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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-09-01 DIRECT TESTIMONY OF SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Scott J. Kinney. I am employed by Avista Corporation as the Director of Transmission Operations. My business address is 1411 East Mission, Spokane, Washington.

Q. Please briefly describe your education background and professional experience.

A. I graduated from Gonzaga University in 1991 with a B.S. in Electrical Engineering. I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions in the Transmission Department. I started at Avista as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a supervisor and support engineer. In 2004, I was appointed as the Chief Engineer, System Operations. In June of 2008 I was selected to my current position as Director of Transmission Operations.

Q. What is the scope of your testimony?

A. My testimony describes Avista's pro forma period transmission revenues and expenses. I also discuss the Transmission and Distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. Dave DeFelice, as well as the Company's Asset Management Program expenses. Company witness Ms. Andrews incorporates the Idaho share of the net transmission expenses, the transmission and distribution capital additions, and the Asset Management Program O&M expenses proposed in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit 8, Schedules 1 and 2. Schedule 1, provides the transmission pro forma adjustments and Schedule 2, includes the Asset Management Program Model.

II. PRO FORMA TRANSMISSION EXPENSES

Q. Please describe the pro forma transmission expense revisions included in this filing.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission expenses from the October 2007 to September 2008 test year to the July 2009 to June 2010 Pro forma period. Each expense item described below is at a <u>system</u> level, with the exception of the $71,000 Grid West adjustment which is Idaho only, and is included in Exhibit 8, Schedule 1.

<u>Northwest Power Pool (NWPP)</u> - Avista pays its share of the NWPP operating costs. The NWPP serves the utilities

in the Northwest by providing regional transmission planning, coordinated transmission operations, and Columbia River water coordination. There is no anticipated change in NWPP costs in the pro forma period compared to the 2007/2008 test year actual expense of $31,000.

<u>Colstrip Transmission</u> - Avista is required to pay its portion of the O&M costs associated with the Colstrip transmission system pursuant to the joint Colstrip contract. In accordance with Northwestern Energy's (NWE) proposed Colstrip transmission plan provided to the Company, NWE will bill Avista $508,000 for Avista's share of the Colstrip O&M expense during the pro forma period. This is a decrease of $82,000 from the actual expense of $590,000 incurred during the test year.

<u>ColumbiaGrid (RTO Development)</u> - In 2006, Avista elected to fund the ColumbiaGrid RTO development effort. ColumbiaGrid is a regional organization whose purpose is to enhance transmission system reliability and efficiency, provide cost-effective regional transmission planning, develop and facilitate the implementation of solutions relating to improved use and expansion of the interconnected Northwest transmission system, reduce transmission system congestion, and support effective market monitoring within the Northwest and the entire Western interconnection. Under the amended ColumbiaGrid

funding agreement signed September 1, 2006, Avista was responsible for a total of $518,000, which represents Avista's share of the ColumbiaGrid operating costs from 2006 through August 31, 2008. Prior to the amended agreement, Avista paid $104,000 of these costs. The remaining balance ($414,000) was accrued over the remaining 20 months of the agreement at a monthly rate of $20,720. Avista signed a 2 year general funding extension in September 2008. Under the new agreement Avista pays its share (10.03%) of the general ColumbiaGrid expenses on a monthly basis. Based on information provided by ColumbiaGrid, Avista expects to pay a monthly fee of $20,000 though the 2 year extension. Therefore, the ColumbiaGrid cost for the pro forma period is anticipated to be approximately $240,000 annually, which is $22,000 more than the actual costs of $218,000 paid during the test period.

<u>ColumbiaGrid Planning</u> - An additional service being provided by ColumbiaGrid is regional planning and expansion. A functional agreement was developed and filed with the Federal Energy Regulatory Commission (FERC) on February 2, 2007 and approved on April 3, 2007. The agreement does not have a termination date and funding is on a two-year cycle with provisions to adjust for inflation. Funding is based on a fixed amount, plus a

portion is based on Avista's load ratio compared to the other members. ColumbiaGrid provided the Company with anticipated costs of $15,000 per month in the pro forma period to support the ColumbiaGrid planning effort going forward. This equates to $180,000 during the pro forma period, which is $76,000 over the test year actual costs.

<u>ColumbiaGrid Developmental and Staffing Reliability Functional Agreement</u> - During 2007 and 2008 ColumbiaGrid began an effort to evaluate opportunities to improve or enhance reliability in the ColumbiaGrid footprint. This effort included expanding the existing regional coordinated outage management process, evaluating combining transmission control centers into a consolidated control center, improved system modeling, and exploring new market products. The ColumbiaGrid members agreed to fund this evaluation effort through the end of 2008. The remaining work associated with this project has been rolled into the general funding agreement so Avista will not incur any costs associated directly with this effort during the pro forma period. Avista did fund $45,000 of this effort in the test year.

<u>ColumbiaGrid Open Access Same-Time Information System (OASIS)</u> - A new service currently being developed by ColumbiaGrid and its members is the development of a common Open Access Same-Time Information System (OASIS). This

service would provide transmission customers the ability to purchase transmission capacity from all ColumbiaGrid members from one common OASIS site instead of having to purchase transmission from each member individually. The ColumbiaGrid members have signed a contract to evaluate and develop this service. Avista's portion of the development cost is expected to be $100,000 during the pro forma period. Avista didn't have any costs associated with this effort during the test period.

<u>Grid West (ID Direct)</u> - Included in transmission expense is an annual amount of $71,000 to recover costs associated with Grid West (and its forerunner, RTO West). Avista signed an initial funding agreement in 2000, as did all other Pacific Northwest investor-owned electric utilities, to provide funding for the start-up phase of Grid West (then named "RTO West"). Grid West had planned to repay the loans to Avista and other funding utilities through surcharges to customers once it became operational. With the dissolution of Grid West, this repayment did not occur. As a result, Avista filed an application with the Commission to defer these costs. The Commission approved, on October 24, 2006, in Order No. 30151, the Company's request for an order authorizing deferred accounting treatment for loan amounts made to Grid West. In its Order the IPUC found these costs to be "prudent and in the public

interest" and required the Company to begin amortization of the Idaho share of the loan principal ($422,000) beginning January 2007, for five years. During the pro forma period Avista will amortize a total of $71,000 associated with Grid West development costs.

<u>Electric Scheduling and Accounting Services</u> - The $55,000 decrease in the pro forma period compared to test year expense for electric scheduling and accounting services is a result of continued reductions in services provided by third party vendors. These services are no longer required because of the development of an internal accounting program and the development of a regional transmission interchange tool by the Western Electricity Coordinating Council (WECC). These new applications replace the services provided by third parties.

<u>Grant County Agreement</u> - This will be discussed in more detail in conjunction with the Seattle and Tacoma revenues associated with the Main Canal and Summer Falls Projects. This agreement expired in October 2007 so no additional costs will be incurred in the pro forma period. In the test year Avista paid Grant County $51,000 per this agreement.

<u>OASIS Expenses</u> - The Open Access Same-Time Information System (OASIS) expenses are associated with travel and training costs for transmission pre-scheduling

and OASIS personnel. This travel is required to monitor and adhere to the NERC reliability standards and FERC OASIS requirements. The costs associated with OASIS expenses in the pro forma period is $3,000 more than the test year. The increase is a result of training required for a new employee who replaced a retired employee in October 2008.

<u>Power Factor Penalty</u> - The power factor penalty costs are associated with Bonneville Power Administration's (BPA) General Transmission Rate Schedule. BPA charges a power factor penalty at all interconnections with Avista that exceed a given threshold for reactive power flow during the month. If the reactive flow from BPA's transmission system into Avista's system or from Avista's system to BPA's system exceeds a given threshold then BPA bills Avista according to its rate schedule. The charge includes a 12 month rolling ratchet payment. Avista currently pays BPA a power factor penalty at several interconnections. Avista paid BPA a total of $178,000 during the test year and anticipates paying a similar amount in the pro forma period based on the ratchet clause in the rate schedule.

<u>WECC - System Security Monitor & WECC Administration and Net Operating Committee Systems</u> - The total WECC fees have and will continue to increase from year to year. The increase is driven primarily by compliance with mandatory national reliability standards. WECC is responsible for

monitoring and measuring Avista's compliance with the standards and therefore has substantially increased its staff and other resources to meet this FERC requirement. WECC is just beginning to develop its 2010 budget, so 2009 actual fees will be used for the pro forma period. The WECC fees are paid in the first part of January every year. WECC System Security Monitor fees in 2009 are $159,000 compared to test year fees of $171,000. This slight decrease is the result of the completion of a significant effort with regards to regional reliability coordination in 2008. The WECC Administrative and Net Operating fees have been increased from $282,000 in 2008 to $329,000 for 2009.

<u>WECC - Loop Flow</u> - Loop Flow charges are spread across all transmission owners in the West to compensate utilities that make system adjustments to eliminate transmission system congestion throughout the operating year. Loop Flow charges can vary from year to year since charges are dependent on transmission system usage and congestion. Therefore a five year average is used to determine future Loop Flow costs. The Loop Flow charge in the pro forma period is expected to be $26,000. This is $10,000 higher than actual test year charges of $16,000.

III. PRO FORMA TRANSMISSION REVENUES

Q. Please describe the pro forma transmission revenue revisions included in this filing.

A. Adjustments were made in this filing to incorporate updated information for any changes in transmission revenue from the 2007/2008 test year compared to the 2009/2010 Pro forma period. Each revenue item described below is at a system level and is included in Exhibit 8, Schedule 1.

Borderline Wheeling - The Borderline Wheeling revenue in the pro forma period is set at $5,354,000, which is a three year average of the 2006, 2007, and 2008 actual revenue levels. Actual test year revenue was $5,375,000. Avista typically uses a five year average of actual annual revenue to estimate future Borderline Wheeling revenue. This helps levelize the revenue requirement since it is based on load demand that is sensitive to temperature variation from year to year. For this case Avista is only using a three year average since 2006, 2007 and 2008 are the only years operating under new contracts signed with BPA. The new Borderline Wheeling revenue methodology is based on a Load Ratio Share[1], which is quite different than

[1] Load Ratio Share is the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load calculated on a rolling twelve-month basis.

the previous revenue calculation under the old contracts. Under the new contracts, BPA, as the network customer, will pay a monthly demand charge, which will be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's annual transmission revenue requirement.

<u>Seattle and Tacoma Revenues and Expenses Associated with the Main Canal and Summer Falls Projects</u> - In March of 2006, Seattle and Tacoma purchased interim long-term firm point-to-point transmission service from Avista under the Open Access Transmission Tariff to move generation from their Main Canal and Summer Falls facilities to their load. These interim point-to-point transmission contracts replaced expired long-term contracts. The transmission was purchased from April 2006 through October 2007. Avista collected $128,000 in October 2007 under these contracts and in turn paid $51,000 to Grant County PUD for use of its system to transfer the entire output of the Main Canal and Summer Falls projects. The interim contracts were meant to give Seattle and Tacoma time to build new transmission facilities to bypass Avista and connect directly to BPA. Pursuant to negotiations among Seattle, Tacoma, Grant County PUD, Grand Coulee Project Hydroelectric Authority and Avista, Seattle and Tacoma decided not to bypass Avista's transmission system. The parties agreed instead,

to a series of long term agreements with service to commence March 1, 2008. Seattle and Tacoma have signed similar contracts with Grant County PUD so Avista will not incur any of the transmission expenses with Grant County PUD that it did in 2007. Under the new Main Canal agreement Avista charges Seattle and Tacoma during the eight months the Main Canal project runs (March-October) and only for that output not used for local load service. The estimated revenue from Seattle and Tacoma for Main Canal transmission usage will be $193,000, which is $38,000 more than collected during the test year. Under the new Summer Falls agreement, Seattle and Tacoma only use a portion of Avista's Stratford Switching Station and are charged a use-of-facilities fee based upon this limited use. The estimated revenue from Seattle and Tacoma for Summer Falls during the pro forma period is $74,000, which is $31,000 higher than actual test year revenue of $43,000. The increase revenue from these two contracts in the pro forma period compared to the test year is a result of additional transmission usage by Seattle and Tacoma.

<u>Grand Coulee Project Revenue</u> - The Grand Coulee Project revenue is a result of a new contract signed in March 2006 with the project owner for a fixed dollar amount, replacing the previous contract which expired in October 2005. The new contract results in monthly revenue

of $673 or annual revenue of $8,100 during the pro forma period, which is the same as the test year.

OASIS Non-firm and Short-term firm Wheeling Revenue - OASIS is an acronym for Open Access Same-time Information System. This is the system used by utility transmission departments for purchasing and scheduling available transmission for other utilities and independent generators. OASIS revenues are revenues received from the sale of transmission capacity to third parties, for transmission above and beyond that needed by Avista to serve native load. These revenues are credited back to customers in a rate case, such as this one, to offset a portion of the overall cost of transmission.

Because these revenues vary year to year depending on electric energy market conditions and available transmission capacity (ATC) on adjacent utility systems, Avista has, in previous rate cases, used the most recent five-year average as being representative of future expectations unless there are known events or factors that occurred during the period that would cause the average to not be representative of future expectations. In 2004, there were some unusual events that caused Avista's OASIS revenues ($5,475,000) to be significantly higher than the other test years.

The Bonneville Power Administration (BPA) had several 500 kV lines out of service for rebuild projects, which resulted in a significant increase in Avista's transmission sales in 2004. During 2004 BPA was constructing a new 500 kV line from Bell substation in Spokane to Grand Coulee Dam in central Washington, installing fiber optic cable on existing transmission lines, and installing new and upgrading existing series capacitor banks on four of its area 500 kV lines as part of the West of Hatwai reinforcement project. This construction resulted in multiple prolonged transmission outages that significantly reduced the BPA ATC on critical transmission paths from eastern Montana. Avista owns rights and facilities in these same transmission paths so Avista experienced a significant increase in transmission sales and revenues during the BPA outages.

Therefore, Avista did not include the 2004 revenue in the calculation of the five-year average revenue. Avista calculated the pro forma OASIS revenue based on revenue from years 2003, 2005, 2006, 2007, and 2008. The resulting average revenue is $3,310,000, which is $201,000 higher than the test year actual revenue of $3,109,000.

Dry Gulch Revenue - Dry Gulch revenue has been adjusted to $269,000 for the pro forma period, which is an $11,000 increase from the test year actual revenue of

$258,000. The current methodology used to forecast Dry Gulch revenue is a five-year average of actual revenue. A five-year average is used since the revenue can vary from year to year. The revenue is calculated using a 12-month rolling ratchet based on monthly peak demands. Load peaks are very sensitive to temperatures, which vary from year to year.

PP&L Series Cap - 1978 - PP&L Series Cap revenue was reduced from $9,000 in the test year to $0 in the pro forma period since the 20 year amortization of the original contract expires in June 2009. In 1989 Pacificorp paid the company a lump sum of $178,222 in lieu of annual payments provided for under the original agreement. The lump sum payment was amortized at $781 per month from August 1990 through June 2009.

Spokane Waste to Energy Plant - No adjustments to Spokane Waste to Energy Plant revenue of $160,000 were made for the pro forma period compared to the 2007 test year. This revenue is the result of a long-term transmission interconnection agreement with the City of Spokane. The contract expires in February 2011.

Vaagen Wheeling - Vaagen Wheeling revenue was reduced slightly to $112,000 for the pro forma period compared to test actual revenue of $116,000. A five-year average is used to determine the pro forma period revenue since revenue can fluctuate year to year depending upon transmission usage.

Northwestern Energy (NWE) - The revenue of $42,000 from NWE in the test year was a result of a load following contract that Avista signed in 2005 with NWE. Under the contract Avista provides up to 15 MW of energy to NWE to help them match hourly fluctuations in loads and resources. This contract also included the purchase of firm transmission capacity from Avista. Since the contract expired in November of 2007 there isn't transmission revenue associated with the contract in the pro forma period.

Forfeited Deposits - Avista was reimbursed $40,000 during the test period to conduct generation interconnection planning studies. Avista is required to determine system impacts based on generation interconnection requests to implement generation within its service territory. Any potential customer can ask for a system evaluation to be performed to determine the impacts of connecting a new generator to the Avista system. The potential customers must reimburse Avista for these system studies. Since Avista can't predict when these requests will occur, the Company is not forecasting any collection of interconnection study fees in the pro forma period.

IV. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects in 2009?

A. In 2007 the Company completed its 5-year (2003-2007) $136.4 million transmission upgrade project that significantly improved the infrastructure of the 230 kV transmission system. With the completion of these projects the transmission project focus has shifted to improving the 115 kV transmission system to meet capacity needs, eliminate thermal loading issues, replace deteriorated equipment, and meet mandatory national reliability standard requirements. Avista will need to continue to invest in its transmission system going forward to maintain reliable customer service and meet the reliability standards. A recent report prepared by The Brattle Group for the Edison Foundation describes the future investment challenge that is facing the utility industry. The report describes how utilities will need to continue replacement of aging equipment while construction costs continue to increase. In order to integrate renewable energy alternatives and incorporate intelligent grid controls utilities will be required to increase capital spending on both Transmission and Distribution systems.

The major capital transmission costs (system) for projects to be completed in 2009 are approximately $15.07

million for specific transmission projects and transmission system equipment replacement projects. The specific transmission projects scheduled for 2009 completion will cost $9.18 million and include:

- Lolo Substation ($2.05 million): This project involves the rebuild of the existing Lolo substation to increase the capacity of the substation bus, breakers, and supporting equipment to match the upgraded area transmission lines. The new Lolo substation design significantly improves reliability and operating flexibility. The substation rebuild is being constructed in three phases. Phase 1 was completed in 2007 and Phase 2 is anticipated to be completed by December of 2009. Approximately $0.80 million of work was completed in 2008 and will be transferred to plant in 2009 with the additional estimated amount of $1.25 million.

- Spokane/Coeur d'Alene area relay upgrade phase 2 ($1.25 million): This project involves the replacement of older protective 115 kV system relays with new micro-processer relays to increase system reliability by reducing the amount of time it takes to sense a system disturbance and isolate it from the system. This is a five year project and is required to maintain compliance with mandatory reliability standards.

- Power Circuit Breakers ($0.54 million): The Company transfers all circuit breakers to plant upon receiving them. In 2009 the Company will receive and replace 4 circuit breakers in its system.

- SCADA Replacement ($0.74 million): The System Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. The SCADA system will be upgraded in 2009 to a new version provided by our SCADA vendor. Several Remote Terminal Units (RTUs) located at substations throughout Avista's service territory will also be replaced. The RTUs are part of the transmission control system.

- Noxon-Pine Creek Fiber ($0.65 million): This project is required to reinforce the optical fiber wire supported by the Noxon-Pine Creek 230 line. This line routes through the mountains of north Idaho and is subjected to severe winter weather. Operational history has demonstrated a need to reinforce the communication circuit. This communication circuit is part of the Noxon/Cabinet WECC certified RAS scheme and is required to meet reliability standards.

- System Replace/Install Capacitor Bank ($0.80 million): This project includes the construction of a 115 kV capacitor bank at Airway Heights ($0.60 million) to support local area voltages during system outages. The project is required to meet reliability compliance and provide improved service to customers. Another $0.20 million will be spent to replace leaking or old capacitors on the Avista system.

- Benewah-Shawnee 230 kV Line Construct ($0.56 million): This work is necessary to increase separation between the 230 kV and 115 kV conductors on this double circuit line. The lines have contacted each other during high winds resulting in line outages. In addition to line work to increase phase clearance, Avista plan to install a Hathaway-traveling wave monitoring system to allow better accuracy of phase to phase contacts. The 230 kV line was constructed to meet reliability standard requirements.

- Mos230-Pullman 115 Reconductor ($0.59 million): The transmission line is being upgraded from 1/0 Copper to 556 kcm Aluminum (100 MVA-Summer) to mitigate thermal overloads experienced during heavy summer load conditions. The line upgrade will improve load service between Moscow and Shawnee.

- Burke 115 kV Protection and Metering ($0.53 million) - This project includes upgrading the Burke interchange meters as well as 115 kV line relaying for the Burke-Pine Creek #3 and #4 lines. This project is required to meet reliability compliance standards. The estimated cost of the relay upgrade is for $400,000 and the metering upgrade is estimated at $125,000.

- Beacon Storage Yard Oil Containment ($0.53 million): The Beacon Storage Yard is a location where circuit breakers and power transformers are staged for rotation into existing substations or for new construction. This site is near the Spokane River and this project work will provide an oil containment system to protect the local environment.

- The remaining transmission specific projects ($0.94 million total) being constructed in 2009 are smaller projects, including a line reconfiguration to provide back up service, minor work associated with Colstrip transmission, and re-insulating a 230 kV line due to failing insulators. These smaller projects are required to operate the transmission system safely and reliably.

The Company will also spend approximately $5.89 million in transmission system equipment replacements associated with storm damage or aging/obsolete equipment. A brief description of the larger projects included in these replacement efforts are given below.

- Transmission Minor Rebuilds ($1.07 million): These projects include minor transmission rebuilds as a result of damage caused by storms, wind, fire, and the public.

- System Rebuild Transmission - Condition ($0.93 million): This project includes transmission lines that are determined to have a high probability of falling down or be a high reliability risk and need to be rebuilt during 2009. For example one specific project identified for a rebuild in 2009 includes sections of the Addy-Gifford 115 kV line.

- Interchange and Borderline Metering Upgrades ($0.64 million): Interchange metering upgrades are required for all of our interchange points with BPA and other adjacent utilities. In 2009, we will complete metering upgrades at Westside, Warden, and Noxon Substations. Borderline metering upgrades are required for all loads within Avista's Balancing Authority. In 2009, we will complete our upgrades at Mead and Noxon (230-13 kV) as well as one additional upgrade at either Deer Park, Priest River, Loon Lake, Spirit, or Wilbur.

- Pine Creek - Replace 115 kV Circuit Switcher & Cap Bank ($0.35 million): The project scope and preliminary engineering design work for this project was started in 2008 and included replacing the circuit switcher and one 13 kV recloser due to equipment age. After further investigation the project was expanded to replace the other two 13 kV reclosers, the cap bank, deteriorated station control wiring, and removal of the small panel house including the obsolete RTU.

- Replacement Programs ($2.23 million): Avista has several different equipment replacement programs to improve reliability by replacing aged equipment that is beyond its useful life. These programs include transmission air switch upgrades, arrestor upgrades, restoration of substation rock and fencing, recloser replacements, replacement of obsolete circuit switchers, substation battery replacement, porcelain cutout replacement, high voltage fuse upgrades, and replacement of fuses with circuit switchers. All of these individual projects improve system reliability and customer service.

Q. Please discuss the national reliability standards?

A. The North American Electric Reliability Corporation (NERC) has developed national reliability standards for utilities to follow to ensure interconnected system reliability. When Avista started its transmission upgrade projects in 2002, compliance with these standards was voluntary. The Energy Policy Act of 2005 required the transition of the standards from voluntary to mandatory. Beginning June 2007 the standards became mandatory and non-compliance may result in monetary penalties.

The reliability standards include several transmission planning and operating requirements. The planning standards require utilities to plan and operate their transmission systems in such a way as to avoid the loss of customers or impacting neighboring utilities for the loss of transmission facilities. The transmission system must be designed and operated so that the loss of up to two facilities simultaneously will have no impact to the interconnected transmission system. These requirements drove the need for Avista to invest in its transmission system.

Q. Please describe the Company's distribution projects in the State of Idaho that will be completed in 2009?

A. Distribution Projects in Idaho (including transformation) for 2009 total $10.76 million. These projects are necessary to meet capacity needs of the system and rebuild aging distribution substations and feeders. The following projects make up the $10.76 million.

- Plummer Substation Rebuild ($1.53 million): This project is required to replace the existing deteriorated wood substation, and increase the transformer capacity to meet existing system capacity needs. These costs don't include the cost of the transformer, which was transferred to plant in 2008.

- Idaho Road 115 kV Substation and Rathdrum 115-13 kV Sub Increase ($4.90 million): These projects (including transformer costs) involve the construction of the new Idaho Road 115-13 kV substation ($2.87 million) and the addition of a second transformer and feeder at the Rathdrum substation ($2.03 million) to meet existing capacity needs in Post Falls and Rathdrum Idaho. When completed these projects will provide improved service reliability to existing customers.

- Wood Sub Rebuilds ($3.60 million): Two wood substations will be rebuilt in 2009. Deary 115-24 kV Substation ($2.05 million including the transformer) and Craigmont 115-13 kV Substation ($1.45 million) will both be completely rebuilt in 2009. Both of these substations are over 50 years old and have reached the end of their useful lives. In addition, the Deary transformer is in need of replacement due to end of life and bushing related issues, so the substation rebuild is in conjunction with the transformer replacement ($0.45 million). An additional $100,000 for other system wood substations that require timber replacement is also included in this rebuild effort.

- Distribution Feeder Reconductor Projects ($0.73 million): These projects involve the reconductor of sections of four feeders in Idaho. The feeders are required to be reconductored to eliminate thermal loading issues and improve service reliability to existing customers during normal and outage conditions.

The Company also will spend approximately $25.27 million (system) in equipment replacements and minor rebuilds associated with aging distribution equipment discovered through inspections, feeders with poor reliability performance, replacements from storm damage, or relocation of feeder sections resulting from road moves. A brief description of the projects included in these replacement efforts is given below.

- Electric Distribution Minor Blanket Projects ($7.92 million): This effort includes the replacement of poles and cross-arms on distribution lines in 2009 as required, due to storm damage, wind, fires, or obsolescence.

- Capital Distribution Feeder Repair Work ($4.10 million): This work is to be done in conjunction with the wood-pole management program. As feeders are inspected as part of the wood-pole management program, issues are identified unrelated to the condition of the pole. This project funds the work required to resolve those issues (i.e. leaking transformers, transformers older than 1964, failed arrestors, missing grounds, damaged cutouts).

- Wood Pole Replacement Program ($3.70 million): The distribution wood-pole management program is a strength evaluation of a certain percentage of the pole population each year. Depending on the test results for a given pole, that pole is either considered satisfactory, reinforced with a steel stub, or replaced.

- Electric Underground Replacement ($3.16 million): Replace high and low voltage underground cable as required in 2009, due to cable failure or obsolescence.

- T&D Line Relocation ($2.30 million): Relocation of transmission and distribution lines as required due to road moves.

- Failed Electric Plant ($1.99 million): Replacement of distribution equipment throughout the year as required due to equipment failure.

- System - Dist Reliability - Improve Worst Feeders ($1.10M total, $350K in Idaho): Based on a combination of reliability statistics, including CAIDI, SAIFI, and CEMI (Customers Experiencing Multiple Interruptions), feeders have been selected for reliability improvement work. This work is expected to improve the reliability of these feeders.

- Open Wire Secondary ($1.0 million) - Avista has over 60 miles of secondary districts that consist of 2 120 volt to ground uninsulated (open wire) conductors installed between poles and served by one overhead transformer. These service installations were installed in the 1950's and 1960's. When there is contact across the 120 volt conductor and the ground wire due to trees or other causes, the conductor fails resulting in customer outages. This project replaces the open wire conductor with insulated conductor and reduces the length of some of the secondary circuits.

This effort should reduce the number and length of outages and improve customer service.

V. AVISTA'S ASSET MANAGEMENT PROGRAM

Q. Please provide additional background to Avista's continuing investment in its transmission and distribution systems?

A. Like most U.S. utilities, after World War II, Avista's growth required installing or updating equipment to meet rising electrical demand. Substations were built or modified to meet increasing loads. The transmission system expanded to bring new generating plant output to population centers. Distribution systems grew and voltage levels were increased to meet new housing and industrial needs.

Avista's installed equipment is aging, and more components are reaching the end of their life. Equipment has become obsolete, and manufacturers no longer support the aged equipment or produce replacement parts, which makes it impractical to rebuild the equipment. Recognizing the increasing cost of aging equipment failure, Avista launched its Asset Management effort in March 2004.

Q. Please describe the Asset Management mission and process.

A. Avista's Asset Management (AM) program manages key electric transmission and distribution assets throughout their life to provide the best value for our customers. By minimizing life cycle costs and the cost per kilowatt-hour to generate and deliver energy, we're able to maximize system reliability and value for our customers.

The Asset Management process combines technology and information in a manner that integrates data from a myriad of sources into a comprehensive plan that maximizes the value of capital assets. The process provides a replacement or maintenance program that minimizes life cycle costs and maximizes system reliability.

Technical experts evaluate each asset and develop a comprehensive Asset Management Model. Available data is examined and where it is not available, expert opinion from the team fills in the gaps. Exhibit 8, Schedule 2 shows the steps in the process for developing an Asset Management Plan. The foundation for the plan involves determining the future failure rates and impacts to the environment, reliability, safety, customers, costs, labor, spare parts, time, and other consequences. The failure model then becomes the baseline to compare all other options. Given this foundation, alternatives can be examined and evaluated to define the optimal asset management plan.

Q. How has Avista implemented and facilitated the Asset Management process?

A. Avista has assigned two full-time engineers to the formal Asset Management program. These individuals are responsible for gathering information, prioritizing work and executing efforts to best meet the Asset Management mission. The engineers utilize a statistical Reliability Centered Maintenance (RCM) software package to analyze data. This software allows detailed analysis of the impacts of increased or decreased reliability based on system configuration and component reliability.

Q. Have any Avista Asset Management plans been implemented?

A. Yes, several programs have been successfully implemented. Two of the successful programs underway are Underground Cable Replacement and Wood Pole Management.

The Underground Cable Replacement program has successfully reduced the number of primary underground distribution cable faults from 250 in 2004 to approximately 180 events in 2007. The replacement program eliminated approximately 5,600 hours of outage time for our customers and resulted in avoided costs impact of $175,000. For 2008, we were projected to have 550 faults prior to starting this program and now we are on track to have less than 150 faults by years end. This equates to avoided cost impact of $1,000,000. The increased emphasis on cable replacement has stabilized the fault rate per mile of cable during the past 4 years. This marks significant progress after a four-fold increase in the fault rate since 1992.

The Asset Management team also studied the Wood Pole Maintenance program. After completing an optimization analysis and the revenue requirement model, the data indicated that distribution poles should be inspected on a 20-year cycle and transmission poles inspected on a 15-year cycle.

Under the new Wood Pole maintenance program Avista tested twice as many Distribution poles in 2007 as in 2006. For 2008 through November, we inspected over 11,600 Distribution Wood Poles and over 2,500 Transmission Wood Poles. Our annual goal is to inspect 12,000 Distribution and 3,000 Transmission poles each year. As a result of the 2008 inspections, Avista reinforced 980 poles, replaced 432 poles, and replaced 950 cross-arms. The Operations and Maintenance portion of the Avista rate request to support Wood Pole maintenance work in 2010 totals $852,000 (system). This represents an increase of $207,000 (system) above the 2007/2008 test year.

Q. What is the Company's request with regards to Asset Management capital expenditures and O&M expenses?

A. Avista is not asking for any planned 2010 capital Asset Management additions to be included in this case.

For Asset Management projects that require additional O&M, proposed 2010 O&M expenses are $12,505,000 (system) compared to 2007/2008 test year expenses of $7,896,000 (system). This represents an increase of $4,609,000 (system) above the 2007/2008 test year included in this rate case. As shown in Table 1 below, Asset Management O&M additions have been divided into six major categories: Substation, Distribution, Transmission, Vegetation Management, Wood Pole Management and Spokane Downtown Network. Cost adjustments also include adjustments for inflation of 6% to bridge the time between the test year and 2010.

Table 1:

Asset Management Operations & Maintenance Amount Above 2007/2008 Test Period		
		(System) Pro forma
Substation	**$**	**616,000**
Distribution	**$**	**458,000**
Transmission	**$**	**401,000**
Vegetation Management	**$**	**2,813,000**
Wood Pole Management	**$**	**207,000**
Network	**$**	**114,000**
Total Additional Requested	**$**	**4,609,000**

Q. Please describe Avista's Substation Asset Management Plan.

A. Avista operates 157 transmission and distribution substations. A significant portion of the equipment and substation structures are more than 40 years old and have operated beyond normal industry expectations. This older equipment has reached a point in its lifecycle where planned replacement or maintenance will add value to our customers by improving reliability and safety, and avoiding outage costs. Costs to support the Substation maintenance work totals approximately $2,073,000 (system) in the 2010 pro forma period. This is an additional $616,000 compared to the 2007/2008 test period.

The Substation plan includes:

- Power Transformers: More than 26% of Avista's Substation Transformers are over 40 years old. These aging transformers need to be either maintained or replaced depending on condition.

- Circuit Breakers: The Power Circuit Breaker Plan has been an ongoing and successful program maintaining approximately 300 High Voltage Oil Circuit Breakers prior to establishing an Asset Management Program. However, Avista has not yet reached the target of a 10 year Circuit Breaker maintenance cycle and is currently at a 15 year cycle. The requested increased funding will allow more Circuit Breaker maintenance each year.

- Circuit Switchers: Avista uses 120 Circuit Switchers to protect substation transformers at smaller Substations as well as 115 kV substation Capacitor Banks. Avista's analysis indicates periodic maintenance based on the age of the Circuit Switcher should extend the life of these devices by 25% based on a graduated cycle plan determined by age. It is anticipated that the program will result in approximately $180,000 of avoided outage related costs to our customers.

- Reclosers: The Recloser/Medium Voltage Circuit Breaker plan covers about 415 substation and 145 Line Reclosers/Medium Voltage Circuit Breakers. Our current maintenance practice strives to sustain the Substation Reclosers/Medium Voltage Circuit Breakers on a 10-year cycle and to refurbish any failed or replaced ones to use as spares for future needs.

- Rock and Fence: The Substation Rock and Fence plan covers the maintenance and replacement of Rock and Fence for Avista's 166 substations. Avista anticipates an average of 4 Substations will require repairs to the fence or rock ground cover in order to ensure safety by preventing public access and maintain the required insulating properties of the Substation Rock. O&M funding is increased by a relatively small amount for minor repairs to Rock and Fence above current levels.

- Relays: The Relay plan covers the maintenance and replacement of over 6000 separate relay hardware devices that provide protection for Avista's generation, transmission and distribution systems. Regulatory requirements for relay testing and record keeping have increased in recent years as part of new mandatory reliability standards.

Q. Please describe Avista's distribution Asset Management Plan.

A. Avista's distribution system includes 324 feeders and over 12,000 miles of conductors, poles, underground cable, distribution transformers, and various other distribution system components. Avista has developed operations and maintenance plans for the distribution system totaling approximately $569,000 for the 2010 Pro forma period. This amount is $458,000 above that included in the 2007/2008 test period.

The distribution plan includes:

- Animal Guards: Data shows that animals are the second-leading cause of outages at Avista, ranking second only behind weather, and accounting for 19 percent of all outages. Outages caused by squirrels and birds are an increasing, on-going and persistent problem on the distribution system. Statistics indicate that 60 feeders were the subject of almost half of all animal-caused outages. Four of those 60 most vulnerable feeders were recently retrofitted with animal guards. Animal-caused outages have decreased to almost zero on all four feeders, compared to 10 or more per month during warm weather in previous years. Avista has included additional O&M funding to begin implementing a four-year program to install animal guards on the remainder of the 60 most vulnerable feeders.

- Underground Cable: Over 6 million feet of unjacketed underground cable was installed prior to 1982; it has been subject to a replacement program since 1984. After 2008, there will be approximately 750,000 feet of pre-1982 cable still left to be replaced. Though primarily a capital intensive program, there is some related maintenance costs associated with underground cable.

- Exacter Testing: This is a new test using an inexpensive method to detect distribution equipment problems before they fail. The new method detects radio frequency failure signatures of distribution equipment and uses a library to identify the problem. Using our Geographical Information System, we can then identify the component and plan the replacement prior to equipment failure. This will add $30,000 to the 2010 budget.

Q. Please describe changes to Avista's Vegetation Management Plan.

A. Avista's system includes over 12,000 miles of distribution circuits and over 2,200 miles of transmission lines that require vegetation management. Avista's vegetation management work is almost entirely contracted out. The primary contractor for this work is Asplundh Tree Experts. Over the past few years, Avista's vegetation management has experienced higher than anticipated rates of inflation over 6% due to labor, fuel costs and equipment costs. Our goal is to clear 1,550 miles per year, which results in a 5 year cycle.

For the transmission system, three factors require an increase from the current spending on vegetation management. FERC Reliability Standard FAC-003-1 has changed the way we manage the transmission system right of ways for vegetation. Vegetation line patrols have been increased to an annual basis for all 200 kV and higher voltages. WECC has also applied these same requirements to 4 other lower voltage line identified as critical to grid reliability. These expanded requirements have expanded the areas requiring action to include more difficult to access portions of the right of way. These difficult access portions have steep rocky hillsides and wet bottom draws and require crews to hike in and cut the vegetation by hand, often taking one to two weeks to clear one span. The new regulations also require clearances to account more stringently for line sag and sway necessitating clear cutting timber through draws where trees have been left to grow for the past 20 - 30 years. This work is very costly and has added significantly to our anticipated costs.

The second factor is the change in access road maintenance requirements included in updates of our Special Use Permits with the Forest Service. This will require Avista to spend more money annually to maintain roads on a planned basis. When combined with increase requirements to patrol transmission lines by FERC and WECC requirements, the roads will be used more frequently and must be maintained more frequently.

The third factor driving the costs up has been a higher than anticipated inflation rate of around 6% that is anticipated to continue. Per FERC requirements, Avista inspects all 230kV transmission lines annually to identify vegetation management needs. In addition to the 230kV transmission lines, Avista also patrols the 115kV transmission lines once every three years.

Along with increased requirements for the transmission systems, the natural gas right-of-ways now require more vegetation management to support leak surveys required by CFR 49, Part 192.723 and Washington State WAC 480-93-188 on high pressure gas pipelines. Avista has 198 miles of high pressure gas pipeline and our plan is to perform vegetation management on a five year cycle for an average of 40 miles per year.

The Company plans to spend $8,390,000 in Operations and Maintenance funding for support of the gas, distribution and transmission vegetation management programs. This is an increase of $2,813,000 above the 2007/2008 Operations and Maintenance spending for this area.

Q. Please describe Avista's Transmission Asset Management Plan.

A. The Avista transmission system is comprised of over 2,300 miles of lines crossing an extreme variety of terrain. The 976 miles of 230kV transmission system is critical to serving Avista's customers and to the stability of transmission resources throughout the region. The 115kV system, comprised of 1675 miles, serves Avista customers and neighboring utilities throughout large portions of Eastern Washington and Northern Idaho. Approximately 75% of the transmission system components are over 35 years old. A more rigorous inventory of the 115kV system is underway. Preliminary results of this survey show over 20% of the 115kV system is pre-1930. Almost all Asset Management work on the Transmission system is capital work, however, as Asset Management completes more models in the future, some O&M funding may be required to support future programs. Avista is requesting $507,000 in Operations and Maintenance funding for support of the transmission system under this proposal to protect our current wood poles from wild fires in key areas. This is an increase of $401,000 above the 2007/2008 Operations and Maintenance spending for this area.

The transmission plan includes:

- <u>Fire Retardant Coatings for Transmission Poles:</u> Random fires can have a significant impact on the reliability of Avista's transmission system. During the past five years, Avista has lost at least 60 wooden poles to brush fires. Protective coatings are now available that can protect wood poles for 20 minutes, or more, from close contact with flames. The coating is especially effective against brush fires. A neighboring utility has used the coating and reported 80% survival rate of wood poles in situations where 20% survival would have been more typical. Avista proposes a four-year program to apply fire retardant coating to critical transmission lines in high fire areas.

Q. Please describe Avista's Network Asset Management Plan.

A. The Network consists of an underground distribution system that feeds the core of downtown Spokane – the region's economic hub – with a very reliable networked distribution system. The Network includes underground vaults, manholes, handholes, substations, network protectors, network transformers, and numerous miles of duct banks and cables. The structural integrity of these vaults, manholes and handholes is vital to public safety because they are typically located under heavily-used streets and sidewalks. Reliability is also essential, because the Network serves the businesses, banks and other critical services located in downtown Spokane. The Operations and Maintenance portion of the Avista rate request to support Network maintenance work totals approximately $114,000. During the 2007/2008 test year no Network asset management work was performed.

The Network plan includes inspecting and maintaining an aging system:

- Vaults: Almost 60% of the vaults are more than 50 years old. Avista plans to add inspection of vacant vaults and additional maintenance activities such as vault cleanings to prevent debris build-up and fire hazards. When necessary an entire vault will need to be replaced with a new one.

- The Manholes/Handholes: Nearly 98% of manholes are approaching 100 years of age. Avista plans to inspect them on a five-year cycle and perform maintenance based on the results of the inspections. Replacement of manholes and handholes may also be required.

Q. Does this complete your pre-filed direct testimony?

A. Yes, it does.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-09-01 EXHIBIT NO. 8 SCOTT J. KINNEY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corporation
- Energy Delivery -
Pro Forma Transmission Revenue/Expenses
($000s)

Line No.			Oct '07 - Sep '08 Actual	Adjusted	July '09 - June '10 Pro Forma Period
		556 OTHER POWER SUPPLY EXPENSES			
1		NWPP	31	0	31
		560-71.4, 935.3-.4 TRANSMISSION O&M EXPENSE			
2		Colstrip O&M - 500kV Line	590	-82	508
3		ColumbiaGrid Development	218	22	240
4		ColumbiaGrid Planning	104	76	180
5		ColumbiaGrid OASIS	0	100	100
6		ColumbiaGrid DSRFA	45	-45	0
7		Grid West (ID)	71	0	71
8		Total Account 560-71.4, 935.3-.4	1,028	71	1,099
		561 TRANSMISSION EXP-LOAD DISPATCHING			
9		Elect Sched & Acctg Srv (CASSO/OATI)	195	-55	140
		565 TRANSMISSION BUSINESS RELATED EXPENSES			
10	*	Grant County Agreement	51	-51	0
		566 TRANSMISSION EXP-OPRN-MISCELLANEOUS			
11		OASIS Expenses	5	3	8
12		BPA Power Factor Penalty	178	0	178
13		WECC - Sys. Security Monitor	171	-12	159
14		WECC Admin & Net Oper Comm Sys	282	47	329
15		WECC - Loop Flow	16	10	26
16		Total Account 556	652	48	700
17		**TOTAL EXPENSE**	1,957	13	1,970
		456 OTHER ELECTRIC REVENUE			
18		Borderline Wheeling	5,375	-21	5,354
19	**	Seattle	64	-64	0
20	**	Tacoma	64	-64	0
21		Seattle/Tacoma Main Canal	155	38	193
22		Seattle/ Tacoma Summer Falls	43	31	74
23		Grand Coulee Project	8	0	8
24		OASIS nf & stf Whl (Other Whl)	3,109	201	3,310
25		PP&L - Dry Gulch	258	11	269
26	***	PP&L Series Cap -1978	9	-9	0
27		Spokane Waste to Energy Plant	160	0	160
28		Vaagen Wheeling	116	-4	112
	****	Northwestern Energy	42	-42	0
29		Forfeited Deposits	40	-40	0
30		Total Account 456	9,443	37	9,480
31		**TOTAL REVENUE**	9,443	37	9,480
32		**TOTAL NET EXPENSE**	-7,486	-24	-7,510

* Grant County Agreement - contract ended 10/31/07
** Seattle and Tacoma - contracts ended 10/31/07
*** PP&L Series Cap - contract ended 6/30/09
**** Northwestern Energy - contract ended 11/30/07

Asset Management Plan Model