Exhibit No. __(SJK-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-07________

DIRECT 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 Chief Engineer, System 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 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 to my current position of Chief Engineer, System Operations.

Q. What is the scope of your testimony?

A. My testimony describes Avista's transmission upgrade projects, and presents Avista's pro forma period transmission revenues and expenses, including the proposed addition to expense to allow the Company to recover its Grid West loan costs. I also describe the Company's Wood-Pole Management Program. Company witness Ms. Andrews incorporates the Washington share of the transmission upgrades and net transmission expenses and the Wood-Pole Management Program O&M expenses proposed in this case.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit Nos. ___(SJK-2) and ___(SJK-3), which were prepared under my direction. Exhibit No. ___(SJK-2) includes a map of the 230 kV Upgrade

Project at page 1, and the "Major Transmission Additions" table at page 2. Exhibit No. ___(SJK-3) provides the Transmission Pro Forma adjustments.

II. TRANSMISSION UPGRADES

Q. Please describe the Company's transmission upgrade project?

A. The Company is in its last year of a multi-year transmission upgrade project that is estimated to exceed $130 million (2003-2007). This multi-year transmission upgrade plan will add over 100 circuit miles of new 230 kV transmission line to Avista's system, and will increase the capacity of an additional 50 miles of transmission line. The upgrade project includes constructing two new 230 kV substations as well as reconstructing three existing transmission substations. Six 230 kV substations are being upgraded to meet capacity requirements, upgrade protective relaying systems, and meet regional and national reliability standards. In total, Avista has or will perform work on eleven of its thirteen 230 kV substations. Avista is also upgrading its telecommunication system by installing fiber and digital microwave systems. This will create redundant communication paths, required by national reliability standards that will improve system monitoring, control, and protection. Exhibit No.__(SJK-2), page 1, includes a map showing the location of the 230 kV upgrade projects.

Q. What transmission project costs are included in this filing?

A. The Company has included the cost of seven projects, with completion dates in 2006 and 2007. As shown in the table below (see also Exhibit No.___(SJK-2), page 2), these projects include the Palouse Reinforcement Project, the Beacon-Bell #5 230 kV line upgrade, the West of Hatwai (WoH) Telecom Projects, the Dry Creek 115 kV Substation Projects, the

Boulder Substation Project, the Lolo Substation Project, and the Critchfield Substation Project - at a total system investment of $66.9 million.

Transmission Projects	Cost: System/WA (000s)	In-Service Date
West of Hatwai (WoH) Telecom	$3,207 / $2,111	* Oct-07
Beacon-Bell #5 230 kV line	$2,915 / $1,919	Apr-07
Palouse Reinforcement Project	$52,392 / $34,489	* Nov-07
Dry Creek 115 kV Substation	$2,236 / $1,472	Nov-06
Boulder Substation	$3,299 / $2,172	* June 07
Lolo Substation	$2,044 / $1,345	Dec-07
Critchfield Substation	$800 / $527	Dec-07
Total	$66,893 / $44,035	

* These projects include multiple phases with various in service dates in 2006 and 2007. The dates shown are the in service dates for the last phase of the project. See details in Exhibit No. __ (SJK–2), page 2).

- **West of Hatwai (WoH) Telecom Projects:** The ability to communicate with, monitor, and control transmission equipment is an important factor in providing reliable service. The WoH Telecom initiative is comprised of several individual projects. The Noxon-Pine Creek fiber project completes a telecommunication ring from Spokane to Noxon Rapids Dam. The ring provides for redundant communication paths, where the loss of one side of the ring will not eliminate the ability to control equipment. The ring is also required to implement the Clark Fork Remedial Action Scheme (RAS) that drops generation at Noxon Rapids and Cabinet Gorge Dams after critical transmission outages to ensure system reliability. Another component of the Clark Fork RAS includes the addition of fiber from the Cabinet generation units to the 230 kV Cabinet Substation. The Hatwai-North Lewiston fiber project completed a fiber ring around the Lewiston/Clarkston load service area. This project is also part of a RAS to improve reliability in the Lewiston area. The Hatwai-North Lewiston and Clark Fork fiber projects were completed and commissioned in 2006 at a total investment of $1,240,000 (fiber and transmission make-ready). The construction phase of the Noxon-Pine Creek fiber project commenced in August of 2006 but heavy snowfall forced the demobilization of line crews until 2007. The project is slated to commission in September of 2007 at an estimated cost of $1,966,800. The total WoH telecomm project costs are $3,207,000 (system).

- **Beacon-Bell #5 230 kV Line:** Avista is increasing the capacity of the second Beacon-Bell 230 kV line. The first Beacon-Bell 230 kV line was upgraded in December 2005. These parallel path transmission lines originate from Avista's Beacon Substation and interconnect with Bonneville Power Administration (BPA) at its Bell Substation. The project involves up-rating the line capacity, from 400 to 800 MVA, as well as increasing equipment ratings at both Beacon and Bell (BPA) substations. The project will mitigate overloads between the largest Avista and BPA substations in Spokane and improve load service to the Spokane area. The transmission line is scheduled to be energized in April 2007 with a total investment of $2,915,000 (system).

- **Palouse Reinforcement Project:** This project involves the construction of 60 miles of new 230 kV transmission line between the Benewah and Shawnee substations and the rebuild of Benewah substation to a more reliable configuration. The project is required to relieve congestion on the existing Benewah-Moscow 230 kV line by providing a second 230 kV transmission line between Avista's Northern and Southern load service areas, significantly improving system reliability. The transmission line portion of the project has been divided into three phases. Construction of the first phase was started in 2006 and included the double circuit Shawnee-Colfax 230 kV and 115 kV line section and the Benewah Substation rebuild. This phase is expected to be moved into service in September 2007. The second phase includes the construction of the Colfax-Rosalia line section and will be completed in September 2007. The final stage is the Benewah-Rosalia line section and will be completed in November 2007. The entire project will be energized and placed into service in November 2007. The total cost of this project is $52,392,000 (system).

- **Dry Creek 115 kV Substation:** To improve load service and system reliability in the Lewiston/Clarkston area, a 230/115 kV auto transformer was added to the Dry Creek Substation. The new transformer provides a back-up for the North Lewiston 230/115 kV auto transformer. This phase of the project includes the construction of the 115 kV portion of the Dry Creek Substation and the loop-in of an area 115 kV transmission line. The project was energized in November of 2006 at a total investment of $2,236,000 (system).

- **Boulder Substation:** This project included the construction of a new 230kV/115kV substation. Two 250 MVA 230 kV to 115 kV transformers were added in two stages at Boulder Substation. The first transformer was placed into commercial operation in December of 2005. The second transformer and corresponding substation work will be energized in June of 2007. The Boulder station will be capable of serving customers throughout eastern Washington and Northern Idaho. The added capacity at Boulder will relieve congestion at Avista's largest transmission substation, Beacon. Shifting load from Beacon to Boulder also improves system reliability. The cost of the second phase of this project is $3,299,000 (system).

- **Lolo Substation:** 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 transmission line ratings that were significantly increased over the last few years. The new substation design significantly improves reliability and operating flexibility. The existing substation bus is also susceptible to failure for different contingency events. The project will be energized in December of 2007 at a total investment of $2,044,000 (system).

- **Critchfield Substation:** This project is required to serve load growth in Clarkston, Washington. Two other substations in the Clarkston area are at full capacity. This new substation will move load off the other two and provide capacity for future load growth in the area. The substation will be built with a single 115/13.8 kV transformer and have two distribution feeders initially. The project will be energized in December of 2007 at a total investment of $2,412,000 (system). Only the costs ($800,000) associated with the 115 kV transmission line and substation (excluding the distribution portion) are included in this rate case.

Q. Will the construction of these new facilities increase third party transmission revenue received by the Company from third party transmission users who move power across Avista's system?

A. No. These projects are being built to improve system reliability, improve area load service, and meet national reliability standards. In the WoH agreement signed with BPA, Avista preserved its existing transfer capability across the WoH cut-plane and BPA gained additional transfer capacity.

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, 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 become 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.

III. PRO FORMA TRANSMISSION EXPENSES

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

A. Several revisions were made to the transmission expenses in the 2008 pro forma period, in comparison to the 2006 test year. Revisions were made to incorporate updated information and actual 2006 transmission expenses. The primary drivers of the additional \$590,000 (system) pro forma adjustments included in this case are \$313,000 (system) for Columbia Grid, \$79,000 (Washington only)[1] for Grid West, and \$132,000 (system) of additional Colstrip O&M costs. Each expense item described below is at a system level, with the exception of the \$79,000 Grid West adjustment which is Washington only, and is included in Exhibit No.__ (SJK-3).

Northwest Power Pool (NWPP) – 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 change in NWPP costs in the pro forma period compared to 2006 actual spend.

Colstrip Transmission - 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

[1] The Idaho Commission has chosen to account for its share of the Grid West costs over a 5 year period starting Jan. 1, 2007.

Northwestern Energy's (NWE) 2007 Colstrip Transmission reports provided to the Company, NWE will bill Avista during 2007 an annual total of $498,000 for Avista's share of the Colstrip O&M expense. This is an increase of $132,000 over 2006 actual expense of $366,000. The significant cost increase is a result of implementing cathodic protection measures and anchor bolt replacements. The existing anchor bolts are disintegrating. The replacements will start in 2007 and will be performed over several years. NWE expects 2008 Colstrip O&M costs to be similar to 2007.

<u>ColumbiaGrid (RTO Development)</u> - In 2006, Avista elected to fund the ColumbiaGrid RTO development effort. This 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 will pay a total of $518,000, which represents Avista's share of the ColumbiaGrid operating costs from 2006 through Augusts 31, 2008. Prior to the amended agreement, Avista paid $104,000 of these costs. The remaining balance ($414,000) is being amortized over the remaining 20 months of the agreement. The monthly amortized amount is $20,720. Avista anticipates that ColumbiaGrid operating costs will continue beyond August 2008 and will likely increase as ColumbiaGrid provides additional services in the future. Therefore, the ColumbiaGrid cost for the pro forma period and beyond is anticipated to be approximately $249,000 annually based on a monthly fee of $20,720.

<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. Avista anticipates its share at $466,200 for the first two-year period. This results in an annual cost of $233,100 during the pro forma period.

<u>Electric Scheduling and Accounting Services</u> - The $52,000 decrease in the pro forma period compared to actual 2006 expense for electric scheduling and accounting services is a result of reductions in services provided by third party venders. These services are no longer required because of the development of an internal accounting procedure 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>OASIS Expenses</u> - The $5,000 increase in Open Access Same-Time Information System (OASIS) expenses is a result of increased travel/training costs for transmission pre-scheduling and OASIS personnel. This increase in travel is required to monitor and adhere to new OASIS requirements approved by FERC in February 2007.

<u>WECC – System Security Monitor & WECC Administration and Net Operating Committee Systems</u> - The WECC System Security Monitor fees have been revised from 2006 actual costs of $85,600, to $108,700 in the pro forma period. Additionally, the WECC Administrative and Net Operating fees have been increased from $145,800 in 2006 to $237,300 for the pro forma period. Both changes reflect significant increases in the WECC forecasted

budget to fund regional reliability initiatives required to meet FERC and NERC mandatory reliability standards. The 2008 WECC budget and corresponding fees are based on an expected 9.4% increase above the 2007 approved budget.

WECC - Loop Flow - WECC Loop Flow charges are dependent on transmission system usage and congestion across the entire Western Interconnection. The 2008 pro forma charge is $28,000 which is equal to the 2006 actual charges as invoiced by the WECC.

IV. PRO FORMA TRANSMISSION REVENUES

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

A. Several revisions were made to the transmission revenues in the 2008 pro forma period, in comparison to the 2006 test year. Revisions were made to incorporate updated information and actual 2006 transmission expenses and revenues. The primary drivers for the revenue reduction of $1,371,000 in the pro forma period as compared to 2006 actual revenue is the expiration of three transmission contracts in the last quarter of 2007. The contracts are with Seattle City Light, Tacoma Power, and Northwestern Energy. The primary drivers of the continued transmission revenue in the pro forma period are Borderline Wheeling and OASIS revenues totaling $8.65 million (system). Each revenue item described below is at a system level and is included in Exhibit No. __(SJK-3).

Borderline Wheeling - The Borderline Wheeling revenue in the pro forma period is set at the 2006 actual revenue level of $5,234,000. The 2006 actual revenue is being used for the 2008 pro forma period since 2006 was the first year under new contracts signed with BPA. The new

Borderline Wheeling revenue methodology is based on a Load Ratio Share[2], which is quite different than the previous revenue calculation under the old contracts.

The General Transfer Agreement (GTA) with BPA expired in 2005 and, due to FERC requirements, was replaced with new individual contracts under the Avista Open Access Transmission Tariff (OATT). Under the old GTA, Avista billed BPA using a distance-based "transfer charge" for each point of delivery. Under the new contracts, BPA, as the network customer, shall pay a monthly demand charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's annual transmission revenue requirement (presently $28,566,969). The net result of the FERC-required change in rate methodology is an overall reduction in revenues associated with providing transfer service to BPA for service to BPA's borderline loads on Avista's system.

<u>Seattle, Tacoma, and Grand Coulee Project Revenues</u> - In March of 2006, Seattle and Tacoma purchased long-term firm point-to-point transmission services from Avista under the OATT to move their generation to load. The transmission was purchased from April 2006 through October 2007. The contracts were signed to give Seattle and Tacoma time to build new facilities to bypass Avista and connect directly to BPA. Since the transmission service that was purchased expires in October 2007, Avista will not receive any transmission revenue in the pro forma period from Seattle or Tacoma. In the 2006 test year, Avista collected a total of $576,500, for each contract year, based on a monthly charge of approximately $64,000 for nine months (April through December).

[2] 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 $1,300 decrease in 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. The 2006 test year revenue was $9,400 but included several interim adjustments for the first few months of the new contract.

<u>OASIS Non-firm and Short-term firm Wheeling Revenue</u> - 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, 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 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. 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 years 2002, 2003, 2005, and

2006. The resulting four-year revenue average is $3,417,000, which is $40,000 higher than the 2006 actual revenue of $3,377,000.

Dry Gulch Revenue - Dry Gulch revenue has been adjusted to $274,000 for the pro forma period, which is a $6,000 decrease from the 2006 actual revenue of $280,000. 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 by $60,000 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 - No adjustments to PP&L Series Cap revenue were made for the pro forma period. The 2006 actual revenue of $9,000 is used as the expected revenue for the pro forma period. 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 ($160,000) were made for the pro forma period compared to the 2006 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 - No adjustments to Vaagen Wheeling revenue were made for the pro forma period. The 2006 actual revenue of $103,000 is used as the expected revenue for the pro forma period since the past six years of actual data has shown a consistent reduction of revenue from a peak of $119,000 in 2001 to $103,000 in 2006.

Northwestern Energy (NWE) - The revenue of $252,000 from NWE in the 2006 test year was a result of a new load following contract that Avista signed in 2005 with NWE. Under the contract Avista provides up to 15 MW of energy to Northwestern to help them match hourly fluctuations in loads and resources. Firm transmission has been purchased for this contract at Avista's full tariff rate. Since this contract expires in November 2007, no revenue will be received in the pro forma period.

V. GRID WEST LOAN

Q. Is the Company proposing to incorporate in this case costs related to loans made to Grid West and its predecessor, RTO West?

A. Yes. The Company is proposing to include in transmission expense an annual amount of $158,000 to recover loan costs to Grid West (and its forerunner, RTO West). Avista's total Grid West loan amount is approximately $1.2 million including interest through March 31, 2006 (or $796,000 Washington share). This amount is proposed to be amortized on a five-year basis with no interest or carrying costs. None of the loan amount is presently included in Avista's rates. Other costs incurred by Avista to support Grid West, such as employee salaries, employee travel, and legal expenses, were expensed as incurred and are not included in this amount.

Q. Please provide background related to Avista's participation in establishing a regional transmission organization (RTO).

A. Avista has been actively involved in the development of a Pacific Northwest RTO. This activity has been aimed at meeting the policies of the FERC, promoting competitive electric markets. More specifically, FERC Order 888 encouraged the development of independent system operators, and FERC Order 2000 required transmission owners to develop and submit a proposal to establish an RTO, or to explain why such an organization could not be developed. Therefore, the Company's effort and associated costs related to Grid West were essential in the ongoing ownership, development, and operation of Avista's transmission system.

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"). These start-up costs included retaining experts and facilitators, as well as other expenses associated with transmission studies and stakeholder participation. The total balance of Avista's loan to Grid West is approximately $1,217,500, including interest of approximately $188,000. 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 will not occur. As a result, Avista filed a petition with the Commission to defer these costs, with the opportunity for later recovery in retail rates. The Commission approved, on July 26, 2006, in Docket No. UE-060665, the Company's request for an order authorizing deferred accounting treatment for loan amounts made to Grid West. The Order required the Company to begin amortization of the loan balance beginning July 1, 2006, for five years, and explain why any amortization of this loan balance should be borne by Washington ratepayers. During the pro forma period Avista would amortize a total of $158,200 associated with Grid West development costs.

Q. Why is the Company proposing that these costs be included in the requested revenue requirement?

A. This activity was required by FERC and necessary for the continued planning and operation of the Company's transmission system. As stated earlier, the Company continues to work with other regional parties to explore ways in which the region's transmission providers can better operate and manage the region's transmission system. On April 10, 2006, Avista joined ColumbiaGrid as one of its six founding members[3] and in August of 2006, ColumbiaGrid members elected an independent board of directors. ColumbiaGrid is drawing upon elements developed in both the Grid West and Transmission Improvements Group (TIG) processes to provide transmission-related coordination and administrative services as soon as possible. Accordingly, ColumbiaGrid has offered a Planning & Expansion Functional Agreement for execution by ColumbiaGrid members and other regional transmission owners. Because the ColumbiaGrid effort is, and will continue to be, using many of the concepts and technical work that began under Grid West, the Company and its customers will benefit from the prior work of Grid West.

VI. ELECTRIC SYSTEM WOOD POLE MANAGEMENT

Q. Would you please provide an overview of the Company's Wood Pole Plant?

A. Yes. Avista's electric distribution and transmission circuits combined span is over 14,000 miles, and contains approximately 340,000 wood poles. The wood-pole population is predominantly distribution (300,000). Approximately half the distribution poles have been installed in the past forty-five years, while the population of transmission poles is somewhat

[3] Incorporated as a non-profit organization, the founding members, in addition to Avista, include Puget Sound Energy, Seattle City Light, Grant County Public Utility District, Chelan County Public Utility District, and the Bonneville Power Administration.

older; 58% were installed in the period between 1950 and 1970 and approximately 20% are pre-1940.

Q. Are transmission and distribution poles managed under separate programs?

A. Yes, they are.

Q. Please describe the management program for wood poles in Avista's electric distribution system.

A. A key element of the distribution wood-pole management program is the 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. The current inspection cost for each pole is $26. Stubbing[4] adds 50% to the life of the pole and currently costs $650, while replacement of the pole costs on average $2,800. The Company is changing its test cycle to ensure the entire pole population is surveyed every twenty years.

Q. How does this differ for transmission poles?

A. The Company is planning to survey the entire transmission pole population every 15 years. The per-pole inspection cost is $100. Stubbing a transmission pole currently averages $750, while replacement of the pole ranges between $3,500 and $4,500 when the work is performed during regular work shifts.

Q. Does the planned wood-pole management program differ from the current approach?

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[4] Stubbing involves driving a galvanized rounded steel plate into the ground next to the pole and banding the plate and pole together. The plate covers approximately 1/3 of the circumference of the pole. Two plates are used if necessary.

A. Yes. In recent years, Avista has tested between 1% and 2% of the distribution pole population each year. This testing schedule was driven by a low rate of pole failures experienced over the past few decades, and produced a survey "cycle time" of between 50 and 100 years for the entire distribution system pole population. In recent years, the Company began to evaluate the costs and benefits of shortening the cycle time for testing as the average age of the pole population increased.

The transmission testing cycle was also reevaluated. The original test period was approximately ten years, but the cycle time has gradually increased over time. About 20% of the transmission system has been inspected twice since 1988.

Q. What has Avista done to evaluate the costs and benefits of revising the cycle time for its wood-pole population?

A. Recently, new mathematical models have been developed by the industry to assist in the evaluation of operational and financial consequences of varying testing cycles for wood-pole populations. In 2006, Avista acquired these models with a software application and began calibrating them to the particulars of our distribution and transmission wood-pole populations. Included in the model are several risk factors and a financial analysis that determines the best overall cycle time and program.

Q. What did the Company learn from the evaluation of cycle times on its distribution pole population?

A. Three cycle times were modeled for the distribution population, including a 100-year cycle, a ten-year cycle, and a model-derived optimized cycle of twenty years. The model results forecast significantly better operational performance for poles tested under both a ten and a twenty-year cycle, as opposed to the 100-year scenario. Operational performance between the ten and twenty-year cycles did not differ significantly. There was a substantial difference, however, in the financial comparisons of the three testing cycles over a fifty-year outlook.

Q. Were the results similar for the transmission pole population?

A. Yes they were. Six scenarios were modeled for the transmission pole population, including testing intervals of 10, 15, 20, 25 and 30 years, and one where no testing program was employed. Operational performance and cumulative costs over a fifty-year horizon were determined to be very similar for the 10 and 15-year cycles, $92 and $98 million, respectively. The results are even closer when the 15-year cycle is coupled with the programmed replacement of very old poles (greater than 80 years old) in the transmission system. Under this scenario, once the programmed replacements of very old poles are completed, the optimized cycle time would be fifteen years. Based on this evaluation and historical testing results, Avista is planning to employ a testing cycle time of fifteen years for its transmission poles.

Q. Do the proposed changes in the Company's wood-pole management program result in changes in annual costs going forward?

A. Yes. Even though this program will result in optimized and much lower life-cycle costs for our customers, it results in an immediate increase in annual funding from current spending levels. For the distribution system, the annual O&M expenses will increase from $206,000 in 2006 to $390,000 (system) in the pro forma period, while the annual capital requirement will increase from approximately $1.1 million to $4.9 million. For the transmission system, the planned annual O&M expenditures will increase from $44,000 in 2006 to $322,000 (system), and $576,000 for capital, from $306,000. No Transmission O&M expenses have been incurred since 2003, because the completed replacements were in support of significant Transmission upgrades that were capitalized.

Q. Are these increases in expense and capital requirements part of the Company's current proposed general rate increase?

A. The O&M expenses only are included in the proposed general rate increase. The combined Transmission and Distribution O&M adjustment for the pro forma period compared to the 2006 test year is $461,000 (system), or $304,000 Washington share, before taxes. Ms. Andrews incorporates these costs in her testimony and exhibits. The capital costs will be included in future rate case filings.

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

A. Yes, it does.