BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. ___________

DIRECT TESTIMONY OF

RICHARD L. STORRO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Richard L. Storro. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as the Director of Power Supply.

Q. What is your educational background?

A. I participated in a program with the College of Idaho and the University of Idaho, where upon completion I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973.

Q. How long have you been employed by the Company?

A. I started working for Avista in 1973 as a distribution engineer. I have worked in various engineering positions, and have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997 and became Director of Power Supply in 2001. My primary responsibilities involve the oversight of both the short-term and long-term planning and acquisition of power supply resources for the Company.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will provide an overview of the history of the ERM and provide a summary of the factors contributing to the power cost deferrals during the 2004 calendar year review period. I provide an overview of the documentation the Company has provided in workpapers, which the Company had agreed to provide in the ERM Settlement Stipulation approved and adopted in Docket No. UE-030751. I will also discuss the transformer outage at Coyote Springs 2 during 2004 and how the lost margin from the plant being out of service in 2004 will likely be much less than the margin from the second half of Coyote Springs 2 that will flow through the ERM to the customer's benefit in 2005.

Q. Are other witnesses sponsoring testimony on behalf of Avista?

A. Yes. Mr. William Johnson will provide testimony regarding the calculation of the monthly power cost deferrals. Mr. Ron Mckenzie will provide testimony concerning the monthly deferral entries and deferral balance.

II. OVERVIEW

Q. Would you please explain the history of the ERM and the annual filing requirement?

A. Yes. The ERM was approved by the Commission's Fifth Supplemental Order in Docket No. UE-011595 dated June 18, 2002, and was implemented on July 1, 2002. That Order approved and adopted a Settlement Stipulation (UE-011595 Stipulation) that explained the mechanism and reporting requirements. Pursuant to the UE-011595 Stipulation, the Company is to make an annual filing on or before April 1st of each year to provide the opportunity for the Commission Staff and interested parties to review the prudence of the ERM deferral entries for the prior calendar year. Interested parties are to be provided a 90-day review period ending June 30th of each year to review the deferral information. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order.

Avista's first Annual ERM Filing to review deferrals covered the six-month period of July 1, 2002 through December 31, 2002. In its Order No. 5 issued February 3, 2004 in Docket

No. UE-030751 the Commission approved and adopted a Settlement Stipulation (UE-030751 Stipulation) that resolved the issues related to the first review period.

Avista's Annual ERM Filing to review deferrals for calendar year 2003 was addressed by the Commission's Order No. 1 dated August 11, 2004 in Docket No. UE-040611. In that order the Commission found that the filing met the requirements of Docket No. UE-011595 and UE-030751, and that the power costs deferrals for 2003 were prudent.

Q. What period is covered by this ERM filing?

A. This ERM filing covers the period January 1, 2004 through December 31, 2004.

Q. What were the changes in power costs, the amounts deferred, and the amounts absorbed by the Company during 2004?

A. During 2004 actual net power costs exceeded authorized net power costs for the Washington jurisdiction by $20,663,573. Of that amount $10,497,216 was deferred, and the remaining $10,166,357 was absorbed by the Company. Under the ERM, the first $9.0 million of net power supply costs above or below the authorized level is absorbed by the Company. Ninety percent of power costs beyond the $9.0 million band are deferred for the opportunity for later recover. The remaining 10% is also absorbed by the Company. Carrying costs amounted to $280,482, resulting in a total deferral balance for the 2004 calendar year of $10,777,698.

III. SUMMARY OF DEFERRED POWER SUPPLY COSTS

Q. Would you please summarize the factors driving power supply expenses during the review period?

A. Yes. Power supply expenses were higher than authorized due primarily to lower hydro generation, losses on the sale of natural gas that was originally purchased for thermal generation, the transformer failure at Coyote Spring 2 that caused the plant to be out of service from January 16 through September 6, 2004 and the expiration of a profitable wholesale contract.

Hydro generation was approximately 23 aMW below the authorized level, which accounts for approximately $5.8 million (Washington allocation) of $20.7 million increased expense. This increased expense attributed to lower hydro generation is based on an average purchase and sale price for power during the review period of $41.93/MWh, which was above the authorized level of $32.17/MWh.

The loss on the sale of natural gas that was purchased for generation and later sold instead of burned was approximately $5.7 million (Washington allocation). It should be noted that most of those losses were attributable to fixed price gas contracts that were purchased during the energy crises in early 2001. The last of those contracts ended October 31, 2004. These contracts and the associated increased costs were addressed by the parties in developing the prior Settlement in Docket No. UE-011595, which was approved by the Commission in June 2002.

Another factor contributing to higher than authorized power supply net expense in 2004 was the outage at CS2 due to a transformer failure. Lost operating margin at CS2 for the period January 16 though September 6, 2004 is estimated to be approximately $1.9 million (Washington allocation).

Avista's long-term sale to PacifiCorp, which lowered authorized net expense by approximately $2.6 million (Washington allocation) ended September 2003, so that margin was not there in 2004.

In addition, the Company' gas-fired projects generated less than the authorized level due to the relatively low price of electricity compared to natural gas costs. The average market implied heat rate (Dow Jones Mid C index divided by Platt's gas Daily Malin Midpoint) during 2004 was 7,947 Btu/kWh. This compares to the average market implied heat rate embedded in the authorized proforma of 10,102 Btu/kWh. The lower market heat rate meant that market economics favored purchasing electricity rather than generating electricity with natural gas and, consequently, the Company's gas-fueled resources ran less than in the authorized proforma and produced lower operating margins.

The Company's other thermal plants, Colstrip and Kettle Falls generated 4 average megawatts below and 22 average megawatts above the authorized level, respectively.

Finally, the Company entered into three new long-term contracts during the review period. In April 2004, the Company signed a 10-year agreement to purchase wind power. In June 2004, the Company entered into an 8-year agreement to purchase power from the City of Spokane's Upriver hydroelectric plant. In October 2004 the Company extended an agreement to purchase power from the Black Creek hydroelectric facility. These contracts were provided as confidential attachments to the monthly deferral reports.

IV. COYOTE SPRINGS 2 TRANSFORMER OUTAGE

Q. Please further explain the transformer outage at the Coyote Springs 2 plant.

A. On January 15, 2004, operating indicators at the Coyote Springs 2 project noted a potential internal arcing problem in the plant generator step-up transformer (the main transformer connecting the plant to the grid). Numerous tests were conducted and found that internal arcing had in fact occurred, however the internal inspection found no visible cause. The manufacturer (Alstom) determined that the only way to find the cause was to return the transformer to its repair facility. The transformer was repaired and returned to the project site. As a result of the transformer malfunction the plant was out of service from January 16, 2004 through September 6, 2004. The transformer and the CS2 plant returned to service on September 7, 2004. Since that time the project has performed very well with an average equivalent availability factor of 99.33%.

Q. Has the Company made an estimate of the lost margin due to the outage?

A. Yes. The Company estimates that the margin that Coyote Springs 2 could have produced during the period when the plant was not available was $1,888,363 (Washington allocation). Of this total, $1,699,527 would have been deferred in the ERM ($1,888, x 90% customer share). This amount is less than one might expect, but as explained earlier, due to the relatively low price of electricity compared to natural gas costs during 2004, the plant would not have operated during a major portion of the time that the transformer was out of service.

Q. Are there any offsets to the Coyote Springs 2 lost margin resulting from the transformer outage?

A. Yes. Avista acquired the second half of CS2 on January 20, 2005 and has been operating the plant for the benefit of customers since that time. The operating margins from the second half of the plant will flow through the ERM and lower 2005 deferrals. The addition of the second half of CS2 was very timely given the very low hydro conditions expected for the balance of the runoff period. Based on actual prices through March 17 and forward prices through December 2005, it is anticipated that the second half of Coyote Springs 2 will produce operating margins of $5,741,293 (Washington allocation). Of this total, estimates show that $5,167,164 ($5,741,293 x 90% customer share) will be flowed through the ERM and reduce 2005 deferrals after the dead band is full.

This benefit of Coyote Springs 2 will accrue to Washington customers during a period when customers are not paying for either the capital costs or the operation and maintenance costs of the second half of the plant in base rates. The situation in 2005 is therefore exactly opposite of 2004, where customers were paying the capital and operating expenses for the first half of the plant in base rates while it was not operating for a portion of the year.

In summary, the operating margin from the second half of Coyote Springs 2 could exceed the Coyote Springs 2 lost margin in 2004 by three-fold. The operating margins in 2005 from the second half of CS2 will benefit customers through the ERM during a period when the capital and operating costs of the second half of CS2 are not in base rates.

Q. Has the Company purchased a spare transformer for CS2?

A. Yes. A spare transformer, from a different supplier than the existing transformer, was delivered to the site in December 2004, and is available for use if needed.

V. SUPPORTING DOCUMENTATION

Q. Please provide a brief overview of the documentation provided by the Company in this filing.

A. The Company maintains a number of documents that record relevant factors considered at the time of a transaction. The following is a list of current documents that are maintained and that have been provided (except for the Credit Reports) electronically as part of this filing on a compact disk:

Gas/Electric Transaction Record: These documents record the key details of the price, terms and conditions of a transaction and include a discussion of market conditions at the time of the transaction, the reason for the transaction, and pertinent transmission or other delivery issues.

(provided for each gas and electric transaction, not including real-time and pre-schedule transactions).

Position Reports: These daily reports provide a summary of monthly loads and resources over an 18-month forward period. Also included are forward hydroelectric generation estimates as well as critical water generation variability. Fixed price natural gas quantities are also shown assigned to the most economic available generation plant.

Long-Term Physical Electric Load & Resource Tabulation: For transactions with deliveries extending greater than the 18-month period covered by the Position Report, the Company includes this document to show the net average system position during the extended period. This document also shows variability associated with an 80% confidence interval around the combined variability of hydroelectric generation and variability of load.

Forward Market Electric and Natural Gas Price Curves: This daily data is maintained in Nucleus, the Company's electronic energy transaction database record system.

Electric/Gas – Heat Rate Transaction Worksheet: For each natural gas transaction a worksheet is prepared which summarizes the economics of the transaction using the forward electric and natural gas prices available in the market at the time of the transaction, the most economic available generator, and the resultant cost to generate electric power (provided as part of Gas/Electric Transaction Record).

Price Quote Worksheet: Provides a record of the natural gas purchase or sales prices available from several parties in the market at the time of a particular gas transaction. This record includes price information at specific points of delivery (provided as part of Gas/Electric Transaction Record).

Credit Report: Lists those counter-parties with which the Company is allowed to enter into either purchase or sales transactions as determined by credit criteria set by the Company.

These documents are in addition to the detailed monthly reports, which are filed with the Commission and provided to interested parties, as discussed by Mr. Mckenzie.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.