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 2003 calendar year review period. I discuss the sale of natural gas originally purchased for thermal generation during 2003 and provide an Exhibit showing that the sale of natural gas lowered power supply expenses by approximately $9.1 million. 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. Finally, I address the status of the transformer at the Coyote Springs 2 plant.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibit No. _____ (RLS-2), which was prepared under my direction. The Exhibit lists the sales of fixed-price natural gas and shows the resulting reduction in power supply expenses.

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 briefly explain the history of the ERM and the annual filing requirement?

A. Yes. The ERM was implemented on July 1, 2002. The ERM was approved by the Commission's Fifth Supplemental Order in Docket No. UE-011595 dated June 18, 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 an opportunity for the Commission Staff and interested parties to review the prudence of and audit 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 dated January 30, 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.

Q. What period is covered by this ERM filing?

A. This ERM filing covers the period January 1, 2003 through December 31, 2003.

Q. What were the excess power costs, the amounts deferred and the amounts absorbed by the Company during 2003?

A. During 2003 actual net power costs exceeded authorized net power costs for the Washington jurisdiction by $33,799,602. Of that amount $22,319,644 was deferred, and the remaining $11,479,958 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 recovery. The remaining 10% is also absorbed by the Company. Carrying costs amounted to $471,728, resulting in a total deferral balance for the 2003 calendar year of $22,791,372.

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 and the sale of natural gas that was originally purchased for thermal generation. Overall, power supply expenses were $33,799,602 (Washington allocation) above the authorized level for the period January through December 2003. The largest factor was the net expense related to the sale of fixed-price gas purchases made in 2001. Based on the average purchase and sale price, the fixed price gas purchases added approximately $16.8 million (Washington allocation) to expenses. Hydro generation was approximately 54 average megawatts below the authorized level, which would account for approximately $14.5 million (Washington allocation) of 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 $36.18/MWh, which was above the authorized level of $32.17/MWh.

Although there were other changes in power supply related costs as compared to the authorized level, they were relatively small. The Company' gas-fired generating plants 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 2003 was 7,671 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.

The Coyote Springs 2 plant came on-line July 1, 2003, therefore there was no generation from this plant prior to July 1, 2003. In its Order dated January 30, 2004 in Docket No. UE-030751, concerning the Company ERM review filing for the period July 2002 through December 2002, the Commission approved and adopted a Settlement Stipulation (UE-030751 Stipulation) that resolved the issue of potential increased costs the Company may have incurred due to the delay in the on-line date of Coyote Springs 2 through June 30, 2003, when Coyote Springs 2 came on-line. For the period when Coyote Springs 2 was available, July 2003 through December 2003, the plant generated 90 average megawatts compared to an authorized level of 98 average megawatts.

The Company has two other thermal plants not fueled by natural gas, a share of the coal-fueled Colstrip plant and the wood-fueled Kettle Falls plant. During the 2003 calendar year review period Colstrip generated 182 average megawatts compared to an authorized level of 187 average megawatts. Kettle Falls generated 42 average megawatts compared to an authorized level of 20 average megawatts.

Power supply expenses in the review period do not include any contract termination payments. The Company entered into three new long-term contracts during the review period. In July 2003, the Company signed a 44 months contract to purchase power from a small co-generation plant (see July 2003 monthly report). In November 2003, the Company entered into a contract with other owners of Colstrip Units 3 and 4 to provide power to the water pumps serving the plant (see November 2003 monthly report). In December 2003, the Company entered into a contract for 2004 to purchase exchange capacity (see December 2003 monthly report). These contracts have been provided as confidential attachments to the monthly deferral reports, as indicated.

IV. NATURAL GAS SALES

Q. Please explain how the Company managed its natural gas fuel supply for thermal generation during the review period.

A. The overall objective in managing the purchase and sale of natural gas for gas-fired generation is to minimize the total power supply expense of the Company. This is done by acquiring energy to serve load at the least cost at the time of the transaction, either by burning gas to fuel power plants or by directly purchasing electricity. Natural gas purchased for generation of power is converted to MWh based on the heat rates of the most efficient and economical plants available. On a daily basis, the cost to generate using gas is calculated using the market value of the gas times the heat rate of the plants plus any variable plant O&M. This cost to generate is then compared to the cost of market electricity for the same forward period. If the cost to purchase market electricity is lower than the cost to generate at the most efficient plants available, then the gas is sold and if needed, the power to replace the lost generation is purchased.

During the review period the Company had a varying amount of fixed-price gas that had been purchased in 2001. For the months January 2003 through October 2003 40,000 decatherms per day (dth/day) of fixed-price gas had been purchased. For the months of

November and December 2003 20,000 dth/day had been purchased. Prior to Coyote Springs 2 coming on-line on July 1, 2003 all 40,000 dth/day of purchased gas was sold and electricity was purchased as necessary to serve load. During the second half of 2003, with Coyote Springs 2 available, anywhere from 10,500 dth/day to all 40,000 dth/day of purchased gas was sold. The remaining gas was used for generation. The net cost of the fixed-price gas net of the gas sold (not used for generation) during the review period was $16,777,531 (Washington allocation).

Q. Was the net expense of selling fixed price gas an expected expense during the review period?

A. Yes. During 2001 Avista had previously contracted for firm natural gas supplies for its gas-fired thermal projects at fixed prices. These contract prices were higher than the market price of gas during the deferral period. It should be noted, however, that 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.

The ERM design included a Company Band that requires the Company to absorb $9 million in expense on an annual basis before any deferrals are recorded. Because of the fixed-price gas purchases that end in October 2004, it was anticipated that the Company's power supply expenses would exceed the authorized level by more than the Company Band in 2002, 2003 and 2004 and the Company would absorb a portion of the net expense of the fixed-price gas purchases.

Q. If selling gas created a net expense then what was the benefit of selling the gas instead of using it for generation?

A. Selling the natural gas fuel was beneficial because it lowered total power supply expense over the review period. Based on the actual gas sales during the review period the Company estimates a reduction in power supply costs of $9.1 million (system basis) for the fixed priced turbine fuel sold for the January 1, 2003 through December 31, 2003 delivery period. A summary page showing the gas sales and electric purchases that resulted in these savings is shown in Exhibit No. __(RLS-2). Details of the savings calculations and additional documentation supporting the gas sales have been provided in workpapers.

V. SUPPORTING DOCUMENTATION

Q. Please provide a brief overview of the documentation provided by the Company in this filing related to its power supply related transactions.

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 Credit Report) as part of this filing in either hard copy form or electronically on a compact disk:

Gas/Electric Transaction Record: These documents record the key details of the price, term 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 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. This report may also provide information on other parties' credit limits placed upon their own transactions with the Company (not provided, but available on request).

In addition, from time to time, special analysis may be performed around a specific decision.

VI. COYOTE SPRINGS 2 TRANSFORMER

Q. Please address the status of the transformer 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 manufacturer's initial estimates are that the transformer could be repaired and returned to the Coyote Springs site by mid-year 2004. Without the transformer, Coyote Springs 2 will be out of service during this period. This outage does not effect the 2003 calendar year ERM review period in this filing.

The Company expects the transformer repairs to be completed and the plant back on line by mid-year 2004. In the interim, the Company does not expect the outage to result in a material impact on its operating costs. Because there is currently little difference in the market price of power and the incremental cost to run the project during the first half of 2004, the impact on overall power supply expenses should be relatively small. The Company has ordered a backup transformer for Coyote Springs 2, from a different vendor than Alstom that is scheduled for delivery in November 2004

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

A. Yes it does.

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EXHIBIT NO. ____(RLS-2)

Avista Corp.
Summary of Savings Obtained by Selling Fixed Priced Gas, Jan 2003 - Dec 2003

Line No.	Transaction Date	Deal Ticket	Delivery Months	Volume (dth/day)	Price ($/dth)	Power Purchases Related to Sale of Gas	Savings from not Generating
3	4-Apr-02	G0370	Nov-Oct 03	5,000	$3.65	No purchases made related to sale of gas due to position length	$1,629,216
4	5-Apr-02	G0372	Nov-Oct 03	5,000	$3.52	No purchases made related to sale of gas due to position length	$1,385,341
24	18-Jul-02	G0515	Mar-Jun	5,000	$3.39	No purchases made related to sale of gas due to position length	$714,288
25	19-Jul-02	G0516	Apr-Jun	5,000	$3.36	No purchases made related to sale of gas due to position length	$565,174
26	15-Aug-02	G0552	Jan	5,000	$3.80	No purchases made related to sale of gas due to position length	$178,365
27	15-Aug-02	G0553	Feb	5,000	$3.70	No purchases made related to sale of gas due to position length	$147,418
28	15-Aug-02	G0554	Mar	5,000	$3.53	No purchases made related to sale of gas due to position length	$68,051
29	30-Sep-02	G0655	May-Jun	10,000	$3.55	No purchases made related to sale of gas due to position length	$521,647
30	30-Sep-02	G0656	May	10,000	$3.53	No purchases made related to sale of gas due to position length	
31	10-Oct-02	G0680	Feb	3,000	$3.93	No purchases made related to sale of gas due to position length	$67,430
32	10-Oct-02	G0681 & 82	Jan	22,000	$4.02	50 aMW Jan 03 @ $39.10/MWh, DT 2279	$561,825
33	20-Nov-02	G0743	Jan	3,000	$4.11	25 MW HLH Jan 03 @ $39.25/MWh, DT 2295	$88,313
34	23-Dec-02	G0792	Feb	5,000	$4.64	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$178,272
35	23-Dec-02	G0793	Mar	5,000	$4.47	50 MW HLH Mar 03 @ $41.25/MWh, DT 2314 & 2315	$175,831
36	23-Dec-02	G0794	Apr	5,000	$4.09	2 - 25 MW HLH Apr 03 @ $39.00 & $39.50/MWh, DT 2321 & 2323	$136,243
37	31-Dec-02	G0804	Feb-Apr	5,000	$4.15	25 MW HLH Mar & Apr 03 @ $41.25/MWh, DT 2325	
38						25 MW HLH Mar 03 @ $42.25/MWh, DT 2324	$361,019
39	3-Jan-03	G0810	Feb	5,000	$4.45	75 MW HLH Feb 03 @ $41.25/MWh, DT 2316 & 2317	$151,672
40	6-Jan-03	G0814	Feb	4,000	$4.19	25 MW HLH Feb 03 @ $41.25/MWh, DT 2318	
41						25 MW LLH Feb 03 @ $36.00/MWh, DT 2322	
42	9-Jan-03	G0822	Mar	7,000	$4.37	No purchases made related to sale of gas due to position length	$141,031
43	9-Jan-03	G0823	Jun	5,000	$4.25	No purchases made related to sale of gas due to position length	$237,165
44	10-Jan-03	G0827	Jun	5,000	$4.27	No purchases made related to sale of gas due to position length	$137,286
45	14-Jan-03	G0831	Feb	3,000	$4.50	25 MW HLH Feb 03 @ $42.00/MWh, DT 2329	$10,851
46	16-Jan-03	G0837	Mar	3,000	$5.00	25 MW HLH Mar 03 @ $45.00/MWh, DT 2335	$30,107
47	25-Feb-03	G0859	Apr	10,000	$4.91	50 MW HLH Apr 03 @ $44.18/MWh, DT 2353 & 2355	
48						25 MW LLH Apr 03 @ $36.75/MWh, DT 2354	$292,134
49	7/18/2002	G0515	Mar 03 - Jul 03	5,000	$ 3.39	No electric purchases made related to sale of gas due to position length.	$98,334
50	3/20/2003	G0900	Aug 03	5,000	$ 5.04	25 MW HL @ $54.00 ,DT 2365	$75,106
51	3/20/2003	G0901	Sep 03	5,000	$ 4.97	25 MW HL @ $53.50, DT 2366	$46,678
52	3/20/2003	G0902	Oct 03	5,000	$ 4.90	No electric purchases made related to sale of gas due to position length.	$118,703
53	3/24/2003	G0905	Jul 03	4,000	$ 4.92	No electric purchases made related to sale of gas due to position length.	$46,626
54	3/25/2003	G0907 & 908	Jul 03	21,000	$ 4.813	No electric purchases made related to sale of gas due to position length.	$411,316
55	4/10/2003	G0922	Aug 03 - Oct 03	1,500	$ 4.98	25 MW HL Aug 03 @ $49.25, DT #2407	$127,863
56						25 MW HL Q3 03 @ $46.25, DT 2409	
57	4/16/2003	G0930	Aug 03 - Oct 03	3,000	$ 5.265	25 MW HL Aug 03 @ $49.25,DT 2047	$169,135
58						25 MW HL Q3 03 @ $46.25, DT 2409	
59	5/14/2003	G0966 & 967	Aug 03	2,000	$ 2.745	25 MW HL @ $53.25, DT 2412	$13,162
60	10/9/2003	G1166	Dec 03	5,000	$ 5.290	No electric purchases made related to sale of gas due to position length.	$65,180
61	11/13/2003	G1241 & 42	Nov 15-30	19,700	$ 4.160	Sale of gas balance of month due to maintenance outage at CSII.	-$21,189
62						No electric purchases made related to sale of gas due to position length.	
63	12/8/2003	G1279 & 1280	Dec 10-31	20,158	$ 5.638	75 MW HL Dec 03 @ avg. of $42.08, DT 2074-2076	$172,653
64						25 MW LL Dec 03 @ avg. of $36.75, DT # 2477-2479	
65							
66	**Total**						$9,102,246