Exhibit No. ___ (WGJ-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14______

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 July 2012 through June 2013 test period power supply revenues and expenses; (2) provide justification for retaining the current level of the Retail Revenue Credit in the Energy Recovery Mechanism (ERM); (3) describe a proposed mechanism to track, defer and return Renewable Energy Credit (REC) revenue to customers; and (4) 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.[1]

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

A. Yes. I am sponsoring Exhibit Nos.___ (WGJ-2) through ___ (WGJ-7), 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. A schematic of the proposed REC revenue rebate mechanism is shown in Exhibit No. ___ (WGJ-5). A table showing the net REC revenues, both actual and projected by year, proposed to be returned to customers beginning in January 2015 is shown in Exhibit No. ___ (WGJ-6). The proposed authorized ERM power supply expense and revenue, transmission expense and revenue, and retail sales are shown in Exhibit No.__ (WGJ-7).

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. Company witness Ms. Knox provides details supporting the proposed Retail Revenue Credit rate.

[1] As discussed by Company witness Ms. Andrews, the Company is basing its electric revenue increase requested in this case on its electric Attrition Study. However, as a "cross check" to the Company's request based on the electric Attrition Study, Ms. Andrews has also prepared an electric Pro Forma Cross Check Study. Both the electric Attrition and Pro Forma Cross Check Studies incorporate Washington's share of the pro forma power supply adjustment described further in my testimony.

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[2] currently in base retail rates, which is based on a calendar 2013 pro forma period, is also shown.

Power Supply Expense	System	Washington Allocation
Power Supply Expense in Current Rates (2013 pro forma)	$188,771,000	$122,720,027
Actual July 2012 - June 2013 Power Supply Expense	$200,403,000	$130,281,990
Proposed 2015 Pro forma Power Supply Expense	$178,835,000	$116,260,634
Proposed 2015 vs July 2012 - June 2013 Test Period	-$21,568,000	-$14,021,357
Proposed 2015 vs Current Rates	-$9,936,000	-$6,459,394

The net effect of my adjustments to the test year power supply expense is a decrease of $21,568,000 ($178,835,000 - $200,403,000) on a system basis and $14,021,357 Washington allocation. The decrease in power supply expense compared to the authorized level in current base rates is $9,936,000 (system) and $6,459,394 (Washington allocation).

[2] 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.

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 the Portland General Electric (PGE) capacity contract (Peaker Capacity) revenue. The Peaker Capacity contract revenue increases from $1,750,181 in the test-year to $17,734,955 in the pro forma. The term of the PGE capacity sale agreement runs from November 1, 1992 to December 31, 2016. In 1998 the Company monetized approximately 90% of the contract value each year for the period January 1999 through January 31, 2015. Through monetizing the majority of the value of this agreement, Avista received the cash up front for the portion monetized.[3] Avista did not monetize the last 23 months of the agreement from February 1, 2015 to December 31, 2016. Therefore, beginning February 1, 2015 the Company will receive the full revenue from the original PGE capacity sale agreement.

Pro forma loads (July 2012 through June 2013 weather adjusted loads) are 1046.6 average megawatts (aMW). This load includes actual weather adjusted test-year load of 1092.1 aMW less Clearwater Paper load of 48.3 aMW, plus Inland Empire Paper incremental load of 1.6 aMW, plus station service load of 1.2 aMW. Clearwater Paper load equal to their generation in the test-year was removed because, beginning July 1, 2013, Clearwater began generating into their own load and therefore reduced their load on Avista. Clearwater load equal to their generation was removed from system load in prior rates cases

[3] Washington's share of the funds was approximately $100 million from the monetization of the agreement. These funds were used to reduce generation rate base by approximately $37 million, to eliminate DSM balance of approximately $21 million and to offset certain expenses that would otherwise have increased customers' rates by approximately $38 million in accordance with the Commission Order in Docket Nos. UE-991606 and UG-991607.

because the Clearwater generation power purchase was assigned 100% to Avista's Idaho jurisdiction. The Inland Empire Paper load was increased because they had an extended outage at their facility that reduced their load during July through September of 2012. Additional load was added to July, August and September of the test-year to reflect the expected load at Inland Empire Paper during the pro forma period. Station service was added because power consumed from the grid at Company-owned generation is not included in native load calculations. After these adjustments, the net effect is that system load is 4.3 aMW higher than loads that current rates are based on (2011 weather adjusted load of 1090.6 aMW including Clearwater load equal to their generation).

III. PRO FORMA POWER SUPPLY ADJUSTMENTS

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.

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. Yes. The pro forma does not include any REC revenues or related REC expenses, as has been the case in prior rate cases. In Order 09 in Docket No. UE-120436, the Commission ordered the Company to separately track all REC revenue and develop a mechanism to return REC revenue to customers. The Commission also ordered the Company to remove REC revenue from base rates beginning January 1, 2015.

Aside from removing REC revenue and REC-related expenses from the pro forma, 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 with 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. No.

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

A. Yes. Four power purchase contracts and two sale contracts end prior to the 2015 pro forma year. The Spokane Waste-to-Energy contract expires November 16, 2014, and the Stateline Wind contract expires March 31, 2014. The Waste-to-Energy purchase provided 16.1 aMW of energy during the test-year. It is likely that there will be a new Waste-to-Energy purchase and the details will be known sometime in 2014. The Stateline Wind purchase provided 8.7 aMW of energy during the test-year.

Two other contracts that expire in 2014 are the Rocky Reach/Rock Island purchase and the Wells Colville Share purchase. The Rocky Reach/Rock Island purchase is a 5-year purchase of a 3% slice of Rocky Reach and Rock Island hydroelectric dams owned by Chelan PUD that expires December 31, 2014. The Wells Colville Share purchase is 21-month purchase of the Colville Tribe's 4.5% share of the Wells hydroelectric dam owned by Douglas PUD that expires September 30, 2014. Together these two contracts provide Avista with approximately 109 MW of Mid-Columbia capacity. Avista uses this capacity along with additional Mid Columbia capacity purchased from Grant and Douglas PUD to meet load regulation/load following requirements during most of the year. The purchase of

Mid Columbia capacity allows the company to more efficiently operate its own hydro facilities and makes possible the sale of load regulation services to other entities.

Chelan PUD and the Colville Tribe use an auction process to sell the Mid-Columbia slice products. These auctions for product available in the 2015 pro forma year will be held in 2014, and Avista will participate in the auction process. The pro forma includes anticipates purchases from Chelan and the Colville Tribe for the same percentage of plant capacity as was purchased in the test-year. The pro forma contains an estimated price for these purchases. The actual price for these purchases will be known before January 1, 2015 and the actual expense can be updated before then.

On the sales side, the Pend Oreille contract expires September 2014 and the Sacramento Municipal Utility District (SMUD) contract expires December 2014. The company is negotiating with Pend Oreille for a new contract and the pro forma includes revenues equal to the test-year. The pro forma doesn't include any SMUD revenue, but also doesn't include the energy obligation of the SMUD contract that existed in the test-year. Pro forma revenue included in the SMUD contract line item is based on the COB minus Mid C price spread utilizing the PGE COB transmission.

<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.

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

A. The pro forma includes transactions entered into through late 2013 for the 2015 pro forma period. These transactions include fixed-price financial electric and natural gas transactions. The AURORA model is used to mark-to-model the financial electric transactions. A mark-to-modeled gas price calculation is performed outside the AURORA model and details of these gas transactions are provided in workpapers.

<u>Thermal Fuel Expense</u>

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 test-year and the expense in current base rates?

A. The biggest change is the reduction in transmission purchased for the Lancaster plant. Currently the Company purchases 250 MW of BPA point-to-point transmission to move Lancaster Generation to the Company's system. On December 13, 2013, the Lancaster substation became a point of interconnection to Avista's transmission system, eliminating the need for BPA transmission for Lancaster. Avista's Lancaster transmission contracts with BPA allowed for the termination of 150 MW of the 250 MW of transmission with a two-year notice. The termination notice was given to BPA on August 31, 2012, when the Company had confirmation that the interconnection to Avista's system was to be completed by the end of 2013.

Other than that significant reduction in transmission expense for Lancaster, there are some increases in point-to-point and other BPA transmission expenses due to rate increases that went into effect on October, 1, 2013.

Summary

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

A. The proposed pro forma power supply expense as shown in Exhibit No. ___(WGJ-2) is a $21,568,000 reduction in expense on a system basis ($14,021,357 Washington allocation) from the July 2012 through June 2103 test-year expense and a $9,936,000 (system)/$6,459,394 (Washington allocation) reduction in expense from the power supply expense in current rates.

IV. MODIFICATIONS TO THE ERM

Q. Is the Company proposing any modification to the ERM?

A. No. The Company is not proposing any changes to the ERM at this time. That said, there is one issue regarding the ERM that needs to be addressed in this case. In the Multi-Party Settlement Agreement in Docket No. UE-120436, the parties agreed to change the retail revenue credit from the full fixed and variable production and transmission revenue requirement to the energy classified production and transmission revenue requirement. This reduced the retail revenue credit from roughly $.05/kWh to $.03/kWh. In Final Order 09, the Commission accepted the settlement and the change in the retail revenue credit as a non-precedent setting agreement. The Commission directed the Company in its next general rate case to seek approval to maintain the change in the retail revenue credit.

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 sales 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 sales 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. Per the Multiparty Settlement Agreement in the last general rate case, the retail revenue credit rate is determined based on the energy classified portion of the fixed and variable production and transmission revenue requirement, as established in the Company's cost of service study from the general rate case.

Q. What effect did the change in methodology approved in the last rate case have on the retail revenue credit rate?

A. Based on the Settlement Agreement approved by the Commission in Docket UE-120436, the retail revenue credit rate that was effective January 1, 2013 is $32.15/MWh. Under the prior method that based the retail revenue credit on the full fixed and variable production and transmission revenue requirement, the rate would have been $48.86/MWh.

Q. Why did the Company propose changing the way the retail revenue credit rate is determined in Docket No. UE-120436?

A. The prior method to determine the retail revenue credit rate, which was based on the full fixed and variable production and transmission costs, resulted in a rate that was 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 should be available to offset costs associated with capital additions that are necessary to add facilities to serve load growth, to replace aging production, transmission, and back-bone distribution infrastructure, and 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 occur 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 level that reflects only the energy classified portion of production and transmission costs the Company retains growth in demand-related revenue to cover the growth in demand-related investment and costs. Setting the retail revenue credit based on the energy classified portion only will also eliminate demand-related production and transmission costs from being recovered through the ERM when retail loads decline. This eliminates any argument that the retail revenue credit operates as a partial decoupling mechanism when loads decline.

The cost changes that are tracked through the ERM are primarily due to changes in the price of energy, or changes to the amount of energy being purchased or sold at the wholesale level. Since the costs being tracked through the ERM are primarily energy related, it is appropriate for the retail revenue credit to be based on the energy-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 and transmission 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 in Idaho was reduced from $48.00/MWh to $30.16/MWh.

V. RENEWABLE ENERGY CREDIT REVENUE MECHANISM

Q. Please explain the issue regarding Renewable Energy Credit (REC) revenue?

A. In Order 09 in Docket No. UE-120436, the Commission ordered the Company to separately track all REC revenue and develop a mechanism to return REC revenue to customers. The Commission also ordered the Company to remove REC revenue from base rates beginning January 1, 2015. Prior to that order, the Company included REC revenue in the power supply pro forma and tracked the difference between actual and authorized REC revenue in the ERM in a manner similar to other power supply expenses and revenues. That meant that the difference in REC revenue between the actual and authorized level was subject to the ERM sharing bands. It also meant that differences in

REC revenue would not flow through to customers until such time as the $30 million ERM trigger was reached and there was either an ERM surcharge or rebate.

Q. Please describe the Company's proposal for returning REC revenue to customers.

A. The Company proposes to implement a REC revenue rebate effective January 1, 2015, coinciding with any change in base rates from this rate case filing. This rebate would be based on actual and projected net REC revenues from 2012 through June 2016. The proposed amortization period for this rebate would be 18 months, January 2015 through June 2016. REC revenue would be based on the actual REC revenue in excess of the amount in base rates for 2012 and 2013, the estimated REC revenue in excess of the amount in base rates for 2014, and the total estimated REC revenue for the period January 2015 through June 2016. The Company proposes that the rebate be implemented on a uniform cents/kWh basis across all rate classes.

Q. Please specify the mechanics of how REC revenues would be rebated.

A. As stated above, the Company proposes to implement an initial net REC revenue rebate beginning January 1, 2015 based on actual and estimated REC revenues. This rebate would be in effect through June 2016. On or before April 1, 2016, as part of the annual ERM filing[4], the Company would provide the Commission with a true-up of net REC revenues through December 2015 and provide an estimate of net REC revenues for the period July 2016 through June 2017. The Company proposes that this estimate, along with the true-up, form the basis for a new REC revenue rebate that would go into effect July 1, 2016 and end June 30, 2017. The same process would repeat each year, where the Company

[4] The annual ERM prudence review is filed by April 1 of each year. There is a 90 day review period ending June 30.

includes a true-up and estimate for a new REC revenue rebate as part of its annual ERM filing. Exhibit No.___ (WGJ-5) shows a schematic of the Company's proposed REC revenue rebate mechanism.

Q. Please describe the accounting relating to REC revenues.

A. The Company currently uses FERC Account 186.322 (Miscellaneous Deferred Debits – WA REC Deferral) to record the actual net REC revenues in excess of the amounts in base rates. Through December 31, 2013, the Company has recorded $1,569,264 net REC revenues in this FERC Account. In addition, the Company has accrued interest of $37,684, through December 31, 2013. Interest has been computed using the same method that is used for the ERM. Interest is applied to the average of the beginning and ending month deferral balances net of associated deferred federal income tax. The Company's weighted cost of debt is used as the interest rate. The interest rate is updated semi-annually and interest is compounded semi-annually.

The Company will continue to defer all net REC revenues in excess of the amounts in base rates for 2014 in FERC Account 186.322. In addition, the Company will defer all net REC revenues for the 2015 in this account. Beginning in January 2015, with the effective date of new base rates from this case, the Company will record the rebate to customers, net of revenue-sensitive expenses, in this account. Interest will continue to accrue, as described above.

The Company will record all net REC revenues for 2016 in a 186.3 FERC Account. A separate FERC account will be used to track the 2016 actual net REC revenues, so these net revenues will be provided in the annual ERM review that will be filed by April 1, 2017. Interest will accrue, as described above.

Any balance in FERC Account 186.322 at December 31, 2016 will be transferred to a 186.3 FERC Account. This process will repeat each year.

Q. Will the Company include and track any REC expenses?

A. Yes. REC revenue will be netted against certain incremental REC expenses. These expenses include items such as WREGIS fees, Green-e fees, broker fees, any REC purchases, and other specific out-of-pocket expenses required to support REC sales[5]. REC expenses will not include any costs associated with generation at Company-owned resources that generate RECs. However, if the Company in the future receives output from a generating resource such that the Company incurs incremental costs associated with incremental RECs received, it would be appropriate to reflect these incremental costs in the REC deferral.

Q. What is the estimated REC revenue rebate to go into effect on January 1, 2015?

A. Based on actual 2012 and 2013 REC revenue plus the estimated REC revenue for the period 2014 through June 2016, the total rebate amount is $7,841,726 (Washington allocation). Amortized over an 18 month period the rebate is $.00094/kWh, or approximately a 1.1% reduction in rates. A table showing net REC revenues, both actual and projected, by year is shown in Exhibit No. ___ (WGJ-6).

[5] WREGIS fees are required to maintain and transact eligible RECs. Green-e fees are payments to the Center for Resource Solutions to certify generation for eligibility in Green-e participation. Broker fees are sometimes incurred in the sale or purchase of RECs. Avista at times purchases RECs, primarily to meet Washington Energy Independence Act requirements. Other REC-related expenses include items such as professional services used to facilitate REC sales.

VI. ERM AUTHRORIZED VALUES

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 $160,443,687. 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 $16,698,737. The proposed level of Transmission Revenue is $16,015,349.

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 July 2012 through June 2013 weather adjusted Washington retail sales adjusted for the Inland Empire Paper load as described earlier. The proposed retail revenue credit is $33.60MWh, 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 are shown in Exhibit No.___ (WGJ-7).

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

A. Yes.