BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-06____

DIRECT TESTIMONY OF

RONALD R. PETERSON

REPRESENTING AVISTA CORPORATION

## I. INTRODUCTION

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

A. My name is Ronald R. Peterson. I am employed by Avista Corporation as the Vice President of Energy Resources. Its offices are located at 1411 East Mission Avenue, Spokane, Washington,

**Q. Would you briefly describe your educational and professional background?**

A. Yes. I began my career at Avista Corporation in 1975 after graduating from Washington State University with a degree in business administration, majoring in accounting. I passed the Washington State Certified Public Accountant examination in 1976 and worked as a staff accountant in a variety of positions until 1987, when I became Supervisor of Corporate Accounting. In 1991, I became the Customer Service Manager. In 1992, I became the Company's treasurer. I was elected Controller and assumed Director of Information Services responsibilities in 1996. In 1998, I was elected Vice President and Treasurer. I served as both the Corporate Treasurer and Utility Controller beginning in August 2001. I was appointed to my current position in March of 2003.

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

A. My testimony will provide an overview of Avista's resource planning and power operations. I will also explain the substantial variability of costs inherent in our power supply operations.

**Q. As the Vice President of Energy Resources, do you have any general comments related to the Energy Recovery Mechanism (ERM)?**

A. Yes. As prices in our key commodity markets (wholesale electric and natural gas) have risen, the costs associated with the purchases and sales necessary to address varying hydroelectric generation and loads are substantially higher and more volatile than in the past. In addition, Avista's resource mix is substantially different today than it was in the past when our system was dominated by hydroelectric and coal-fired generation. Today, hydroelectric generation meets barely half of our needs. Our load growth has been met with more than 300 MW of new gas-fired generation. We use a substantial portion of this new generation capability to serve base-load energy requirements. Natural gas prices have risen dramatically and remain volatile. The base-load nature of the Coyote Springs 2 (CS2) plant means that we are buying substantially more natural gas at higher and more volatile prices than was the case in prior years.

Given the increased level of wholesale electric and natural gas prices and the corresponding volatility in our power supply-related expenses, the ERM mechanism is even more important now that when first implemented. As an example, when wholesale electricity prices were around \$20 per MWh, prior to the energy crisis, a ten percent (10%) reduction in hydroelectric generation would result in increased costs of approximately \$9 million on a system basis (Washington and Idaho operations). With a continuation of recent wholesale electricity prices around \$60 per MWh, the same ten percent reduction in generation would result in increased costs of approximately \$28 million.[1] With total annual Avista Utilities earnings[2] of approximately \$50 million after-tax, a relatively small change in resource conditions can have a significant impact on the Company's financial results.

[1] 538mw x 10% x 8760 hours x \$60/MWh = \$28 million.
[2] For electric and natural gas operations in Washington, Idaho and Oregon.

As other Avista witnesses have already explained, because of the persistent below-normal hydroelectric conditions and the high natural gas prices that are, even now, not reflected in base retail rates, the existence of the $9.0 million deadband has caused the Company to continue to not recover the power supply costs associated with providing service to our customers.

**Q. Does the Company have meaningful control over the variability it experiences in hydroelectric generation, and wholesale electric and natural gas prices?**

A. We do have the ability to hedge our resource portfolio and do so as conditions warrant it. The Company believes that customers benefit from the results of this hedging by locking in prices ahead of time, thereby avoiding the spot market for many purchases.

We explained in our recent rate case how gas-fired turbines are fueled when load conditions warrant it, and when running the plants is less costly than purchasing power in the wholesale electricity marketplace. When in a surplus position (e.g., when hydro conditions are better than expected), we sell the surplus gas or electricity in the wholesale marketplace, which results in lower net power supply costs for our customers.

Unfortunately we do not control the underlying factors that drive our costs. By this I mean we control neither the weather that drives our hydroelectric generation, nor the marketplaces that provide us natural gas for turbines and wholesale power to serve our remaining needs. Avista represents less than five percent of the overall Northwest electricity demand, and less than one percent of Western Interconnect load. The same goes for natural gas, except that this market is national in nature and we represent well below one-half of one percent of total demand.

## II. OVERVIEW OF AVISTA'S RESOURCES AND OPERATIONAL PLANNING

**Q. Please provide a brief overview of Avista's resource planning and operations?**

A. The Company uses a combination of owned and contracted-for resources to serve its retail and wholesale load requirements. Resource dispatch decisions are made within the Energy Resources Department of Avista Utilities. The department conducts studies on a regular basis to determine capacity and energy resource requirements over time. The Company enters into short-term and medium-term wholesale sales and purchase transactions to balance resources with load requirements. Longer-term resource decisions related to building new resources, upgrades to existing resources, demand-side management and long-term contract purchases are generally made in conjunction with the Company's Integrated Resource Plan (IRP) and Request For Proposal (RFP) processes.

**Q. Please provide a brief overview of Avista's power resources.**

A. Avista's resource portfolio includes a diverse mix of hydroelectric generation projects, base-load coal and natural gas-fired thermal generation facilities, wood waste-fired renewable generation, natural gas-fired peaking generation projects, long-term contracts including wind generation, Mid-Columbia hydroelectric generation, and market power purchases and exchanges. For 2006, Avista-owned generation facilities have a total capacity of approximately 1,815 MW, of which 54% is hydroelectric and 46% is thermal. The following Illustration No. 1 summarizes the present capacity of Avista's generation resources.

**Illustration No. 1**

| Company-Owned Projects | MW |
|---|---|
| Noxon Rapids | 527 |
| Cabinet Gorge | 261 |
| Post Falls | 18 |
| Upper Falls | 10 |
| Monroe Street | 15 |
| Nine Mile | 25 |
| Long Lake | 88 |
| Little Falls | 36 |
| Total Hydroelectric Generation | 980 |
| | |
| Colstrip Units 3 and 4 | 222 |
| Coyote Springs 2 | 285 |
| Kettle Falls | 53 |
| Total Base-Load Thermal Generation | 560 |
| | |
| Northeast CT | 67 |
| Kettle Falls CT | 7 |
| Boulder Park | 25 |
| Rathdrum CT | 176 |
| Total Natural Gas Peaking Generation | 275 |
| | |
| Total Generation | 1,815 |

Our native load service obligation for 2006 is approximately 1,881 megawatts (MW) at the time of system peak.[3] In addition to the above mix of Company-owned generation resources, the Company's resource portfolio includes specific resources for which the Company has contractual rights for a portion of project output. The Company has long-term contractual rights for a total of 138 MW of capacity from the Mid-Columbia generation projects that are owned and operated by the Public Utility Districts of Grant, Chelan and Douglas counties. PURPA resources contribute approximately 65 MW of power under long-term arrangements. The Company also has a ten year contract in place for the purchase of 35 MW of wind generation from the Stateline Wind Energy Facility.

[3] Total obligation at system peak is forecasted peak load of 1,628 MW, plus a 253 MW planning reserve margin.

## III. VARIABILITY OF POWER SUPPLY COST-COMPONENTS

**Q. What are the key components affecting the variability of your power supply costs?**

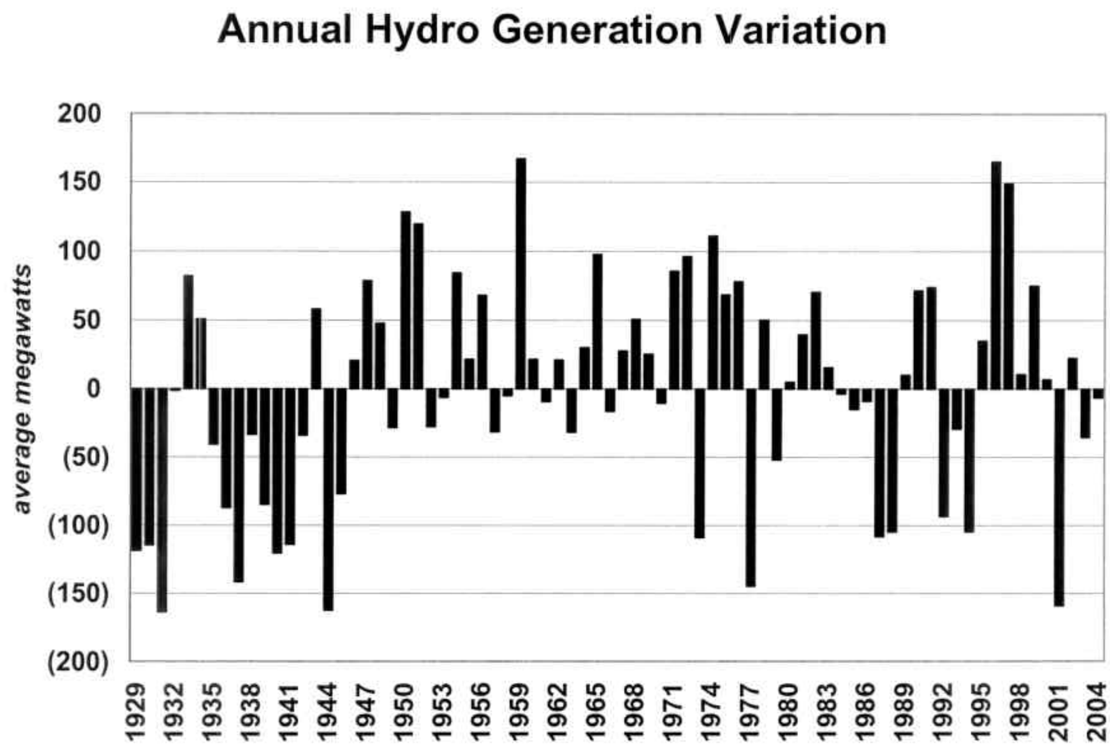
A. Although our power supply costs are affected by many factors, the most significant factors impacting power supply costs are hydroelectric generation, thermal fuel prices, and wholesale electric prices.

**Q. Please explain the impact of varying hydroelectric generation on power supply costs.**

A. The Company generates approximately 538 aMW from its owned- and contracted-for hydroelectric plants. The following Illustration No. 2 presents annual variation from average generation levels by year for the period 1929 through 2004.[4]

[4] The data for 1929 – 1988 is from the Northwest Power Pool hydro regulation study, which is commonly used in regional resource studies. It excludes the Grant County Priest Rapids project. The data for 1989 – 2004 is based on actual generation from Avista's records, adjusted for the contractual loss of the Priest Rapids project that occurred on November 1, 2005.

**Illustration No. 2**




As explained earlier, with wholesale electric prices at approximately $60 per MWh, a ten percent (10%) reduction in hydroelectric generation (54 aMW) would result in increased costs of approximately $28 million on a system basis.

It is also important to remember that flow variation affects other owners of hydro plants in the Northwest in the same manner. This means that when Avista experiences below-normal hydroelectric generation, others utilities in the region experience the same or similar condition. The market can become either flooded with surplus power, or very deficient causing hydro owners to bid against one another for power in the market.

Avista, as well as all other owners of Northwest hydroelectric generation, cannot predict with any meaningful degree of accuracy the annual streamflows that will occur, nor can the owners control the total streamflow during a year. The hydroelectric generation each year is essentially a random event which causes significant variability in the Company's power supply costs.

**Q. Please explain the significance of thermal fuel prices on your overall power supply costs.**

A. Avista purchases fuel, as needed, to operate 835 MW (46%) of its resource portfolio. Fuel prices for coal, wood, and natural gas greatly affect the ultimate cost of the energy we provide to our customers. While fuel costs for our coal-fired generation plant has remained relatively stable in recent years, the 50 MW Kettle Falls wood-fired plant has experienced a 44 percent increase in fuel costs over the past four years. With the closure of some lumber mills in recent years, fuel is more difficult to acquire and must be gather from greater distances.

Approximately 585 MW of thermal generation is fired by natural gas. Of this generation, approximate 280 MW is the Coyote Springs 2 (CS2) baseload generation. The balance of gas-fired resources are used primarily as peaking resources. The price of natural gas over the past few years has reached unprecedented highs and has demonstrated extraordinary volatility.

Avista's natural gas costs in 2005 for thermal generation, primarily for CS2, were $71 million. One way to look at natural gas price variability in our portfolio is to consider the impact of a one-dollar change in gas prices for gas-fired generation. Each one-dollar change in the natural gas price would increase the cost of running CS2 by approximately $13 million per year.[5] During periods of the year when CS2 is surplus to Avista's resource needs, the surplus can be

[5] 280 Mw x 75% capacity factor at 7000 heat rate x $1.00/dth = $13 million

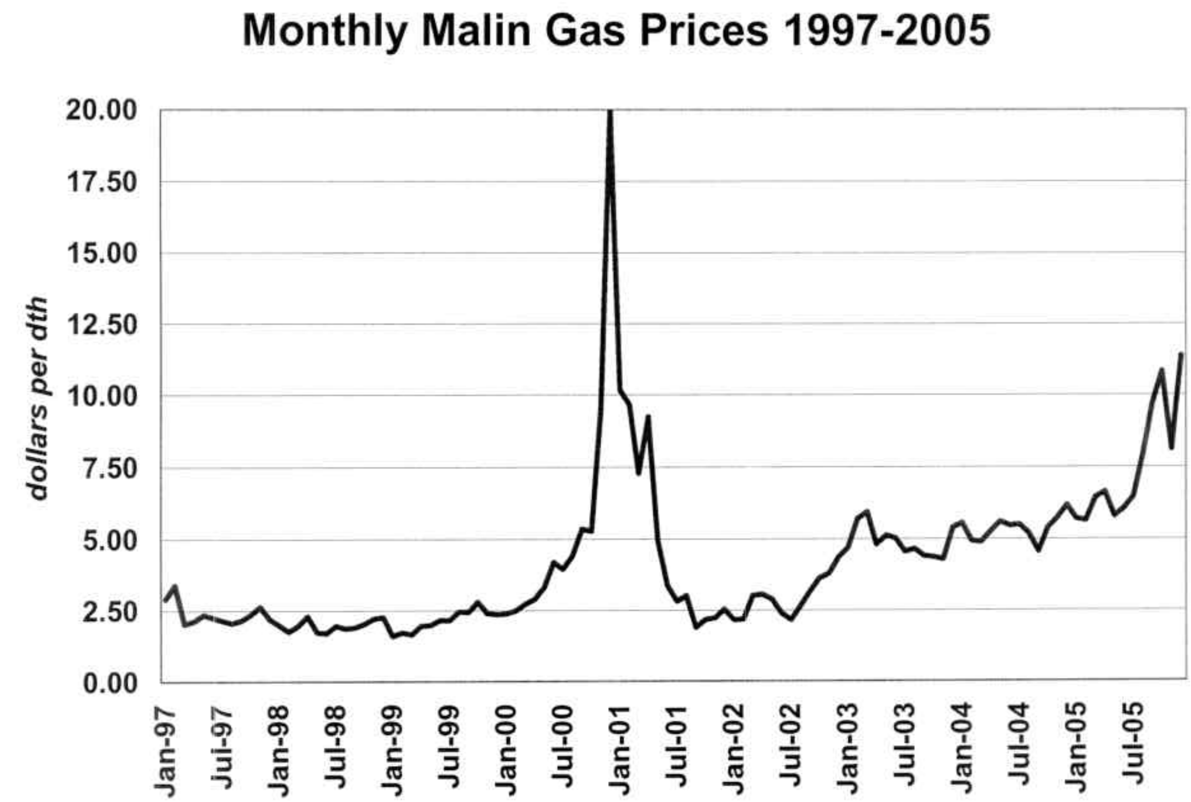
sold and the margin from the sales would mitigate the additional $13 million cost to some degree. However, the cost of the CS2 generation used to serve retail load during the year would go up by the one-dollar change in the natural gas price.

**Q. How much price volatility has been present in the natural gas market in recent years?**

A. Natural gas price volatility has increased substantially in recent years. Illustration No. 3 below provides historical monthly index prices for natural gas at the Malin market hub, where CS2 is located.[6] Prices and volatility prior to the energy crisis were relatively moderate, hovering around $2.15 per dth. Prior to calendar year 2000, natural gas prices ranged on a monthly basis between $1.59 and $3.37 per dth. Since 2000, prices have increased substantially and are much more volatile. The average Malin price between 2000 and 2005 was $5.20 per dth. The price range was between a low of $1.89 per dth and a high of $20.00 per dth.

[6] Monthly averages are calculated using the average of daily market prices.

**Illustration No. 3**




**Q. What price for natural gas is currently included in the Company's base rates?**

A. The recent Settlement Agreement included an average price of $7.25/DTH for Avista's gas-fired generation. The price of natural gas at Malin for calendar years 2006 and 2007 is currently running at $7.87 and $9.09 per DTH, respectively. Although the Company hedged a portion of its 2006 natural gas costs for CS2, Avista will still experience volatility in its gas costs for the volumes that were not previously hedged for 2006, as well as for the majority of gas for CS2 in 2007 that has not been hedged.

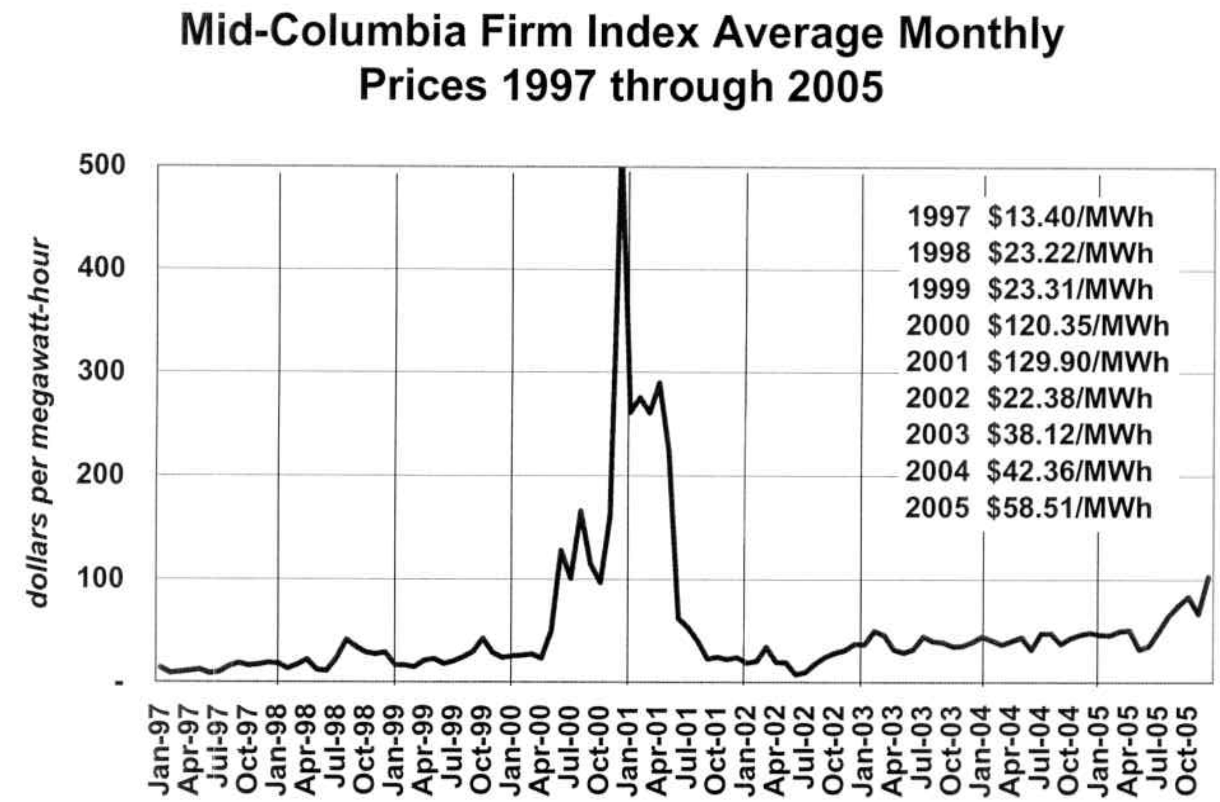
**Q. How do wholesale electricity prices affect Avista's power supply costs?**

A. Avista operates its available resources to serve its load requirements and, to the extent that it has surplus energy available, the Company will sell the surplus into the wholesale market at prevailing market prices. The value of these sales is credited against Avista's power supply costs to arrive at a net cost to serve customers. In some circumstances Avista will purchase energy from the wholesale market to serve load requirements rather than pull water from reservoirs for hydroelectric generation, or will purchase energy rather than run more expensive gas-fired generation. These types of transactions occur on an hourly and daily basis to balance Avista's resources with its load requirements.

The net power supply cost to serve Avista's customers is established in a general rate case based on "normal" hydroelectric and wholesale market conditions. As explained earlier, if the Company experiences hydroelectric conditions that are below normal, the cost from the wholesale electric market to replace that lost generation can vary significantly depending on the wholesale market price. In addition, to the extent that Avista's other loads and resources are different than planned in the last rate case, it will affect the volume of energy purchased or sold in the wholesale market, which will affect the Company's net power supply costs.

In 2002, the average wholesale electricity price at the Mid-Columbia market hub was $22.38 per MWh. Market prices in 2005, at $58.51 per MWh, were two-and-a-half times greater than in 2002. The following Illustration No. 4 shows historical Mid-Columbia electricity prices from 1997 through 2005.

**Illustration No. 4**




**Q. Should long-term power contracts be included in the ERM?**

A. Yes. The Company historically has relied on contracts to meet a portion of its retail load obligations. Oftentimes contracts can provide lower-cost alternatives when compared to traditional resource construction. In many cases, new contracts simply are replacing expiring contracts.

As Mr. Norwood explained in his testimony, in designing the ERM it was recognized that the addition or termination of a power contract would affect other power supply cost items, and in order to capture all cost changes (up and down) on an "apples to apples" basis, it is necessary to include new contracts.

Under the ERM Avista identifies any new long-term contract in its monthly ERM report to the Commission, and provides a copy of the new agreement. In addition Avista makes a filing with the WUTC on or before April 1st of each year to provide the opportunity for interested parties to review the prudence of power costs during the prior calendar year. Therefore, the costs of any new contracts under the ERM are subject to review prior to being approved for ultimate recovery from customers.

**Q. Has the ERM caused Avista to favor purchase contracts over the construction of new resources?**

A. No. The Company has made only one multi-year power purchase, for ten aMW, since the ERM came into effect (this contract was for energy from the Stateline Wind Energy Facility). However, the Company has made or committed to make many other resource investments. The largest was the 140 MW acquisition of the second half of CS2 in early 2005. We also have committed to plant upgrades at Colstrip Units 3 & 4 and at the Cabinet Gorge and Noxon Rapids hydroelectric facilities. These long-term upgrade investments will bring a total of approximately 52 MW of new capacity and 36 aMW of additional energy when completed.[7]

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[7] See pages 7-32 and 7-34 of the Company's 2005 Integrated Resource Plan.

## IV. CONCLUSION

**Q. Finally, please summarize why the ERM should remain in place, and why the deadband should be eliminated.**

A. The Company today faces significant volatility in many of its power supply costs. As we do not control the weather or market prices, we simply cannot eliminate this variability through hedging. The ERM tracks these varying costs while providing an incentive for the Company to do its best to manage them on behalf of customers.

The present 90/10 sharing mechanism provides a strong incentive to manage our costs in the interests of customers. Continuation of the ERM is vitally important to the Company. As Mr. Malquist explains in his testimony, elimination of the deadband to provide more effective recovery of volatile energy costs is especially important in the next few years as the Company faces significant maturing debt and capital requirements.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes it does.