Exhibit No. ___ (WGJ-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12______

DIRECT TESTIMONY OF

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is William G. Johnson. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Resources Department.

Q. What is your educational background?

A. I graduated from the University of Montana in 1981 with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve power contract origination and management, and power supply regulatory issues.

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

A. My testimony will 1) identify and explain the proposed normalizing and pro forma adjustments to the January 2011 through December 2011 test period power supply revenues and expenses, 2) identify and explain proposed modifications to the Energy Recovery Mechanism (ERM) and 3) describe the proposed level of expense and retail revenue credit for ERM purposes, using the pro forma costs proposed by the Company in this filing

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit Nos.___ (WGJ-2) through ___ (WGJ-5), which were prepared under my supervision and direction. Exhibit No. ___ (WGJ-2) identifies the power supply expense and revenue items that fall within the scope of my testimony. A brief description of each adjustment is provided in Exhibit No. ___ (WGJ-3). Exhibit No. ___ (WGJ-4) shows the pro forma fuel costs for each thermal plant and short-term purchase and sales by month. The proposed authorized ERM power supply expense and revenue, transmission expense and revenue, and retail sales are shown in Exhibit No.__ (WGJ-5).

Q. Are there other Company witnesses providing testimony regarding issues you are addressing?

A. Yes. Company witness Mr. Kalich provides detailed testimony on the AURORA model used by the Company to develop short-term power purchase expense, fuel expense and short-term power sales revenue included in my exhibits.

II. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please provide an overview of the pro forma power supply adjustment.

A. The pro forma power supply adjustment involves the determination of revenues and expenses based on the generation and dispatch of Company resources and expected wholesale market power prices as determined by the AURORA model simulation for the pro forma period under normal weather and hydro generation conditions. In addition, adjustments are made to reflect contract changes between the historical test period and the pro forma period. The table below shows total net power supply expense during the test period and the pro forma period. For information purposes only, the power supply expense[1] currently in base retail rates, which is based on a calendar 2012 pro forma period, is also shown.

Power Supply Expense	
	System
Power Supply Expense in Current Rates (2012 pro forma)	$213,676,000
Actual 2011 Power Supply Expense	$203,655,000
Proposed 2013 Pro forma Power Supply Expense	$196,610,000
Proposed 2013 vs 2011 Test Period	-$7,045,000
Proposed 2013 vs Current Rates	-$17,066,000

The net effect of my adjustments to the test year power supply expense is a decrease of $7,045,000 ($196,610,000 - $203,655,000) on a system basis. The decrease in power supply expense compared to the authorized level in current base rates is $17,066,000 (system) and $11,133,858 (Washington allocation).

Q. Why is the power supply expense for the pro forma year lower than the level of power supply expense currently in base rates?

A. The decrease in pro forma power supply expense from the expense currently in base rates is primarily a result of lower natural gas and power prices. The natural gas price included in the AURORA model has decreased from an annual average of $4.34/dth to 4.10/dth. The average modeled power purchase price has decreased from $35.87/MWh to

[1] For the remainder of my testimony, for purposes of the power supply adjustment I will refer to the net of power supply revenues and expenses as power supply expense for ease of reference.

$33.90/MWh[2]. Also contributing to lower power prices is less forward power purchases for 2013 compared to purchases for 2012 included in current base rates. Because energy prices have been on a downward trajectory for several years, the Company's hedging program, which layers in power purchases and fuel purchases over time, has purchased energy at prices greater than the subsequent spot market prices. The 2013 pro forma, in this case, has a lower level of net forward purchases than the 2012 pro forma and therefore there is a smaller impact from these forward purchases in the 2013 pro forma.

Pro forma loads (2011 weather adjusted loads) are 3.9 average megawatts (aMW) higher than loads that current rates are based on (2010 weather adjusted loads).

Other than the addition of the power purchase from the Palouse Wind project and the Spokane Waste to Energy plant the contracts and resources in this pro forma are the same as in current base rates.

III. PRO FORMA POWER SUPPLY ADJUSTMENTS

Overview

Q. Please identify the specific power supply cost items that are covered by your testimony and the total adjustment being proposed.

A. Exhibit No. ___ (WGJ-2) identifies the power supply expense and revenue items that fall within the scope of my testimony. These revenue and expense items are related to power purchases and sales, fuel expenses, transmission expense, and other miscellaneous power supply expenses and revenues.

[2] The natural gas price included in the AURORA model and the modeled power purchase price does not include the actual natural gas and power transactions that have been entered into for the pro forma period. These actual transactions have been separately accounted for in the pro forma expense.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. The purpose of the adjustments to the test period is to normalize power supply expenses for normal weather and normal hydroelectric generation and to reflect current forward natural gas prices and other known and measurable changes for the pro forma period.

The AURORA Model, as explained by Mr. Kalich, dispatches Company resources using the current forward natural gas prices and calculates the level of generation from the Company's thermal resources, fuel costs for thermal resources, and the short-term purchases and sales necessary to balance system requirements and resources.

Q. Are there any changes in how the pro forma in this case was developed versus the authorized power supply expense currently in base rates?

A. No. The process to develop the pro forma net power supply expense in this case is the same as the process used to develop authorized power supply expense in current base rates.

A brief description of each adjustment is provided in Exhibit No. ___ (WGJ-3). Detailed workpapers have been provided to the Commission coincident to this filing to support each of the pro forma revenues and expenses. The detailed workpapers for each adjustment show the actual revenue or expense in the test period, and the pro forma revenue or expense.

<u>Long-Term Contracts</u>

Q. How are long-term power contracts included in the pro forma?

A. Long-term power contracts are included in the pro forma by including the energy receipt or obligation associated with the contract in the AURORA model and including the cost or revenue in the pro forma net power supply expense.

Q. Are there any new long-term power purchases or sales in the pro forma that are not in the current base rates?

A. Yes. This pro forma includes the expenses and generation related to the purchase from the Palouse Wind project, a 105 MW capacity (39 aMW energy) wind facility located 30 miles south of Spokane. Additional information regarding this purchase is contained in Mr. Lafferty's testimony. The pro forma also includes a purchase from the Spokane Waste-to-Energy plant located on the west side of Spokane. The plant produces approximately 15 aMW of energy.

Q. Why did the Company enter into a power purchase agreement with the City of Spokane's Waste-to-Energy plant?

A. The output from the Waste-to-Energy plant had been purchased by Puget Sound Energy for the past 20 years. That contract with Puget expired December 31, 2012. As a Purpa resource, Avista is required to purchase the output if the generator so requests, which they did. The purchase price is at the avoided cost rates in Avista's 2011 Integrated Resource Plan.

Q. Are there any long-term power purchases or sales that are in current base rates but not in this pro forma?

A. No.

<u>Short-Term Power Purchases and Sales</u>

Q. How are short-term transactions included in the pro forma?

A. After including the actual physical forward short-term transactions as resources and obligations in the AURORA model, the balance of the short-term electric power purchases and sales are an output of the AURORA model. The model calculates both the volumes and price of short-term purchases and sales that balance the system's generation and long-term purchases with retail load and other obligations. The price of the short-term transactions represents the price of spot market power as determined by the AURORA model. Short-term financial electric and all natural gas transactions are included as a mark-to-model price line item in the pro forma and are not included as inputs in the AURORA model.

Q. What actual forward short-term transactions are included in the pro forma?

A. The pro forma includes transactions entered into through January 20, 2012 for the 2013 pro forma period. These transactions include 2 physical electric transactions, 31 financial electric transactions, 9 physical natural gas transactions and 33 financial natural gas transactions. The details of these transactions are provided in workpapers.

Thermal Fuel Expense

Q. How are thermal fuel expenses determined in the pro forma?

A. Thermal fuel expenses include Colstrip coal costs, Kettle Falls wood-waste costs, and natural gas expense for the Company's gas-fired resources including Coyote Springs 2, Lancaster, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion turbine. Unit coal costs at Colstrip are based on the long-term coal supply and transportation agreements. Unit wood fuel costs at Kettle Falls are based on multiple shorter-term contracts with fuel suppliers and inventory. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation as determined by the AURORA model.

Exhibit No. ___ (WGJ-4) shows the pro forma fuel costs by month for each plant. Mr. Kalich provides details and supporting workpapers regarding the level of generation for the Company's thermal plants, and the fuel cost for thermal and natural gas-fired plants.

Transmission Expense

Q. What changes in transmission expense are in the pro forma compared to the expense in current base rates?

A. The only change in transmission expense is the elimination of the Black Creek wheeling expense since the final deliveries under that contract ended in 2011. There are also some increases in all BPA transmission expenses beginning October, 1, 2013 based on BPA's proposed rate increases.

Summary

Q. Please summarize your proposed pro forma power supply expense that are provided to witness Andrews.

A. The proposed pro forma power supply expense as shown in Exhibit No. ___(WGJ-2) is a $7,045,000 reduction in expense on a system basis ($4,596,158 Washington allocation) from 2011 actual test-year expense and a $17,066,000 (system)/$11,133,858 (Washington allocation) reduction in expense from the power supply expense in current rates.

IV. PROPOSED MODIFICATIONS TO THE ERM

Q. Would you please identify the Order that authorizes the review of the ERM, and allows the Company and other parties to propose modifications to the ERM?

A. Yes. Order 03 in Docket No. UE-060181 dated June 16, 2006, approved the Settlement Agreement in that case. Paragraph (H) of the Settlement Agreement provides that "Avista will initiate a filing not sooner than five (5) years from the date this Settlement is approved, to allow all interested parties the opportunity to review the ERM, and make recommendations to the Commission related to the continuation, modification or elimination of the mechanism."

Q. What are the Company's recommendations regarding the ERM?

A. The Company recommends continuation of the ERM, and proposes modifications to 1) the deadband and sharing bands, 2) the way the retail revenue credit is calculated, and 3) the way rate adjustments are triggered and structured.

Continuation of the ERM

Q. What is the ERM designed to do, and why should it be continued?

A. Actual net power supply costs will vary from the level of costs reflected in base retail rates. Avista's ERM is designed to defer, for future recovery or rebate, variations in revenues and costs associated primarily with hydroelectric generation, wholesale electric prices, thermal fuel costs and changes in power contract revenues and expenses. The ERM is designed to both recover increased net power supply costs, as well as to pass through reductions in costs from those embedded in base retail rates. The ERM helps to stabilize the Company's earnings, as well as cash flows, and provides benefits to customers in the form of lower financing costs that the utility incurs as well as providing the opportunity for rebates to customers when power supply costs are lower than those included in retail rates. The ERM also results in retail rates to customers over time that more closely reflect the actual power supply costs to serve customers. Customers will experience ERM surcharges, but will also experience rebates when actual power supply costs are lower than those embedded in base retail rates.

The variability in net power supply costs can be quite substantial and the Company's increased reliance on natural gas-fired generation has added to the variability. However, in cases when market prices are above the cost of gas generation, and the Company does not need the gas-fired generation to serve its retail load, the generation can be sold on the secondary market at a profit, with that profit being reflected in the ERM and passed on to customers. Further, when market prices are above the cost of gas-fired generation, and the Company needs the gas generation or secondary purchases to serve its retail load, there is a savings from serving the load from gas generation that is reflected in the ERM. In certain circumstances, forward purchases of natural gas may later be sold at a loss when 1) power is needed to serve retail load and the wholesale electric prices are such that it is cheaper to purchase the power and sell the gas, rather than to use the gas for generation, or 2) power is not needed to serve retail load, and the loss on the sale of the gas is less than the loss associated with using the gas to fuel generation that is sold in the wholesale market.

To illustrate the issue of variability, as an example, with wholesale electric prices averaging approximately $40/MWH, only a 10% reduction in Avista's hydro generation would reduce the Company's Washington electric pre-tax operating results by approximately $12.3 million (hydroelectric generation of 538 aMW x 10% x 8760 hours x $40/MWH x the 65% WA jurisdictional share = $12.3 M).

Avista believes the ERM needs to be continued to provide for the recovery or rebate of power supply related costs, and so that it will continue to provide benefits to both customers and shareholders.

<u>Deadband and Sharing Bands</u>

Q. Would you please describe the existing ERM deadband and sharing bands, and when they were approved?

A. Yes. On an annual (calendar-year) basis the Company absorbs the first $4 million of the difference between certain actual and authorized power supply related costs, either in the surcharge or rebate direction. This is referred to as the "deadband," since no costs are deferred until this band is exceeded. When actual costs exceed authorized costs by more than $4 million (surcharge direction), 50% of the next $6 million of difference in costs is absorbed by the Company, and 50% is deferred for future recovery from customers. When actual costs are less than authorized costs (rebate direction), 25% of the next $6 million of difference above the $4 million deadband is absorbed by the Company, and 75% is deferred for rebate to customers. If the difference in costs exceeds $10 million, either in the surcharge or rebate direction, 10% of the amount above $10 million is absorbed by the Company, and 90% is deferred.

In Order 03 in Docket UE-060181, dated June 16, 2006, the Commission approved the $4 million deadband, a 50/50 sharing of the next $6 million in either the rebate or surcharge direction, and a 90/10 sharing beyond the $10 million threshold. In Order 08 in Docket UE-080416, dated December 29, 2008, the Commission approved a settlement agreement that included a modification to the sharing level in the second ERM band ($4 million to $10 million) to 75% customer/25% Company when the cost difference is in the rebate direction.

Q. What is the Company's proposal to modify the deadband and sharing bands?

A. The Company proposes to eliminate the $4 million deadband, eliminate the $4 million to $10 million sharing bands, and go strictly to a 90% customer/10% Company sharing level that would be applied to the entire difference between actual and authorized power supply related costs that are included in the ERM.

Q. Why is the Company proposing to eliminate the $4 million deadband, and the $4 million to $10 million sharing band?

A. In theory, the deadband and the sharing band are intended to motivate the Company to manage its power supply costs by making sure it has some "skin in the game." The reality is that the outcome is driven almost entirely by factors beyond the Company's control.

The primary drivers of changes in power supply expense are stream flow conditions, natural gas prices, market power prices, forced outages, and retail load variations. The Company does not have direct control of any of these factors. So the amount Company absorbs with the dead band and sharing band ultimately results in a random variation that the Company cannot control. The incurrence of power costs to serve electric customers is similar to the Company's purchase of natural gas for distribution to its natural gas customers. The Company's Purchased Gas Adjustment (PGA) mechanism provides for the recovery of 100% of the variation in purchased gas costs. The PGA has no deadband or sharing bands.

Q. How do financial rating agencies view the ERM, and the $4 million deadband and $4 million to $10 million sharing bands that the Company is proposing be eliminated?

A. Generally, the ERM is viewed positively by the rating agencies, while the deadband and first sharing bands are not. Moody's credit opinion of Avista dated March 17, 2011, states:

> "In addition to the rate approvals in Washington, Idaho and Oregon, each commission allows for cost recovery mechanisms that factor significantly into Moody's credit assessment. As the inherent volatility of commodity costs comprises one of the most significant risk factors to the industry, Moody's views the existence of commodity cost recovery mechanisms as a significant credit benefit."

Standard & Poor's rating of Avista dated January 26, 2012, states:

> "The company also has flexibility in implementing rate changes through its energy recovery mechanism in Washington and the power cost adjustment in Idaho, but the recovery of excess power costs in Washington is not complete due to minimum thresholds and progressive and asymmetrical deferral bands. Each year, uncollected costs are subject to defined sharing bands, which allow the company to potentially defer certain portions for collection from customers. <u>This mechanism is weaker than for some utilities with high hydrological or significant gas generation exposure in western states.</u> [Emphasis added.] Purchased gas adjustments for gas distribution units in all three jurisdictions, along with hedging, mitigate gas supply risk. We view these as important in averting large cost adjustment requests and, thus, they continue to support the rating."

Regulatory Research Associates' rating dated December 22, 2011, in discussing regulation in Washington states:

> "The regulatory environment in Washington is somewhat restrictive from an investor viewpoint. Recent equity return authorizations, some of which were approved following settlements, were below prevailing industry averages. The state's electric utilities remain vertically integrated and are regulated under a traditional regulatory paradigm. Power-cost adjustment mechanisms are in effect for most of the state's electric utilities. <u>However, while significantly reducing the companies'</u>

exposure to power price volatility, these mechanisms contain deadbands and sharing mechanisms that, while allowing the company to receive a benefit, also limit the costs that may be recovered from ratepayers."[Emphasis added.]

Fitch's rating dated September 6, 2007, in discussing the ERM states:

> "Adopted by the WUTC in July 2002, AVA's energy recovery mechanism (ERM) facilitates the deferral and pass-through of the lion's share of power supply cost deviations from amounts reflected in base rates to ratepayers. Nonetheless, the negative effect of the portion of power supply costs borne by the utility under its power cost adjustment mechanisms can be significant during prolonged periods of below-normal water conditions and high demand. This factor, combined with timing differences between when power supply costs are incurred and recovered in rates, can cause significant stress on a utility's creditworthiness."[Emphasis added.]

Q. Would the Company still have some "skin in the game" if the deadband and sharing bands, other than the 90%/10% sharing band, were eliminated?

A. Yes. Under the current ERM the Company has to absorb $7 million of the first $10 million of actual power supply related costs that exceed the level authorized for recovery in base rates ($4 million deadband plus 50% of the next $6 million = $7 million). Under the Company's proposal to do away with the $4 million deadband, and the $4 million to $10 million sharing band, the Company would still absorb $1 million of the first $10 million of additional cost ($10 million times 10% = $1 million). When actual costs are less than authorized costs (rebate direction), the Company currently keeps $5.5 million of the first $10 million of the difference in costs ($4 million deadband plus 25% of the next $6 million = $5.5 million). Without the deadband, and the $4 million to $10 million sharing band, the Company would keep $1 million of the first $10 million of cost difference in the rebate direction instead of $5.5 million. Under the Company's proposal for the first $10 million of cost difference there would be a 90% customer/10% Company sharing level, and there would continue to be a 90% customer/10% Company sharing above $10 million of cost difference. So, under the Company's proposal, the Company would still have some "skin in the game."

Having the Company sharing at 10% of changes in power supply costs, as well as having all of the Company's power supply decisions and costs subject to thorough review in general rate cases and in the annual ERM review filings, is sufficient incentive for Avista to pay particular attention to all power supply decisions.

Q. How much does power supply expense vary?

A. The Company's Integrated Resource Plan (IRP) provides a useful tool to estimate how much power supply expense can vary. The IRP evaluates power supply costs using Monte Carlo simulations that vary hydro conditions, natural gas and market power prices, loads and forced outages. It produces a range of power supply expenses for 500 simulations for the year 2013. The absolute range of power supply expense is over $200 million on a system basis, roughly equal to the mean level of power supply expense. In comparison to the ERM dead band and sharing band of $10 million, 60 percent (301 out of 500 simulations) of the variations in power supply expense (Washington allocation) are greater than $10 million. So this means that 60 percent of the time the Company will either absorb $7 million of additional expense or retain $5.5 million of lower expense, and will be into the 90%/10% portion of the ERM sharing.

Q. Doesn't the Company employ a hedging strategy to mitigate power supply expense variability?

A. Yes. The Company does follow a hedging strategy to mitigate the impact of market exposure and timing of natural gas and power purchases. The primary purpose of the hedging strategy is to prevent a "blowout" of power supply expense in bad hydro conditions and/or high price market conditions by limiting the amount of near-term exposure to large increases in market fuel (natural gas and power) prices. It does this by imposing a systematic approach to layering in energy purchases or sales to close open positions before the start of a month, and thus reduce exposure to price swings. The hedging strategy does not close all open positions for the next year, so the Company is still exposed to some natural gas and power price changes, nor does the strategy eliminate any variability due to hydro conditions, loads, or a forced outage, which create new open positions. As stated before, the primary purpose of the hedging strategy is to reduce the risk of a major increase in power supply expense due to very high natural gas and power prices, possibly coupled with low hydro conditions.

Q. But doesn't the hedging strategy mitigate some of the power supply expense variability?

A. Yes it does, but not by that much. In order to estimate how much the hedging strategy might mitigate variability, the Company again used its IRP power supply simulation model. This time, the model was modified to close out all open positions for the year by either buying or selling power. This should reduce volatility because the exposure to swings in market prices is reduced. The simulation with the hedging strategy does have a lower standard deviation than the un-hedged simulation, which means that the average variation around the mean is less. However, the percent of simulations that are outside the $10 million dead band and sharing band is roughly the same. The most notable difference is the reduction in the tail-block scenarios. There is a 33 percent reduction in expense variation in the worst 5 simulations. That is, in really high cost conditions, hedging significantly lowers power supply expense. The conclusion from the simulation with the hedging strategy is that the Company's hedging program does what it is supposed to do, which is to lessen the impact of very high cost years, but it does not appreciably lessen the impact of the $10 million dead band and sharing band.

Q. How might the elimination of the dead band and sharing band affect the general rate case process?

A. Since the ERM calculates the difference between actual and authorized power supply related costs, the amount of authorized costs included in base rates impacts the amount of difference between actual and authorized costs. If the authorized level is set too low, it would increase the likelihood of the Company absorbing increased expense through the deadband in the surcharge direction. If the authorized level is set too high, it increases the likelihood that the Company would receive a benefit through the deadband in the rebate direction. The determination of "normal" power supply costs for the future rate year in a general rate case is almost always a contentious issue, with proposals/recommendations by the parties that can be many millions of dollars apart. Elimination of the deadband, and the $4 million to $10 million sharing bands, would reduce the impact of setting the level of power costs in base rates at the wrong level, thus protecting both the customers and Company from over or under collection of power supply expenses.

Q. Do other states have electric commodity tracking mechanisms that don't have deadbands or sharing bands?

A. Yes. In February of 2012 Avista sent a questionnaire to the EEI Rate Committee that was distributed to its members. The questionnaire asked if the companies have an electric power/fuel clause adjustment mechanism in any of their electric jurisdictions and, if so, if the mechanism has a deadband and/or sharing bands. Listed below is a summary of the responses:

1) Barbados Light & Power Company, Wisconsin – no deadband or sharing bands

2) Progress Energy Carolinas, North and South Carolina – no deadband or sharing bands

3) Arizona Public Service, Arizona – no deadband, 90/10 sharing (eliminated in pending settlement)

4) Hawaiian Elec. Co., Hawaii – no deadband, no sharing bands, heat rate incentive

5) Ameren Missouri, Missouri – no deadband, 95/5 sharing

6) LG&E and KU Services Company, Kentucky - no deadband or sharing bands

7) LG&E and KU Services Company, Virginia - no deadband or sharing bands

8) Minnesota Power, Minnesota - no deadband, no sharing bands

9) Alliant Energy, Minnesota - no deadband or sharing bands

10) Iowa – no deadband or sharing bands

11). Mississippi Power, Mississippi - no deadband, no sharing bands

12) Energy Corp, Louisiana - no deadband or sharing bands

13) Energy Corp, Arkansas - no deadband or sharing bands

14) Energy Corp, Mississippi - no deadband or sharing bands

15) Energy Corp, Texas - no deadband or sharing bands

16) Energy Corp, New Orleans – no deadband or sharing bands

17) Florida Power & Light, Florida - no deadband or sharing bands

18) Avista, Idaho – no deadband, 90/10 sharing

19) Idaho Power, Idaho – no deadband, 95/5 sharing

20) Rocky Mountain Power, Idaho – no deadband, 90/10 sharing

Q. How is the Company's ERM proposal comparable to its Purchased Gas Adjustment (PGA) mechanism?

A. As I mentioned earlier, the Company's PGA mechanism in both Washington and Idaho allows for the recovery of 100% of the difference between actual and authorized purchased gas costs. There is no deadband or sharing bands in the PGA mechanism. The Company is proposing elimination of the deadband and first sharing band in the ERM. While the Company believes that it should be allowed to recover 100% of the difference between actual and authorized power supply related costs included in the ERM, as it is allowed to do in the PGA, the Company is proposing a 90% customer/10% Company sharing level for the ERM.

Q. Would you please summarize the reasons for eliminating the deadband and the $4 million to $10 million sharing band in the ERM?

A. Yes. The Company has essentially no control over variations in costs due to stream flow conditions, or fuel and purchased power prices reflected in the ERM, and the Company should not have to absorb power supply related costs that the Company has to incur to meet customer loads. The Company's PGA mechanism provides for the recovery of 100% of the variation in prudently incurred purchased gas costs. Elimination of the deadband, and the $4 million to $10 million sharing bands, will reduce the impact of setting the level of power costs in base rates at the wrong level. Other states have electric commodity recovery mechanisms that don't have deadbands. And, the elimination of the deadband and first sharing band will help relieve financial stress on the Company, and will be viewed positively by the financial community.

<u>Retail Revenue Credit</u>

Q. Would you please describe how the retail revenue credit works within the ERM?

A. Yes. When retail loads are higher than authorized loads, there is a higher power supply expense to serve the increase in load that is included in the ERM. There is also a retail revenue credit adjustment within the ERM that multiplies the retail revenue credit rate times the increase in load to take into account that there is an increase in retail revenue to correspond with the increase in power supply expense. Absent the retail revenue credit adjustment, customers would be overcharged through the ERM for the increase in power supply expense.

Likewise, when retail loads are lower than authorized loads, there is a lower net power supply expense to serve the decrease in load that is included in the ERM. The retail revenue credit is applied to the decrease in load to take into account that there is a decrease in retail revenue that corresponds with the decrease in power supply expense. Absent the retail revenue credit adjustment, customers would receive an undue benefit through the ERM, since the net reduction in power supply expense is directly related to a reduction in retail revenue.

Q. How is the retail revenue credit rate currently determined?

A. The retail revenue credit rate is currently based on a revenue requirement calculation of the fixed and variable production and transmission costs authorized in the Company's last rate case. The net costs include production and transmission related sales for resale and other revenues, operating expenses, maintenance expenses, purchased power expenses, depreciation and amortization expenses, and a return on production and transmission rate base including federal income tax.

Q. What is the new method of determining the retail revenue credit rate that the Company is proposing?

A. The Company is proposing that the retail revenue credit rate be determined based on the <u>energy</u> classified portion of the fixed and variable production and transmission revenue requirement identified above, as established in the Company's cost of service study from the general rate case.

Q. What affect does the proposed method have on the retail revenue credit rate?

A. Based on the Settlement Agreement approved by the Commission in Docket UE-110876, the retail revenue credit rate that was effective January 1, 2012, and that is currently in place under the existing method is $50.37/MWh. Under the proposed method the energy classified portion of the rate would be $32.92/MWh. In the current case, based on the Company's proposed revenue requirement, the retail revenue credit is $50.59 /MWh under the existing method, and $33.29/MWh under the proposed, energy-classified method.

Q. Why is the Company proposing to change the way the retail revenue credit rate is determined?

A. The existing retail revenue credit rate, which is based on the fixed and variable production and transmission costs, is set too high. When retail loads increase, too much new revenue is credited back to customers through the ERM, rather than being available to offset increased costs. Because too much revenue is credited back to customers through the ERM, the matching principle is violated following a general rate case. New revenue from load growth is not available to offset costs associated with capital additions that are necessary to replace aging production, transmission, and back-bone distribution infrastructure, or increased operation and maintenance expenses. Inherent in the use of historical test-period ratemaking is the expectation that retail revenue will grow following the test year, and that revenue is available to help cover the increase in costs that occurs following the test year. If the Retail Revenue Credit is designed to rebate to customers the growth in revenue following the test year then it violates the matching principle and is in conflict with the use of historical test period ratemaking

By setting the retail revenue credit rate at a lower level, there is more revenue available to offset the aforementioned costs that is not credited back to customers through the ERM. Setting the retail revenue credit at a lower level will also eliminate fixed production and transmission costs from being recovered through the ERM when retail loads decline.

The cost changes that are tracked through the ERM are primarily due to changes in the price of <u>energy</u>, or changes to the amount of energy being purchased, sold, or generated. Since the costs being tracked through the ERM are primarily <u>energy</u> related, it is appropriate for the retail revenue credit to be based on the <u>energy</u>-related portion of production and transmission costs reflected in retail rates.

Q. What retail revenue credit method is used in the Idaho PCA?

A. Effective April 1, 2011 the Idaho Public Utilities Commission authorized a switch to the energy classified portion of embedded production revenue requirement to determine the retail revenue credit, which is referred to as the "Load Change Adjustment Rate" in Idaho. The method applies to all three investor-owned, electric utilities in Idaho, namely, Avista, Idaho Power, and Rocky Mountain Power. On April 1, 2011 the retail revenue credit for Avista was reduced from $48.00/MWh to $30.16/MWh.

Rate Adjustment Trigger and Rate Spread

Q. What is the current rate adjustment trigger for the ERM?

A. The rate adjustment trigger is set at 10% of base revenues per the Settlement Stipulation approved by the Fifth Supplemental Order in Docket UE-011595, dated June 18, 2002. What this means is that the ERM rate adjustment trigger is currently $45.3 million (10% of the base level of revenue approved in Docket UE-110876 of $453,007,000). The Company believes that allowing deferrals to grow to 10% of base revenues, or approximately $45 million, needlessly delays the recovery or rebate of variations in power supply related costs.

Q. What is the Company's proposed modification to the trigger mechanism?

A. The Company is proposing to replace the trigger mechanism with annual ERM rate adjustments. These annual rate adjustments would occur with rates effective July 1 each year, based on the deferrals from the previous calendar year. The Company would continue to file its annual deferral report on or before April 1 of each year, accompanied by a proposed rate adjustment to recover or rebate the deferral balance over a twelve-month period. Commission Staff and other interested parties would still have 90 days to review the filing prior to the July 1 effective date of the tariff.

Q. Do annual rate adjustments result in smaller rate adjustments as compared to the existing trigger mechanism?

A. Yes, the Company's proposal would result in smaller surcharge or rebate rate adjustments, than adjusting rates when a 10% trigger is reached. The rate adjustments would also be more understandable to customers since the costs being recovered or rebated relate to a recent period. Annual rate adjustments would result in a more timely recovery of costs when deferrals are in the surcharge direction, and a timelier pass-through of refunds when deferrals are in the rebate direction. The proposal of annual rate adjustments also fits within the existing 90-day review process.

ERM Related Revenues and Expenses, Retail Sales and Proposed Retail Revenue Credit

Q. What is Avista's proposed authorized power supply expense and revenue for the ERM?

A. The proposed authorized level of annual system power supply expense is $176,595,377. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). The proposed level of Transmission Expense is $18,058,719. The proposed level of Transmission Revenue is $11,065,962.

Q. What is the level of retail sales and the proposed retail revenue credit for the ERM?

A. The proposed authorized level of retail sales to be used in the ERM is the January 2011 through December 2011 weather adjusted retail sales. The proposed retail revenue credit is $33.29/MWh, which is the energy classified portion of the fixed and variable production and transmission revenue requirement in this filing developed by Company witness Ms. Knox.

The proposed authorized ERM power supply expense and revenue, transmission expense and revenue, and retail sales is shown in Exhibit No.___ (WGJ-5).

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

A. Yes.