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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-11-01 DIRECT TESTIMONY OF ROBERT J. LAFFERTY

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

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

A. My name is Robert J. Lafferty. I am employed as the Director of Power Supply at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

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

A. Yes. I received a Bachelor of Arts degree in Business Administration and a Bachelor of Science degree in Electrical Engineering from Washington State University, both in 1974. I began working as a distribution engineer for Avista in 1974 and held several different engineering positions with the Company. In 1979, I passed the Professional Engineering License examination in the state of Washington. I have held management positions in engineering, marketing, demand-side-management and energy resources. I began work in the Energy Resources Department in March 1996, and have held various positions involving the planning, acquisition and optimization of energy resources. I became the Director of Power Supply in March 2008, where my primary responsibilities involve management and oversight of the short- and long-term planning and acquisition of power resources for the Company.

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

A. My testimony provides an overview of Avista's resource planning and power supply operations. This includes summaries of the Company's generation resources, the current and future load and resource position, future resource plans, and an update on the Company's plans regarding the acquisition of new renewable resources. As part of an overview of the Company's risk management policy, I will provide an update on the Company's hedging practices. I will address hydroelectric and thermal project upgrades, followed by an update on recent developments regarding hydro licensing.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 4, Schedule 1, which includes Avista's 2009 Electric Integrated Resource Plan, Schedule 2 which provides a forecast of Company load and resource positions from 2011 through 2031, and confidential Schedule 3C which includes Avista's Energy Resources Risk Policy.

II. RESOURCE PLANNING AND POWER OPERATIONS

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

A. Yes. Avista's resource portfolio consists of hydroelectric generation projects, base-load coal and natural gas-fired combined-cycle generation facilities, woodwaste-fired generation, natural gas-fired peaking generation, 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 1,777 MW, which includes 56% hydroelectric and 44% thermal resources.

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

Illustration No. 1: Avista's Generation

Avista-Owned Generation							
Hydroelectric Generation	**MW**		**Base-Load Thermal Generation**	**MW**		**Natural Gas Peaking Generation**	**MW**
Noxon Rapids	557		Colstrip Units 3 & 4	222		Northeast CT	56
Cabinet Gorge	255		Coyote Springs 2	278		Kettle Falls CT	7
Post Falls	18		Kettle Falls	50		Boulder Park	24
Upper Falls	10					Rathdrum CT	149
Monroe Street	15						
Nine Mile	18						
Long Lake	83						
Little Falls	35						
Total Hydroelectric	**991**		**Total Base-Load Thermal**	**550**		**Total Peaking**	**236**
Total Owned Generation	**1,777 MW**						

In addition, the Company currently has long-term contractual rights for 134 aMW from Mid-Columbia hydroelectric projects in 2012, from projects owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Avista also has a long-term power purchase agreement (PPA) in place entitling the Company to dispatch, purchase fuel for and receive the power output from the 275 MW Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho.

Q. Would you please provide a summary of Avista's power supply operations and planning for new resources?

A. Yes. Avista uses a combination of owned and contracted-for resources to serve its load requirements. The Power Supply Department is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. The Department monitors and routinely studies capacity and energy resource needs. Short- and medium-term wholesale transactions are used to economically balance resources with load requirements. Longer-term resource decisions such as the acquisition of new generation resources, upgrades to existing resources, energy efficiency measures, and long-term contract purchases are generally made in conjunction with the Integrated Resource Plan (IRP) and will typically include a Request for Proposals (RFP) or other market due diligence process.

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

A. Avista's 2009 Electric Integrated Resource Plan shows forecasted annual energy deficits beginning in 2018, and sustained annual capacity deficits beginning in 2019.[1] These capacity and energy load/resource positions are shown on pages 2-27 and 2-28, respectively of Schedule 1 of Exhibit No. 4. However, our most recent load and resource projection, which is attached as Schedule 2 of Exhibit No. 4, indicates that the annual deficits have moved out another year. Therefore, Avista's current projection shows an annual energy deficit beginning in 2020 of about 19 aMW, and increasing to a 406 aMW deficit in 2031. The Company's January capacity resource position, based on an 18-hour peak event (6 hours per day and over 3 days), is currently projected to be surplus through 2021. Sustained annual capacity deficiencies, based on a January peak, begin at 148 MW in 2022 and increase to a 779 MW deficit in 2031. The Company's August capacity resource position, based on an 18-hour peak event, is currently projected to be surplus through 2018. Sustained annual capacity deficiencies, based on an August peak, begin at 56 MW in 2019 and increase to a 667 MW deficit in 2031.

Q. How does the Company plan to meet future energy and capacity needs beginning in 2020 and 2019, respectively?

[1] The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 which results in short-term annual capacity deficits in 2015 and 2016. Sustained annual capacity deficits begin in 2019.

A. The Company will be guided by its Preferred Resource Strategy. The current Preferred Resource Strategy is described in the 2009 Electric IRP, which is attached as Schedule 1 of Exhibit No. 4. The IRP provides details about projected resource needs, specific resource costs, resource operating characteristics, and the scenarios used for evaluating the mix of resources for the Preferred Resource Strategy.

The Company's 2009 Electric IRP was submitted to the Commission in August 2009, following the completion of a public process involving six Technical Advisory Committee meetings. The IRP represents the preferred resource plan at a point in time, however, the Company will continue evaluating resource options to meet future load requirements, including medium-term market purchases, generation ownership, hydroelectric upgrades, renewable resources, distribution efficiencies, energy efficiency measures, 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 may acquire some resources outside of formal RFP processes.

Avista's 2009 Preferred Resource Strategy includes 5 MWs of distribution efficiencies, 339 MWs of energy efficiency, 5 MWs of upgrades to existing hydroelectric plants, 750 MWs of natural gas-fired combined-cycle combustion turbine (CCCT), and 350 MWs of wind located in the Pacific Northwest. The timing of these resources as published in the 2009 IRP is shown in Illustration No. 2 below.

Illustration No. 2: 2009 Electric IRP Preferred Resource Strategy

Resource Type	By the End of	Nameplate	Energy
Northwest Wind	2012	150.0	48.0
Distribution	2010 / 2015	5.0	2.7
Little Falls	2013 / 2016	3.0	0.9
Northwest Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls	2020	2.0	1.0
Northwest Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Energy Efficiency	All Years	339.0	226.0
Total		1,449.0	1,020.6

Q. Are there any costs specifically associated with meeting Washington State's renewable portfolio standard included in this case?

A. No. All direct costs related to meeting Washington State's renewable portfolio standards have been assigned to Washington customers.

Q. Can you provide some background regarding why the Company initiated an RFP for renewable resources in 2011.

A. Yes. Avista has continued to monitor renewable resource market conditions, particularly with respect to projects bid into its 2009 renewable resource RFP. Avista was recently made aware of a significant drop in prospective project costs associated with construction of new wind generation facilities that are still in a position to take advantage of currently available near-term tax incentives for projects brought on-line prior to December 31, 2012. The material drop in project cost was the primary reason for the Company's decision to issue a request for proposals in February 2011 for up to 35 aMW of renewable energy. The 2011 renewable resource RFP seeks qualifying projects or project output for the 2012 to 2032 time period. Avista stated in the RFP that the Company expected that bids should not exceed $62/MWh and that Avista would not submit a self-build option. The combination of the significant drop in project cost and the substantial tax incentives available today for projects completed by December 31, 2012 point toward long-term benefits for customers compared to the alternative of waiting until a later time when tax incentives, attractive project pricing, and particularly attractive wind project sites may no longer be available to Avista.

Q. What is the status of the 2011 renewable resource request for proposals?

A. The Company completed its due diligence and negotiations for the 2011 renewable resource request for proposals. The Company has signed a 30-year power purchase agreement with Palouse Wind, LLC, (Palouse Wind) an affiliate of First Wind Energy, LLC. Under the PPA, Avista will acquire all of the power produced by a wind project being developed by Palouse Wind in Whitman County, Washington. The project will have approximately 100 MW of nameplate capacity and is expected to produce approximately 40aMW. Deliveries are expected to begin in the second half of 2012.

Q. What is the status of the Reardan wind project?

A. Avista continues to study the Reardan wind project site in preparation for later development. The Company expects to issue an RFP at a later date to meet additional future resource needs, and expects that the Reardan project would be considered in that later process. The Company chose not to introduce a Reardan project option into the 2011 renewable resource RFP primarily because of the short time frame available to secure competitive bids for turbines and balance of plant construction. When the Company decided in mid-February to initiate a 2011 renewable resource RFP, potential bidders had indicated that they would need a power purchase agreement executed by early to mid-May in order to be able to complete a project that would qualify for all of the available tax incentives. Therefore, Avista sought projects that were ready to be built and required bids to be due by March 7, 2011. The competitive bidding for wind turbines and balance of plant work necessary to prepare the Reardan project for evaluation did not fit into the short bidding window for this RFP.

Q. Can you provide an update of the Company's evaluation of a direct connection of Avista transmission to the Bonneville Power Administration's Lancaster substation?

A. Yes. Avista is currently engaged in a process with the Bonneville Power Administration (BPA) to jointly study interconnecting Avista's transmission lines to the BPA Lancaster substation, where the Lancaster plant is currently interconnected. The proposed project would interconnect the transmission systems of BPA and Avista at the BPA Lancaster substation. An Avista transmission interconnection to the BPA substation, however, would continue to utilize the BPA Lancaster substation. The costs associated with continued use of the substation would be subject to negotiation between the Company and BPA.

Pursuant to Avista's Line and Load Interconnection request dated September 2, 2009, Bonneville completed its Line and Load Interconnection System Impact Study on August 20, 2010 and is in the process of finalizing its Line and Load Interconnection Facilities Study, currently expected to be completed in August of 2011. Upon completion of the Line and Load Interconnection Facilities Study, Bonneville will tender a Construction Agreement to Avista. Bonneville has communicated to Avista that its current engineering and construction schedule suggests that the Avista-Bonneville Lancaster 230 kV interconnection may be constructed in 2013.

Construction of a stand-alone Avista interconnection (where the Lancaster project is disconnected from the Bonneville system and connected directly to the Avista system) would not provide the reliability benefits and additional import capacity that an Avista-Bonneville 230 kV transmission interconnection provides, therefore, this form of a self-build option has not received any further consideration as part of the joint study work.

III. RISK MANAGEMENT POLICY

Q. Can you provide a high level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving load and managing Company-owned and controlled resources. Avista's Energy Resources Risk Policy provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 36 months), the short-term (monthly and quarterly periods up to approximately 36 months), and the immediate term (present month). A copy of the current Energy Resources Risk Policy is in Confidential Schedule 3C in Exhibit No. 4.

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any particular time, but is a guideline used by management when making procurement decisions for electric power and natural gas fuel for generation. 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 Company aims to strategically develop or acquire long-term energy resources as suggested by the Company's IRP acquisition targets, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. On the other end of the time spectrum, electric power and fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability, reliability considerations, and other near-term operational factors.

For the short-term timeframe, the Company's Energy Resources Risk Policy guides its approach to hedging financially open forward positions. A financially open forward period position may be the result of either a short or a long position. A calendar quarter occurring at a future time is an example of such a forward period. A short position situation occurs when the Company has not yet purchased the fixed price fuel to generate power, nor, alternatively, has it purchased fixed price electric power from the market, in order to meet a projected average load for a forward time period. The amount of load that is in excess of the amount of fixed price power available for that forward time period represents an open short position.

A long position situation occurs when the Company has fixed priced generation or fueled generation above its expected average load needs (e.g. hydroelectric generation during the May-June time period) and has not yet made a fixed price sale of that surplus power into the market in order to balance resources and loads. The amount of fixed priced generation that is in excess of the average load for that forward period represents an open long position.

The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power in order to approach a generally balanced position against expected load as forward periods draw nearer.

Q. Please describe the Electric Hedging Plan.

A. The Electric Hedging Plan is detailed in Exhibit 2 of the Risk Policy (Exhibit No. 4, Confidential Schedule 3C). The use of the Electric Hedging Plan approach, as outlined in Exhibit 2 of the Risk Policy(Confidential Schedule 3C), describes what is essentially a layering strategy aimed to average-in purchases or sales of electric power and natural gas generation fuel over a period of time. This approach aims to smooth the impacts of price volatility in the energy markets.

The Electric Hedging Plan in the Risk Policy describes the basic analytic approach that the Company utilizes to guide hedging electric power positions over the short-term, prompt month, and through the next 34 to 36 month period. The plan guides management of financially open positions in increments of 25 aMW. Open financial positions that exceed 25 aMW are cured with a variety of transactions as permitted under the Risk Policy including fixed price physical power, fixed price physical natural gas, and combinations of financial fixed for floating swap transactions coupled with index physical transactions. The Company uses statistical price movement triggers, based on historic volatility in the forward power and natural gas markets, the entire short-term period and also uses triggers based on expiring time periods in the nearer-term period up to 18 months in the future to trigger transactions to cure open positions. The trigger indicators from the Hedge Scheduler statistical model are indicated on the daily position reports and provide guidance to management for prospective forward transactions. Additional details concerning how the Hedge Scheduler works can be found in Exhibit 2 of the Energy Resources Risk Policy. (Exhibit No. 4, Confidential Schedule 3C).

Q. Can you provide some additional background regarding how the near-term hedging plan operates?

A. Yes. The Electric Hedging Plan (sometimes referred to as the "Hedge Scheduler") operates somewhat differently between two separate time periods within the short-term 36-month window. The period beginning with the prompt month and up to approximately 18 months into the future, as determined by the monthly and quarterly tradable forward periods, focuses on mechanically layering in transactions, as well as taking advantage of price declines in electric energy or fuel prices. The period approximately 19 months to 36 months into the future, as determined by the number of quarterly tradable forward periods, primarily looks for declines in electric energy prices or fuel prices.

Electric surplus and deficit positions are hedged using the Electric Hedging Plan as a guide and may be adjusted by management judgment depending upon the circumstances of a particular surplus or deficit situation. The short-term electric position report is distributed each business day.

The power supply position is managed by the Director of Power Supply. Similar types of position issues are also addressed in regards to natural gas supplies and are managed by the Director of Gas Supply. Any changes to practices are communicated to the Risk Management Committee.

The Risk Management Committee (RMC) is comprised of Avista management who are not directly part of Energy

Resources operations, and are appointed by the Chief Executive Officer. The RMC provides an oversight and advisory role concerning energy resource management and wholesale energy market risk policies and adherence to those policies.

IV. GENERATION CAPITAL PROJECTS

Q. Please describe the upgrade projects for the Noxon Rapids generating units.

A. The Company is nearing the end of a multi-year program to upgrade four of the five Noxon Rapids generating units from 1950's era technology[2]. Once completed, the upgrades on these four units are expected to improve reliability and increase efficiency by adding 30 MW of additional capacity and approximately 6 aMW of energy to the Noxon Rapids project. Illustration No. 3 below summarizes the upgrade schedule, and the additional capacity and efficiency gains of these upgrades by unit.

Illustration No. 3: Noxon Rapids Upgrades

Noxon Rapids Unit #	Schedule of Completion	Additional Capacity	Efficiency Improvement
1	April 2009	7.5 MW	4.16%
3	April 2010	7.5 MW	4.15%
2	May 2011	7.5 MW	2.42%
4	May 2012	7.5 MW	1.49%

The Noxon Unit #1 work included the replacement of the stator core, rewinding the stator, installing a new turbine and performing a complete mechanical overhaul. This

[2] The fifth unit was installed in 1977.

upgrade increased the Unit's energy efficiency by 4.16%, and increased the unit rating by 7.5 MW. The upgrade also fixed several reliability concerns for Unit #1 including mechanical vibration and stator age. This work was completed in 2009. The costs and additional generation of this project were pro formed, and approved for recovery, in Case No. AVU-E-09-01.

The Noxon Unit #3 upgrade, completed in May 2010, increased energy efficiency by 4.15%, and boosted the unit rating by 7.5 MW. The costs and additional generation for Unit #3 were approved for recovery in Case No. AVU-E-10-01.

Noxon Unit #2 had a new turbine installed and complete mechanical overhaul in May of this year. This upgrade is projected to increase Unit #2 efficiency by 2.42% and increase the unit rating by 7.5 MW. The costs for the Unit #2 upgrade were $9.1 million (system).

The upgrade work at Noxon Unit #4 involves the installation of a new turbine and a complete mechanical overhaul starting in August 2011 and ending in May 2012. The Unit #4 upgrade is projected to increase efficiency by 1.49% and increase the unit capacity rating by 7.5 MW.

The costs associated with Noxon Unit #2 are $9.1 million (system) and Unit #4, planned for completion in May 2012, will cost approximately $8.8 million (system). Company witness Ms. Andrews incorporates the Idaho share of these costs in her adjustments. The increased generating capability from these units is reflected in Mr. Kalich's $AURORA_{XMP}$ modeling of pro forma power supply costs.

Q. Can you please provide a brief description of the other generation-related capital projects that are included in this case?

A. Yes. The total 2011 and 2012 generation projects included in the Company's case, as identified by Company witness Mr. DeFelice and described below, total $59.6 million on a system basis. The 2011 Noxon Unit #2 and Unit #4 upgrade projects discussed above represent $17.9 million of this total. The other generation capital projects totaling $41.9 million (system), are discussed below.

Thermal - Kettle Falls Capital Additions - $1,731,000

Kettle Falls Capital Projects include the acquisition of water rights and subsequent development of the wells for the long-term plant water supply beginning in 2011. The other major capital project includes the replacement of the boiler control system (DCS). $731,000 of capital additions for this category are for 2011 and the remaining $1,000,000 of capital additions are for 2012.

Thermal - Colstrip Capital Additions - $11,889,000

Colstrip capital additions in 2011 and 2012 include major work on the ash storage ponds for Units 3 and 4. This project will increase the capacity of the ponds to their final permitted level and is necessary for continued plant operation. During our 2011 outage on Unit 3, we completed installation of a new set of low pressure rotors, a major inspection of the intermediate pressure turbine, a generator rewind and other capital projects as part of our maintenance program to maintain plant reliability and performance. Capital additions for 2012 include superheat section replacement costs for Unit 4, environmental costs associated with the EPA's Hazardous Air Pollutants rule, and a rotor rewind. $6,926,000 of the capital additions for this category are for 2011 and the remaining $4,963,000 are for 2012 capital additions.

Thermal - Coyote Springs 2 Capital Additions - $11,030,000

At Coyote Springs 2, we are expected to reach 48,000 hours of operation. Major gas turbine components are scheduled to be inspected and/or replaced in accordance with original