what reporting is required.

Q. Does the Company's proposal on commercial trading operations take into consideration the entire range of possible transactions?

A. No. The Company's proposal to include only those costs and revenues associated with Dispatch Model short-term sales and purchases appears to be based on only a portion of the Risk Policy addressing the operation of owned resources. Even that portion of the policy is not fully carried out. Staff has difficulty understanding how monthly model results capture the true value of "optimizing" the Company's resources. Staff believes the Company's claim (which the Company emphasized) in direct testimony that ". . . the Company's filing provides to retail customers the full benefit of all secondary purchase and sales transactions associated with the operation of the Company's power resources, and transactions related to serving load," (Exhibit T-151, p. 23-24) is incorrect. Staff believes the authors of the Risk Policy had other transactions in mind that the Resource Optimization Department could use with reasonable limits and risks. In addition, the Company overlooks numerous other resources available to provide additional benefits to both ratepayers and shareholders, such as:

1) the experience of its personnel;
2) the technology available;
3) the possession of market information; and, perhaps most importantly
4) the transmission system of the Company.

Q. **Have you reviewed the transactions that the Company claims as risky?**

A. Yes. I reviewed Exhibits 187 and the Company's response to ICNU Data Request 10, which together are the Generation and Purchase Summaries and the Sale for Resale

Summaries provided by the Company for 1995 through 1999. In addition, I reviewed the Company's responses to Staff Data Request 314, which consists of copies of all pages from the informal books kept by the Company's Scheduler/Trader employees for 1998 and 1999. These later documents contain information such as dates, parties involved, delivery location, amount of power and the duration, price, and profit (or loss). It appears that all of the documents indicate a mix of system sales and commercial trading transactions.

Q. Can you comment on the transactions you have reviewed?

A. Yes. I can see nothing from my review that indicates any particular transaction or set of transactions as being overly risky. As noted earlier, some of the transactions are labeled as system and some as off-system. In the detailed informal books, it appears that some transactions have a negative profit while most show a positive profit. There is no evidence that any of the transactions go beyond what would normally be expected from the Resource Optimization Department following risk management policy.

Q. Do you have further comments on the "riskiness" of the Company's trading activities that they are proposing be excluded?

A. Yes. In response to cross examination, Avista's own Chairman of the Board, Chief Executive, and President described an example of a transaction that would be considered risky and speculative under the Company's proposal.

> Q. . . . The transactions, the short-term speculative transactions that are conducted by Avista utilities that the company seeks to exclude from rates, why aren't these transactions conducted through Avista Energy?

A. Whether you could be or not – because of the FERC rules of communication is the issue, I guess, because the opportunities come up inside the utility. As an example would be the utility does a lot of exchange power activities across the state between Puget and Montana Power and others. Oftentimes, they'll come up to be certain situations where because of that trade going on inside a utility, Puget will tell Avista utilities, We've got an extra block of power, can you move it for us. And they'll go do that. That communication is forbidden with Avista Energy.

Oftentimes in their work they do with Avista – I mean, with Bonneville Power Authority, a lot of the trades that go across the Northwest are done between Avista and Bonneville, from a utilities standpoint. And Bonneville might have surface [surplus] power. They will use the utility issues to move circuit power. A lot of that sort of communication is forbidden to go outside of the utility.

So it's just the opportunities that come up with system optimization between multiple utilities stays within utility. Avista Energy's activities generally dealing with real third-party buying and selling outside utility operations."

(Tr. 148-149) Mr. Matthews' words provide excellent examples of the types of transactions Staff would expect the Company to make using all of its resources, and with not a lot of risk. Taking advantage of information obtained as a result of other transactions or using its resources, such as the transmission system, are both examples of opportunities of which the Company should take advantage. Transactions such as these can be carried out with minimal risk. Furthermore, there is very little difference between many of the transactions that the Company calls short-term and risky (thus removed from the Company's case) and those that have been included in their model input as long-term. In my earlier testimony I described a series of purchases and sales that the Company carried out that were not for system requirements but were, instead, simple buy-sell arrangements. There is virtually no risk in these transactions, as they take advantage of either the Company's transmission system or its ability to market power in different geographic locations. The fact that these arrangements were for longer than a year appears to be the justification for including them in rates. However, the underlying nature of the arrangements is virtually the same as those short-term transactions the Company is attempting to exclude.

Q. How did you determine your proposed adjustment amount?

A. I looked at the short-term sales and purchase amounts for 1996, 1997, 1998, and 1999. Using the Company's methodology of removing modeled short-term sales and purchase amounts from the total, I calculated a "trading or marketing" sales and purchase amount for each year. My totals for trading purchase expenses were significantly higher than the Company's due to the lower short-term amounts from Staff's Dispatch Model run that were subtracted to derive trading amounts. This results in lower total annual revenues than would be calculated using Company amounts because Staff's expense side of the equation is higher for each year. For example, the Company's numbers indicate an approximate $12 million profit from trading activities for the test year 1998. Using Staff's Dispatch Model results, the estimated trading profit decreases to about $7.2 million. 1998 also represent a reasonably average water-year. For purposes of estimating a fair and reasonable amount for expected future trading activities that should be included for ratemaking, I used the lowest of the annual amounts that was calculated, or approximately $5.15 million. Using a four-year average would have resulted in an amount just over $10 million. The use of the lower amount reflects a conservative goal for ratemaking purposes, addresses the possible lowering of margins for trading activities, and allows the Company to provide additional value for its shareholders. Finally, Staff believes that absent a showing by the Company that the transactions represented are truly risky and outside the risk management policies, the Commission should adopt Staff's proposed adjustment of $5.15 million in additional normalized power sales revenues.

XVII. POWER COST ADJUSTMENT MECHANISM

Q. Can you summarize your recommendations related to the Company's proposed Power Cost Adjustment mechanism?

A. Yes. Staff is recommending that the Commission not adopt the Company's proposed mechanism as filed. Staff is concerned that such a mechanism, which would greatly affect the risks that customers bear as well as their bills, has been proposed without a sufficient opportunity for comment or involvement. The Company's proposal also clearly does not address all of the conditions set forth by this Commission in previous proceedings related to power cost adjustment mechanisms. Staff recommends that the Company initiate a process that involves customer input and also explicitly addresses those conditions that the Commission has, on several occasions, set forth in regard to power cost adjustment mechanisms. The results of the process can then be used to develop a complete power cost adjustment proposal that can be brought before the Commission.

Q. Can you review the policies that the Commission has set forth relating to power cost adjustment mechanisms?

A. Yes. In Docket No. U-88-2363-P and Docket Nos. UE-901183-T and UE-901184-P the Commission reaffirmed three key policy directions relating to power cost adjustment mechanisms. The Commission has consistently stated that it favors mechanisms that insulate a company from the noncontrollable effects of fluctuations in hydro conditions, provided that the following three conditions are met:

1) ratepayers should receive the benefit of a cost of capital reduction if the Commission approves a PCA for a company;

2) a power cost adjustment mechanism should be linked to those factors that are weather-related; and

3) a power cost adjustment mechanism should be a short-run accounting procedure that reflects the short-run cost changes affected by unusual weather.

Q. Has the Company's proposal explicitly addressed these three conditions?

A. I will start with the first condition. The Company's witness, Mr. Johnson, testifies that:

> The company is proposing a PCA in Washington to enhance earnings stability by flowing through to customers variations in the company's power supply revenues and expenses due to changes in uncontrollable factors, primarily hydro generation and short-term energy prices.

(Exhibit T-420, p.2) Clearly, this enhancement provides benefits in the form of reduced risk for the Company and increased risk for ratepayers, yet neither Mr. Johnson or the other Company witnesses explicitly address reductions in the cost of capital if the Commission were to approve the proposed power cost adjustment mechanism.

Q. **Can you comment on the remaining conditions?**

A. Yes. Turning to the second condition, Staff is concerned that the proposed mechanism goes well beyond that of simply making adjustments for random weather-related events. I believe the Company's proposal is unacceptable for two reasons. First, the proposed mechanism tracks long-term changes in costs for PURPA. No other rate base or expense item is tracked, whether it is projected to increase or decrease beyond the proforma test year period. This proposed tracking clearly includes more than weather-related events. Second, the mechanism makes adjustments based on differences between the energy prices developed using the Dispatch Model and actual short-term prices. This adjustment is made irrespective of hydro generation conditions, and may not even be related to them at all. Mr. Johnson testifies that:

> . . . In reality, energy prices can vary by a large amount even when hydro generation is close to normal. In both 1995 and 1998 hydro generation was within 3 percent of the 60-year average, yet the average energy price for the year was around $12/MWh in 1995 and $22/MWh in 1998. This variation in energy price can have a large impact on Avista's net power supply and the company cannot control the market price of power. There will always be unpredictable variation in actual short-term energy prices, and it is very likely that the future short-term energy prices will be different than the normalized rates included in this case. A mechanism to track the impact of short-term energy prices on the company's net power supply expenses is the best method to insure that customers pay, and/or receive the benefits of the costs actually incurred by the company.

(Exhibit T-420, p.4) Furthermore, when questioned about possible sharing, Mr. Johnson testifies that:

> The Company is proposing that 100% of the change in net power supply expenses be flowed through to customers. The cause of the cost changes that the company proposes to track, hydro generation, market energy prices, and PURPA expenses, are substantially beyond the company's control.

(Exhibit T-420, p. 5) The Company's proposed mechanism is structured to recover costs well beyond those that are weather related, even to the extent of the costs associated with dispatching the Rathdrun CT into the market.

Q. Do you agree that market prices are beyond the Company's control?

A. Not entirely. While there are aspects of the market that are beyond the Company's control (such as posted prices at trading hubs), the Company can control many market-related factors. These include the type of power purchased or sold, the time of day of the transaction, delivery points, or other similar characteristics. In addition, the Company controls other resource decisions, such as when to acquire long-term resources to meet its requirements. In addition to not necessarily being related to weather, Staff is concerned that the direct passing through of all short-term market expenses provides little incentive to acquire power in a least-cost manner.

Q. **Can you comment on the third condition?**

A. For reasons similar to the previous condition, I believe the Company's proposal falls short. Again, the Commission has required a short-term procedure that is tied to changes affected by weather. I have already established that the tracking of PURPA costs has nothing to do with weather and the adjustment of short-term energy expenses may or may not have the required connection.

Q. Do you have other concerns reagarding the proposed power cost adjustment?

A. Yes. Staff maintains that one of the most important characteristics of a power cost adjustment mechanism is ease of administration and auditing. The Company's proposal falls short of that goal. One can compare actual generation to what was used to set base rates and calculate the difference. However, the calculations beyond this point become difficult to administer and to audit. Based on the examples included as Exhibit 421, the Company proposes to use only those sales and purchase transactions related to operating its system for purposes of determining the weighted-average secondary price. The Company does not have the ability to distinguish between these transactions and what it calls "trading transactions." As long as the two types of transactions cannot be "tagged," there will be controversy as to which actual transaction to use in the calculation of the power cost adjustment. Upon audit, the parties will be forced to review all transactions of the Company in order to insure that the proper procedure was followed.

In addition, the Company's proposed hydro hourly shape adjustment (Exhibit 422) is extremely difficult to follow. This adjustment is meant to match the hourly shape of the change in hydro generation with the correct hourly shape of the short-term energy prices. Staff finds it surprising that the Company has proposed such a complicated adjustment in the power cost adjustment mechanism since the Company apparently is unable to shape generation from its using the Dispatch Model. This adjustment also is deficient because it attempts to use actual short-term system purchase and sales volumes during specific hours even though the Company has stated that it cannot distinguish between different types of short-term transactions. Finally, the amount of data that one would need to collect and audit to carry out the adjustment makes administration exceedingly difficult.

Q. **What additional issues need to be considered in connection with the power cost adjustment?**

A. Avista's power cost adjustment proposal has one serious problem that is perhaps unique to the Company's specific resource portfolio. The calculation includes setting the costs and revenues associated with certain contract obligations and rights at fixed levels. In previous times, these long-term arrangements would rarely change. Today, many of the arrangements, which Avista proposes to incorporate into the power cost adjustment calculation on a long-term fixed basis, will expire shortly after the initial rate period. They will, no doubt, be replaced by other transactions with different characteristics, also probably of a shorter-term nature. Staff is quite concerned that potential changes in these relatively short-term contracts could undermine the very revenue stability the Company is seeking to obtain through the proposed power cost adjustment.

Q. Does this complete your testimony?

A. Yes.