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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

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. 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.

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Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 4, Schedules 1 through 5. Schedule 1 is Avista's 2007 Electric Integrated Resource Plan, Schedule 2 is a map and picture of the Lancaster Generation Facility, Schedule 3 is the Lancaster Generating Facility Power Purchase Agreement Evaluation Overview, Schedule 4 is the Independent Valuation of the Lancaster Facility Tolling Agreement, and Schedule 5 is the 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.

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

Table 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 Kalich's Exhibit No. 5, Schedule 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, which is attached as Exhibit No. 4, Schedule 1. 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. 4, Schedule 2 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.

Although we are providing documentation regarding the decision-making related to Lancaster in this filing, we are not proposing that the revenues and expenses be reflected in retail rates in this filing. Lancaster will become a utility resource on January 1, 2010, and this case will be concluded prior to that time. It is unlikely, however, that Avista's next general rate case will be concluded on or before January 1, 2010. As Mr. Johnson explains in his testimony, we are proposing that the Lancaster revenues and expenses, beginning January 1, 2010, be included in the PCA until they can be reflected in base retail rates.

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 4, Schedule 3. 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 4, Schedule 4. 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. Table 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.

Table 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. Table 3 summarizes the results of this aspect of the study.

Table 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, all owned by Goldman Sachs through its Cogentrix subsidiary, located across the U.S. in 2007. 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 4, Schedule 4 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 4, Schedule 4 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 ourt 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 4, Schedule 4, 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 4, Schedule 5.

IV. HYDRO AND THERMAL 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 Case No. AVU-E-08-01.

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. Table No. 4, Noxon Rapids Upgrades, summarizes the timing and additional capacity and efficiency of these upgrades.

Table 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), is further described in Company witness Mr. DeFelice's testimony. Company witness Ms. Andrews incorporates the Idaho share of these costs in her adjustments. The costs for the remaining Noxon Rapids upgrades for units #3, #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 2009/2010 proforma 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 included in the last Idaho General Rate Case, No. AVU-E-08-01.

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

[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.

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 proforma 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 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 Company witness Ms. Andrews, the majority of these charges were reviewed in the

Company's previous general electric rate case proceeding, Case No. AVU-E-08-01. 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 (Case No. AVU-E-08-01). 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 Idaho's share of the 2009-2010 proforma period incremental non-labor costs above the test period of approximately $899,000 (Idaho 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 estimated 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 Idaho 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.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-09-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-09-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 4
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	RICHARD L. STORRO
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At

http://www.avistautilities.com/inside/resources/irp/electric/Pages/default.aspx

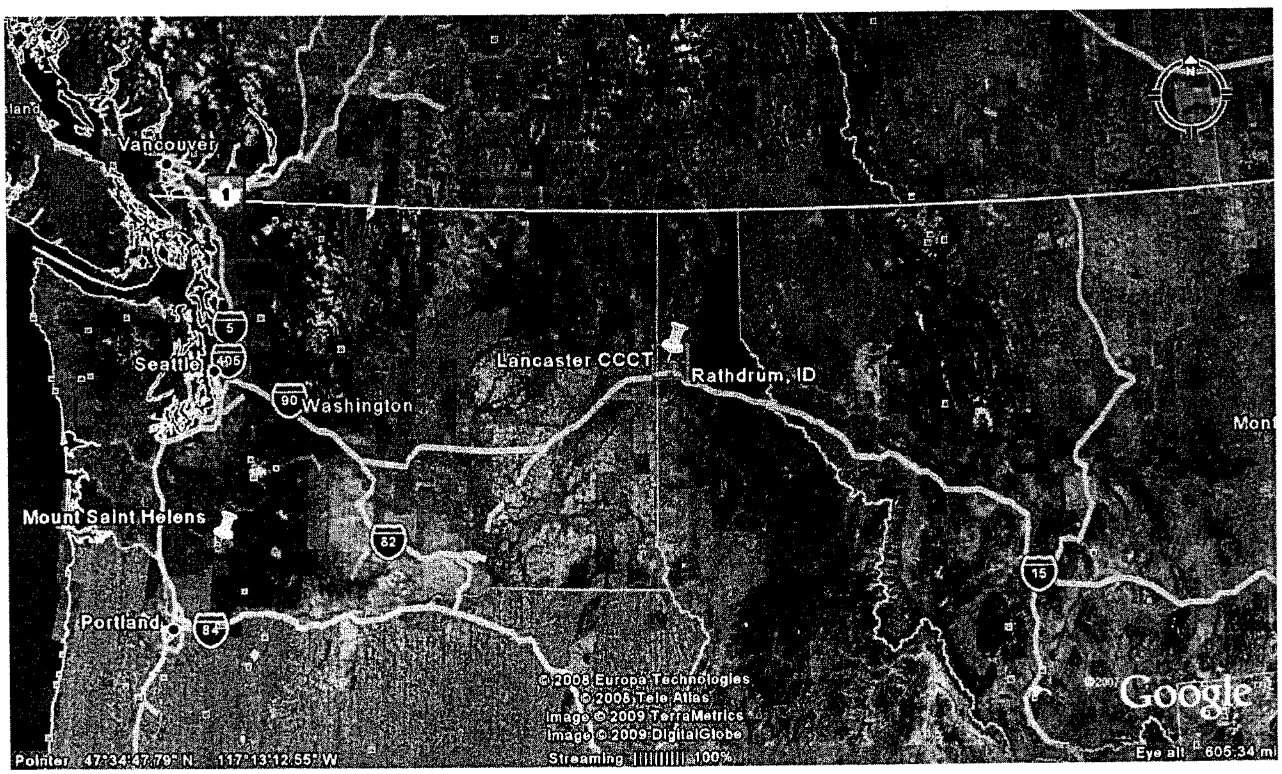

Exhibit No.4
Case No. AVU-E-09-01
R. Storro, Avista
Schedule 2, p. 1 of 2

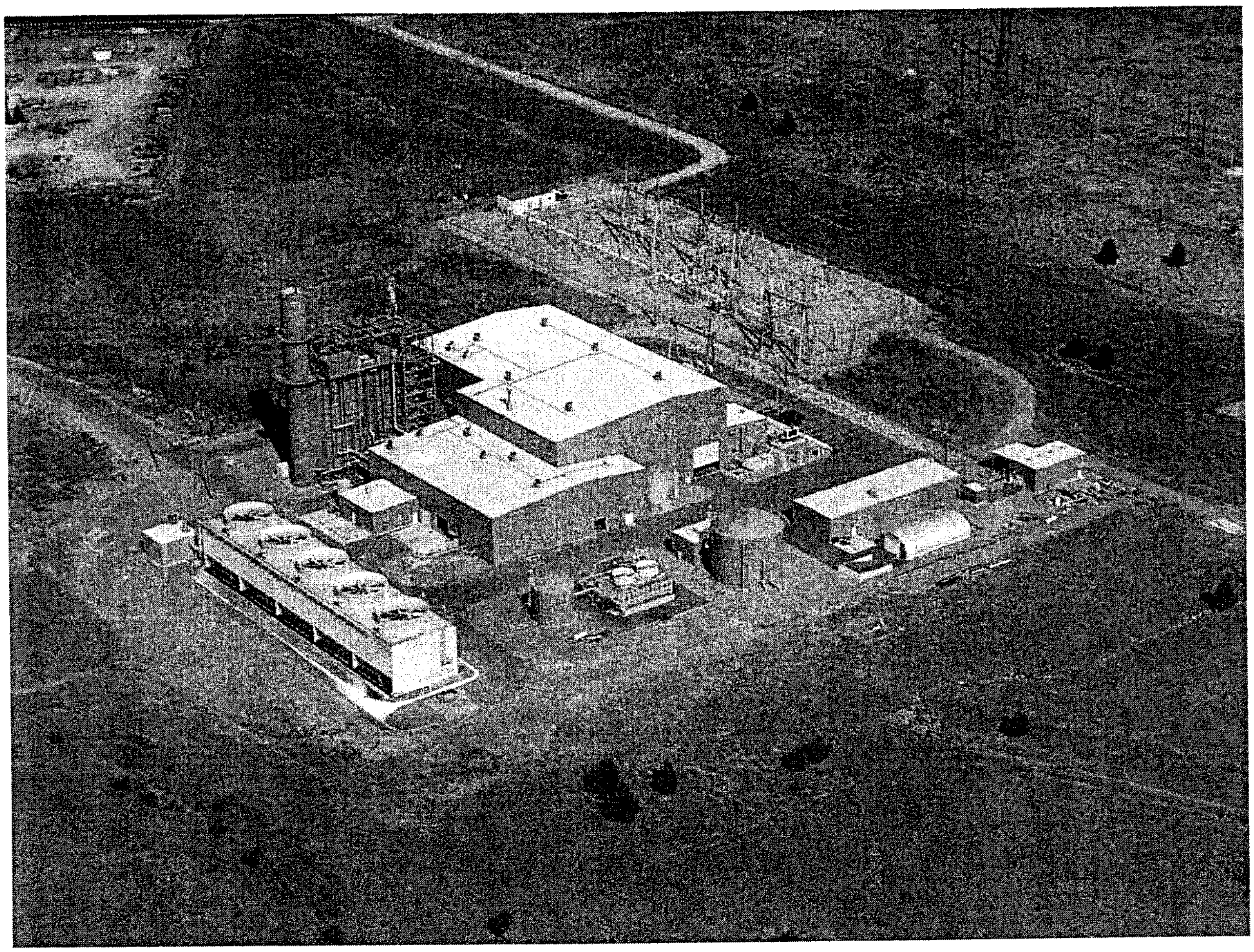

Exhibit No.4
Case No. AVU-E-09-01
R. Storro, Avista
Schedule 2, p. 2 of 2

Lancaster Generating Facility Power Purchase Agreement Evaluation Overview

April 11, 2007

Introduction & Summary

In early 2007 Energy Resources was asked to determine if Avista utilities would benefit from acquisition of the 275 MW Lancaster Generating Facility Power Purchase Agreement ("Power Purchase Agreement" or "Lancaster") then owned by Avista Energy.

The plant is an option to the utility as part of Avista Corporation's proposed sale of Avista Energy to Coral Energy. The Power Purchase Agreement is essentially a "tolling arrangement" whereby the Lessee delivers natural gas to the plant and receives the capacity and energy output in exchange for paying the Lessor fixed and variable Power Purchase Agreement payments. The Power Purchase Agreement expires on October 31, 2026.

Analyses based on the Avista IRP and Northwest Power and Conservation Council's ("NPCC") planning assumptions indicate that the acquisition of an existing gas-fired combined-cycle turbine (CCCT) is potentially more valuable than the construction of a new gas-fired plant. Avista's 2007 Draft IRP had identified a CCCT as a preferred resource. The analysis further shows that the Power Purchase Agreement will benefit Avista when compared both to new and other existing CCCT plants that were recently transacted or constructed in the Pacific Northwest region.

Assumptions

Assumptions in a number of different areas are necessary to complete the Lancaster Power Purchase Agreement comparison, including alternative resources the company might consider, natural gas supply, taxes and transportation, electricity transmission, plant operating and maintenance costs, end-of-life plant values, and rates for inflation and discounting. Because the comparative resources are all newer-vintage natural gas-fired CCCTs with similar heat rate and operating costs, natural gas supply and transportation costs and operation costs were assumed to be the same for each plant; therefore, these costs were not explicitly modeled in the comparative evaluation. One benefit not modeled is the fact that the Power Purchase Agreement places some of the risk of forced outages and maintenance on the Lessor, removing some of this risk from Avista and its customers.

A brief discussion of the modeling assumptions is provided below.

Power Purchase Agreement Alternatives

Avista's 2007 IRP process provides guidance on the resources available to serve customer needs. The IRP process shows that the Company needs up to 350 MW of gas-fired generation along with other renewable generation technologies and conservation.

Given the significant component of gas-fired CCCT resources in the 2007 IRP, the Power Purchase Agreement evaluation focuses on comparisons with other potentially available CCCT options. The 2007 IRP estimates new, or "greenfield", CCCT plant costs at $786/kW in 2007 dollars, or approximately $850/kW in inflation-adjusted 2010 dollars. This later figure is used to represent the cost of a new plant for the analysis.

The Power Purchase Agreement is also compared to an estimated cost of an existing, or "brownfield", CCCT plant in the Northwest. Table 1 is a list of Northwest CCCT plants. Plants not owned by regional utilities are highlighted.

Table 1 – Northwest CCCT Plants

Name	*Utility*	*Owner*	*Capacity (MW)*
Coyote Springs 2	Avista	Utility	287
Frederickson	Puget	Utility	256
Big Hanaford	TransAlta	Non-Utility	322
River Road 1	Clark PUD	Utility	248
Hermiston Power Project	Calpine	Non-Utility	648
Coyote Springs 1	PGE	Utility	246
Goldendale Energy Center	Puget	Utility	240
Port Westward Power Plant	PGE	Utility	400
Rathdrum Power Project	Cogentrix	Non-Utility	276
Chehalis Generation Facility	Tractebel	Non-Utility	550
Hermiston Cogen 1	PacifiCorp	Utility	486
Klamath Cogeneration	City of Klamath Falls	Non-Utility	150
Encogen 1	Puget	Utility	170
Total Non-Utility (MW)			**1,946**

As shown, total non-utility CCCT plant capacity is under 2,000 MW, including the Lancaster Generation Facility. Besides Lancaster, only 4 plants are not owned by a utility today. To Avista's knowledge, none of the plants are for sale. Two are larger than the amounts recommended by the IRP process.

Acquiring another brownfield CCCT plant is therefore considered unlikely; however, Avista chose to compare the Power Purchase Agreement economics as if brownfield options were available to it. The following table provides a summary of recently-completed CCCT transactions. The "2010 Price" escalates each transaction for inflation to 2010 dollars assuming 3% annual inflation.

Table 2 – Recent Pacific Northwest CCCT Plant Sales ($/kW)

Plant Name	Buyer	Purchase Year	Purchase Price	2010 Price
Frederickson	Puget Sound Energy	2003	590	726
Coyote Springs 2	Avista	2004	446	533
Goldendale	Puget Sound Energy	2007	480	525

Given the 2010 price range in Table 2, the company selected for this analysis two cost estimates for brownfield sites: $550/kW and $500/kW.

Electric Transportation (Transmission)

The Lancaster Generation Facility is located in Avista's Northern Idaho service territory. It presently is interconnected into the Bonneville Power Administration ("BPA") control area. Avista plans to explore the option to directly interconnect the Lancaster plant to its transmission system to avoid most of the BPA firm transmission costs. The interconnection cost is estimated at $3 million.

Along with the Power Purchase Agreement the company will receive a long-term firm transmission path from the Lancaster point of receipt to John Day. Under the assumption that Avista will be able to interconnect Lancaster directly to its transmission system, it will not require the BPA transmission during most of the year. The BPA transmission can therefore be used to better optimize Avista's resource operations or be sold to 3rd parties wanting to move energy across the "West of Hatwai" constrained path. The analysis assumes that only 25% of the existing firm transmission contract cost is not recovered through re-marketing of the BPA transmission or otherwise optimized through other power transactions.

Greenfield and brownfield plants are assumed to require a transmission contract with the Bonneville Power Administration for their entire operating capacity, as such a path would be necessary to move electrical energy from their respective locations to Avista's service territory.

In the event Avista does not interconnect the Lancaster plant directly to its system, it would not incur the $3 million interconnection cost but would directly utilize BPA transmission. In a worst case scenario where none of the BPA transmission was re-marketed or otherwise optimized, the cost of the Power Purchase Agreement would rise by approximately $66 million on a present value basis. However, since Lancaster is a dispatchable plant, it is reasonable to assume that at least a portion of the BPA transmission costs could be recovered. A 25% cost recovery is a reasonable assumption and represents a cost of approximately $42 million on a present value basis.

Power Purchase Agreement and Capital Recovery Payments

The Power Purchase Agreement includes a known set of payments. Brownfield and Greenfield options would be owned by Avista and capital recovery would occur over a defined schedule. The analysis uses the 2007 IRP capital recovery factors applied to all owned plant options.

Ending Value

The Lancaster Generation Facility Power Purchase Agreement expires on October 31, 2026. Avista will retain no value from the plant after expiration. To level the playing field with ownership options where residual, or ending, value would apply; all ownership option comparisons (i.e., all except the Lancaster plant) assume an ending value. For brownfield comparisons, the ending value is 10% of what a new plant would cost in 2027, in line with industry estimates. A greenfield plant ownership option would have a longer life due to its being constructed as much as ten years later than the brownfield and Lancaster plants. The greenfield residual value equals the brownfield ending value *and* the present value of forecasted wholesale market values through the end of its 30-year economic life after 2026.

Scenarios

It is unclear at this time when the Lancaster plant will be made available to Avista. There is also uncertainty over when the company will be resource deficit because of changing load forecasts.

Avista Loads and Resources Deficiency

The value of a new resource depends on the utility's loads and resources balance. Where the company is long–i.e., resources exceed loads–the value is what can be generated through sales into the wholesale marketplace. When the company is short–i.e., loads exceed resources–it is reasonable to include not only the market value of energy, but also the capital recovery and other fixed costs associated with plant ownership. Both of these assumptions are consistent with the IRP methodology.

The analysis considers two starting deficiency dates: 2011 based on work performed in the 2007 IRP, and immediate based on regional work by the Northwest Power and Conservation Council (NPCC). The first load deficiency identified in the 2007 IRP process is in 2011. Loads, including a planning margin equal to 10% of peak day load and 90 MW for reduced resource capabilities due to river freeze ups and coal handling issues, are compared to expected peak-day resource capability. The planning margin approximates 15%.

The NPCC is leading an effort to better define the peak generating capability of the Northwest. The NPCC planning criteria, based on a cross-functional work effort including many Northwest utilities, is approximately 25% based on a 5% loss-of-load probability across the entire northwest electric system and loads. Though the criterion is not yet finalized, the reserve level has remained approximately the same throughout the work effort. To meet the NPCC target, each Northwest utility would need to own or control resources capable of generating at levels 25% greater than their expected peak load. Under this criterion, Avista is capacity deficient immediately.

Power Purchase Agreement Availability Date

Because Power Purchase Agreement negotiations with Coral Energy are ongoing, the company chose to evaluate the Power Purchase Agreement across three start dates: 2009, 2010, and 2011. In the greenfield and brownfield evaluations, the plants are assumed to begin in the actual year of resource deficiency where the Power Purchase Agreement begins on the start date irrespective of the load and resources balance. For example, in the scenario where the Power Purchase Agreement is transferred to Avista in 2009 and the IRP methodology identifies a 2011 deficit, Power Purchase Agreement costs and benefits begin in 2009. Brownfield and greenfield plants, however, are not brought into the mix until 2011. Because the analysis assumes that the sum of the fixed and variable costs of the Power Purchase Agreement exceed the value of power in the spot market, the early inclusion of the Power Purchase Agreement prior to the deficit year decreases its value relative to other options.

Results

The following summarizes the results of the analysis shown in Appendix 1 – Study Results:

- The Lancaster Power Purchase Agreement is lower cost than the greenfield plant being included in the Preferred Resource Strategy of the 2007 IRP. A greenfield project is the company's most realistic alternative to Lancaster for acquisition of a CCCT resource.
- The Lancaster Power Purchase Agreement is less expensive than either brownfield or greenfield plants under all cases where Avista carries reserve margins in line with the NPCC reserve requirements.
- The only scenarios where a brownfield CCCT was shown be more beneficial than the Lancaster Power Purchase Agreement was where the plant was transferred to Avista prior to 2010, or where such brownfield plant's purchase cost is below $550/kW.
- Transmission scenarios, where less than 75% of the BPA firm transmission cost might be recovered in the market, have the effect on reducing the positive values shown in Table 3. As stated earlier, the maximum impact is estimated to be approximately $66 million if none of

the BPA transmission is re-marketed or otherwise optimized. Because Lancaster is a dispatchable CCCT, it is reasonable to expect that some level of cost recovery, possibly up to 25%, will be achievable even in the case where the project is not interconnected to the Avista system and remains on the BPA transmission system. A 25% transmission cost recovery scenario adds approximately $42 million to the Power Purchase Agreement value (cost of Power Purchase Agreement). A greenfield plant continues to be more costly than the Lancaster Power Purchase Agreement in each of the three start date scenarios under this transmission circumstance.

In summary, the study found that in most scenarios the Power Purchase Agreement will have a positive value to customers. In all base cases the Lancaster Power Purchase Agreement provides a significant benefit relative to constructing a new greenfield plant. The 2010 start date showed a positive benefit to the Lancaster Power Purchase Agreement except in the case where Avista were to have an opportunity to acquire a brownfield plant at a cost below $550 per kilowatt. The Company is not aware of such a brownfield opportunity available in the marketplace at this time.

Table 3 – Study Results

Option	Alternative Start Dates of Avista Resource Deficiencies and Lancaster Plant Availability					
	IRP Reserves (~15%) – 2011 Deficit			NPCC Reserves (25%) – 2009 Deficit		
	2009-2026 ($millions)	2010-2026 ($millions)	2011-2026 ($millions)	2009-2026 ($millions)	2010-2026 ($millions)	2011-2026 ($millions)
Lancaster Lease Value						
Cost of Lease	275	271	266	275	271	266
Lease Alternatives						
Greenfield CCCT @ $850/kW	320	332	337	358	348	337
Brownfield CCCT @ $550/kW	267	275	286	308	293	286
Brownfield CCCT @ $500/kW	254	261	271	291	277	271
Lease Savings Versus						
Greenfield Savings	46	62	72	83	78	72
Brownfield Savings @ $550/kW	(8)	4	21	34	22	21
Brownfield Savings @ $500/kW	(21)	(10)	5	16	6	5

Assumptions:

1) greenfield CCCT assumption based on 2007 IRP/NPCC.
2) transmission for off-site CCCTs @ $2.25/kW-mo plus 1.9%; leased CCCT is 25% of off-site.
3) residual values for non-lease CCCTs assumed to be 10% of installed cost @ end of life, plus net value against market for remainder of "economic life" from 2007 IRP. For greenfield, residual value is ~$220 million; for brownfield the residual value is ~$36 million. The difference being attributed to 10 years of additional life for the greenfield project.
4) greenfield plants assume 30-year recovery and depreciation; brownfield 20 years.
5) general escalation assumptions of 3% per year.
6) nominal discount rate of 7.41% (WA after tax rate)
7) values prior to resource deficiency use market value from 2007 IRP runs; after deficiency, fully allocated cost of new plant.

Independent Valuation of Lancaster Facility Tolling Agreement

October 30, 2007

Thorndike Landing, LLC

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Executive Summary

Thorndike Landing, LLC ("Thorndike Landing") was retained by Avista Corporation ("Avista") to perform an independent valuation of the tolling arrangement ("Toll") associated with the Lancaster generating facility, a 262 MW gas-fired combined cycle plant ("Facility") currently owned by a third party. The Toll will become available to the portfolio of Avista's regulated utility, Avista Utilities, Inc. as of January 1, 2010,

For this effort, Thorndike Landing looked at several different valuation metrics and perspectives to derive the valuation for the transaction contemplated by Avista. First, we performed a discounted cash flow ("DCF") analysis to determine the value of the Toll from the perspective of the Lessee under the terms of the Toll and taking into consideration all of the key factors for that agreement. Second, we performed a valuation of the Facility under a purchase scenario. For this valuation, we used the DCF method to value the Facility as of the valuation date (as more fully described herein) from the perspective of the owner without the Toll (i.e., assuming merchant operations). The approach and assumptions for this valuation were consistent with that used in valuing the Toll, except for factors that were clearly not applicable for a plant valuation versus a toll valuation (e.g., the useful life period was assumed to be 35 years versus the term of the Toll, the tolling payments were excluded, etc.).

The next valuation metric we employed was to identify a few select assets in the market and perform valuations of those similarly-situated plants. For this effort, Thorndike Landing performed valuations of the Goldendale facility as purchased by Puget Sound Energy earlier this year, the Coyote Springs 2 plant as currently owned by Avista Utilities and the Port Westward facility as being developed by Portland General. We also employed the DCF method to value these comparable facilities. As a final valuation reference check, Thorndike Landing reviewed transaction market activity to identify similar assets that have transacted and to assess the value of these assets and whether they were comparable to the contemplated transaction for the Toll. We recognize that this transaction – a toll versus an asset transaction – is fundamentally different than these comparables but these comparables served as an additional reference for market value.

Based on these four differing, yet complimentary, valuation perspectives Thorndike Landing has found that the Toll provides positive value to Avista and its customers (see Results and Conclusions section) and the value of the Lancaster facility appears consistent with—if not greater than—the value of other resources in that market.

Thorndike Landing also performed a review of Avista's analytical process and methodology to identify any potential shortcomings or areas that may be improved to provide it with a better, more comprehensive analytical process. Based on this review, we have found that Avista's analytical process and methodology is a very contemporary approach to analyzing resources. We have found that Avista's analytical process is sound and even surpasses processes used by many of their peers across the industry.

As part of this review, Thorndike Landing also reviewed Avista's analysis of the Toll to ensure both the methodology was appropriate and that the quality of the analytics was reasonable. We identified two areas in the Toll-specific analysis that warranted attention, but found neither of concern or to have a material impact on the overall results.

Objective and Purpose

Thorndike Landing was retained by Avista to perform an independent valuation of the Toll associated with the Lancaster generating facility currently owned by a third party. Avista has the opportunity to add this toll to the portfolio of its regulated utility. Avista Utilities has performed its own valuation of the Toll. The determination of this independent valuation performed by Thorndike Landing, as set forth in this report, will be relied upon by Avista in connection with its efforts to add the Toll to its regulated portfolio.

Thorndike Landing has performed several tasks to aid in determining the value of the Toll to Avista and its customers. First, we have reviewed information and data provided to us by Avista regarding the Facility, its financial parameters, its operations, and the Toll itself. Next, we have used the DCF approach to assess the value of the Toll and we have also performed a valuation of the Facility itself for comparison purposes. Next, we have identified transaction values for other generating assets that have sold in this market to establish a set of market comparables and their values for comparison purposes. Lastly, we have taken this comparables assessment further than is customarily done in these situations and have performed valuations of relevant generating assets that have been constructed or have transacted recently in this market. Next, we reviewed Avista's analytical approach to determine if there were any deficiencies and any areas that could be improved. Lastly, we prepared this report describing the salient assumptions used, our approach and our findings regarding whether the Toll is of sufficient value to Avista and its customers to warrant being included in its regulated generating portfolio.

For this effort, Avista has provided Thorndike Landing with specific instructions regarding this effort: (a) we are to use the analytical methods currently and customarily used in the market for valuation purposes; (b) we are to value the Toll as an independent, third-party would value it; (c) we are to remain independent at all times and are to use our best judgment regarding assumptions to be used; and (d) when reviewing their analytical process we are to remain independent and are to offer all constructive feedback with the goal of improving this process in every way possible.

The remainder of this report describes the approach Thorndike Landing has used in determining the value of the Toll, the salient assumptions used, our assessment of Avista's analytical process and our results and conclusions.

Description of Facility and Tolling Agreement

The Facility is a 262 MW, gas fired combined cycle generation facility located on a 15-acre site approximately 2.5 miles from Rathdrum, Idaho.

Table 1: Facility Characteristics

Category	Description
Location	Rathdrum, ID
Capacity	262 megawatts
Primary fuel	Gas
In-service date	September 2001
Turbine manufacturer, type	GE 7FA
Employees	20
Average net heat rate (2006)	6,925 btu/kWh
Average equivalent availability (2006)	92.9%

Power offtake was originally contracted to Avista Energy under a long-term tolling agreement (the "Toll"). On July 1, 2007 the Toll was assigned to an unrelated third party ("Seller" or "Lessor"). The Toll will become available to Avista Utilities, Inc. as of January 1, 2010, or the "Valuation Date" for purposes of our analysis.

Under the terms of the Toll, Avista Utilities ("Purchaser" or "Lessee") would have call rights to energy and capacity from the Facility over the term of the agreement. As consideration for those rights, Avista would pay the Seller a capacity charge and an energy charge as described in more detail below. Avista would also remain responsible for gas supply, as well as electric transmission. Specific key terms of the tolling agreement include the following:

- Term: For purposes of our analysis, the starting date will be January 1, 2010. The Toll expires on October 31, 2026.
- Capacity:
  - Includes both "standard" capacity (baseload) and "supplemental" capacity (duct-fired)
- Payments:
  - Capacity payment comprised of a capital charge and an O&M charge
    - Capital charge: $4.352/kW-month in 1998 dollars, escalated at 1% per year

        - Operations and Maintenance (O&M) payment: $1.302/kW-month in 1998 dollars, escalated with a specified annual inflation measure thereafter
    - Energy charge: $1.463 per MWh in 1998 dollars, escalated with a specified annual inflation measure thereafter
    - Start payment: $6,000 per start for starts greater than 100 in a contract year.
- Other key terms:
    - Availability: Seller has a 97% availability target. Capacity payments related to periods with realized availability less than 97% are reduced on a pro rata basis.
    - Guaranteed heat rate was specified

The facility continues to be managed under an O&M agreement with a third party. This agreement is effective through September 2026.

Electric transmission service is available through an agreement with Bonneville Power Administration ("BPA"). Key terms of this agreement are as follows:

- Term: July 1, 2001 through June 30, 2026
- Point of delivery: John Day
- Pricing is consistent with that under the published BPA tariff
- Transmission rights under the BPA agreement will transfer to Avista Utilities January 1, 2010

Thorndike Landing Approach

This section of the report describes the analytical methods used to perform the various valuations and assessments conducted for this effort. The results of these analyses are presented in the Results and Conclusions section of this report.

For this effort, we looked at several different perspectives to derive a valuation for the transaction contemplated by Avista. First, we performed a valuation of the Toll, taking into consideration all of the key factors for that agreement. Second, we performed a valuation of the Facility under a purchase scenario. Next, we identified comparable assets in the Northwest market and performed valuations of those to get a sense as to what the values of those assets are. Lastly, we reviewed comparable transactions in the generation market and assessed the average values of those deals in the most appropriate market.

Valuation of the Toll

In order to value the Toll, Thorndike Landing developed a discounted cash flow ("DCF") analysis of the Lancaster facility from the perspective of the Lessee under the terms of the toll. For purposes of our valuation, the applicable valuation date is January 1, 2010 ("Valuation Date"). As noted above, this is the date at which Avista would expect to assume the rights and obligations under the toll. The DCF analysis is based on projections of the Lessee's forecasted annual after-tax free cash flows through the end of the lease term, discounted at Avista's after-tax weighted average cost of capital. The cash flows accruing to or paid by the Lessee would include all margins from sales of energy and capacity, lease payments, and operating costs expected to be borne by the Lessee (and not the Lessor/Seller) under the terms of the toll. Our approach to forecasting the components of free cash flows and the related key assumptions are discussed below.

General assumptions

- Valuation Date: January 1, 2010
- Term of analysis: January 1, 2010 – October 31, 2026
- Capacity: Average annual plant capacity was assumed to be 262 MW, of which 25 MW was assumed to be related to duct-fired peaking capacity. The total capacity was based on the average (summer / winter) capacity as reported by the Energy Information Administration ("EIA")
- Forced outage rate: 5%

Energy margins and capacity revenues

Energy margins and capacity revenues were forecasted using Thorndike Landing's proprietary Integrated Energy and Capacity Model ("IECM"), a production cost model which dispatches regional resources (including the Facility) against forecasted hourly load on an economic basis to derive market clearing energy pricing and unit dispatch / margins. The IECM also derives regional capacity values based on: (a) supply and demand dynamics, (b) new build economics, and (c) derived energy margins. The Facility revenues and margins derived from IECM are based on merchant (uncontracted) dispatch and are net of variable production costs including:

- Delivered gas costs including costs associated with gas commodity, delivery costs (excluding fixed gas transportation), gas transportation losses, fuel taxes (if any), etc.
- SO2 costs
- CO2 costs

Note that our analysis included three pricing scenarios for purposes of valuing the toll: base, low and high. See additional discussion of IECM methodology, assumptions and results in the Appendix.

Toll payments

Payments made under the Toll for capacity, energy and start charges were based on the terms as described in the Description of the Facility and Tolling Agreement section above. Additionally, escalation rates used for payments under the toll were as follows:

- Capital charge: 1% per the terms of the agreement
- O&M and Energy charges:
    - From 1998 to 2007: 2.4%. This was derived from our review of the associated referenced Gross Domestic Product Implicit Price Deflator.
    - From 2007 through 2026: 2.5%

Gas costs

Modeled gas costs include both fixed and variable components, as requested by Avista gas personnel on staff, to derive our forecasts for both these fixed and variable components.

- Fixed gas transportation costs: According to Avista, gas for the Facility is sourced from 2 delivery points—Alberta and Malin. As such, there are gas transportation contracts for both of these paths.
    - From Alberta:
        - 27,841 GJ per day through October 31, 2017

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        - Price: $.187 per mmbtu (in 2007 dollars)
    - From Malin:
        - 26,388 GJ per day through October 31, 2017
        - Price: $.26 per mmbtu (2007 $)

  Note that the total gas transportation exceeds the total gas needs of the plant when operating at full capacity by approximately 20% (approximately $550,000 in 2007). It appears that the additional capacity was obtained to allow the Facility to arbitrage between the gas supply points. Note that we did not include the cost for the excess gas supply, which was assumed to have been remarketed or otherwise utilized for utility service at cost. We also did not include the offsetting the arbitrage opportunity between Alberta and Malin hubs in our analysis. In order to estimate the impact of this arbitrage opportunity, we analyzed gas data for the Malin and Alberta hubs from the prior 3 years. Given the gas transportation limitations for both hubs (as shown above) and assuming perfect optimization of pricing between the hubs, the blended gas price for Lancaster would be approximately $.25/mmbtu (1.9%) lower than pricing at the Alberta hub alone. Further, note that it would also be possible for Avista to derive additional value from monetizing gas transportation for periods in which the Facility is down either for maintenance or for economic reasons. If the gas transportation necessary to meet daily gas requirements could be remarketed or otherwise utilized at cost, this would represent an additional value of approximately $9,000 pre-tax per day ($6,000 after-tax).

- Variable gas costs: (these are included in the energy margins modeled by the IECM)
    - Gas commodity: Priced at Alberta hub
    - Delivery costs:
        - Commodity fee: $.01 per mmbtu
        - Fuel transportation fee: 2.03%
    - Gas taxes: None for the Lancaster Facility. Unlike the state of Washington, Idaho does not currently have such a tax. For those comparable facilities located in the state of Washington, a fuel tax of 3.852% was applied. Based on our analysis, the impact of a 3.852% fuel tax on the value of the Toll would be approximately $26 million.

Both fixed and variable costs were escalated at an annual rate of 1.5%

Electric transmission

The Facility currently takes electric transmission services under a services agreement with BPA, under the BPA transmission tariff. Refer to tariff rates under the Description of Facility and Tolling Agreement above. However, Avista estimates that it could directly interconnect the Facility to its own system at a total cost of approximately $3 million, thereby negating the need to take service through BPA. For purposes of our analysis, we have assumed that Avista performs the interconnection work. The transmission agreement with BPA in this case will be utilized in other ways. We have assumed that a portion (75%) of the electric transmission capacity under the BPA agreement is remarketed at cost—or otherwise used for utility load service—and therefore not borne by the Facility / Lessee. We note that the utility's customers avoid BPA's charge for electric losses of 1.9% once the facility is interconnected directly with Avista's system. As compared to an otherwise identical unit that would incur this cost, the Facility reflects higher margins (1.9% of market clearing prices) in all hours when both facilities would be dispatched. In addition, the Facility would also be dispatched in additional (lower margin) hours relative to its peer when it is at—or close to—the margin. Based on our analysis, the value of a 1.9% loss factor on the value of the Toll is approximately $12.5 million.

Tax Depreciation

Capital expenditures—specifically the interconnection cost—were depreciated based on 20-year MACRS.

Taxes

Combined state and federal tax rate was assumed to be 39.94%

Discount rate

After-tax free cash flows were discounted based on Avista's after-tax weighted average cost of capital of 7.41%.

Costs Associated with Imputed Debt

Rating agencies generally consider long-term power purchase contracts to be equivalent in some regards to long-term debt. As such, they impute a value for debt that they apply to the power purchaser's balance sheet. This imputed debt places downward pressure on the credit quality of the "borrower" and upward pressure on financing costs. In order to take into account the costs associated with the imputed debt, we included a cost of equity that would be necessary to neutralize the reduction in credit quality from the imputed debt.

Rating agencies have differing methodologies for imputing debt. For purposes of our analysis, we have utilized the process employed by Standard & Poor's. The calculation begins with the determination of the fixed obligations associated with the demand payment. This payment stream is then discounted at the utility's average cost of debt. A risk factor is then applied to the net present value of the stream of fixed obligations to arrive at the amount of imputed debt.

The incremental cost applied to the Toll is based on the amount of equity that would need to be issued to maintain the utility's existing capital structure. The annual cost is then based on the utility's cost of equity applied to the calculated additional equity required.

Valuation of the Lancaster Facility

As a reference check, we also performed a valuation of the Facility as of the Valuation Date from the perspective of the owner without the toll—in other words, the value of the Facility assuming merchant dispatch. For this effort, we used the discounted cash flow ("DCF") method. The approach and assumptions used for this analysis were largely consistent with those of the analysis of the Toll above. Key differences include the following:

- Forecasting period / useful life. The facility was assumed to have a useful life of 35 years (through 2036). The value of the cash flows accruing to the project over its useful life were calculated as follows:
  - Jan. 1, 2010 – Dec. 31, 2030: Annual cash flows modeled through the use of IECM forecasting model.
  - Jan. 1, 2031 – Dec. 31, 2036 (end of useful life): Annual free cash flows assumed to be consistent with IECM terminal year (2030).
  - Residual value (post-2036): Assumed to be $0. Implicitly, the value of the site and associated scrap value of the equipment, etc. are assumed to be equal to the cost of dismantlement and any necessary site remediation.
- Tolling payments: By definition, excluded from this analysis
- O&M, including Major Maintenance – Based on estimated actual charges expected to be incurred for the Facility (not prescribed O&M fee per the terms of the Toll).
- Property taxes and insurance – Projected costs were included. In accordance with the terms of the Toll, these costs had previously been excluded from the Toll valuation.
- Tax depreciation: Based on both the historical construction cost of the Facility as well as additional capital (interconnection, major maintenance). The implicit assumption is that ownership of the Facility would be transferred via a purchase of the third party's equity (e.g., a stock purchase) and not a purchase of the underlying assets themselves (e.g., an asset purchase).

Valuation of Select Assets Transacted in Market

Thorndike Landing performed a valuation analysis for a few selected assets that compete against the Facility within the local or regional marketplace. Specifically, we valued the Goldendale facility as purchased by Puget Sound Energy earlier this year, the Coyote Springs 2 as owned by Avista Utilities and the Port Westward facility as being developed by Portland General. Given that these assets were not for sale, this exercise was intended to merely assess what the potential values of these assets would be *if* they were to transact and, hence, be available to Avista instead of the Toll.

For this assessment, we used the same DCF approach and general assumptions as outlined above.

Transaction Market Comparables

As a final reference check, we have also reviewed transaction market activity to identify similar assets that have transacted and to assess the value of these assets and whether they were comparable to the contemplated transaction for the Toll. We recognize that this transaction – a toll versus an asset transaction – is fundamentally different than these comparables; thus while this information has been reviewed as yet another reference point it has not been relied upon extensively to determine our conclusions. There are several factors to consider when reviewing and applying comparable transactions as a reference for a particular transaction: (a) similar fuel and technology type facilities; (b) salient attributes of the situation, such as whether the asset has an off-take agreement for the output, etc., if known; (c) geography and, specifically, the market the asset competes within; and (d) the period in which the transaction was executed.

For the first factor, it is important to filter the information and data and isolate those transactions that were for assets of a similar fuel and technology type; in this case gas-fired combined-cycle facilities. Depending on the number of transactions available for comparison purposes, occasionally portfolios of assets can also be applied if that portfolio is largely of a similar fuel and technology type. There is no set parameter or threshold of how many assets in the portfolio are similar or what percentage of the portfolio's capacity is similar, but it is generally acceptable to use a portfolio that is nearly all of similar fuel and technology type. Conversely, if there are a sufficient number of single-asset transactions those are generally preferred as a comparison set.

The second factor to consider is whether there exists any extenuating circumstances or attributes of a given transaction. The clearest example would be if an asset had an off-take agreement for a portion or all of its output. Depending on the prices and terms of that agreement (i.e., higher-than-market pricing vs.

lower-than-market pricing), the value of the transaction can be skewed. Specifically, if an asset had an off-take agreement that had pricing that was significantly greater than current market views, the value of that asset (including the contract) to a buyer would be greater than if it were a merchant facility. These details are not always known.

The third factor to consider when selecting a comparable set of transactions is geography. This geographical parameter is most easily identified by power pool or market (e.g., PJM, ERCOT, etc.). In this case, the specific market is less defined as the Toll is with a project in WECC which is a large control area versus a tightly-managed ISO as in other markets.

The fourth factor to consider when selecting a comparable set of transactions is the timing or era of the transactions to be included in the comparison set. Again, this is largely driven by the number of transactions available and there is no specific rule or threshold to use. It is common to use a term of between 18 and 24 months prior to the assessment if there is sufficient data and transactions available. This period is based on the premise that fundamental drivers to transactions (i.e., fuel prices and trends, credit markets, etc.) remain consistent for a period of time but do eventually change. As these fundamentals change, so do the resulting transaction activity and the values in this market. Lastly, if the number of transactions or data for those transactions is limited, it is common to use a period of up to three years to gauge comparable transactions.

During the past few years there have been several transactions that would be considered comparable to this proposed deal; again, using the general aforementioned criteria of similar types of plant, market, etc. Below is a summary of the publicly-available transactions that have occurred in this market during this three year period.

Date Announced	Asset(s)	State(s)	Fuel	Type	MW Xfer	Seller	Buyer	Total Price (MM$)	Value ($/kW)
12/17/2004	Coyote Sptings 2 (50%)	OR	Gas	CC	140	Mirant	Avista	$63	$446
5/18/2005	La Paloma	CA	Gas	CC	1022	Citibank lender consortium	Complete Energy Partners	$610	$597
5/19/2005	El Dorado (50%)	NV	Gas	CC	240	Reliant	Sierra Pacific Resources	$132	$550
6/21/2005	Silverhawk	NV	Gas	CC	427.5	Pinnacle West	Nevada Power	$208	$487
5/11/2006	Griffith	AZ	Gas	CC	300	PPL	LS Power	$115	$383
2/7/2007	Goldendale	WA	Gas	CC	250	Calpine	Puget Sound Energy	$120	$480
9/13/2007	Klamath Falls cogeneration	OR	Gas	CC cogen	506	City of Klamath Falls	PPM	$290	$573

As shown, during this period, there have been seven transactions averaging $533/kW. During this same period, there have been approximately 25 similar transactions executed throughout the remainder of the U.S., resulting in an average value of $465/kW. The relatively small divergence in these numbers is driven by several factors, including location/market, whether there exists an off-take agreement and, if so, what term exists for the contract, each specific buyer's view to commodity prices, cost of capital, etc.

It may be more appropriate to utilize a shorter period of time to assess comparable transactions, given that there has been a fairly significant change in several factors during the past three years in this sector; namely financing costs and commodity costs. The data set gets much smaller during this time and includes just the Puget acquisition of Goldendale and the PPM acquisition of the Klamath Falls cogeneration facility. The results of this period, however, remain very consistent with that of the three year period. Specifically, the average value of these transactions in this market is $542/kW as compared to $503/kW for the remainder of the U.S. during that same one-year period.

Other Considerations (Toll versus Ownership)

We have derived values for the Toll, the Facility and other indicators as described above. As mentioned, the Toll—although it conveys many of the rights and obligations of ownership—remains fundamentally different from actual ownership. Some of the primary considerations of a toll versus ownership include:

- Term of "ownership": Beyond the term of the Toll, the Lessee has no rights of ownership and the full value of any "terminal" or "residual" value reverts back to the Lessor/Seller.
- Operational risk: Under the provisions of the Toll, the Lessor/Seller has guaranteed a stipulated forced outage rate (approximately 3.0%), as well as a realized heat rate. Any costs associated with not meeting the operational parameters are borne entirely by the Lessor/Seller. For instance, in the event of an extended forced outage, the Lessee / Purchaser is entitled to replacement power (as defined) at the Lessor/Seller's cost, thereby mitigating such risk under a Toll arrangement.
- Limited risk of cost escalation: Cost escalation under the term of the Toll is limited to 1% annually for the capital charge and to an inflationary index for the O&M and energy rates. As such, there is little risk for cost overruns associated with regional or plant-specific impacts such as (local) labor costs, property taxes, insurance, etc. The Lessor/Seller bears the risk of such cost escalation in excess of economy-wide increases.
- Initial capital outlays: For purposes of our analysis, we derived the value of assuming the Toll as of the Valuation Date. We also determined the total value of certain facilities as of the Valuation Date. Note, however, in the case of the latter, we expressly excluded any capital costs associated with owners' acquisition of the facilities (e.g., construction costs, acquisition costs). Such initial capital outlays would be required to be made in the case of taking ownership but not in the case of the Toll since the tolling payments themselves is consideration for the use of the Facility over the Toll term.

Review of Avista Analytical Process

Thorndike Landing has performed a review of Avista's analytical process and methodology to identify any potential shortcomings or areas that may be improved to provide it with a better, more comprehensive analytical process. Our review consisted of a meeting and discussion session to review the overall methodology, ways in which they addressed contemporary issues (e.g., emissions, etc.), and a discussion surrounding the modeling platform and software used and how they interacted throughout the analytical process. We did not review the assumptions used by Avista in their analysis, other than to ensure that they had used current perspectives when deriving their assumptions. This section reviews Avista's current analytical approach, as well as the results of our review.

Overview of Avista Analytical Approach

Avista utilizes a dynamic and interactive modeling approach to resource planning and analyzing new resources for its system. This approach considers and analyzes both the Avista system, as well as its interaction with the broader Western Electricity Coordinating Council ("WECC"), analyzes and determines the risk associated with various scenarios and resources, and determines the optimal resource portfolio for its system based on power supply expenses, incremental capital costs and operating risk.

To accomplish this level of analytical rigor, Avista employs several distinct modeling platforms. First, it uses AURORAxmp to perform the market modeling, generate the capacity expansion plans and forecast electric market prices. Avista currently plans to a capacity planning target. Specifically, the scenarios within AURORAxmp introduce resources into the system to cover adverse or short load conditions; in essence, adding resources to exceed average needs. This philosophy ensures that resources are in the system and ready and available to meet system requirements in all but the most extreme conditions. This approach reflects sound utility planning in the market today, especially in WECC where many participants are still feeling the ramifications of the power crisis a few short years ago. The generic resources that the model calls upon for the capacity expansions include gas-fired combined-cycle combustion turbines, single-cycle combustion turbines, pulverized coal plants, integrated gasification combined-cycle coal plants with and without sequestration and wind turbines. This wide array of resources provides Avista's planning process with significant diversity when assessing various scenarios and the advantages and disadvantages of each with respect to both cost and risk.

Avista also uses AURORAxmp for risk assessment by performing stochastic analyses to determine the volatility of prices and potential resource valuations. Several salient assumptions are modeled stochastically, including hydroelectric conditions, natural gas prices, load conditions, wind production, forced outages of the facilities and the cost of emissions compliance. The Avista team reviews and determines the input assumptions for these and other variables into AURORAxmp and reviews the output of this model to ensure the results of logical and correct. By performing this stochastic analysis, Avista incorporates a measure of volatility for the projected electricity market prices and the resulting resource values to Avista and its customers.

Avista also uses another model, The Preferred Resource Strategy Model, or PRiSM, which is a proprietary model developed by Avista to aid it in selecting its preferred resource strategy. PRiSM quantifies the cost and risk associated with Avista's current resource portfolio and that of new potential resource additions. The PRiSM model uses a linear programming approach. This method enables complex decision-making in situations or processes that often have one- or multi-dimensional objectives, such as resource planning for both cost and reliability measures and goals. This model relies upon several factors to arrive at an optimal resource portfolio, including the base case assumptions as used in AURORAxmp, Avista load requirements for capacity and energy, capital costs associated with new resources, local transmission costs, and the market and cost values of each new and existing resource as modeled in AURORAxmp. PRiSM determines the preferred resource strategy based on several resource and portfolio metrics, including present value of the expected power expenses, incremental capital costs and operating risk to Avista.

Results of Thorndike Review

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. We do recommend, however, that Avista continue to review its methodology as it has for the past several years as analytical approaches continue to evolve with new techniques and information and Avista needs to maintain a current process given the challenges that inevitably lie ahead in our industry.

With respect to the analysis of the Lancaster Toll specifically, we likewise found the approach to be appropriate. However, we did identify items that warranted further consideration:

- *Exclusion of gas transportation costs*: We noted that gas transportation costs had been excluded from Avista's preliminary analysis of the Toll despite the fact that Avista would incur such costs after assumption of the Toll. Based on our discussions with Avista personnel, it appears that the internal assessment of gas transportation costs had not been completed as of the date of the preliminary analysis. We noted that these costs were excluded for both the Toll and the "offsystem CC" comparative analysis. As a result, any comparative results would only be impacted by any differences in gas transportation costs. Likewise, any upside from sourcing from dual gas hubs was also excluded from the Avista analysis.
- *Exclusion of costs associated with imputed debt:* Due to the fact that rating agencies impute debt associated with power purchase agreements such as the Toll, there is a cost associated with entering into such agreements. In connection with our analysis, we calculated such cost as described in the Valuation of the Toll section above. We noted that Avista did not include such costs in their analysis.

The items listed above do impact absolute values but did not have a material impact on relative values or overall conclusions. We noted no other material issues with Avista's process generally or its analysis of the Lancaster Toll specifically.

Results and Conclusions

Base results

Based on the aforementioned analyses, reviews and assessments, Thorndike Landing has determined the following base case results for the Toll, the Lancaster Facility and other comparative facilities.

Table 2: Summary of Toll Valuation Results

	Value	
Description	$000s	$/kW
NPV excluding imputed debt	$40,500	$155
Cost of imputed debt	(24,000)	(91)
NPV including imputed debt	16,500	64

The valuation of the Lancaster Facility is shown in Table 3 below.

Table 3: Summary of Lancaster Facility Ownership Valuation Results

	Value	
Description	$000s	$/kW
Lancaster	177,500	677

The valuation of the other similar combined cycle facilities in the region is shown in Table 4 below.

Table 4: Summary of Comparable Combined Cycle Ownership Valuation Results

	Value	
Approach / Asset	$000s	$/kW
DCF Analysis		
Coyote Springs 2	169,500	652
Port Westward	236,000	528
Goldendale	84,000	365
Transaction Comps Analysis	n/a	530

These values do not provide a direct comparison of each plant's (net) value to Avista. Instead, the values represent the value to Avista if it could assume the rights and obligations of the plant's current owner at no cost. For example, if the Goldendale plant were made available to Avista at no cost its value would be $84 million—or, in other words, Avista could pay up to $84 million for the plant. In the case of the Lancaster Toll, given our assumptions regarding the specific financial obligations and benefits as previously described in this report, the contract available to Avista is worth $16.5 million more than its costs. As such, Avista could pay up to $16.5 million for the contract and it would still represent a positive NPV (return) investment.

Sensitivities

As discussed above, we also ran high and low cases for the value of the Toll and for the Facility. These scenarios are derived by assuming distinct market drivers that are in the range of potential future market developments. As the subject of this report is a combined-cycle (CC) related product we focused on the two drivers that would produce relevant upside or downside to these types of plants. The core drivers we varied were (1) a doubling of assumed future CO_2 prices, and (2) the introduction of an additional 5,000 MW of combined-cycle capacity throughout WECC. Higher CO_2 prices result in a substantial relative benefit to CC's, while the CC overbuild simulated for the low case leads to a merchant margin depression. The results are as follows:

Table 5: Summary of Results

	Value - $000 ($/kW)	
Description	**Toll**	**Facility**
Base Case	$16,500 ($64)	$177,500 ($677)
Low Case	500 (2)	155,500 (594)
High Case	20,500 (78)	181,500 (692)

We also ran sensitivities around Avista's ability to re-market the excess electric transmission under the BPA contract that would be available after completion of the interconnection to Avista's system. For our base case values, we have assumed that 75% of the BPA transmission costs would be recouped through remarketing. However, given the materiality of the costs, we ran sensitivities based on the percentage of costs that would be recovered through third party sales.

Table 6: Lancaster Base Case Toll Values As a Function of BPA Transmission Costs Remarketed

% of Costs Remarketed	Value $000s	Value $/kW
0%	(7,500)	(29)
25%	500	2
33%	3,000	12
50%	8,500	33
67%	13,750	52
75%	16,500	64
100%	24,750	94

Conclusion

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. This 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)

Appendix A: Description of IECM

Thorndike Landing uses its proprietary model, the Integrated Energy Capacity Model ("IECM"). The IECM is an economic forecasting tool that derives capacity and energy forecasts by combining a set of sophisticated market simulation algorithms into one integrated piece of software. Unlike most other standard forecasting software, capacity markets are integrated into the forecast rather than being modeled as an add-on, which aids greatly with the validity of return requirement calculations needed to add future resources to the model.

The model works in power markets that follow the rules of economic dispatch in the energy markets and that have a formal capacity market, a regulatory reserve margin requirement, or a bilaterally traded capacity market. This makes the IECM useful in most current domestic power markets.

Obvious Advantages of Integration

The real market linkage between energy and capacity markets is undisputed and is most relevant for the very important new build and retirement asset decisions (i.e., even markets with low spark spread forecasts and little incentive from an energy market perspective to install new plants or keep aging units operating will, in real life, encourage retirement delays or even new builds). The IECM allows the forecaster to easily integrate assumptions and results in both markets to arrive at conclusions to typically difficult questions, such as: "Does the capacity market in my region lead to new combustion turbines or does it put a new combined-cycle or coal plant into my new build assumption? Is there a difference under a carbon regime?"

Methodology

For the energy module, the IECM uses an hourly chronological merit order dispatch approach to arrive at a 20 year energy price forecast. These 175,000 price points are one part of the economic assessment for new and old resources. For the capacity module, the model applies the appropriate capacity market construct, e.g. a demand curve or a bilaterally traded market, to the same resources used in the energy module to derive an annual capacity market price point for the same 20 year period. Both the 175,000 energy and the 20 capacity price points enter the retirement and new build assumptions that then circle back into the two forecasts in an iterative fashion.

Emissions: Pollutants and Carbon Dioxide

The cost of emission allowances is an important adder to the marginal cost of fossil generators. In the case of CO_2, there is even uncertainty around such basic rules as allocation mechanisms and price caps. The IECM incorporates our standard forecasts for emission allowances and allows for scenarios around fuel and emission market dislocations.

Extrinsic Value Drivers

Models such as the IECM that use a fundamental approach to forecast energy prices typically exhibit a weakness when it comes to estimating the energy margin from plants that can be dispatched flexibly, based on market conditions. E.g., the average daily price on the same weekday in the same month may be very similar in the fundamental dispatch model, as it is likely based on similar load and fuel price conditions. In real markets, there are many parameters that shift the daily prices up or down. While the average will be roughly the same, this introduction of volatility into the pricing enhances the energy margins of the above mentioned flexible plants. In WECC, flexible plants, such as combustion turbines (CT) and combined-cycle (CC) plants are important as they form an important part of the new build economics. The model, if it did not include volatility in its output, would understate CC and CT returns, with the important impact that it would delay new build decisions, leading to exaggerated market heatrate forecasts. The IECM therefore, as a final step, after fundamental intrinsic prices are derived, introduces volatility into the generated pricing, not changing the absolute pricing levels, but introducing just enough volatility, on a simple mean-reverting basis, to result in appropriate returns for the flexible plants.

Key Assumptions and Results for the Various Scenarios

Note that gas prices refer to the AECO, and power prices to the Mid-C pricing points.

Core Underlying Commodity Assumptions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas	$7.16/MM BTU	$6.96/MM BTU	$7.10/MM BTU	$7.24/MM BTU	$7.38/MM BTU	$7.53/MM BTU	$7.68/MM BTU	$7.84/MM BTU	$7.99/MM BTU	$8.15/MM BTU	$8.31/MM BTU
CO_2	$0/t	$0/t	$8/t	$8/t	$8/t	$10/t	$13/t	$16/t	$19/t	$22/t	$25/t
CO_2 (High Case Only)	$0/t	$0/t	$16/t	$16/t	$16/t	$20/t	$26/t	$32/t	$38/t	$44/t	$50/t
Hydro (of Normal)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Other (Low Case Only)		5,000 MW uneconomic CC capacity									
Resulting Market Heatrate											
Low	8,456	8,128	8,651	8,711	8,760	8,924	9,053	9,264	9,457	9,572	9,735
Base	8,456	8,526	9,056	9,090	9,116	9,247	9,368	9,549	9,720	9,824	9,969
High	8,456	8,526	9,546	9,574	9,594	9,835	10,114	10,452	10,774	11,017	11,299

Appendix B: Conditions and Assumptions

This report developed by Thorndike Landing shall be received and accepted with the accompanying limiting conditions and assumptions:

- This report has been prepared solely for the purposes stated and should not be used for any other purpose. The use and distribution of this report and the conclusions contained herein are limited as stated in the report and the related engagement letter.

- Our analysis: (i) assumes that as of the date of this report the Facility and its assets will continue to operate as configured as a going concern; (ii) is based on the past and present financial condition of the Facility and its assets; and (iii) assumes that the Facility had no undisclosed real or contingent assets or liabilities, no unusual obligations or substantial commitments, other than in the ordinary course of business, nor had any litigation pending or threatened that would have a material effect on our analyses.

- We have relied on information supplied by Avista without audit or verification. We have assumed that all information furnished is complete, accurate, and reflects Avista's good faith efforts to describe the status and prospects of the Facility at the date of this report from an operating and a financial point of view. As part of this engagement we have relied upon publicly-available data from recognized sources of financial information which have not been verified in all cases. Nothing came to our attention to make us believe that any of the information provided by Avista was other than reasonable.

- Any use of Avista's projections or forecasts in our analysis does not constitute an examination or compilation of prospective financial statements in accordance with standards established by the American Institute of Certified Public Accountants ("AICPA"). We do not express an opinion or any other form of assurance on the reasonableness of the underlying assumptions or whether any of the prospective financial statements, if used, are presented in conformity with AICPA presentation guidelines. Further, there will usually be differences between prospective and actual results because events and circumstances frequently do not occur as expected and these differences may be material.

- The terms of our engagement are such that we have no obligation to update this report or to revise our assessment because of events and transactions occurring subsequent to the date of this report.

- We assume no responsibility for legal matters including interpretations of either the law or contracts. We have made no investigation of legal title and have assumed that the owner(s) claim(s) to property are valid. We have given no consideration to liens or encumbrances except as specifically stated. We assumed that all required licenses, permits, etc. are in full force and effect, and we made no independent on-site tests to identify the presence of any potential environmental risks. We assume no responsibility for the acceptability of the valuation approaches used in our report as legal evidence in any particular court or jurisdiction. The suitability of our report for any legal forum is a matter for the client and the client's legal advisor to determine.

- Neither Thorndike Landing, nor any individual associated with this report shall be required to give testimony or appear in court or other legal proceedings unless specific arrangements have been made in advance.

- We have not investigated the extent of any hazardous substances that may exist, as we are not qualified to test for such substances or conditions. If the presence of such substances, such as asbestos, urea formaldehyde foam insulation, or other hazardous substances or environmental conditions may affect the valuation of the Facility, the valuation was estimated predicated on the assumption that there is no such condition on or in the property or in such proximity thereto that it would cause a loss in value. No responsibility is assumed for any conditions, or for any expertise or engineering knowledge required to discover them.

- We assume no liability whatsoever with respect to the condition of the Facility or for hidden or unapparent conditions, if any, of the subject property, subsoil or structures, and further assume no liability or responsibility whatsoever with respect to the correction of any defects which many now exist or which may develop in the future. Equipment components considered, if any, were assumed to be adequate for the needs of the Project's improvements, and in good working condition, unless otherwise reported.

Appendix C: Lancaster Toll Forecasted Financials, Valuation

LANCASTER TOLL - BASE CASE

($000s unless otherwise noted)

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity (MW)																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	17,207	17,660	18,169	18,670	19,200	19,003	19,731	20,516	20,344	20,864	21,432	21,020	21,672	22,349	22,012	18,935	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,390)	(3,402)	(3,505)	(3,608)	(3,697)	(3,736)	(3,832)	(3,921)	(3,962)	(4,056)	(4,177)	(4,232)	(4,356)	(4,484)	(4,541)	(3,897)	-
Gross margin		30,841	31,238	31,997	32,727	33,455	34,232	34,339	35,319	36,371	36,520	37,315	38,136	38,052	38,969	39,915	39,926	34,093	-
Non-fuel fixed operating expenses																			
O&M[2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment[3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	5,840	6,228	6,580	6,923	7,309	7,017	7,592	8,231	7,960	8,328	8,715	8,187	8,654	9,141	8,685	7,663	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	5,624	6,027	6,394	6,752	7,150	6,871	7,457	8,097	7,826	8,194	8,581	8,054	8,521	9,007	8,551	7,529	-
Taxes		(2,275)	(2,246)	(2,407)	(2,554)	(2,697)	(2,856)	(2,744)	(2,978)	(3,234)	(3,126)	(3,273)	(3,427)	(3,217)	(3,403)	(3,598)	(3,415)	(3,007)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Capital Expenditures		(3,000)																	
Free Cash Flows		533	3,594	3,820	4,026	4,226	4,453	4,273	4,614	4,997	4,834	5,055	5,288	4,971	5,251	5,544	5,270	4,656	-
Terminal Value[4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	3,229	3,195	3,135	3,064	3,005	2,685	2,699	2,722	2,451	2,387	2,324	2,034	2,001	1,966	1,740	1,431	52
Total NPV, excluding cost of imputed debt		40,635																	
Total NPV, excluding cost of imputed debt (rounded)		$\boxed{40,500}$																	
		155	($/kW)																

Footnotes:

[1] - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

[2] - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

[3] - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

[4] - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

LANCASTER TOLL - LOW CASE

($000s unless otherwise noted)		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	14,073	14,430	14,907	15,391	15,909	15,743	16,428	17,127	17,014	17,524	18,048	17,801	18,353	18,951	18,789	16,181	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,165)	(3,176)	(3,282)	(3,390)	(3,487)	(3,508)	(3,611)	(3,708)	(3,732)	(3,832)	(3,959)	(4,003)	(4,131)	(4,260)	(4,318)	(3,711)	-
Gross margin		30,841	28,330	28,993	29,689	30,394	31,152	31,307	32,238	33,195	33,419	34,198	34,970	35,062	35,876	36,741	36,925	31,525	-
Non-fuel fixed operating expenses																			
O&M[2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment[3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	2,933	3,224	3,542	3,862	4,229	3,985	4,510	5,055	4,860	5,211	5,548	5,198	5,561	5,967	5,685	5,095	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	2,716	3,024	3,357	3,690	4,070	3,839	4,375	4,922	4,726	5,078	5,415	5,064	5,427	5,834	5,551	4,961	-
Taxes		(2,275)	(1,085)	(1,208)	(1,341)	(1,474)	(1,626)	(1,533)	(1,747)	(1,966)	(1,888)	(2,028)	(2,163)	(2,023)	(2,168)	(2,330)	(2,217)	(1,981)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Total capital expenditures		(3,000)																	
Free Cash Flows		533	1,848	2,016	2,201	2,388	2,603	2,452	2,763	3,090	2,972	3,183	3,386	3,175	3,393	3,638	3,468	3,113	-
Terminal Value[4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	1,660	1,686	1,714	1,731	1,757	1,541	1,616	1,683	1,507	1,503	1,488	1,299	1,293	1,290	1,145	957	52
Total NPV, excluding cost of imputed debt		24,438																	
Total NPV, excluding cost of imputed debt (rounded)		24,500																	
		93	($/kW)																

Footnotes:

[1] - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

[2] - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

[3] - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

[4] - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

LANCASTER TOLL - HIGH CASE

($000s unless otherwise noted)		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Selected Operational Measures:																			
Operational metrics																			
Months in service		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	10	-
Capacity																			
Baseload		237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	237	-
Duct-fired		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	-
Total		262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	-
Financial Projections:																			
Energy margins, excluding allowances		17,068	17,207	17,915	18,425	18,936	19,537	19,388	20,227	21,156	21,021	21,669	22,263	21,775	22,472	23,198	22,785	19,619	-
Capacity revenues		17,109	17,421	17,740	18,063	18,393	18,730	19,072	19,421	19,776	20,138	20,506	20,881	21,264	21,653	22,050	22,454	19,055	-
Energy payment (toll)[1]		(3,337)	(3,165)	(3,176)	(3,282)	(3,390)	(3,487)	(3,508)	(3,611)	(3,708)	(3,732)	(3,832)	(3,959)	(4,003)	(4,131)	(4,260)	(4,318)	(3,711)	-
Gross margin		30,841	31,464	32,478	33,207	33,939	34,780	34,952	36,036	37,224	37,427	38,343	39,185	39,036	39,995	40,988	40,921	34,962	-
Non-fuel fixed operating expenses																			
O&M [2]		5,352	5,485	5,622	5,763	5,907	6,055	6,206	6,361	6,520	6,683	6,850	7,022	7,197	7,377	7,562	7,751	6,620	-
Transmission		1,170	1,200	1,230	1,260	1,292	1,324	1,357	1,391	1,426	1,462	1,498	1,536	1,574	1,614	1,654	1,695	1,448	-
Gas Transportation		3,410	3,461	3,513	3,566	3,619	3,674	3,729	3,785	3,842	3,899	3,958	4,017	4,077	4,138	4,200	4,263	3,606	
Capacity / capital toll payment [3]		15,100	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755	-
Total non-fuel operating expenses		25,033	25,398	25,769	26,147	26,532	26,923	27,322	27,727	28,140	28,559	28,987	29,422	29,864	30,315	30,773	31,240	26,430	-
EBITDA		5,808	6,066	6,709	7,060	7,407	7,856	7,630	8,309	9,084	8,867	9,357	9,764	9,172	9,680	10,215	9,681	8,532	-
Tax Depreciation (based on purchase price)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	
EBIT		5,696	5,849	6,508	6,874	7,236	7,698	7,484	8,173	8,950	8,733	9,223	9,630	9,038	9,546	10,081	9,547	8,398	-
Taxes		(2,275)	(2,336)	(2,599)	(2,746)	(2,890)	(3,075)	(2,989)	(3,264)	(3,575)	(3,488)	(3,684)	(3,846)	(3,610)	(3,813)	(4,026)	(3,813)	(3,354)	-
Depreciation (tax)		113	217	200	185	171	159	147	136	134	134	134	134	134	134	134	134	134	-
Total capital expenditures		(3,000)																	
Free Cash Flows		533	3,730	4,109	4,314	4,517	4,782	4,641	5,045	5,509	5,379	5,673	5,917	5,562	5,867	6,188	5,868	5,178	-
Terminal Value[4]																			187
NPV (mid-year convention)																			
Annual discount factor based on discount rate of:	7.41%	0.96	0.90	0.84	0.78	0.72	0.67	0.63	0.59	0.54	0.51	0.47	0.44	0.41	0.38	0.35	0.33	0.31	0.28
PV of annual cash flows @ discount rate of		515	3,350	3,437	3,359	3,275	3,227	2,916	2,951	3,001	2,728	2,678	2,601	2,276	2,235	2,195	1,938	1,592	52
Total NPV, excluding cost of imputed debt		44,326																	
Total NPV, excluding cost of imputed debt (rounded)		44,500																	
		169	($/kW)																

Footnotes:

[1] - Represents the energy payment portion of tolling payments. Amount is based on MWhs generated and an energy charge that is escalated annually with an inflation measure.

[2] - Represents the O&M portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated annually with an inflation measure.

[3] - Represents the capital / capacity portion of tolling payments. Amount is based on a flat charge (expressed in terms of $/kW-month) that is escalated at 1% per year.

[4] - Terminal value represents tax benefit from write-off of undepreciated basis in capital outlay (interconnection costs)

Exhibit No.4
Case No. AVU-E-09-01
R. Storro, Avista
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LANCASTER TOLL - COST OF IMPUTED DEBT

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Stream of capacity payments		21,126	15,251	15,404	15,558	15,714	15,871	16,029	16,190	16,352	16,515	16,680	16,847	17,016	17,186	17,358	17,531	14,755
Discount rate (AVA pre-tax cost of debt)	8.28%																	
NPV	148,692																	
Risk factor [1]	25%																	
Imputed debt	37,173																	
AVA capitalization structure:																		
Debt	58.6%																	
Preferred stock	1.4%																	
Common stock	40.0%																	
	100.0%																	
Equity required to maintain cap structure [2]	25,383																	
After-tax cost of equity	10.4%	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,640	2,200
NPV	24,926																	
NPV (rounded)	24,000																	

Footnotes:

[1] - Per S&P guidelines, a risk factor is applied to the discounted stream of Toll capacity payments based on regulatory / rate treatment (and likelihood of recoverability).

[2] - Represents the equity that would be required to be issued after the imputed debt in order to maintain current capitalization structure.

Executive Summary

Avista Utilities plans to acquire the Power Purchase Agreement for the 275 MW Lancaster Generating Facility ("Lancaster") combined cycle combustion turbine (CCCT), which is located in the company's service territory near Rathdrum, Idaho. Acquisition of the Lancaster Power Purchase Agreement is consistent with Avista's 2007 Integrated Resource Plan Preferred Resource Strategy, which calls for a natural gas fired CCCT to meet base load needs by 2011. The Lancaster CCCT Power Purchase Agreement acquisition was found to be cost-effective compared to similar CCCT base load resources.

Background and Summary

In February 2007, Avista Utilities was informed of the possibility to acquire the Power Purchase Agreement (tolling) rights for Lancaster sometime between 2009 and 2011. The Power Purchase Agreement acquisition opportunity presented itself during Avista Corporation's negotiation for the sale of Avista Energy.

In April 2007, the utility completed an initial assessment of the potential Lancaster Power Purchase Agreement acquisition. Avista Utilities Resource Planning staff performed an analysis based upon the 2007 Integrated Resource Plan (IRP) models. It had been determined, as part of the IRP process, that there was a need for energy and capacity within the relevant timeframe as evidenced by load and resource tabulations which showed an expected annual average energy deficiency starting in 2011. An analysis of the average Q1, Q3, and Q4 (no Q2) quarters indicated deficits beginning in 2010. Capacity deficits started at 146 MW in 2011 and grew into the future. Furthermore, guidance from the 2007 IRP indicated 350 MW of natural gas baseload resource as part of the Preferred Resource Strategy (PRS) over the first 10 years of the plan (2008-2017).

On April 17, 2007, Avista Corporation announced an agreement with Coral Energy to sell Avista Energy. As part of the agreement with Coral Energy, Avista Corporation would assume the Lancaster Power Purchase Agreement beginning January 1, 2010. The draft 2007 IRP Preferred Resource Strategy (PRS) that was presented to the Technical Advisory Committee members on June 6, 2007 included a discussion of the Lancaster Power Purchase Agreement opportunity and its fit with the PRS.

The sale of Avista Energy to Coral became effective on July 1, 2007 thereby transferring the Lancaster Power Purchase Agreement to Avista Utilities on January 1, 2010. In August 2007, Avista Utilities contracted for an independent assessment of the Lancaster Power Purchase Agreement relative to other utility gas-fired options. Thorndike Landing, LLC completed the study and assessment work in late October 2007. Thorndike Landing found the Lancaster Power Purchase Agreement acquisition favorable relative to other natural gas-fired CCCT generation options generally available to utilities in the Pacific Northwest.

This white paper provides an overview of the Lancaster Power Purchase Agreement as well as analysis and assessment documentation addressing the prudence criteria as articulated by the Washington Utilities and Transportation Commission (Eleventh Supplemental Order and the Nineteenth Supplemental Order both in Docket No. UE-920433) and by the Idaho Public

Utilities Commission (Order No. 28876 in Case No. AVU-E-01-11, dated October 12, 2001, and its Order No. 29130 in Case No. AVU-E-02-6, dated October 11, 2002).

Lancaster – Overview of the Agreements

The 275 MW Lancaster CCCT entered into service in 2001. As a combined-cycle combustion turbine, it is among the most efficient natural gas-fired plants in the Northwest. The plant is located in the utility's service area, near Rathdrum, Idaho. The Lancaster plant is configured with as a 245 MW natural gas-fired CCCT with an additional 30 MW of duct firing capability.

In addition to the Lancaster plant Power Purchase Agreement rights, the company will receive long-term natural gas transportation rights necessary to fuel the plant as well as long-term electric transmission rights for power off-take.

The following is a summary of each of the agreements:

1) The Lancaster Generating Plant and Power Purchase Agreement

The Lancaster plant Power Purchase Agreement is available to the company January 1, 2010 through October 31, 2026. In exchange for payments outlined in the Power Purchase Agreement agreement, the utility will have the right to dispatch the Lancaster plant. As such, the company is responsible to arrange and pay for natural gas fuel procurement and transportation to the Lancaster plant and is entitled to the entire plant electric capacity and energy output. The company will also be responsible for electric transmission to move power from the Lancaster plant.

2) Natural Gas Transportation Associated With Lancaster

The Lancaster plant is interconnected with the Gas Transmission Northwest (GTN) natural gas pipeline system. As part of the agreement with Coral, 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 arrangements 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.

3) Electric Transmission Associated With Lancaster

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 Corporation.

The Lancaster CCCT Power Purchase Agreement Is Needed for Utility Service

The company was engaged in the process of finalizing its Integrated Resource Plan in April 2007 when the Lancaster Power Purchase Agreement option was evaluated for potential acquisition by Avista Utilities. At that time the tabulation of the company's loads and resources (L&R) positions showed energy and capacity deficits beginning in 2011; the energy deficit was 73 MW; the capacity deficit was 146 MW. Those needs increased substantially in the years 2012 and beyond. The February 2007 L&R tabulation is shown in Table No. 1 below.

Table No. 1
February 23, 2007 L&R Tabulation

Position	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy (aMW)	131	88	42	(73)	(156)	(162)	(194)	(219)	(272)	(263)
Capacity (MW)	148	94	5	(146)	(251)	(268)	(324)	(357)	(414)	(300)

The company submitted its 2007 IRP on August 31, 2007. There was only a small increase in amount of the energy deficit for 2011. The 2007 IRP L&R tabulation is shown in Table No. 2.

Table No. 2
2007 IRP L&R Tabulation

Position	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Energy (aMW)	121	79	33	(83)	(170)	(178)	(206)	(228)	(281)	(272)
Capacity (MW)	148	94	5	(146)	(251)	(268)	(324)	(357)	(414)	(300)

The utility's current October 25, 2007 L&R tabulation (without the Lancaster Power Purchase Agreement included) continues to show energy and capacity deficits beginning in 2011 (20 aMW, 83 MW). The updated L&R tabulation was based on the company's latest load forecast and assessment of resource capabilities and maintenance. The October 25, 2007 L&R tabulation is shown in Table No. 3.

Table No. 3
October 25, 2007 L&R Tabulation

Position	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Energy (aMW)	125	94	(20)	(86)	(123)	(127)	(179)	(211)	(225)	(245)
Capacity (MW)	116	43	(83)	(166)	(203)	(252)	(325)	(370)	(252)	(283)

The company's 2007 IRP process indicated that 350 MW of additional base-load CCCT capability (nameplate MW) should be included in the overall PRS for the first 10 years (2008 – 2017) of the 20-year planning horizon. The IRP process considers not only the cost of certain resource options, but also their contribution to meeting other planning goals such as reducing portfolio risk and meeting renewable portfolio standards. The 2007 IRP evaluated numerous options available to the utility, including gas-fired CCCTs, wind plants, biomass plants, and various coal-fired technologies. Given these options, the IRP identified a preferred mix of future resource alternatives.

The company used the PRiSM decision support software to help guide its resource planning decisions. The PRiSM model brings together the intrinsic and extrinsic values of Avista's existing portfolio of resources, its load obligations, and resource opportunities available to meet future load requirements. To capture the optionality inherent in each resource option (listed in the 2007 IRP, Table 8.1) available to the company, the results from 300 Monte Carlo runs were considered. Capital, transmission and fixed operations and maintenance costs attributable to each new resource option were evaluated. PRiSM was used to review the existing resource portfolio and select an optimal mix of new resources from the available options. Alternative resource mixes, including the PRS mix, were subjected to additional comparison and testing to assess the optimum balance of risk and cost. The PRS was selected on a comparative basis taking into account the balance of risk and costs of different resource mix strategies.

The resulting PRS for the first 10-year period of the 2007 IRP shows a need to add 772 MW of new resources consisting of the following resource types: 350 MW – Combined Cycle Combustion Turbine; 300 MW - Wind Generation; 35 MW – Other Renewable; 87 MW – Conservation. The Lancaster CCCT fills a portion of the PRS mix.

The Lancaster Plant Is Cost-Effective

<u>April 2007 Analysis:</u>
The April 2007 analysis of the Lancaster Power Purchase Agreement, along with associated natural gas transportation and electric transmission agreements, showed the acquisition of the Lancaster Power Purchase Agreement to be cost-effective compared to other alternatives. Because a firm transfer date for the Lancaster Power Purchase Agreement had not been set as part of the overall negotiations concerning the sale of Avista Energy to Coral Energy, the analysis initially looked at three potential start dates of January 1st of 2009, 2010 or 2011. The January 1, 2010 date ultimately became the agreed upon transfer date.

The company analyzed Power Purchase Agreement start date alternatives from two planning scenarios. The first scenario was based on the load and resource tabulation that was developed as part of the ongoing 2007 IRP process which indicated annual average deficits beginning in 2011. This load and resource tabulation was based on the company's traditional planning margin criteria, which is approximately 15% of peak load. The second scenario was an adjusted load and resource tabulation based on the Northwest Planning and Conservation Council (NPCC) planning reserve margin level of 25% of peak load. This load and resource tabulation indicated an immediate 2008 planning deficit.

For the January 1, 2010 Power Purchase Agreement transfer date, the analysis demonstrated the Lancaster Power Purchase Agreement was less costly than either a new "greenfield" or a potential existing "brownfield" natural gas-fired CCCT plant alternative. The Lancaster Power Purchase Agreement was estimated to save customers $4 million under the traditional planning reserve scenario and $22 million based on the NPCC planning reserve scenario, on a present value basis when compared to a brownfield site. A similar comparison to a greenfield site indicated present value saving of $62 million under the traditional reserves planning scenario and savings of $78 million based on the NPCC planning reserve scenario.

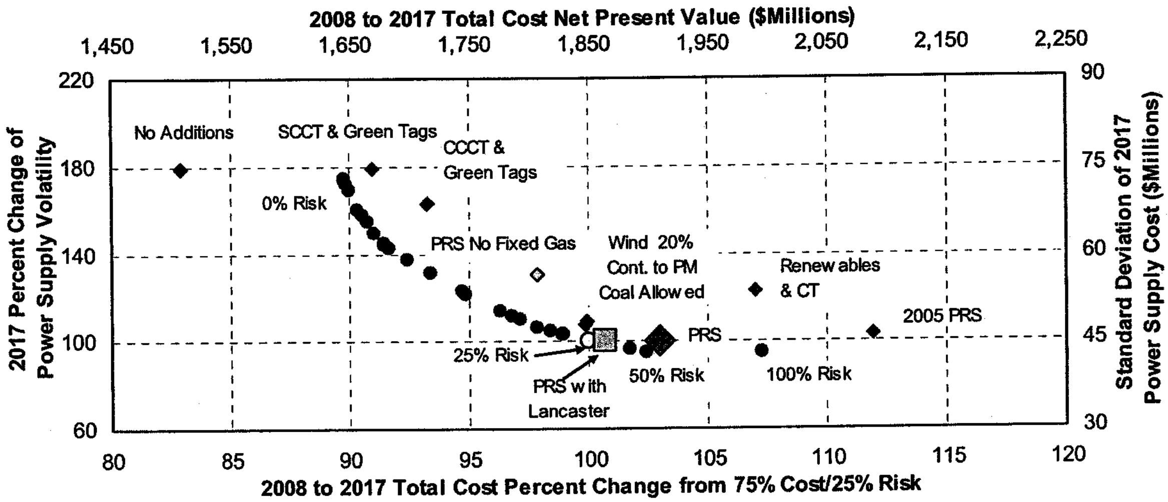
Lancaster's location in the company's Idaho service territory has the advantage of avoiding the nearly 4% Washington state fuels tax. However, that comparative savings was not considered in the April 2007 analysis. The comparative benefit from the lack of fuel tax in Idaho is estimated to add an additional $2 million in annual savings, or approximately $15 million on a present value basis. Another factor in favor of the Lancaster Power Purchase Agreement that was not explicitly included in the economic comparison to other new plant alternatives was the absence of construction risk.

2007 Integrated Resource Plan – Lancaster Assessment:
The 2007 IRP had already developed assessments of resource alternatives and had determined the PRS for the company at the time that the Lancaster Power Purchase Agreement opportunity was made to the utility. As stated earlier, the IRP considers not only the cost of certain resource options, but also their contribution to meeting various other planning goals such as reducing portfolio risk and meeting renewable portfolio standards. After assessing the costs and benefits of various resource mix options, a PRS was selected in the 2007 IRP process which included the addition of 350 MW of new gas-fired CCCT generation as part of that resource mix within the first ten years of the plan.

Subsequent to the announcement concerning the sale of Avista Energy to Coral energy on April 17, 2007, the company made the IRP Technical Advisory Committee aware of the Lancaster Power Purchase Agreement and the timing of its transfer to Avista Corporation on January 1, 2007. Lancaster was identified as a technologic match with the 350 MW of CCCT that was part of the PRS. Given that and because the Lancaster was available to the utility in the same timeframe as the PRS, there was not a need to update the strategy in the 2007 IRP. The 2007 IRP explained that the Lancaster Power Purchase Agreement reduced costs by 2.3% relative to the original PRS that included 350 MW of new gas-fired CCCT generation as shown in Table No. 4 below. The document states, on page 8-30, that "savings are created by acquiring a more cost-effective plant [relative to a greenfield plant] and an adjustment to new resource additions [changing the timing of other new resource additions]."

As explained earlier, the preferred resource strategy is selected based on a balance between resource mix cost and risk. A graphical depiction from the final 2007 IRP shows how Lancaster provides a similar risk profile while being lower-cost than the PRS absent the Lancaster Power Purchase Agreement.

Table No. 4
2007 Integrated Resource Plan
Figure 8.32: Efficient Frontier with Lancaster Plant



Thorndike Landing, LLC – Independent Valuation:

In August 2007 the company retained an independent consulting firm to perform an assessment of the Lancaster Power Purchase Agreement acquisition. Thorndike performed a ___ year discounted cash flow (DCF) analysis to determine the intrinsic and extrinsic value of the Power Purchase Agreement under Base, High and Low case scenarios. The base case assumes that Lancaster can be interconnected to the Avista transmission system and that the transmission will be remarketed or otherwise optimized to recover 75% of the cost. The high case scenario included a doubling of CO_2 prices. The low case scenario included the addition of 5,000 MW of combined cycle capacity throughout the WECC, which negatively impacts margins. The total value of the Lancaster Power Purchase Agreement, as dispatched against the market, was positive in all three cases.

Table No. 5
Lancaster Power Purchase Agreement 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

Because the transmission cost assumption had a material impact on the Lancaster valuation, Thorndike Landing performed sensitivity analyses based on the percentage of the BPA 250 MW transmission cost that would be recovered through remarketing it to third parties. The analyses show the Lancaster Power Purchase Agreement has positive value in all cases except where none of the transmission is remarketed.

Table No. 7
Transmission Impact On Lancaster Power Purchase Agreement Value

Percent of BPA Transmission Cost Re-marketed	Power Purchase Agreement Value ($000)	Power Purchase Agreement Value ($/kW)
100%	$24,750	$94
75%	$16,500	$64
67%	$13,750	$52
50%	$8,500	$33
33%	$3,000	$12
25%	$500	$2
0%	($7,500)	($29)

Based on the above valuation perspectives, Thorndike 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."

Thorndike further performed a review of Avista's analytic process and methodology to identify any potential shortcomings or areas that might be improved to provide the company with a better, more comprehensive analytical process. Thorndike identified two items [exclusion of natural gas transportation costs and exclusion of costs associated with imputed debt] to warrant further consideration by Avista. They concluded that those items did not have a material impact on the calculated values or the overall conclusions with respect to the Lancaster Power Purchase Agreement. Thorndike found that "Avista's analytical process and methodology is a very contemporary approach to analyzing resources." Thorndike furthers stated that "[w]e have found that Avista's analytic process is sound and even surpasses processes used by many of their peers across the industry."

Avista's initial April 2007 assessment, the 2007 IRP analysis, and the Thorndike Landing independent review all indicate that the Lancaster Power Purchase Agreement is cost-effective compared to other resource options under base case conditions as well as under various different scenarios.

The Lancaster Facility is Highly Dispatchable

The Power Purchase Agreement for the Lancaster plant provides its owner the ability to operate the plant in a flexible manner as if the utility owned the plant itself.

Gas-fired CCCT plants are one of the most dispatchable electricity-generating technologies available to utilities. Relative to other viable options, only simple-cycle gas-fired turbines can have more operational flexibility. Gas-fired CCCTs are capable of providing energy and capacity on short notice. The plants also can provide capacity for both spinning and non-spinning reserves. Many utilities use a portion of CCCT plant capacity to provide regulation services. Gas-fired CCCTs with the "duct-firing" capability of Lancaster provide additional flexibility to meet changing load and market conditions. CCCTs, by their inherent design, operate significantly more efficiently over a range of operating levels when compared to simple-cycle CTs.

The IRP modeling process dispatches all resource options to the wholesale marketplace. Where a resources' cost is lower than purchasing power from the market, the model causes that plant to run and the savings, as compared to market, are tracked for the portfolio. The modeling accounts for start-up costs, plant heat rates, and minimum up and minimum down times when it considers whether or not to dispatch a resource. The model also accounts for minimum and maximum generating levels, as well as hourly ramp rate capabilities. In the case of CCCT plants like Lancaster, the IRP dispatch model also separately dispatches duct-firing capabilities using each plants' unique heat rate, operating characteristics, and costs, bringing that capacity on-line when market conditions support it.

Electric Transmission

The Lancaster plant is currently interconnected only to the BPA transmission system. As stated above, the utility will receive assignment of 250 MW of firm transmission capacity on the BPA transmission system as part of the acquisition of the Lancaster Power Purchase Agreement beginning January 1, 2010. The transmission point of receipt is Lancaster and the point of delivery is John Day at the head of the Southern Intertie.

Compared to other CCCT projects in the region, Lancaster is unique as it is located within the company's service area. The utility plans to investigate whether the Lancaster project can be directly interconnected to the Avista transmission system in the Rathdrum area. The BPA interconnection agreement for Lancaster is held by the project owners [Cogentrix/Goldman Sachs and Energy Investors Funds Group].

The cost of the BPA transmission was explicitly included in the Lancaster modeling and analyses by both Avista and by Thorndike Landing. The base case assumes that Lancaster can be interconnected to the Avista transmission system and that the transmission will be remarketed or otherwise optimized to recover 75% of the cost.

Avista and Thorndike did consider an alternative, due to economics or other factors, where the Lancaster plant is not directly interconnected to the company's transmission system. In that case, a smaller portion of the transmission would be remarketed principally at times when the plant is not operating. However, because the firm transmission currently has John Day as a point of delivery, there may be opportunity to capture additional value for customers by selling power at that point or at COB. Firm power sales into California can often command a higher price compared to purchasing replacement power for delivery within the Northwest region. Optimization through selling power at COB or John Day and buying power in the region may be an alternate method of covering some of the cost of the BPA transmission if an interconnection with the Avista transmission system is not reasonably achievable.

Natural Gas Transportation

The Lancaster plant benefits from firm gas transportation from AECO to the Malin trading hubs. This transportation can serve the entire needs of Lancaster, including duct firing (approximately 46,168 Dth/d). This firm transportation will allow for deliveries of up to 26,256 Dth/d from the AECO trading hub on the Alberta system and up to 26,388 Dth/d from either the Stanfield or Malin trading hubs south of the plant. This dual source approach gives the company the ability to fuel the plant at an overall lower cost than if the firm transportation was solely from the AECO trading hub to the plant intake. Further, this transportation arrangement allows the company to make use of any excess transportation for other gas-fired generation resources such as the Coyote Springs 2 project duct firing, the Rathdrum combustion turbine project and/or the Boulder Park generation project. During periods where Lancaster is not dispatched and the transportation is not utilized for other Avista gas-fired facilities, the utility may be able to optimize the transportation value by purchasing gas at the lowest priced trading point on the transportation path and selling gas at the highest-priced trading point on the transportation path. During extended periods where the plant is offline, the company also has the option of releasing the transportation capacity in the capacity rePower Purchase Agreement market.

The transportation capacity on the GTN pipeline segment, in both the north-to-south and the south-to north directions, is under a contract held by Shell Corporation that will be temporarily assigned to Avista Corp for the period January 1, 2010 through October 31, 2017. Shell currently holds roll-over rights to that capacity. The company expects to be able to acquire transportation capacity necessary to replace that temporary assignment of firm capacity on the GTN system prior to October 31, 2017.

Comparison To Other Combined Cycle Combustion Turbine Plants

The Lancaster Power Purchase Agreement opportunity was made available to the utility as part of the sale of Avista Energy to Coral Energy. The company made comparisons to other similar resources based on industry data available at the time. In addition, the company had requested Thorndike Landing to perform comparisons to other combined cycle plants as part of their independent analysis.

Avista IRP – Comparative Analysis:
As stated earlier, the company's 2007 IRP selected 350 MW of combined cycle combustion turbine resource for acquisition by 2017. The IRP used generic resource assumptions to provide a roadmap with regard to the type of resources that Avista should procure. The company

developed the generic CCCT plant cost from a combination of NPPC data, purchased plant modeling data, and other publically available plant cost data. The generic CCCT plant is assumed to be located in Idaho, resulting in lower fuel costs, and connected to Avista's transmission system thereby avoiding third-party wheeling charges. The expected cost for the generic CCCT resource was $786 per kW in 2007 dollars ($850 per kW in 2010 dollars) and escalated at 2.8% per year. Using the plant and market data from the 2007 IRP, a generic resource beginning service in 2010, was estimated to cost $83.64 per MWh (2010 nominal dollars, levelized over the period 2010-2040 and excluding the cost to firm natural gas transportation)[1].

Avista – Plant Comparisons:
Shortly after Avista Energy's sale to Coral, Goldman Sachs announced that it was selling its interest in Lancaster along with a substantial portion of its Cogentrix's resource portfolio. The Lancaster Generation Facility, along with 13 other facilities across the country, was put up for auction. Avista responded to Goldman's announcement with a proposal for the purchase of Lancaster. Goldman later sold 80% of its Cogentrix resource portfolio interest, including Lancaster, to Energy Investors Funds Group for an undisclosed amount.

Avista performed several Lancaster valuation studies in preparation for making a purchase proposal, which included a comparison to similar combined cycle combustion turbine plant transactions in the Northwest. The analysis included comparisons between Coyote Springs 2, Port Westward, Goldendale, and Lancaster. The comparative analysis calculated the levelized cost of each plant as if Avista owned the resource. Table No. 8 shows the levelized costs in nominal 2010 dollars for each resource studied. This table shows that the Lancaster Power Purchase Agreement is slightly more expensive than Avista's previous acquision of Coyote Springs 2. The Port Westward and Goldendale plants would be significantly more costly to Avista because of fuel costs and other costs associated with the locations of the facilities. Port Westward and Goldendale both have fuel supplies based on higher Sumas prices whereas Lancaster and Coyote Springs 2 are based on AECO prices. Goldendale is also at a financial disadvantage because it must pay the Washington state fuel tax and has a higher heat rate because of its hybrid cooling technology. The Port Westward project is a greenfield facility which has relatively higher capital requirements.

Table No. 8
Lancaster Levelized Cost vs. Other Regional CCCT Projects

Plant	Levelized Cost (2010-2026) $/MWh
Coyote Springs 2	78.37
Goldendale	97.72
Port Westward	92.80
Lancaster Power Purchase	79.37

[1] The 2007 IRP at page 6-19 shows a CCCT cost estimate of $65.14 per MWh in 2007 levelized real dollars over the plant life. This amount is equivalent to the $83.64 per MWh in 2010 levelized nominal dollars.

Agreement	

For each plant, the levelized cost consists of all fuel costs, variable O&M, transmission cost and losses, emissions costs (based on 2007 IRP), fixed O&M, fuel transport, outage risk, site value, property taxes, income taxes, state fees, and Power Purchase Agreement payments and debt equivalent charges. The levelized cost values shown are based on the plants operating at their maximum availability. In reality, the plants would not operate during all periods of the year, and would be displaced with lower cost market purchases.

The levelized cost results shows that the Lancaster project Power Purchase Agreement is comparable to the Coyote Springs 2 project and a better alternative than either the Goldendale or Port Westward projects would have been for Avista's customers.

Thorndike Landing – Plant Comparison:
Thorndike also performed a valuation of Lancaster under an ownership scenario which was then compared to ownership values of other recent plant transactions. This represents 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. [Note that the variable dispatch cost does not include the Power Purchase Agreement cost in the case of Lancaster or the recovery of capital or fixed costs in the case of other plants.] The comparison indicates that the Lancaster project has a greater value than other recently constructed or transacted facilities in the region. Though Avista does not own the Lancaster plant, this comparison is a strong indication that a similar Power Purchase Agreement (or toll) opportunity at one of these other plants would be somewhat less favorable economically to the company than the Lancaster opportunity. Plant values are summarized in the following Table No. 9

Table No. 9
Lancaster Plant Value vs. Other Regional CCCT Projects

Description	Plant Value ($000)	Plant Value ($/kW)
Lancaster	$177,500	$677
Coyote Springs 2	$169,500	$652
Port Westward	$236,000	$528
Goldendale	$84,000	$365

Thorndike Landing attributes the greater relative value of the Lancaster project to the following primary drivers:

- Lower electric transmission costs;
- Lower natural gas transportation costs;

- Lower natural gas taxes (the state of Idaho has no fuel tax); and
- Dual sourcing of fuel (Alberta/Malin vs. Sumas).

Self-Build Alternatives

As described in the cost-effectiveness section, self-build options were expected to be more expensive than the Power Purchase Agreement agreement. The Power Purchase Agreement was estimated to be between $62 and $78 million dollars less than an equivalent greenfield project. Thorndike Landing concurred with this conclusion.

Revenue Requirement Impact

While the Lancaster project becomes available one year prior to the company's annual average resource need in 2011, as indicated in the company's 2007 IRP, it is a timely opportunity to acquire a base-load resource at a cost lower than a new greenfield project and at a lower cost for Avista than similar projects transacted in the region. Even when compared to an alternative greenfield combined cycle combustion turbine plant that would come on-line with perfect timing, the Lancaster plant has a lower revenue requirement impact.

Table No. 10 shows the expected annual revenue requirement impact over the period 2010 through 2026 for Lancaster and a greenfield and brownfield plant, along with the decreased revenue requirement for the Lancaster plant compared to other capacity alternatives. The revenue requirement impact is calculated by subtracting the spot market energy value of the plant from the total plant cost. The remaining revenue requirement impact represents the capacity cost of acquiring a new resource.

As shown in Table No. 10 below, a greenfield plant coming on-line in 2011 would be expected to cause a levelized revenue requirement impact that is $11.3 million/year greater than Lancaster over the period 2010 to 2026. Acquisition of a similar brownfield plant located outside of the utility's service territory (at a cost of $500/kW as shown in the April 2007 analysis) is calculated to have a levelized revenue requirement impact that is $300,000/year greater than Lancaster over the period 2010 to 2026.

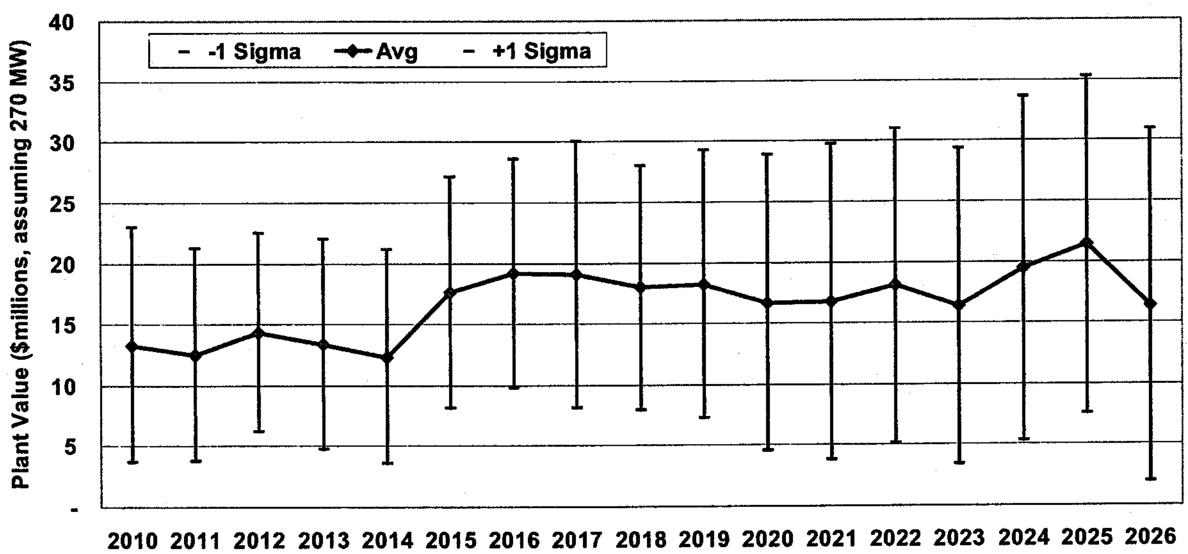
Table No. 10
Annual Revenue Requirement Impact ($million/year)

	Revenue Requirement Impact			Lancaster Savings vs	
Year	$850/kW Green Field	$500/kW Brown Field	Lancaster Lease	$850/kW Green Field	$500/kW Brown Field
2010	0.0	0.0	12.9	(12.9)	(12.9)
2011	31.3	18.3	14.2	17.1	4.2
2012	32.8	18.7	13.0	19.8	5.7
2013	32.9	19.2	14.3	18.5	4.9
2014	33.1	19.9	15.8	17.3	4.1
2015	27.4	14.7	11.3	16.1	3.3
2016	25.4	13.1	10.5	14.9	2.6
2017	24.9	13.0	11.1	13.8	1.9
2018	25.3	13.8	12.6	12.7	1.2
2019	24.6	13.4	12.9	11.6	0.5
2020	25.5	14.7	14.9	10.5	(0.2)
2021	24.9	14.6	15.5	9.4	(0.9)
2022	23.2	13.3	14.9	8.4	(1.6)
2023	24.3	14.8	17.1	7.3	(2.3)
2024	21.0	11.8	14.8	6.2	(3.0)
2025	18.8	10.0	13.7	5.1	(3.7)
2026	23.0	14.6	19.0	4.0	(4.4)
Levelized	25.5	14.5	14.1	11.3	0.3

Sensitivity Analyses

Several sensitivity analyses were performed as part of the Lancaster assessment process. The company's IRP analysis process provided figures for both the intrinsic and extrinsic values of the Lancaster plant over 300 Monte Carlo iterations of market conditions (varied for natural gas price, hydroelectric generation levels and forced outages) during the term of the Lancaster Power Purchase Agreement. 2007 IRP results for the range of value attributed to a gas-fired CCCT are show in Table No. 11 below.

Table No. 11
Lancaster Plant Value – Sensitivity Analysis



Thorndike Landing valued the Lancaster tolling arrangement under Base Case, Low Case and High Case conditions as explained in their report and the results of which are previously summarized in Table No. 5. That sensitivity analysis indicates that the Lancaster plant performs well against the market due largely to circumstance that natural gas-fired generation is the marginal resource in the regional marketplace.