BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-99

DIRECT TESTIMONY OF WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

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EXHIBIT # T-420
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Exhibit T-43

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

A. My name is William G. Johnson. My business address is East 1411 Mission Avenue, Spokane, Washington, and the company employs me as a Power Contracts Analyst in the Resource Optimization 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 Power Contracts Analyst?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Resource Optimization Department as a Power Contracts Analyst in June 1996. My primary responsibilities include the evaluation of the company's long term electricity supply and wholesale opportunities. I also perform the calculations for the monthly Power Cost Adjustment (PCA) deferral for the Idaho jurisdiction.

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

A. My testimony will explain why the company is proposing a power cost adjustment mechanism for the Washington jurisdiction. I will also explain the mechanism the company is proposing to calculate the difference between actual power supply expense and authorized power supply expense.

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

A. Yes. I am sponsoring Exhibit No(s). 44 and 45, as previously marked for identification, which were prepared under my supervision and direction.

Q. Are other company witness providing testimony on the proposed PCA mechanism?

A. Yes. Company witness Mr. McKenzie is providing testimony that addresses the procedures and related accounting associated with the PCA mechanism.

Q. Why is the company proposing a Power Cost Adjustment (PCA) in this filing?

A. The company is proposing a PCA in Washington to enhance earnings stability by flowing through to customers variations in the company's power supply revenues and expenses due to changes in uncontrollable factors, primarily hydro generation and short-term energy prices. Variations in hydro generation and short-term energy prices will affect short-term sales revenue, short-term purchase expense, and thermal fuel expenses related to the dispatch/displacement of the thermal units. For the remainder of my testimony I will refer to these revenues and expenses as net power supply expense. The net power supply expenses charged to customers through implementation of the PCA will more closely match the actual revenues and expenses incurred by the company.

Q. What is the rationale behind the PCA concept?

A. A PCA is intended to enhance the concept of normalizing expenses, especially for a utility such as Avista with significant hydro generation. Normalization assumes that, over time, variations in expense due to hydro generation and energy prices will balance out. Over a long enough period, hydro generation will probably tend to be close to the average. In the shorter term, however, deviations from normal can occur. The company's proposed normalized power supply expense is based on 60 years of hydro information. While the company believes this is the most complete and best information to use for setting base retail rates, it is very possible that in the short-term, say the next 5 years, hydro conditions may vary significantly from the 60 year average. For example, the last 5 years, including 1999, all have had hydro generation close to or above normal with three years, 1996, 1997 and some months of 1999, being among the highest hydro generating years in the history of the company. On the other hand, the second half of the 1980s saw hydro generation generally below average. This is not to suggest that there are known trends or cycles in hydro conditions that should be used in the rate making process, but rather that the near term average may be quite different from a long term average. The best means to account for variations in the near term is by the means of a tracking mechanism as is being proposed.

Short-term energy prices are also an important factor in determining the company's net power supply expenses. The energy prices the company used in this filing are developed using the company's Dispatch Simulation Model. The Dispatch Simulation Model determines energy prices for each month of the 60 water years used in the power supply analysis based on the fundamentals of regional energy surpluses and the current incremental cost of displaceable thermal generating plants. The model produces an average annual energy price of $21.35/MWh. In reality, energy prices can vary by a large amount even when hydro generation is close to normal. In both 1995 and 1998 hydro generation was within 3 percent of the 60-year average, yet the average energy price for the year was around $12/MWh in 1995 and $22/MWh in 1998. This variation in energy price can have a large impact on Avista's net power supply expense and the company cannot control the market price of power. There will always be unpredictable variation in actual short-term energy prices, and it is very likely that the future short-term energy prices will be different than the normalized rates included in this case. A mechanism to track the impact of short-term energy prices on the company's net power supply expenses is the best method to insure that customers pay, and/or receive the benefits of the costs actually incurred by the company.

Q. What other costs is the company proposing to track in the PCA?

A. The only other cost item the company is proposing to track is changes in the cost for PURPA resources from the authorized levels. PURPA resources are power purchases the company is required to make by Federal law and over which the company has no direct control.

In summary, the company is proposing to track changes to power supply revenues and expenses that are generally beyond the company's control. The company cannot control precipitation and snow pack, which determines hydro generation. The company cannot control or influence short-term wholesale energy prices, and the company cannot control PURPA power purchase expenses.

Q. Is the company proposing to track changes in costs due to changes in long-term contracts or retail loads?

A. No. The company is not proposing to track cost changes due to changes in long-term contracts or retail loads. Retail load requirements, along with the energy requirements and obligations associated with long-term contracts will remain constant at the levels approved for inclusion in base retail rates.

Q. Is the company proposing a sharing of cost increases or decreases between the company and its customers in the PCA?

A. No. The company is proposing that 100% of the change in net power supply expenses be flowed through to customers. The cause of the cost changes that the company proposes to track, hydro generation, market energy prices, and PURPA expenses, are substantially beyond the company's control. Therefore, the company believes that a sharing mechanism would not be appropriate since it implies that the company has some control over these factors.

Q. Is it therefore true that the company is not proposing that an incentive mechanism be part of the PCA?

A. Yes, that is correct. Once again, the company believes it would not be appropriate to include an incentive mechanism related to changes in costs that are substantially beyond the company's control.

Q. Does the company currently have a PCA mechanism in place in the State of Idaho?

A. Yes. The company has had a PCA mechanism in Idaho since October 1989.

Q. What variables are tracked by the Idaho PCA?

A. The Idaho PCA tracks the difference between authorized net power supply expense and actual net power supply expenses related to hydro generation, short-term energy prices, and the PURPA contracts. These are the same variables that the company is proposing to track in the Washington jurisdiction.

Q. What has been the overall result of the PCA in Idaho?

A. Since the PCA was implemented in Idaho there have been eight rebates to customers and three surcharges. Overall rebates have exceeded surcharges by $14 million.

Q. What kind of response has there been from Idaho customers regarding the PCA?

A. The company and the Idaho Public Utilities Commission have received few inquiries or comments from customers regarding rate changes resulting from the PCA. Since the rebates or surcharges are limited to roughly 2.5% each, with a maximum of two rebates or surcharges in effect at any one time (5% total decrease or increase), the impacts are relatively small.

Q. What type of PCA mechanism is the company proposing?

A. The company is proposing a PCA mechanism similar to the PCA mechanism used in the Idaho jurisdiction. The mechanism would track the monthly difference between net power supply expenses based on actual hydro generation and energy prices, and the normalized expense level. The mechanism would also track the difference in PURPA related power supply expense between actual expense and the authorized expenses.

Q. Have you prepared an exhibit to show how the PCA would be calculated?

A. Yes I have. Exhibit No. 44 shows the proposed PCA worksheets that would be used to calculate the deferral amount each month.

Q. Can you please explain page 1 of Exhibit No. 44?

A. Yes, Page 1 is the cover page summarizing the components of the total deferral. The first line is the Weather Related Adjustment which accounts for changes in net power supply expenses related to actual hydro generation, actual short-term wholesale energy prices, and the dispatch of the thermal resources, which will be explained later. The second line is the PURPA Contract Tracker, which accounts for differences in PURPA contract expense. The third line is the Hydro Hourly Shape Adjustment which accounts for the difference in the hourly shape of the change in hydro generation from normalized levels and the hourly shape of the short-term wholesale energy prices. The fourth line would include any Prior Period Adjustments to reflect any changes in prior month PCA calculations. These four components sum to the Net Adjustment to the Balancing Account, which is the PCA deferral entry for the month.

Q. Can you please explain page 2 of Exhibit No. 44?

A. Yes. Page 2 shows the summary calculation of the weather-related and PURPA contract comparison of actual expense to authorized expense. Lines 1 through 10 show the weather-related calculation. Lines 1 – 4 represent the net power supply expenses using actual hydro generation and actual short-term energy prices. These are calculated on pages 3 and 4 of Exhibit No. 44 and are explained below. Lines 5 – 8 represent the power supply revenues and expenses that are approved by the Commission for inclusion in base retail rates, typically in a general rate case. Line 9 is the difference between the adjusted actual net expenses, Line 4, minus the authorized net expenses, Line 8. Line 10 is the Washington allocation (66.99%) of Line 9, the difference between adjusted actual and authorized net expenses.

Lines 11 through 14 are for PURPA contract expense. Line 15 is the sum of the Washington share (66.99%) of the weather-related and PURPA contract expense adjustment. The figures for the relevant month (June in this example) are carried forward to the cover page, page 1 of Exhibit No. 44.

Q. Can you please explain pages 3 and 4 of Exhibit No. 44?

A. Yes. Pages 3 and 4 show the inputs to the weather-related calculations. Lines 1 through 13 show the company's energy requirements, which includes weather adjusted net system load and long-term contract obligations. Lines 14 through 24 show the long-term energy purchases. These values in the calculation of the PCA adjustment each month, remain identical to the values used in the determination of base retail rates in the general rate case.

Lines 25 though 26 show the actual monthly Mid–Columbia and System Hydro generation from company generation records. Lines

25 and 26 are in boxes because they are monthly inputs to the calculation. All values shown in boxes in both Exhibits No(s). 44 and 45 are inputs that are actual values for that month. Values that are not included in boxes are either 1) inputs that are identical to those used in the determination of base retail rates in the rate case, or 2) calculated values in the PCA spreadsheet.

Line 27 is the sum of long-term contract purchases and hydro generation. Available energy for the base load thermal plants (Centralia, Colstrip, and Kettle Falls) is shown on lines 28 though 30. The available energy for each plant comes from the Dispatch Simulation Model and is equal to the dependable capacity of the plant times the equivalent availability factor (EAF). Line 31 shows the normalized incremental cost of Colstrip from the Dispatch Simulation Model and includes incremental fuel, O&M and line losses. Line 32 is the actual short-term energy price for the month, which is calculated on page 6 of Exhibit No. 44. The actual short-term energy price represents Avista's average purchase and sales rate for short-term (one year or less) energy transactions net of wheeling expenses and losses.

Lines 33 through 36 show the amount of thermal generation for each plant. Colstrip generation is based on the energy availability (Line 29), the incremental cost of Colstrip (Line 31) and the secondary energy price (Line 32). If the incremental cost of Colstrip is less than the secondary energy price then the unit is assumed to generate at its availability, and if the incremental cost is greater than the secondary energy price the plant is assumed not to generate because it is less expensive to purchase short-term energy. Centralia and Kettle Falls are assumed to generate at their normalized amount (authorized in the last rate case) because of fuel availability at both plants. Centralia is currently limited to approximately 800,000 tons per year, which normalized generation is based on. Kettle Falls has limited fuel available at the normalized incremental cost of 12 mills/kWh. Additional generation from Kettle Falls would require more expensive fuel purchases.

Line 36, Rathdrum generation, is the actual energy generation from Rathdrum for the month and is shown in a box as an input to the PCA model. Rathdrum generation is included in the PCA as an actual monthly input because of its flexibility in producing energy and the variability of its fuel cost. The Rathdrum plant is primarily a peaker unit that can produce energy as an alternative to short-term energy purchases. Including both Rathdrum generation and gas purchase expense as actual monthly inputs to the PCA calculations treats Rathdrum generation similar to short-term energy purchases. If the incremental operating cost of Rathdrum is less than the short-term market price, customers receive the benefit of the lower cost Rathdrum generation. If the incremental cost of Rathdrum is higher than the market price, the units would be displaced and customers receive the benefit of lower cost market purchases. Including the actual generation and fuel expense for Rathdrum in the PCA calculation will provide customers with the full benefit of this dispatchability.

Line 37 is the energy surplus or deficit, which is the sum of contract purchases plus hydro and thermal generation minus Total Requirements (line 13). If line 37 is positive then the company is in a surplus condition for the month. Secondary Sales, line 38, is equal to the surplus times the hours in the month times the secondary energy price. When line 37 is negative then the company is in a deficit condition for the month. Secondary Purchases, line 39, is equal to the deficit times the hours in the month times the secondary energy price. Lines 38 and 39 are carried forward to the Calculation Summary on lines 1 and 2 of page 2 of Exhibit No. 44. Lines 40 through 42 show the units of fuel consumed at Centralia, Colstrip and Kettle Falls based on the generation (lines 33 – 35) and the conversion factors shown. Lines 43 through 45 show the authorized fuel cost per unit for the thermal plants. Both the conversion factors and the fuel cost are the same as authorized in the rate case to limit the scope of the PCA mechanism. The thermal fuel expense for each plant is shown on lines 46 through 48 and is equal to the units of fuel consumed (lines 40-42) times the fuel cost per unit (lines 43-45). Line 49, Rathdrum fuel expense is the actual cost of gas consumed at Rathdrum. Line 50 is the total thermal fuel expense and is carried forward to the Calculation Summary, line 3 on page 2 of Exhibit No. 44.

Q. Can you please explain page 5 of Exhibit No. 44?

A. Yes. Page 5 is the PURPA Contract Tracker calculation. Lines 1 though 9 show the level of PURPA contract costs in the normalized power supply expense included in base retail rates. Lines 10 - 18 show the actual PURPA contract expense for the month. The actual values shown on Lines 10 – 17 in this exhibit are for illustrative purposes only. Actual booked expenses will be entered for each month's calculation. Line 18 is carried forward to the Calculation Summary, line 11 on page 2 of Exhibit No. 44.

Q. Can you please explain page 6 of Exhibit No. 44?

A. Yes. Page 6 is the calculation of the actual secondary energy price. The secondary energy price is based on Avista's short-term (1 year and less) system energy sales and purchases adjusted for wheeling and losses. Lines 1 through 5 show the actual booked dollars for sales, purchases and wheeling expense. Lines 6 through 10 show the actual booked energy volumes of sales, purchases and losses. Line 11 is the weighted average short-term energy rate calculated by dividing total dollars by total energy. Line 11 is carried forward to the Weather-Related Calculation, line 32 on page 4 of Exhibit No. 44. Lines 12 – 18 show the short-term energy prices from the authorized case, which were determined by the Dispatch Simulation Model. They are shown for informational purposes only and are not part of the PCA calculation.

Q. Please explain the purpose of the Hydro Hourly Shape Adjustment.

A. The purpose of the Hydro Hourly Shape Adjustment is to adjust the Weather Related calculation of secondary sales and purchases to properly value the changes in hydro generation. The Weather-Related Calculation determines the amount of secondary sales or purchases based on the weighted secondary energy price. The weighted secondary energy price is based on Avista's short-term energy sales and purchases during both heavy load and light load hours. Prices during heavy load hours (6 am to 10 p.m., Monday through Saturday) can be $5/MWh to $10/MWh or more higher than prices in light load hours (10 p.m. to 6 am, Monday through Saturday and all day Sunday). If the hourly shape of the change in hydro generation, from the authorized level, does not match the hourly shape of the sales and purchases that comprise the short-term energy price, then the PCA Weather-Related calculation will either over-value or under-value the change in hydro generation. The Hydro Hourly Shape Adjustment aligns the change in hydro generation during heavy-load hours with heavy load prices and the light-load generation with light load prices.

Q. What are the important factors in calculating the Hydro Hourly Shape Adjustment?

A. The important factors are the hourly shape of the change in hydro generation, the hourly shape of the sales and purchases that are used to calculate the short-term energy price, and the difference between heavy load hour and light load hour prices.

Q. Have you prepared an exhibit to show how the Hydro Hourly Shape Adjustment would be calculated?

A. Yes I have. Exhibit No. 45 shows the proposed Hydro Hourly Shape Adjustment worksheets that would be used to calculate the adjustment each month.

Q. Can you please explain page 1 of Exhibit No. 45?

A. Yes. Page 1 of Exhibit No. 45 shows the calculations to determine how much the short-term energy price used in the Weather-Related PCA calculation has over or understated the value of the change in hydro generation. Lines 1 through 11 show the amount of normalized hydro generation (60-year average) in heavy load hours and light load hours. The separation of normalized hydro generation into heavy load and light load hours will be explained later in my testimony. Lines 12 through 28 show the actual hydro generation from company records separated into heavy and light load hours.

Lines 29 and 30 show the PCA secondary energy price from page 6 of Exhibit No. 44 and the difference in price between heavy and light load hours. Lines 31 and 32 show the percent of short-term purchases and sales volume (used to determine PCA secondary energy price) that occurred in heavy and light load hours. Lines 33 and 34 compute what the heavy and light load hour secondary energy prices are based on the PCA Secondary Price (line 29), the difference between heavy and light load hour prices (line 30), and the percent of purchases and sales that occurred in heavy and light load hours (lines 31-32).

For example, in June the short-term energy price was \$19.12/MWh (Line 29) and the difference between heavy load and light load prices was \$11.14/MWh (Line 30). The short-term energy price was derived from purchases and sales occurring 87% of the time in heavy load hours and 13% of the time in light load hours (Lines 31 & 32). Based on these values, the average short-term energy prices were \$20.58/MWh in heavy load hours and \$9.43/MWh in light load hours (Lines 33 & 34). Weighting these heavy load and light load prices by the energy volumes during heavy load and light load hours results in an average price of \$19.12/MWh (\$20.58 x 87% + \$9.43 x 13% = \$19.12).

Lines 35 through 39 show the change in hydro generation (actual versus authorized) in heavy and light load hours. Line 40 shows what the energy price should be for the change in hydro generation based on the hourly shape of the hydro generation (lines 36-37) and the PCA heavy and light load hour prices (lines 33-34). Line 41 shows the difference between the unadjusted PCA price and the energy price adjusted for the hourly shape of the hydro generation. Line 42 shows the over-statement or under-statement of the value of the hydro generation, calculated by multiplying line 35 by line 41. Line 43 is Washington's share of the change in value. Line 43 is entered as the Hydro Hourly Shape Adjustment on page 1 of Exhibit No. 44.

Q. Can you please explain page 2 of Exhibit No. 45?

A. Yes. The purpose of page 2 of Exhibit No. 45 is to calculate the difference between heavy load hour and light load hour prices, and to determine what portion of Avista's short-term system purchases and sales volume occurred during heavy load hours and what portion occurred during light hours. Lines 1 through 9 show the actual volume of short-term purchases and sales energy during heavy and light load hours, along with the percentage of total short-term energy transactions (purchases and sales) during heavy and light load hours. Lines 8 and 9 are carried forward to lines 31 and 32 on page 1 of Exhibit No. 45.

Lines 10 through 16 show the dollar amount of the short-term transactions separated into heavy and light load hours based on the actual transactions. Lines 17 through 19 are calculations of the heavy load hour, light load hour and average secondary energy prices based on the energy and dollar volumes of short-term purchases and sales. Line 20 is the calculated difference between heavy and light load hours for Avista's short-term system purchases and sales. Line 20 is carried forward to line 30 on page 1 of Exhibit No. 45. The average price on Line 19 of page 2 of Exhibit No. 45 may be slightly different than the average price on Line 11 of page 6 of Exhibit No. 44 because the latter includes prior period billing adjustments, wheeling and losses and the former is based solely on the actual sales and purchase transactions for the month.

Q. How was the hourly load shape of Avista's hydro generation under normal stream flow conditions determined?

A. Generation records for the years 1989 through 1995 were used to develop the hourly load shape for Avista's normalized hydro generation. The average hydro generation during these years is similar to the level of hydro generation used to calculate normalized power supply expense. Actual hourly generation for Noxon Rapids, Cabinet Gorge and the company's share of the Mid-Columbia projects was used to develop monthly averages of generation during heavy load hours and light load hours. Daily generation records were used to develop load shapes for the company's Spokane River facilities. Generation during heavy load hours and light load hours was developed from daily generation records for the Long Lake and Little Falls projects using an algorithm based on maximum hourly generation capability and the number of heavy load hours. All other Spokane River plants are operated on a run of river basis and generation is assumed to be constant over all hours. Exhibit No. 45, page 1, lines 1 through 11 show the load shape of Avista's normalized hydro generation based on actual generation for the period 1989 through 1995.

Q. How will each month's hourly shape of the change in hydro generation from the normalized level be calculated?

A. Actual hourly generation records for Noxon, Cabinet Gorge, Long Lake, Little Falls and Mid Columbia, along with monthly records for the remaining Spokane River plants, will be used to develop the total hydro generation during heavy load hours and light load hours for the month. This information is entered into lines 12-18 and lines 21-23 of the Hydro Hourly Shape Adjustment (Exhibit No. 45, page 1).

Q. How does the hourly shape of hydro generation change when stream flows are greater than normal?

A. During the runoff period, in years when stream flows are above normal, a lower percentage of generation occurs in the heavy load hours than under normal stream flow conditions. The reason for this is that the hydraulic capability of the hydro facilities limits the amount of water that can be used for generation during peak periods. When there is more water than can be used by the plants during heavy load hours, then that additional water is used to generate power during the light load hours. This is especially true in the runoff months of May and June, because even under normal stream flows there is very limited capability of generating additional energy during heavy load hours. When stream flows are much above normal as in 1996, 1997, and 1999 generation in the runoff months occurs flat across all hours of the day because the total stream flow in the day exceeds the hydraulic capacity of the plant times the hours of the day. In this situation virtually all of the <u>additional</u> hydro generation occurs during light load hours. For example 99% of the <u>additional</u> hydro generation above normal came during light load hours during June 1999.

Q. Why does the hourly shape of the hydro generation cause the PCA model to over-value or under-value that generation?

A. An increase in hydro generation from normal is valued at short-term energy prices in the proposed PCA model and lowers power supply expenses. Expenses below authorized expense levels create deferrals in the rebate direction. Heavy load hour prices are greater than light load hour prices. It is possible that the hourly shape of the short-term energy transactions (purchases and sales) that determine the short-term energy price will not match the hourly shape of additional hydro generation above normal. Therefore, it is important to value additional hydro generation during heavy load hours at heavy load prices, and additional generation during light load hours at light load prices.

Q. What role does the price spread between heavy load hours and light load hours have in determining the over-valuation of the additional hydro generation?

A. The over-valuation of additional hydro generation is directly related to the spread in prices between heavy and light load hours. If there is no difference in heavy load hours and light load hours prices then the hourly shape of the surplus hydro generation does not affect its value. In June of 1999, the spread was over $11/MWh.

Q. Is the hourly shape adjustment important when hydro generation is below normalized levels?

A. Yes it is. When hydro generation is below normalized levels, the hourly shape of the hydro generation shortfall may not match the hourly shape of the short-term energy price. The hourly shape adjustment will align the generation shortfall with the hourly energy prices to properly determine the cost of purchasing energy to make up for the hydro generation shortfall.

Q. Please summarize your testimony?

A. The company is proposing a PCA in Washington to account for the variations in the company's power supply expense due to changes in uncontrollable factors, namely hydro generation and energy prices. The proposed PCA enhances the concept of normalizing expenses by truing up the actual costs incurred by the company to the normalized net power supply expenses recovered from customers in base rates. The normalized net power supply expense developed for this rate case is based on a long-term average of hydro generation and current wholesale market price conditions. Changes in either hydro generation or energy prices can have a significant effect on the company's net power supply expenses. The company has proposed a tracking mechanism that accounts for changes in power supply expense due to changes in hydro generation, energy prices, and PURPA contract expenses. The company has very little or limited control of these three factors. History has shown that, over the relatively short period that rates from this filing would be in effect, the average hydro generation can vary significantly from the long-term average used to determine the normalized net power supply expenses. Also, energy prices may be materially different than the energy prices embedded in the company's normalized net power supply expenses. The proposed tracking mechanism will assure that factors substantially beyond the company's control, namely the level of hydro generation, energy prices, and PURPA contract costs will be trued up to the normalized levels on an ongoing basis. Because the PCA mechanism being proposed is similar to what has been in use for almost 11 years in the company's Idaho jurisdiction, the company is confident that it will accurately produce the intended results in a simple and symmetrical manner.

Q. Does that conclude your direct testimony?

A. Yes.