Exhibit No.__(DPV-1T)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-08___________

DOCKET NO. UG-08___________

DIRECT TESTIMONY OF

DENNIS P. VERMILLION

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Dennis P. Vermillion. 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. I received a Bachelor of Science degree in electrical engineering from Washington State University in 1985. I started working for Avista in 1985 and have held numerous postions in energy trading, marketing, risk management, power transmission contracting, resource planning and coordination and regulatory issues. I was appointed as President and Chief Operating Officer of Avista Energy in 2001. I was appointed Vice President of Energy Resources in 2007 at the close of the sale of Avista Energy.

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 which includes summaries of the Company's resources, current and future load and resource position, future resource plans, and a brief discussion of the Company's decision to join the Chicago Climate Exchange. The next section of my testimony discusses hydro project upgrades. This is followed by the Montana riverbed lease issue, hydro relicensing issues, mercury abatement at Colstrip, and Jackson Prairie storage. My testimony ends with a discussion of Avista's risk management policy.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit Nos.__DPV-2 (Avista's 2007 Electric Integrated Resource Plan), DPV-3 (Memorandum concerning Montana Riverbed Settlement), DPV-4 (Memorandum of Negotiated Settlement Terms), and DPV-5 (Avista's Risk Policy).

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 diverse portfolio of assets including 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 1,815 MW, of which 54% is hydroelectric and 46% is thermal.

Table 1 summarizes the present capability of Avista's owned generation resources. The Company also has long-term contractual rights for a total of 166 MW of capability from the Mid-Columbia generation projects in 2009 that are owned and operated by the Public Utility Districts of Grant, Chelan, and Douglas counties. The Company also has a ten-year contract for 35 MW of wind generation capability from the Stateline Wind Project. The Company receives 100 MW of energy from several contracts through 2010.

Table 1 – Avista Generation

Company-Owned Projects	MW
Noxon Rapids	541
Cabinet Gorge	261
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	15
Long Lake	90
Little Falls	36
Total Hydroelectric Generation	**986**
Colstrip Units 3 and 4	230
Coyote Springs 2	287
Kettle Falls	51
Total Base-Load Thermal Generation	**568**
Northeast CT	62
Kettle Falls CT	7
Boulder Park	25
Rathdrum CT	167
Total Natural Gas Peaking Generation	**261**
Total Generation	**1,815**

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 regularly studies capacity and energy resource needs. The Company utilizes short and medium-term wholesale transactions to balance resources with load requirements. Longer-term resource decisions requiring new resources, upgrading existing resources, demand-side management (DSM), and long-term contract purchases are generally made in conjunction with the Company's 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 is currently in a balanced-to-surplus energy position through 2017 on an average annual basis. This assumes the addition of Lancaster, which is a 245 MW gas-fired plant with an additional 30 MW of duct firing capability; this resource will be described in more detail later in my testimony. 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 increase from that time forward. The average annual energy resource deficiency beginning in 2018 is 8 aMW and increases to 515 aMW in 2028.

The Company's capacity resource position is surplus through 2018. Capacity deficiencies begin in 2019 at 67 MW and increase to 843 MW in 2028. Additional details concerning the load and resource positions are in Company witness Kalich's Exhibit No.___ (CGK-2).

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. Avista's 2007 Electric IRP is attached as Exhibit No.__ (DPV-2). The IRP provides details about the need for additional resources, 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 of 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, pursuant to Commission rules, although the Company does acquire some resources outside of formal RFP processes. The Company's Preferred Resource Strategy in the 2007 IRP includes a mix of 87 MW of DSM, upgrades to its existing plants, 350 MW of gas-fired CCCT, 300 MW of wind, and 35 MW other renewable generation (small co-generation, biomass and geothermal).

The Company has added a variety of resources to its portfolio in recent years, including: 100 aMW of medium-term purchases through 2010; the purchase of approximately 7 aMW of small hydroelectric generation from the City of Spokane; hydroelectric upgrades at Cabinet Gorge; approximately 3.5 aMW of efficiency improvements at Colstrip Unit #4; and a new purchase agreement signed with Grant County PUD for a continued share of the output from the Priest Rapids and Wanapum hydroelectric projects beginning in 2005.

The Company continues to evaluate and acquire various DSM measures. Avista has acquired approximately 96 aMW of DSM over the past eighteen years. This equates to 5.3% 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. We are also actively engaged in planning to acquire additional renewable resources to satisfy the Washington Clean Energy Initiative.

Q. Can you please provide an overview of the Chicago Climate Exchange and why the Company decided to become a member?

A. Yes, the Chicago Climate Exchange (CCX) is the only marketplace for integrating voluntary, verifiable and legally-binding emissions reductions with emissions trading and offsets for all six of the greenhouse gases (GHG). The CCX binds members to reducing their GHG emissions by six percent through 2010 based on a baseline level of emissions established by the rules of the CCX. Members must buy credits through the CCX if they are not able to meet their emissions reductions goals up to a maximum amount, or they may sell or bank credits up to a specified amount if they exceed their reduction goals.

Avista decided to join the CCX in order to gain experience and develop the internal infrastructure to trade GHG credits. The Company believes this skill will be necessary since we anticipate state or federal legislation regarding GHG emissions in the near future, as discussed in our 2007 Electric IRP. The CCX was also chosen because the Company anticipates that we will have credits to sell in this market. The exact number of credits through 2007 will be known after the baseline audit is completed in the first quarter of 2008. The decision of how or when to dispose of the excess credits has not been made at this time, but will be done after the audit has been completed and the official baseline and reduction goals have been established. The Company plans to pass the net proceeds of the sale of any credits on to customers.

III. HYDRO PROJECT UPGRADES

Q. Can you provide an overview of the repairs and capital improvements that are being done on the Noxon Rapids Project?

A. Yes. The Company plans to upgrade the Noxon Rapids generating units 1 through 4. 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 on these units. One upgrade is planned for completion each year, starting in March 2009 with completion of each of the upgrades by 2012. The following table summarizes these upgrades:

Table 2

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

For Unit #1, we plan to have the stator core replaced, rewind the stator, install a new turbine and have a complete mechanical overhaul beginning in July 2008 and ending in March 2009. This upgrade is expected to increase the unit's efficiency from 87.5% to 92.5% and the unit rating from 105 MW to 112.5 MW. The upgrade will also solve several reliability concerns for the unit including mechanical vibration, the age of the stator, and increase in partial discharge activity and the low efficiency of the unit. This upgrade will also help the Company reach its renewable energy goals under Washington State Initiative 937.

The remaining upgrade work on Units #2 through #4 is planned from 2009 to 2012. Unit #2 is scheduled to have a new turbine and complete mechanical overhaul between August 2009 and February 2010. This upgrade is planned to increase unit efficiency from 89.0% to 95.0% and boost the unit rating from 105 MW to 112.5 MW. The upgrade work at Unit #3 involves the installation of a new turbine and a complete mechanical overhaul from August 2010 through February 2011. This upgrade is planned to increase unit efficiency from 87.2% to 95.0% and boost the unit rating from 105 MW to 112.5 MW. The work planned for Unit #4 includes the installation of a new turbine and a complete mechanical overhaul from August 2011 through February 2012. This upgrade is planned to increase unit efficiency from 90.3% to 95.0% and boost the unit rating from 105 MW to 112.5 MW.

In addition to the upgrades described above, work is currently being done on Unit #5, the largest and most efficient unit at the project, which was installed in 1977. This reliability work began in September 2007 and is expected to be completed by April 2008. The work is not expected to increase the units 92.0% efficiency rating or the 125 MW unit rating, but is expected to solve several reliability concerns. The reliability concerns for Unit #5 include stator frame distortion, varying air gap, numerous forced outages, and the need to have a one-hour pre-warming of thrust bearings prior to the unit being started. The costs associated with this work is approximately $1.6 million (system) and has been included in this case as further described in Company witness Mr. DeFelice's testimony and Company witness Ms. Andrews includes the Washington share of these costs in her adjustments.

IV. MONTANA RIVERBED LEASE

Q. Can you provide background information on litigation surrounding the Montana riverbed lease?

A. Yes. The Montana riverbed lease involves payment for the use of the land that is located underneath the Clark Fork River Project located in the State of Montana. This includes the entire Noxon Rapids Project and the portion of the Cabinet Gorge Project that is within Montana borders, which includes most of the reservoir. The litigation began in October 2003 when residents of Bozeman, Montana, with children in the Montana public school system, filed a lawsuit against the owners of all privately-owned hydroelectric project owners in the state, including Avista, PPL Montana, LLC and PacifiCorp, seeking payment for the use and occupancy of School Trust Lands. This lawsuit was later joined by the school districts from Great Falls, Montana and the State of Montana in March of 2004. Although the matter was dismissed by the Federal District Court on jurisdictional grounds, a subsequent declaratory judgment was brought in the state court in November of 2004, in order to resolve the issue.

This action in state court involved extensive discovery and motion practice around a number of key issues surrounding navigability of the Clark Fork River and the proper measure of damages for any prior trespass since construction of the Noxon Rapids and Cabinet Gorge Projects in the early 1950's. Future ongoing damages were also sought. At time of trial, the State of Montana was prepared to assert damage claims that exceeded $200 million for prior damages and $8.4 million per year for future trespass. Exhibit___(DPV-3) is an overview of the litigation, that describes the nature of the claims and the basis for the settlement that was ultimately reached.

PacifiCorp was dismissed from the lawsuit in June 2006 after they entered into a voluntary settlement with the State of Montana. Avista was also dismissed from the lawsuit in October 2007 after entering into a voluntary settlement with the State. PPL Montana, LLC was the only hydroelectric owner in the lawsuit that elected to proceed to trial. The outcome of the lawsuit has not been decided at this time.

Q. What issues were decided by the court in advance of trial?

A. In September and October of 2007 the Montana District Court made several determinations as a matter of law in advance of trial: The Clark Fork River was deemed "navigable" for the express purposes of the establishment of the State's claim to title of the riverbed. The State owns the Clark Fork riverbeds and may therefore charge the hydroelectric owners for the use of the beds. The riverbed lands are School Trust Lands. There are no statutes of limitation or equitable defenses which would limit claims back to the time when the hydroelectric projects were constructed. Because the riverbeds were deemed to be School Trust Lands, there was an obligation to pay rents under the Montana Hydroelectric Resources Act. The water rights held by the hydroelectric owners do not preclude the State from seeking damages and rents. The State is not precluded from presenting evidence based upon the shared net benefits theory, taking into account the value of the generation produced by the facilities. Finally, the damage claims are not limited to the actual footprint of the dam itself; the claim may include the use of upstream State-owned riverbeds.

Accordingly, only the question of damages remained to be determined at trial, with the State seeking in excess of $200 million for prior trespass and $8.4 million per year for future rents.

Q. What are the details for the settlement agreement regarding the Montana riverbed lease issue?

A. A settlement was reached between Avista and the State of Montana in October 2007, on the eve of trial. It represented the culmination of several months of settlement discussions that enlisted the support of a mediator. On October 19, 2007, the Company reached a settlement with the State of Montana resolving this matter. (See Exhibit___DPV-4 "Memorandum of Negotiated Settlement Terms") Pursuant to this settlement, Avista has agreed to make lease payments in the initial amount of $4 million per year beginning February 1, 2008, for the calendar year 2007, and continuing through calendar year 2016, adjusted each year by the Consumer Price Index (CPI), with no payment for prior damages. The level of payments, the start date of payments, as well as other terms and conditions of settlement, were all integral to the resolution of these claims.

On or before June 30, 2016, Avista and the State of Montana will determine whether the annual lease payments remain consistent with the principles of law as applied to the facts and negotiate an adjusted lease payment for the remaining term of Avista's Federal Energy Regulatory Commission license for its hydroelectric facilities on the Clark Fork River, which expires in 2046. If Avista and the State of Montana do not agree in an adjusted lease payment, the parties will engage in advisory arbitration and submit the arbitrator's recommendations to the State Board of Land Commissioners ("Land Board") for approval. The settlement also contains provisions that could reduce the amount of Avista's lease payments as a result of future judicial determinations in related cases or governmental actions. As mentioned, Avista will not make any lease payments for the periods prior to 2007.

Q. Why did the Company settle the case instead of going to trial?

A. The Company decided to settle the case to avoid liability for retroactive rents and avoid a large potential judgment against it. The State of Montana was demanding over $200 million for past rents combined with ongoing lease payments of approximately $8.4 million per year. The settlement also stipulated that the Company could reduce the amount of future lease payments if future judicial determinants, court cases or governmental actions indicated that a lower lease amount was appropriate. Accordingly, the settlement avoids the potential costly litigation and exposure to very substantial claims by the State of Montana. The Noxon Rapids and Cabinet Gorge hydroelectric projects are the Company's lowest-cost resources and are integral to the Company's resource base. The Company continues to make every effort to preserve the generation from these projects for the benefit of its customers at the lowest possible cost. Ms. Andrews has included the Washington share of these costs in her pro forma adjustments.

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 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. 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 costs associated with the PM&E measures were reviewed in a prior case and are included in retail rates.

Total dissolved gas levels occurring during spill periods at Cabinet Gorge Dam was an unresolved issue when the new 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 plan originally called for modification of the first tunnel by 2010 at an estimated cost of $38 million. The second tunnel would only be constructed after a performance analysis and an evaluation of the environmental benefits of the first tunnel. The Company, with the support of engineering contractors, spent several years developing feasibility and cost studies to retrofit the first tunnel.

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

A. Yes. 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). Analysis of the predicted total dissolved gas (TDG) performance indicated that the tunnel would increase TDG by up to 18% rather than the 4% stipulated in the GSCP. The total estimated cost of the first tunnel was determined to be $58 million, which is an increase of $20 million over the original estimate. The schedule for completion of the first tunnel also slipped to March of 2012 instead of the 2010 date set by the GSCP. These findings led the Gas Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project is not viable to meet the GSCP. The subcommittee is currently amending the plan with alternatives to the original GSCP and the results are expected by the end of 2008. With the completion of the Bypass Tunnel analysis, the Company is proposing recovery of these costs of approximately $5.4 million in this case through rate base treatment of the costs over the remaining life of the Cabinet Gorge Project.

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 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 at this time, but expects to receive a new 50-year license by the end of 2008. Company Witness Howard provides detailed testimony about the entire Spokane River Hydroelectric Project relicensing process and costs associated with the relicensing effort and Ms. Andrews has included the pro forma costs in this case.

VI. MERCURY ABATEMENT AT COLSTRIP

Q. Please provide a summary of the mercury abatement project that is being done on Colstrip Units 3 and 4.

A. Mercury emissions laws are going into effect January 1, 2010 with a second phase going into effect in 2018. In order to comply with the new regulations, testing of two different mercury control technologies was initiated at Colstrip. The tests did not meet the targets set by the Montana Department of Environmental Quality, but optimization of the mercury control systems is expected to meet the required emissions levels. More testing is being done at this time and we expect to begin full mercury control operations by mid-2009 to ensure that there is 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 estimated to be sufficient to meet the capital expenditures for this project. This increase in O&M costs is expected in June 2009, therefore Ms. Andrews has included six months or $1.5 million of the annual expenditures in her pro forma adjustments in this case.

VII. JACKSON PRAIRIE STORAGE

Q. Can you please provide an overview of Avista's involvement with Jackson Prairie Storage?

A. Yes, the Jackson Prairie Storage Project is an underground reservoir project located near Chehalis, Washington. Avista was one of the three original developers of the storage facility at Jackson Prairie. Avista, Puget Sound Energy and Northwest Pipeline each own equal shares of this underground storage facility. Development began in the 1960's and the project first went into service in 1972. A number of expansions have been developed and Avista currently holds a total of 8,308,694 Dth of seasonal capacity and 294,667 Dth of daily withdrawal capacity.

Q. Is the Company participating in any other storage expansion projects?

A. Yes. In 2006, Avista and its partners started an expansion project at Jackson Prairie (FERC Certificate in CP06-412) for deliverability that will be in service in the Fall of 2008 and will result in Avista's daily deliverability increasing by 104,000 Dth.

Q. What analysis was done to support the deliverability expansion costs?

A. Avista's performed analysis on the Jackson Prairie deliverability expansion. This analysis compared the total expected costs of current infrastructure and supply compared to the total expected costs including the deliverability expansion. Results showed the Company's total costs were lower when including the deliverability expansion.

In addition to this review, the company also examined the potential for improved reliability of supply and peak pricing mitigation benefits.

Q. You mentioned improved reliability of supply, please explain.

A. The Company relies on monthly and longer-term seasonal and annual contracts for supply to satisfy its projected average daily demand. For daily swings in load, above and below average, the Company relies on a combination of storage and daily purchases and sales. In today's market virtually all physical short-term purchases are done at market hubs like Sumas/Huntingdon. While these purchases are generally reliable there is a risk of delivery failure. There are a number of reasons why delivery risk can be problematic. First, using the Sumas/Huntingdon Hub as an example, gas may change hands (trade) 3 or 4 times between parties. The failure of one party in the chain relying on interruptible transportation or a less than secure supply source can result in supply loss on any given day. A second reason is that it just takes one scheduling error in the supply chain to result in a supply loss. And third, actual physical problems like well freeze-offs or pipeline force majeure situations along the transportation path can also result in supply loss. Access to more storage deliverability provides the Company with more control and therefore more reliability of supply during these events.

Q. Please explain what you mean by peak pricing mitigation.

A. As with most local distribution companies in the Northwest, Avista's demand is extremely temperature sensitive. The result is that Avista is a "winter peaking" utility. During severe cold weather events in its service territory or cold events in large market centers on the eastern seaboard, natural gas prices may increase dramatically. To the extent that the Company can rely on storage withdrawals, the purchase of potentially higher priced spot gas may be avoided during these events.

Q. You mentioned potentially higher spot prices; can you identify the magnitude of these price deviations?

A. Yes, we performed a frequency analysis of Gas Daily pricing at Sumas/Huntingdon for the period from January 1, 2000 to date. This analysis showed that during this period the daily price exceeded $10.00 per Dth ninety-seven times and the average price for those occurrences was $13.77 per Dth. Approximately half of those occurrences exceeded $12 per Dth at an average price slightly over $17.00 per Dth.

Q. How does additional daily deliverability from storage benefit customers during these price deviations?

A. As mentioned above, these price deviations usually occur during periods of high demand. The ability to withdraw larger volumes of storage gas on any day allows the company to directly offset higher costs that others in the marketplace may be bearing.

Q. What other benefits accrue to customers through the company's participation in expansion projects that increase storage capacity and daily deliverability?

A. The larger deliverability allows the company to deliver gas to its service territory utilizing currently available transportation contracts for longer periods of time before reaching the decline curve of the project. The decline curve is simply the reduction of daily deliverability that occurs as gas is withdrawn and the pressure in the field declines. Jackson Prairie can currently provide 100% daily deliverability until 40% of the working capacity has been withdrawn. Then there is a gradual decline in deliverability until the pressure and resulting working gas in storage reaches contractual minimums.

Q. How will the new daily deliverability be split between Avista's service territories?

A. The Company has firm demand in Washington, Idaho and Oregon. The demand is split between Washington/Idaho and Oregon on a 75%/25% basis. This demand allocation was determined by using the estimated Oregon average load of approximately 9.360 million Dth in comparison to the estimated Company total average load of approximately 36.833 million Dth in the Company's 2007-2008 procurement Plan. The Company proposes to allocate this new deliverability based on that ratio.

Q. Is there any pipeline transportation capacity available to provide delivery of these storage volumes?

A. Yes, although no new capacity is available, existing transportation contracts from Sumas can be used to redeliver storage volumes. The Company will avoid a portion of winter purchases and utilize storage as a substitute for this supply. Therefore, the same transportation contracts that are currently utilized for physical supply purchases will be used for the delivery of storage gas.

Q. Is the Company requesting specific rate relief or accounting treatment at this time to cover the cost of the Jackson Prairie Storage deliverability expansion project?

A. Yes. The Company has included Washington's share of the JP deliverability expansion project cost. The deliverability expansion will be completed in the Fall of 2008. At that time, the benefits associated with this additional Jackson Prairie deliverability will begin accruing to customers via the PGA mechanism. Ms Andrews includes the JP expansion costs in her pro forma adjustments in this case.

Q. Has the company discussed the proposed allocation of this new Jackson Prairie capacity, and associated costs, with Commission Staff?

A. Yes. The Company has had discussions with the Commission Staff and they have indicated initial support for the Company's proposal as described above.

VIII. AVISTA'S RISK MANAGEMENT POLICY

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 the risks associated with serving load and managing Company resources. The Company's risk management approach uses price diversification by forcing 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 (more than 18 months), short (monthly and quarterly periods out to 18 months), and immediate terms (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 Risk Policy addresses the types of risks that are covered, power and natural gas supply positions, authorized transactions, resource optimization, reports, credit and contracts, information systems, confirmation and settlement, and employee conduct. There are also five exhibits covering authorized products, the electric hedging plan, the natural gas hedging plan, roles and responsibilities, and transaction authority levels. Exhibit No.__(DPV-5) is a copy of the Avista Utilities Energy Resources Risk Policy.

Q. What types of risks are addressed in the Risk Policy?

A. The Risk Policy defines several different types of risk and how they are addressed by the Risk Policy. Exhibit No.__(DPV-5) provides specific details concerning each of these risks. The Risk Policy does not supersede the responsibilities of other areas of the Company that are responsible for other risk management issues, such as Treasury, State and Federal Regulation, and corporate Information Systems. The most relevant types of defined risks addressed in the Policy are the mitigation of market risks and the description and assignment of roles and responsibilities in internal operations risks.

Q. What is the power supply position and how does it fit into the Risk Policy?

A. The power supply position is the difference between electric resources and requirements. Surplus positions occur when resources exceed requirements and deficits occur when requirements exceed resources. Power supply position considers all of the variables that affect short term power supply. The dynamic nature of the power supply position is actively managed "by establishing control processes for load and obligation estimation, resource estimation, and management of the expected net surplus or deficit position." All of these areas are under my responsibility as the Vice President of Energy Resources. The same types of position issues are also addressed in regards to natural gas supplies. Any changes to practices are communicated to the Risk Management Committee.

Electric loads and obligations are estimated based upon an analysis of historic loads, adjusting for weather variability, expected additions or decreases in large customer loads, all known wholesale contract obligations, and adjustments as necessary based on analysis of prior estimating accuracy and other factors. Electric resources are estimated based on expected output after consideration for variability in conditions such as streamflow, forced outages, maintenance, and environmental concerns.

Electric surplus and deficit positions are hedged using the electric hedging plan as a guide which can be deviated from based on management judgment of each surplus or deficit situation.

All changes to the Short Term electric position are reported every business day in an electric position report.

Q. Please describe the current electric hedging plan.

A. The electric hedging plan, detailed in Exhibit 2 of the Risk Policy (Exhibit No.__(DPV-5)), relies heavily upon the Hedge Scheduler. The Hedge Scheduler is the analytical tool that the Company utilizes to guide hedging positions over the next 14 to 18 months. The tool manages open positions of 25 aMW of generation. Open positions that are greater than 25 aMW are cured with electric commodity transactions or fuel transactions. Price control limits and time periods are employed to trigger purchases or sales to cure open positions. The curing transaction occurs whenever a price control limit is exceeded or the cure period expiration date is crossed. The Hedge Scheduler does not make the final decisions, but is an important tool that is utilized to aid in management discretion in the Company's electric hedging plan.

Q. How are transactions authorized in the Risk Policy?

A. The Risk Policy establishes parameters for different types of transactions. These parameters specify individuals and positions along with the types and lengths of transactions they are authorized to carry out. The details of transaction authorizations are provided in Exhibit 1 of the Risk Policy (Exhibit No.__(DPV-5)).

Q. Are other topics covered in the Risk Policy?

A. Yes. Besides subjects that are specifically related to non-fuel gas resources, there are a variety of areas that are covered under the Risk Policy. These areas include reports, credit terms, counterparty contracts, information systems, confirmation and settlement, employee conduct, and risk policy updates. Additional details about these areas are contained in Exhibit No.__(DPV-5).

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

A. Yes it does.