Exhibit No.__(RLS-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-09____________

DIRECT TESTIMONY OF

RICHARD L. STORRO

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Richard L. Storro. I am employed as the Vice President of Energy Resources by Avista Corporation located at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational and professional background?

A. Yes. I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973. I began working for Avista in 1973 as a distribution engineer and have held several other engineering positions with the Company. I have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997, became Director of Power Supply in 2001, became President of Avista Ventures in 2007, and became Vice President of Energy Resources in January 2009.

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

A. My testimony will provide an overview of Avista's resource planning and power operations. This overview includes summaries of the Company's resources, the current and future load and resource position, future resource plans, and an update on the Company's involvement with the Chicago Climate Exchange. The third section discusses the Lancaster Power Purchase Agreement. The fourth section of my testimony discusses hydro and thermal project upgrades. This is followed by a hydro relicensing update. My testimony concludes with a discussion of generation plant operation and maintenance issues.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring five exhibits: Exhibit Nos.__(RLS-2) (Avista 2007 Electric Integrated Resource Plan), __(RLS-3) (Map and picture of the Lancaster Generation Facility), __(RLS-4) (Lancaster Generating Facility Power Purchase Agreement Evaluation Overview), __(RLS-5) (Independent Valuation of the Lancaster Facility Tolling Agreement), and __(RLS-6) (Overview of the Lancaster Power Purchase Agreement).

II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide a brief overview of Avista's power generating resources?

A. Yes. Avista's resource portfolio consists of a mix of hydroelectric generation projects, base-load coal and natural gas-fired thermal generation facilities, wood waste-fired renewable generation, natural gas-fired peaking generation projects, long-term contracts including wind and Mid-Columbia hydroelectric generation, and market power purchases and exchanges. Avista-owned generation facilities have a total capability of 1,787.6 MW, which includes 55% hydroelectric and 45% thermal resources.

Illustration No. 1 below summarizes the present net capability of Avista's owned generation resources:

Illustration No. 1: Avista Generation

Company-Owned Projects	**MW**
Noxon Rapids	541
Cabinet Gorge	261
Post Falls	18
Upper Falls	10.2
Monroe Street	15
Nine Mile	15
Long Lake	90.4
Little Falls	36
Total Hydroelectric Generation	**986.6**
Colstrip Units 3 and 4	222
Coyote Springs 2	280
Kettle Falls	45
Total Base-Load Thermal Generation	**547**
Northeast CT	56
Kettle Falls CT	10
Boulder Park	24
Rathdrum CT	164
Total Natural Gas Peaking Generation	**254**
Total Generation	**1,787.6**

The Company also has long-term contractual rights for 166 MW of capability from Mid-Columbia generation projects in 2009, owned and operated by the Public Utility Districts of Grant, Chelan and Douglas counties. The Company has a ten-year contract for 35 MW of wind generation capability from the Stateline Wind Project and also receives 100 MW of energy from other contracts through 2010.

Q. Would you please provide an overview of Avista's resource planning and power supply operations?

A. Yes. The Company uses a combination of owned and contracted-for resources to serve its requirements. Dispatch decisions related to these resources are made by the Power Supply section of the Energy Resources Department. The Department studies capacity and energy resource needs on an ongoing basis. The Company utilizes short and medium-term wholesale transactions to balance resources with load requirements. Longer-term resource decisions for new resources, upgrades to existing resources, demand-side management (DSM), and long-term contract purchases are generally made in conjunction with the Integrated Resource Plan (IRP) and Request for Proposals (RFP) processes.

Q. Please summarize the current load and resource position for the Company.

A. The Company had forecasted annual energy and capacity deficits starting in 2011 in the 2007 Electric IRP, without the addition of the Lancaster Power Purchase Agreement (PPA). The Company is currently projecting a balanced-to-surplus energy position through 2017 on an average annual basis with the inclusion of the Lancaster PPA. However, as I will explain later, there are monthly and quarterly deficits and surpluses prior to 2017. The Company's annual energy net resource position becomes deficient in 2018 and the deficiencies will increase from that time forward if additional resources beyond the Lancaster PPA are not added. The average annual energy resource deficiency in 2018 is 8 aMW which increases to 515 aMW in 2028.

The Company's capacity resource position is surplus through 2018 with the inclusion of the Lancaster PPA. Capacity deficiencies begin at 67 MW in 2019 and increase to 843 MW in 2028. Additional details concerning the load and resource positions are in Company witness Mr. Kalich's Exhibit No.__ (CGK-3).

Q. How does the Company plan to meet future resource needs beginning in 2018?

A. The Company has pursued the Preferred Resource Strategy laid out in the 2007 Electric IRP, which is attached as Exhibit No.__(RLS-2). The IRP provides details about resource needs, specific cost and operating characteristics of the resources evaluated for the Preferred Resource Strategy, and the scenarios used for resource evaluations.

The Company's 2007 Electric IRP was submitted to the Commission in August 2007. The Company will continue evaluating a mix of resource options to meet future load requirements, including medium-term market purchases, generation ownership, hydroelectric upgrades, renewable resources, customer load reduction (e.g., conservation), long-term contracts, and generation lease or tolling arrangements. As stated earlier, longer-term resource decisions are generally made in conjunction with the Company's IRP and RFP processes, although the Company does acquire some resources outside of formal RFP processes. The first decade of the Company's Preferred Resource Strategy in the 2007 IRP included a mix of 87 MW of DSM, upgrades to existing plants, 350 MW of gas-fired CCCT, 300 MW of wind, and 35 MW of other renewable generation (such as small co-generation, biomass and geothermal).

The Company continues to evaluate and acquire various demand side management (DSM) measures. Avista has acquired approximately 138 aMW of DSM over the past 30 years. The Company has over 110 aMW of DSM still in place today, which equates to 6.2% of the Company's owned generation. Avista continues to acquire cost-effective DSM and anticipates acquiring an additional 87 aMW of DSM over the next decade based on the 2007 IRP results.

The Company's Preferred Resource Strategy will be updated in the 2009 Electric IRP, which we plan to submit to the Commission in August 2009. Research and modeling for this new plan are currently underway by the Company's Resource Planning Department with the aid of the Technical Advisory Committee.

Q. Please provide an update on renewable energy acquisitions.

A. The Company has actively pursued renewable energy projects that meet the resource acquisition goals set in the Preferred Resource Strategy (PRS) of the 2007 Electric IRP. The PRS is in the process of being updated for the 2009 IRP. The renewable component of the first decade of the 2007 PRS included 300 MW of nameplate capacity wind and 35 MW of other renewable resources. Other renewable resources include low or carbon neutral technologies such as biomass, geothermal and solar generation.

The Company purchased the rights to develop a 50 MW wind site located at Reardan, Washington from Energy Northwest in May 2008. This site has already been proven to be a viable wind site through several studies based on collected and historical wind data. We are also investigating the acquisition of additional leases to expand the potential of the site to 65 MW. The Reardan site is currently scheduled to be developed and on line by 2013. The Company has also placed met towers at other locations within its service territory and will determine whether or not to proceed with further development of any of those sites after sufficient wind speed data is collected. Other renewable energy options are also being considered. The Company will consider a request for proposals for wind and other renewables after the 2009 IRP has been completed in August 2009.

Q. Can you provide an overview of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses a variety of techniques to manage risks associated with serving load and managing Company resources. The Company's risk management approach uses price diversification through the use of a layering strategy for forward purchases and sales, and by using stop-loss price controls to protect against market price run-ups and run-downs by utilizing upper and lower price control limits. The Energy Resources Risk Policy provides general guidance to manage the Company's energy risk exposure, as it relates to electric power and natural gas resources over the long term (more than 18 months), short term (monthly and quarterly periods out to 18 months), and immediate term (present month). The purpose of the Risk Policy is not to develop a specific procurement plan for buying or selling power or natural gas for generation at any particular time. Several factors, including the variability associated with loads, hydroelectric generation, and electric power and natural gas prices, are considered in the decision-making process regarding procurement of electric power and natural gas for generation.

The use of a layering strategy reduces the Company's and its customers' exposure to purchases of large amounts of energy during high-priced periods. An after-the-fact view of the purchases over time will show that some of the transactions will be advantageous, while other transactions will not be as advantageous. However, this layering strategy will provide for more stable pricing for customers over the long-term.

Q. Can you please provide an update of the Company's involvement with the Chicago Climate Exchange?

A. Yes. The Company joined the Chicago Climate Exchange (CCX) in 2007. The CCX commitment is divided into Phases 1 and 2 which span 2003 to 2006 and 2007 to 2010 respectively. The Company liquidated its 400,000 metric tons of surplus Phase 1 credits in 2008 for $2,577,100 for an average price of $6.44 per metric ton. The Company presently has approximately 147,000 tons of surplus credits from the 2007 compliance year which the Company plans to sell after the CCX prices rebound since they have been below $2 per ton since September 2008. The Company anticipates a surplus of credits for all of the remaining years in Phase 2. We do not plan on continuing with the CCX past Phase 2 when it ends in 2010, because of Washington's involvement with the Western Climate Initiative. The CCX is a voluntary reduction program and companies can no longer be a member if they are bound by a mandatory emissions reduction program.

III. LANCASTER POWER PURCHASE AGREEMENT

Q. What is the Lancaster Power Purchase Agreement?

A. The Power Purchase Agreement for the Lancaster Generating Facility (Lancaster PPA) is a tolling arrangement for a merchant gas-fired plant. This merchant plant is located in the Company's service territory just outside of Rathdrum, Idaho. Exhibit No.__(RLS-3) includes a picture of the Lancaster Generating Facility and a map of its location.

The Lancaster Generating Facility is a General Electric Frame 7FA turbine that went into commercial service as a merchant plant in September 2001. The plant is comprised of a 245 MW gas-fired combined-cycle combustion turbine plus 30 MW of duct firing capability. The plant employs 20 people, had an average net heat rate in 2006 of 6,925 btu/kWh, and an average equivalent availability of 92.9% in 2006.

Internal and independent reviews both indicated that the Lancaster PPA is cost-effective compared to other resource options under base case conditions as well as under several scenarios that will be described in more detail later in my testimony.

Lancaster will become a utility resource on January 1, 2010; therefore, as discussed by Company witness Mr. Johnson, the Company has included the revenues and expenses associated with the Lancaster addition in its pro forma power supply adjustment.

Q. Could you please provide some background related to the acquisition of the Lancaster PPA by Avista Utilities?

A. Yes. The opportunity to acquire the power purchase agreement (tolling) rights for Lancaster was a result of negotiations related to the sale of Avista Energy which held the rights to this tolling arrangement. In April 2007, the utility completed an initial assessment of the Lancaster PPA utilizing the 2007 IRP model. The assessment concluded that this type of resource fit the Company's long-term capacity and energy needs. The PRS for the 2007 IRP had indicated that a 350 MW natural gas baseload resource was needed in the 2008 – 2017 timeframe. As part of the April 17, 2007 announcement of the sale of Avista Energy to Coral Energy, the Company also announced that Avista Utilities would have rights to the Lancaster PPA beginning on January 1, 2010.

Q. Please provide an overview of the agreements included with the Lancaster PPA.

A. There are three main components to this agreement, which include the actual Power Purchase Agreement, natural gas transportation for the plant, and transmission for the plant.

The PPA for Lancaster is available to the Company from January 1, 2010 through October 31, 2026. In exchange for payments outlined in the PPA, the utility will have the right to dispatch Lancaster. This requires the Company to arrange and pay for natural gas fuel procurement and transportation to the Lancaster plant, as well as subsequent transmission to move the power from the plant. In turn, the Company is entitled to the entire electric capacity and energy output from the plant.

The Lancaster plant is interconnected with the Gas Transmission Northwest (GTN) natural gas pipeline system. On January 1, 2010, the Company will receive permanent assignment of firm natural gas transportation capacity on the TransCanada Alberta and TransCanada BC systems and temporary assignment of firm natural gas transportation capacity on the GTN system. The GTN temporary assignment of firm transportation capacity on the GTN pipeline by Shell Corporation terminates on October 31, 2017. These firm transportation agreements will allow for deliveries of approximately 26,000 Dth/d from the AECO trading hub on the Alberta system and approximately 26,000 Dth/d from either the Stanfield or Malin trading hubs south of the plant off of the GTN system.

The Lancaster plant is interconnected electrically with the Bonneville Power Administration (BPA). There is a transmission agreement, held by the Company in the name of Avista Energy, with BPA for 250 MW of long-term transmission capacity rights from the Lancaster point of receipt to the John Day point of delivery that was assigned to Coral on a short term basis through December 31, 2009. Effective January 1, 2010, there will be a permanent assignment of the long-term transmission rights to Avista Utilities. These transmission rights will be used while the Company evaluates interconnecting Lancaster directly with our system.

Q. How did the Company determine the need and suitability of the Lancaster PPA?

A. The initial analysis was performed by the Company's Resource Planning staff based on the 2007 IRP models and methodology. It had already been determined as part of the IRP process that there was a need for energy and capacity in the timeframe for the availability of the Lancaster PPA based on the load and resource tabulations. An analysis of the first, third and fourth quarters (excluding the spring runoff months) showed deficits beginning in 2010, with annual average energy deficiencies in 2011. Capacity deficits started at 146 MW in 2011 and grew into the future. These energy and capacity deficits, combined with the IRP identified need of 350 MW of base load natural gas-fired resources, indicated that the Lancaster PPA was an alternative option for the Company and its customers.

Q. Please provide more details about the internal study on the Lancaster PPA.

A. The Lancaster Generating Facility Power Purchase Agreement Evaluation Overview was completed on April 11, 2007. A copy of this study is included as Exhibit No.__(RLS-4). The study identified all of the natural gas-fired combined cycle plants located in the Northwest to use as a comparison to Lancaster. Of the 13 plants identified with a combined capacity of 1,946 MW, only four of those plants besides Lancaster were not owned by utilities. None of these plants were known to be for sale at the time the study was completed. This essentially ruled out the purchase of a brownfield site. However, the study was conducted with the assumption that a brownfield site was available. Brownfield site costs were chosen based on a review of the most recent plant purchases in the Pacific Northwest.

Q. What were the results of the internal study concerning the Lancaster PPA?

A. In all base cases, the Lancaster PPA provided a significant benefit relative to the construction of a greenfield plant. The 2010 start date showed a positive benefit to the PPA unless a brownfield project of less than $550/kW were located. The Company was not aware of any such projects at the time of this study and has not found any projects in this price range since the study was completed.

Q. Were any third-party reviews of the Lancaster PPA solicited?

A. Yes, in August 2007 the Company contracted with Thorndike Landing, LLC for an independent assessment of the Lancaster PPA relative to other utility gas-fired operations. The study used four different valuation metrics and perspectives including discounted cash flow analysis, valuation under a purchase scenario, identification and valuation of similar assets, and a review of similar market transactions in the region. They also reviewed the Company's analytical processes used for the Lancaster evaluation and resource planning in general.

Thorndike Landing completed their study and assessment late in October 2007 and it is included as Exhibit No.__(RLS-5). The study concluded that the Lancaster PPA was cost-effective and financially favorable relative to other natural gas-fired options generally available to utilities in the Pacific Northwest.

Q. Can you describe the discounted cash flow aspect of the Thorndike Landing study and the results of that study?

A. Yes. Thorndike Landing performed a discounted cash flow analysis to determine the intrinsic and extrinsic value of the Lancaster PPA under base, high and low case scenarios. The base case assumed that the output from Lancaster can be interconnected to the Avista transmission system and that the transmission will be remarketed or otherwise optimized. The high case scenario included a doubling of CO_2 prices, which raised the overall cost of running this plant by the price of the CO_2 emissions credits. The low case scenario assumed the addition of 5,000 MW of combined cycle capacity throughout the WECC, which negatively impacts margins by providing a large amount of regional surplus power. The total value of the Lancaster PPA, as dispatched against the market, was positive in all three cases modeled for the Thorndike Landing study showing that the PPA was cost-effective for Avista. Illustration No. 2 shows the results of this independent evaluation. The results ranged from a PPA value of $500,000 in the low case up to $20.5 million in the high case.

Illustration No. 2: Lancaster PPA Value vs. Market

Description	Power Purchase Agreement Value ($000)	Power Purchase Agreement Value ($/kW)
Base Case	$16,500	$64
Low Case	$500	$2
High Case	$20,500	$78

Q. Can you describe the valuation under the purchase scenario section of the Thorndike Landing study along with the valuation of similarly-situated plants?

A. Yes. Thorndike Landing performed a valuation of Lancaster under an ownership scenario which was then compared to ownership values of other recent plant transactions in the region. This aspect of the study represented the present value of the difference between the variable dispatch costs, fixed O&M, insurance, and taxes for each plant compared to the project market net revenue. In this portion of the study, the variable dispatch cost excluded the cost of the PPA in the case of Lancaster or the recovery of capital or fixed costs in the case of other plants. This comparison indicated that the Lancaster project had a greater value per kilowatt than recently constructed or transacted plants in the region. Even though the Company will not own the Lancaster plant, this section of the study is a strong indication that a similar PPA or toll opportunities at one of the other regional plants would be somewhat less economically favorable to the Company than Lancaster. Illustration No. 3 summarizes the results of this aspect of the study.

Illustration No. 3: Lancaster Plant Value vs. Regional CCCT Projects

Project Name	Plant Value ($/kW)
Lancaster	$677
Coyote Springs 2	$652
Port Westward	$528
Goldendale	$365

Q. Why did the Company not purchase Lancaster outright rather than taking a power purchase agreement?

A. The Thorndike Landing study, along with the Company's own studies, indicated that the outright purchase of Lancaster would be a beneficial and preferable option to the Company. The Lancaster plant became available for purchase in 2007 along with 13 other power plants located across the U.S., all owned by Goldman Sachs through its Cogentrix subsidiary. The Company submitted a bid for the Lancaster plant, but that bid was rejected because Goldman Sachs wanted to sell all of the plants to a single purchaser. This left the power purchase agreement as the only viable option for obtaining the generation output from the Lancaster plant.

Q. Please discus the aspect of the Thorndike Landing study that identified market activity for similar types of plants.

A. The Thorndike Landing review of similarly-situated plants found seven comparable transactions that yielded an average value of $533/kW within the region. Approximately 25 comparable transactions were found throughout the rest of the U.S. with an average value of $465/kW. Therefore, the Lancaster value of $677/kW compares very favorably with these transactions.

Q. What was the final opinion of the Thorndike Landing study concerning the Lancaster PPA?

A. Thorndike Landing stated that they "found that the Toll provides positive value to Avista and its customers...and the value of the Lancaster facility appears consistent with – if not greater than – the value of other resources in the market." (See Exhibit No.__(RLS-5) at p. 1) Thorndike Landing also reviewed Avista's analytic process and valuation methodology and found the following:

> Thorndike Landing has reviewed Avista's analytical methodology and has found that Avista's analytical process and methodology is a very contemporary approach to analyzing resources. In fact, the utility industry in general has been slow, as compared to other industries, to adopt risk analysis into its process and it wasn't until the power and sector crises of 2001-02 that even some utilities began to incorporate risk into their processes. Today, we find that many utilities do factor risk analyses into their processes, but many still do not. Additionally, Avista's process is also grounded on sound resource planning using multiple scenarios and a robust vs. static process through which the company is able to assess multiple scenarios and resource portfolios, not just a single resource in isolation. For these reasons, we have found that Avista's analytical process is sound and even surpasses processes used by many of their peers across the industry. Therefore, we have not identified any area or aspect of its process generally for which we would suggest modification at this time. (See Exhibit No.__(RLS-5) at p. 15)

Thorndike Landing concluded as follows:

> In conclusion, Thorndike Landing believes that the transaction for the Toll is reasonable and that the value Avista would remit for the Toll is reasonable and would result in a net benefit to Avista and its customers. Further, based on our analysis and assumptions, the value of the Lancaster Facility appears to be greater than that of other recently constructed or transacted facilities in the region. The greater value appears to be primarily driven by one or more of the following:
>
> - Lower electric transmission costs
> - Lower gas transportation costs
> - Lower gas taxes (the state of Idaho has no fuel tax)
> - Dual sourcing of fuel (Alberta/Malin vs. Sumas). (See Exhibit No.__(RLS-5) at p.19)

Q. Is the Lancaster PPA a prudent acquisition?

A. Yes, the Lancaster acquisition is prudent. As shown in the internal and external studies covered in the preceding testimony, the Lancaster PPA is needed for utility service, it is cost-effective compared to other alternatives, and fits within the resource needs identified in the 2007 IRP.

Q. Can you summarize the studies that lead the Company to believe that the Lancaster PPA is a prudent decision?

A. Yes. Both the internal and external studies regarding the Lancaster PPA showed that the PPA was cost-effective when compared to similar base load resources and is needed for utility service based on the Company's load and resource position, and fits within the resource guidelines established in the 2007 IRP. The cost-effectiveness of the PPA included an analysis of the associated natural gas transportation and electric transmission agreements. Furthermore, the Lancaster PPA provides the Company with the ability to operate the plant in a flexible manner consistent with an owned-plant and the PPA stipulations provide protections against losses due to mechanical failures at the facility. A white paper that summarizes the Lancaster studies can be found in Exhibit No.__(RLS-6).

IV. HYDRO PROJECT UPGRADES

Q. Can you provide an overview of the capital improvements that were recently completed on the Noxon Rapids Project?

A. Yes. Reliability work was completed on Noxon Rapids Unit #5, the largest and most efficient unit at the project, which was installed in 1977. This reliability work began in September 2007 and was completed in 2008. The work was not expected to increase the unit's 92.0% efficiency rating or the 125 MW unit rating, but solved several reliability concerns. The costs associated with this work were approximately $9.2 million (system) and were included and approved in Docket No. UE-080416.

Q. Please describe the upgrade projects planned for the Noxon Rapids generating units starting in 2009.

A. The Company plans to upgrade the Noxon Rapids generating units #1 through #4 which are currently using 1950's era technology. The upgrades on these four units are expected to add an additional 30 MW of capacity and 6 aMW of energy to the Noxon Rapids project and improve reliability. One upgrade is planned for completion annually, starting in April 2009 and ending in 2012. Illustration No. 4, Noxon Rapids Upgrades, summarizes the timing and additional capacity and efficiency of these upgrades.

Illustration No. 4: Noxon Rapids Upgrades

Noxon Rapids Unit #	Schedule of Completion	Additional Capacity	Additional Efficiency
1	April 2009	7.5 MW	5.0%
3	April 2010	7.5 MW	7.8%
2	April 2011	7.5 MW	6.0%
4	April 2012	7.5 MW	4.7%

For Unit #1, we are replacing the stator core, rewinding the stator, installing a new turbine and performing a complete mechanical overhaul which is expected to be completed in April 2009. This upgrade is expected to increase the unit's efficiency 5.0% and increase the unit rating 7.5 MW. The upgrade will also solve several reliability concerns for the unit including mechanical vibration and the age of the stator.

The remaining upgrade work on Units #2, #3 and #4 are planned from 2009 to 2012. The Unit #3 upgrade is planned to increase unit efficiency 7.8% and boost the unit rating 7.5 MW. Unit #2 is scheduled to have a new turbine and complete mechanical overhaul between August 2010 and April 2011. This upgrade is planned to increase unit #2 efficiency 6.0% and boost the unit rating by 7.5 MW. The upgrade work at Unit #4 involves the installation of a new turbine and a complete mechanical overhaul from August 2011 through April 2012. The Unit #4 upgrade is planned to increase efficiency 4.7% and increase the unit rating by 7.5 MW.

The costs associated with Unit #1 are planned for completion in April 2009, totaling approximately $17.2 million (system), and Unit #3 is planned for completion in April 2010 at a cost of approximately $8.5 million (system), as further described in Company witness Mr. DeFelice's testimony. Company witness Ms. Andrews incorporates the Washington share of these costs in her adjustments. The costs for the remaining Noxon Rapids upgrades for units #2 and #4 have not been included in this case, but will be included in future rate proceedings.

V. HYDRO RELICENSING

Q. Would you please provide an update on work being done under the existing FERC operating license for the Company's Clark Fork River generation projects?

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on March 1, 2001. The Company has made significant progress working in collaboration with 27 signatories to the Clark Fork Settlement Agreement toward meeting the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program has resulted in the protection of approximately 2,500 acres of bull trout, wetlands, uplands, and riparian habitat. The fish passage program, using electrofishing and trapping with over 150 adults radio tagged and their movements studied, has reestablished bull trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet Gorge Dam. Avista has worked with the U.S. Fish and Wildlife Service to develop two experimental fish passage facilities. The testing of these facilities, however, has not produced a design that will attract adult bull trout. Nevertheless, studies will continue to seek solutions for developing a volitional fish passage facility.

Recreation facility improvements have been made to 30 sites along the reservoirs. Finally, tribal members continue to monitor known cultural and historic resources located within the project boundary to ensure that these sites are appropriately protected. The earlier costs associated with the PM&E measures were reviewed and were included in prior cases. Ms. Andrews has included a pro forma adjustment to reflect the planned PM&E expenditures for the 2010 pro forma period.

Q. Would you please provide an update on the current status of the Cabinet Gorge Bypass Tunnels Project?

A. Yes. Total dissolved gas levels occurring during spill periods at Cabinet Gorge Dam was an unresolved issue when the current Clark Fork license was received. The license provided time to study the actual biological impacts of dissolved gas and subsequent development of a dissolved gas mitigation plan. The studies documented no biological impact from dissolved gas below the project; however, the stakeholders ultimately concluded that dissolved gas levels should be mitigated, in accordance with federal and state law. A plan to reduce dissolved gas levels was developed with all stakeholders, including the Idaho Department of Environmental Quality. The original plan called for the modification of two existing diversion tunnels which could redirect streamflows exceeding turbine capacity away from the spillway.

The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass Tunnels Project indicated that the preferred tunnel configuration did not meet the performance, cost and schedule criteria established in the approved Gas Supersaturation Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The subcommittee is developing an addendum to the original GSCP and it is expected to be completed in the first quarter of 2009. Even though the final addendum has not been completed, the subcommittee has agreed that the tunnel bypass project did not meet expectations so an addendum to the GSCP with mitigation and other alternatives must be pursued. The cost of the original study was completed in 2008 and was included in the last Washington General Rate Case, Docket No. UE-080416.

Q. What is the status of expenditures related to compliance with the Clark Fork PM&E's?

A. Since implementation began, the Clark Fork Management Committee[1] (CFMC) and FERC have reviewed and approved all annual PM&E budgets. The CFMC has been very deliberate in their review and approval of annual budgets to assure that only quality projects directly tied to the CFSA are approved. In addition, during the last several years, unforeseen conditions such as severe rain and snow events, extended spring run-off sometimes resulting in flooding, and dramatic swings in fuel and materials costs have resulted in a number of previously approved projects eventually being postponed or eliminated. Those projects combined with the prudence review of the CFMC, have resulted in a larger then anticipated unexpended PM&E obligation currently estimated at $4.3 million. In anticipation of the need to reduce the unexpended obligation and to assure that the unexpended obligation does not continue to grow, Avista plans to expend, with CFMC approval, an additional $500,000 per year in O&M expenditures, starting in early 2010, for the 2010 – 2015 timeframe. Ms. Andrews has included a pro forma adjustment to reflect this increased spending level.

Q. Would you please give a brief update on the status of efforts to relicense the Spokane River Hydroelectric Projects?

A. Yes. The Company filed applications with FERC in July 2005 to relicense five of

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[1] The Clark Fork Management Committee is comprised of representatives from the 28 Agency, Tribal and Non-governmental signatories to the Clark Fork Settlement Agreement.

its six hydroelectric generation projects located on the Spokane River. The Spokane River Project, which is currently under a single FERC license, includes Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls. Little Falls, the Company's sixth project on the Spokane River, is not under FERC jurisdiction, but operates under separate Congressional authority. Our current license for the Spokane River Project expired in August 2007. The Company is currently operating under an annual license, but expects to receive a new 50-year license by July 2009.

The Spokane River Relicensing costs include actual life-to-date expenditures from April 2001 through the end of December 2008, and 2009 pro forma expenditures through June 30, 2009. As explained by Ms. Andrews, the majority of these charges were reviewed in the Company's previous general electric rate case proceeding, Docket No. UE-080416. Through the Settlement agreement approved by the Commission in that case, the Company was allowed to defer the amortization of these charges, including a carrying charge on the deferrals and unamortized balance, and include recovery of these costs in its next general rate case.

Q. Has there been a final resolution to the relicensing issues associated with the Coeur d'Alene Tribe?

A. Yes. A comprehensive agreement was signed with the Coeur d'Alene Tribe and the U.S. Department of the Interior. This agreement supports the issuance of a 50-year FERC license for the Post Falls hydroelectric project and the Spokane River hydroelectric projects. The comprehensive settlement provides for payment over the life of the license of over $150 million for environmental measures in and around Coeur d'Alene Lake and for compensation to the tribe, as well as rights-of-way for transmission lines over tribal lands and future storage payments connected with a new FERC license for the Post Falls dam. The settlement also includes provisions for Avista to make payments to the Tribe for past and future use of submerged Tribal lands and to satisfy the Company's obligation to mitigate the impacts of the Post Falls dam on the Tribes natural and cultural resources on its Reservation.

The proposed settlement between the Coeur d'Alene Tribe, Avista, and the U.S. Department of the Interior was explained in Avista's prior general rate case (Docket No. UE-080416). In the WUTC's Order No. 08 in Docket No. UE-080416, the Commission concluded, with regard to Avista's settlement with the tribe, that "Avista's actions were both reasonable and prudent" (Paragraph 76). The WUTC also concluded in Paragraph 78 that the provisions in the Multiparty Settlement Agreement providing recovery of the payments to the Tribe "are reasonable and supported by the record." Ms. Andrews has reflected the costs associated with the settlement in this case through a pro forma adjustment.

VI. GENERATION PLANT OPERATION & MAINTENANCE EXPENSES

Q. Is the Company experiencing increased expenditures associated with the operation and maintenance of its generation facilities?

A. Yes. The operation and maintenance expenses for Avista's generating facilities continue to increase. Ms. Andrews has included Washington's share of the 2010 pro forma period incremental non-labor costs above the test period of approximately $2.3 million (Washington share). These increases are mainly due to major O&M expenditures planned for Colstrip (completed 1984 – 1986), Kettle Falls (completed in 1983), and Rathdrum CT (completed in 1995). Increased costs at Colstrip include major overhauls of units # 4 and #3 in 2009 and 2010 respectively. Kettle Falls will be undergoing a turbine overhaul in 2009.

Rathdrum CT has a hot gas path maintenance scheduled for unit #1 in 2010 and painting of both units in 2011. These increases represent a new and higher level of O&M costs that are expected to continue given where each of the projects are in their respective life-cycles.

Q. In addition to the O&M expenses described above, are there other significant O&M expenses anticipated by the Company?

A. Yes. The Company and the owners of Colstrip Units #3 and #4 are required to mitigate the mercury emissions from these projects. Mercury emissions laws in Montana are going into effect January 1, 2010 with a second phase going into effect in 2018. Initial testing of mercury control technologies at Colstrip did not meet the targets set by the Montana Department of Environmental Quality, but further optimization of the mercury control systems is expected to meet the required emissions levels. Full mercury control operations are expected to begin by mid-2009 to provide enough time to fine tune the system with Colstrip plant operations.

The largest expense involved with the mercury control project will be a significant increase in O&M costs. The Company's share of the new O&M costs is expected to be approximately $3 million per year. The current capital budget for Colstrip is expected to be sufficient to meet the capital expenditures for this project. After some initial capital expenditures planned in 2009, the increase in O&M costs is expected to start in December 2009. Ms. Andrews has included the Washington share of the pro forma period expenses in her pro forma adjustments in this case.

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

A. Yes it does.