Exhibit No. ___(SJK-4T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-090134

DOCKET NO. UG-090135

DOCKET NO. UG-060518

(consolidated)

REBUTTAL TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

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. Have you previously provided direct testimony in this Case?

A. Yes. My testimony discussed the transmission and distribution expenditures that are part of the capital additions testimony provided by Company witness Mr. DeFelice, as well as the Company's Asset Management Program expenses.

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

A. Commission Staff witness Mr. Kermode, in his direct testimony at pages 27 through 41, proposes to exclude for rate making purposes certain generation, transmission, distribution and general plant capital investment that the Company pro formed in its direct case, which will be in service by December 2009 and will be used to serve customers. For generation and transmission plant additions, Staff only included projects completed during the period October 1, 2008 through June 30, 2009. These projects were selected by Staff since they were known and measurable. Company witnesses Mr. Norwood and Mr. DeFelice address these issues raised by Staff in their rebuttal testimony.

In support of Mr. Defelice's rebuttal testimony, I will provide descriptions of the transmission and the asset management distribution related capital projects that will be completed and in-service by the end of 2009 that are included in this case.

In addition, I will discuss the Company's Asset Management Program and the Company's analysis of off-setting factors.

Q. Briefly describe your responsibilities and your duties related to the transmission capital projects and electric distribution capital projects that are part of the asset management program.

A. In my role as Director Transmission Operations, I am responsible for the management of the planning and operational control of the Company's Transmission and Distribution facilities. I am also a member of the Capital Budget Committee and am actively involved in the prioritization and approval of all Transmission and Distribution Capital projects. My position requires knowledge of the planning, construction and energization of new transmission projects and upgrades to existing projects to ensure compliance with NERC Reliability Standards. My Department is responsible for approximately 80% of all Reliability Compliance Standard requirements. This knowledge enables me to provide details about which transmission and asset management distribution capital projects will be completed by the end of 2009.

Q. What is the total amount that will be spent on transmission and asset management electric distribution capital through the end of 2009?

A. The total amount of 2009 capital spending that will be completed by the end of the year will be $11,381,000 for transmission projects and $10,377,000 for asset management electric distribution projects. Table 1 below details these capital projects for 2009 (system) and shows the amount that was transferred to plant-in-service through June 30, 2009 and the amount that will be transferred before the end of 2009.

Table 1
2009 Transmission and Electric Distribution Projects - System
(000s)

Transmision:	**Projects Completed January 1, 2009 through June 30, 2009**	**Projects Completed July 1, 2009 through December 31, 2009**	**2009 Final Costs**
Lolo 230 - Rebuild 230 kV Yard	$ 9	$ 2,891	$ 2,900
Spokane-CDA 115 kV Line Relay Upgrades	0	900	900
SCADA Replacement	32	676	708
Noxon-Pinecreek 230kV:Ready Fiber Optic	0	650	650
Benewah-Shawnee 230 kV Construction	34	642	676
Mos23-N Moscow 115 Recond	0	785	785
Burke 115 kV Protection & Metering	0	525	525
Other small specific transmission projects	0	0	-
Interchange and Borderline Metering Upgrades	(6)	529	523
Metro Sunset 115 kv	0	0	-
Grangeville 115 Substation Capacitor Bank	0	950	950
Other small transmission projects	988	1,776	2,764
	$ 1,057	**$ 10,324**	**$ 11,381**
Electric Distribution:			
Wood Pole Management	$ 2,919	$ 4,880	$ 7,799
T&D Line Relocation	912	1,066	1,978
WSDOT Highway Franchise Consolidation	35	565	600
	$ 3,866	**$ 6,511**	**$ 10,377**

Q. Are these expenditures for different transmission and asset management electric distribution capital projects than those originally submitted by Company witness DeFelice?

A. No, these expenditures are for the same transmission and asset management electric distribution capital projects that were included in Mr. DeFelice's direct testimony. The project costs have been updated with actual or known charges and have been reviewed to ensure that these projects will be completed by the end of 2009. The planned expenditures for these transmission projects in our original filing were $8,608,000 and the current estimate of $11,381,000 shows that we have understated our costs in its rate filing. The planned expenditures for the asset management distribution projects in our original filing were $10,897,000 which is very close to the current estimate of $10,377,000.

Q. Is the Company proposing to update its revenue requirement in this case using these updated estimates?

A. No. This updated information is being provided in response to testimony filed by Staff and Public Counsel, to emphasize the fact that these projects will be completed in 2009, are known and measureable, and the costs should be included for recovery in this case.

II. TRANSMISSION AND DISTRIBUTION CAPITAL PROJECTS

Q. Please describe the Company's capital transmission projects that will be completed in 2009?

A. The 2009 Transmission Capital Projects are being constructed to meet either compliance requirements, improve system reliability, fix broken equipment, or replace aging equipment that is soon to fail. Included in the compliance requirements are the North American Electric Reliability Corporation (NERC) requirements, which are national reliability standards for utilities to follow to ensure interconnected system reliability. Beginning June 2007 the standards were made 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 otherwise impacting neighboring utilities due to 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.

Avista project requirements are developed through system planning studies, engineering analysis, or scheduled upgrades or replacements. The larger specific projects that are developed through the system planning study process typically go through a thorough internal review process that includes multiple stakeholder review to ensure all system needs are adequately addressed.

Three of the projects are upgrades or completion of projects associated with the Company's 5-year 230 kV Upgrade projects that were constructed from 2003 though 2007 (previously approved by the WUTC).

These projects include:

- <u>Lolo Substation ($2.90 million)</u>: 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 and meet compliance with Reliability Standards. The new Lolo substation design significantly improves reliability and operating flexibility. The Lolo Substation project was constructed in phases to allow operational flexibility due to system reliability concerns associated with other scheduled construction in the area. Phase 1 was completed and placed into service in 2007 and the second phase will be constructed over a two year period with energization scheduled for fall of 2009. Approximately $0.80 million of work was completed in 2008 and will be transferred to plant in December 2009 with the additional estimated amount of $2.10 million. The Lolo Substation project costs were developed by the Engineering Department and approved through the capital budget process. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, and TPL-003-0a R1-R3.

- Noxon-Pine Creek Fiber ($0.65 million): This project is required to reinforce the optical fiber wire supported by the transmission poles on the Noxon-Pine Creek 230 kV 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 Remedial Action Scheme and is required to meet reliability standards. The work associated with this project will be completed in November 2009. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.
- Benewah-Shawnee 230 kV Line Construct ($0.67 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 plans to install a Hathaway-traveling wave monitoring system to more accurately determine the location of phase to phase contacts. The work associated with this project will be completed in November 2009. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

The Noxon–Pine Creek and Benewah–Shawnee are projects that will enhance the reliability and utilization of the projects completed during the 5 year 230 kV Upgrade program. As described above, these projects involve the redesign and minor rebuild of sections of these lines that have experienced equipment failure or malfunction. These project costs were developed by the Transmission Design Department and have been reviewed and approved through the Company's capital budget process.

Several other projects are being constructed to meet requirements in the mandatory reliability standards. We are required to construct all of these compliance-related projects, to avoid fines and penalties associated with the reliability standards. These projects include:

- Grangeville 115 kV Capacitor Bank ($0.95 million): This project involves the addition of a shunt capacitor bank at the Grangeville 115 kV substation to support area voltages during outages of Transmission lines in the area. Without this reactive addition, the voltages in the area drop below acceptable levels required to ensure all load remains in service. The capacitor bank was placed into service in July 2009. This project was required to ensure compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.
- Spokane/Coeur d'Alene area relay upgrade phase 2 ($0.90 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 and to install fiber optic cables to provide required high-speed communications between system relays. This is a five year project and is required to maintain compliance with mandatory reliability standards. Phase 2 will be completed in December 2009. This project is required to meet Reliability Compliance under NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.

- SCADA Replacement and Backup Control Center Enhancements ($0.71 million): The Supervisory Control and Data Acquisition (SCADA) system is used by the system operators to monitor and control the Avista transmission system. A portion of this project is necessary to upgrade the current software application to the latest version released by our third party provider. The upgrade will ensure Avista has adequate control and monitoring of its Transmission facilities. This portion of the project is required to meet Reliability Compliance under NERC Standards: TOP-001-1, TOP-002-2a R5-R10, R16, TOP-005-2 R2, TOP-006-2 R1-R7. The second portion of this project includes improvements to our existing Transmission Backup Control Center to provide full operational flexibility of the facility while our main Control Center is decommissioned to allow for an HVAC renovation involving asbestos abatement. A projection map board of our Transmission System and associated equipment will be added to our Backup Control Center to replace the current static map board. This work is required to meet the requirements of NERC Standard EOP-008-0. All work associated with these projects will be completed in December of 2009.
- 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. The meter replacement and upgrade projects are required to ensure Avista has adequate interchange metering with adjacent utilities to keep track of power flow between the entities and is required to meet reliability compliance standards. The estimated cost of the relay upgrade is $400,000 and the metering upgrade is estimated at $125,000 and will be completed in December 2009. This project is required to meet

Reliability Compliance under NERC Standards: BAL-005-0.1b R1, R6 BAL-006-1.1 R2, R3.

- Moscow 230-Pullman 115 Reconductor ($0.78 million): The transmission line was 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 improves load service between Moscow and Shawnee and ensures compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a R1-R3.. The project was energized in August 2009.
- Interchange and Borderline Metering Upgrades ($0.54 million): Interchange metering upgrades are required for all of our interchange points with BPA and other adjacent utilities. By the end of 2009 we will complete metering upgrades at Westside, Warden, and Noxon Rapids Substations. Borderline metering is also required for all loads within Avista's Balancing Authority or metered boundary. By the end of 2009 we will complete meter upgrades at Mead substation. This project is required to meet Reliability Compliance under NERC Standards: BAL-005-0.1b R1, R6 BAL-006-1.1 R2, R3.

Other Capital Transmission projects are being constructed to improve system reliability and service to customers. These projects include minor transmission line rebuilds or reconductor projects. The replacement projects involve the removal of older deteriorated equipment and the installation of newer in-kind equipment. These projects don't require significant engineering analysis or design.

- Other Small Transmission Projects ($2.76 million total): The remaining transmission specific projects being constructed in 2009 are smaller projects, including a line reconfiguration to provide backup service, minor work associated with Colstrip transmission, re-insulating a 230 kV line due to failing insulators, and the reconductor of sections of 115 kV lines. These smaller projects are required to operate the transmission system safely and reliably. These projects have a direct impact to system reliability due to equipment age and the possibility of failure.

The Company has also developed a 5 year asset management plan that includes a wood pole inspection and management program. Results of the inspection program are incorporated into the following capital replacement efforts.

- <u>Wood Pole Replacement Program ($3.70 million)</u>: 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 under this program.
- <u>Wood Pole - Capital Distribution Feeder Repair Work ($4.10 million)</u>: 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).

The Company has additional Capital projects that are required by government agencies. These projects include:

- <u>T&D Line Relocation ($1.98 million)</u>: Relocation of transmission and distribution lines as required due to road moves by government authorities. The Company is required to relocate sections of our lines as requested by the state, county and city for new road construction or expansion.

- WSDOT Highway Franchise Consolidation ($0.6 million – WA): This project is required by the State of Washington and involves verification of our lines on existing state property along Washington highways. The project includes surveying and plotting of poles.

Since the capital projects are being constructed to meet compliance requirements, improve system reliability or replace broken or aging equipment; the Company is not anticipating collecting any additional revenues. The Company anticipates these projects may mitigate expected increasing operating costs over time, but do not expect a decrease in operating expenses from these projects from the level built into the company's case.

Q. Please summarize your rebuttal testimony relating to capital investment.

A. During the first six months of 2009, the Company spent and transferred to plant in-service $1,057,000 for transmission capital expenditures and $3,866,000 for asset management distribution capital expenditures. The Company has already spent or will spend an additional $10,324,000 for transmission capital expenditures and $6,511,000 for asset management distribution capital expenditures before the end of 2009 that will be transferred to plant in-service prior to December 31, 2009. These expenditures are known and measureable for projects that will be operational by the end of 2009.

III. AVISTA'S ASSET MANAGEMENT PROGRAM

Q. Please describe the Company's Asset Management Program, including Vegetation Management and Wood Pole Management.

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 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 multiple 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.

The AM program began over 5 years ago when the Company consolidated many of its individual maintenance programs into a consolidated effort to maximize efficiency and provide flexibility. Company witness Ms. Andrews addresses the costs of the asset management programs and the pro forma increase included in the Company's case. A few of the successful AM programs include Vegetation Management and Wood Pole Inspection.

<u>Vegetation Management</u> - 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. The Company's goal is to clear 1,550 miles per year, which results in a 5 year cycle.

For the transmission system, 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. These same requirements apply to four 115 kV lines identified as critical to grid reliability by WECC. These additional requirements have expanded the areas that require management 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. Another factor that has added to the increased cost of the vegetation management program includes changes in access road maintenance requirements in our updated Special Use Permits with the Forest Service. This requires Avista to spend more money annually to maintain roads on a planned basis.

For the distribution system, the vegetation management program covers significantly more miles. Outage data shows a dramatic increase in outages on circuit miles that haven't been adequately maintained. The AM analysis has determined that a 5 year clearing cycle provides optimized reliability for program costs. Ms. Andrews addresses the costs of the vegetation management program and the pro forma increase included in the Company's case.

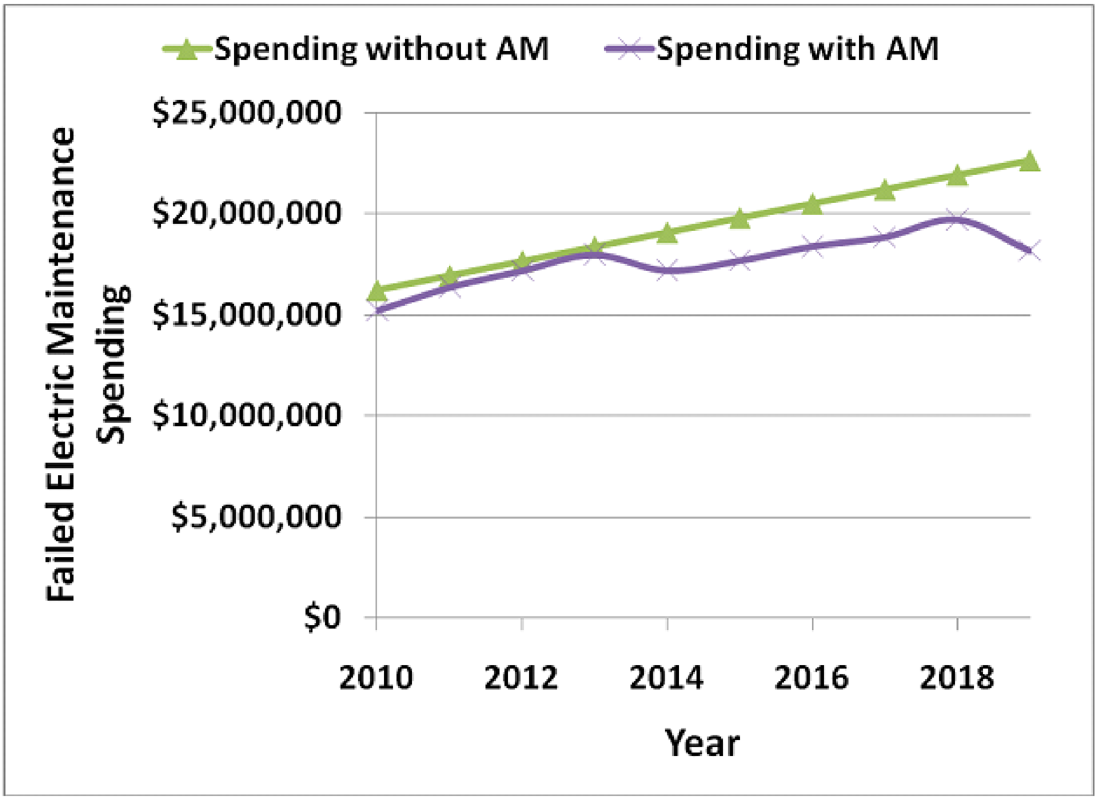
<u>Wood Pole Management</u> – The wood pole maintenance program is another successful AM program. After completing an optimization analysis, the data indicated preferred testing cycles for both Transmission and Distribution poles. The analysis showed that distribution poles should be inspected on a 20-year 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. In 2008 the company inspected approximately 12,000 Distribution Wood Poles and over 2,500 Transmission Wood Poles. Our annual goal is to inspect 12,000 Distribution and 3,000 Transmission poles. As a result of the 2008 inspections, Avista reinforced 980 poles, replaced 432 poles, and replaced 950 cross-arms. Ms. Andrews addresses the costs of the wood pole management program and the pro forma increase included in the Company's case.

Q. Please describe any "offsetting factors" resulting from Avista's Asset Management Plan.

A. Analysis performed by Avista's Asset Management team shows that the incremental Operations and Maintenance (O&M) spending on Asset Management will produce savings for our customers over the long term, however the majority of the savings will be observed in future years. AM programs take time to mature and provide positive results and the avoidance of future O&M costs and capital investments. Many of the Company's programs are in their infancy so the full benefits will not be observed until a complete maintenance cycle has been completed. However for the more mature programs, we anticipate some savings. Table 2 shows a comparison of future failed electric maintenance costs with and without AM from 2010 through 2019. The projections are based on a 5 year trend of actual failed electric maintenance costs.

Table 2
Forecasted Failed Maintenance Spending



When all of the Asset Management programs in this rate case excluding the Vegetation Management portion are combined the net O&M savings is $2.05 million in 2010 compared to the test year. However, Vegetation Management will incur a net O&M cost increase of $1.02 million to ensure a 5 year maintenance cycle is achieved. Also the Failed Electric Maintenance costs are projected to increase by $1.12 million in 2010 based on the previous 5 year projected average. When all of these are combined, the <u>net</u> overall effect on O&M is a $100,000 increase in 2010 over the test period, i.e. no net offset.

A mature AM program may provide additional offsetting factors. Reducing outages associated with equipment failures or vegetation allows the Company to realize additional revenue that would otherwise have been lost. It is very difficult, however, to quantify the potential revenue increase resulting from avoided outages. Outages can last from a few seconds to several hours depending upon the circumstances such as the location of crews to respond or the time of the incident. Also a mature AM program can't guarantee outages will not occur. The Company believes that any additional revenue received through reduced outages will not be significant and therefore won't offset the increased maintenance costs associated with failed equipment based on current and forecasted expenditures.

A complete AM program can help customers avoid costs associated with outages. A 2004 report titled, "Understanding the Cost of Power Interruptions to U.S. Electricity Consumers"[1], estimates customer costs associated with outage events. As the report indicates there are multiple factors that can influence the actual costs borne by customers. Table 13 in the report summarizes estimated costs per outage per customer by region. Table 3 below shows the outage cost estimates for the Pacific region and U.S. in total.

Table 3
Estimated Cost-per-Outage-per-Customer

Region	Outage Duration	Residential	Commercial	Industrial
Pacific	0 Seconds	$1.80	$604	$1,881
Pacific	Sustained	$2.45	$1,050	$4,111
U.S. Total	0 Seconds	$2.18	$605	$1,893
U.S. Total	Sustained	$2.99	$1,067	$4,227

As an example from Table 3 above, an industrial customer in the Pacific region that experiences a momentary outage will incur a cost, on average, of $1,881. If they experience a

[1] Report by Kristina Hamachi LaCommare and Joseph H. Eto at Ernest Orlando Lawrence Berkeley National Laboratory, Sept 2004, LBNL-55718 for Imre Gyuk, Energy Storage Program, Office of Electric Transmission and Distribution, U.S. Department of Energy and Sam Baldwin, Office of Planning, Budget, and Analysis, Assistant Secretary for Energy Efficiency and Renewable Energy, U.S. Department of Energy.

sustained outage the estimated cost will be $4,111 per event. As Avista continues to implement its Asset Management Program and maintain its associated maintenance schedules, although the Company may not experience significant savings until future time periods, our customers should experience less outages and therefore, see a reduction in outage related costs.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.