

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-11 \_\_\_\_\_

DOCKET NO. UG-11 \_\_\_\_\_

DIRECT TESTIMONY OF

DAVE B. DEFELICE

REPRESENTING AVISTA CORPORATION

**I. INTRODUCTION**

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

A. My name is Dave DeFelice. I am employed by Avista Corporation as a Senior Business Analyst. My business address is 1411 East Mission, Spokane, Washington.

**Q. Please briefly describe your educational background and professional experience.**

A. I graduated from Eastern Washington University in June of 1983 with a Bachelor of Arts Degree in Business Administration, majoring in Accounting. I have served in various positions within the Company, including Analyst positions in the Finance Department (Rates Section and Plant Accounting) and in the Marketing/Operations Departments, as well. In 1999, I accepted the Senior Business Analyst position that focuses on economic analysis of various project proposals as well as evaluations and recommendations pertaining to business policies and practices.

**Q. As a Senior Business Analyst, what are your responsibilities?**

A. As a Senior Business Analyst, I am involved in financial analysis of numerous projects within various departments such as Engineering, Operations, Marketing/Sales and Finance.

**Q. What is the scope of your testimony?**

A. My testimony and exhibits in this proceeding will cover the Company's proposed restating and pro forma adjustments for capital investments in utility plant for the 2010 test period.

**Q. Are you sponsoring any exhibits?**



1           (2)     An adjustment was also made to reflect certain 2011 capital additions  
2           together with the associated accumulated depreciation and deferred federal  
3           income taxes at a 2012 AMA basis. This adjustment included associated  
4           expenses (depreciation expense and property taxes) and offsets to expenses for  
5           the pro forma additions. These specific capital additions are identified later in  
6           my testimony.

7           (3)     An adjustment was also made to include the 2011 Noxon Unit #2  
8           generation plant upgrade (approved in the 2010 rate case), and the 2012 Noxon  
9           Unit #4 generation plant upgrade at a 2012 AMA basis.<sup>1</sup>

10           The utility plant investment that we have included in this filing represents utility plant  
11           that will be "used and useful" in providing service to customers during the period that new retail  
12           rates from this filing will be in effect and will be "known and measurable." In addition, the plant  
13           investment that was pro formed into this case was matched with offsetting factors. Including the  
14           costs associated with this investment in retail rates provides a proper "matching" of revenues  
15           from customers, with the costs associated with providing service to customers (including the cost  
16           of utility plant to serve those customers).

17           **Q.     Is the Company's application of these ratemaking principles in this filing**  
18           **consistent with prior general rate cases?**

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<sup>1</sup> The 2012 Noxon upgrade will be completed in May 2012. The Company included this investment since the project is part of a multi-year upgrade at the facility and is included in the Aurora power cost model for the 2012 rate year. The costs of these Noxon upgrades have previously been approved by the Commission as pro forma adjustments. See Paragraph No. 81 in Order 10 in Docket No. UE-090134.

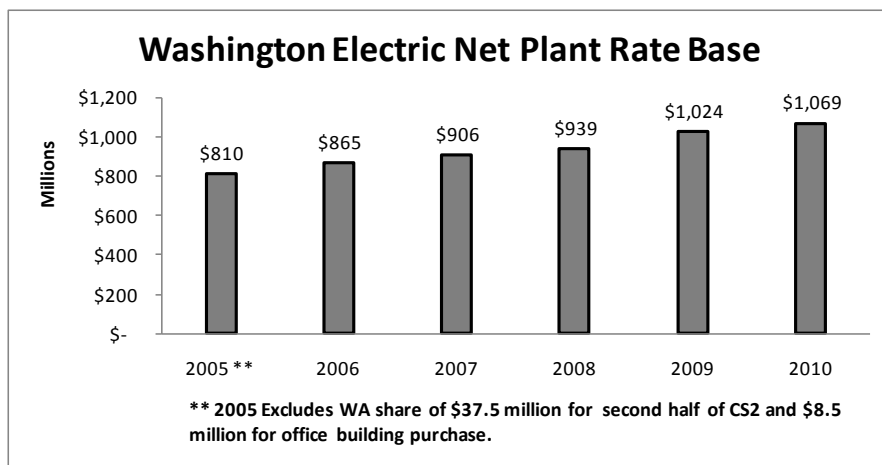
1 A. Yes. In prior cases, the objective has been the same -- to include in retail rates the  
 2 investment, or rate base, that is providing service to customers, and ensure that there is a proper  
 3 matching of revenues and expenses during the period that rates are in effect.

4 **Q. How does new investment in utility plant change rate base over time for**  
 5 **ratemaking purposes?**

6 A. Historically (until roughly the last five years), the annual dollars spent by the  
 7 Company on new utility plant was relatively close to the level of depreciation expense, with the  
 8 exception of years where the Company invested in major new generating projects.<sup>2</sup> Net rate base  
 9 stayed at a relatively constant level and the use of the rate base amount from a prior year, i.e., a  
 10 historical test year, would be adequate for setting rates for the upcoming year, because there was  
 11 little change in the net plant investment used to serve customers.

12 In more recent years, however, Avista’s investment in utility plant has significantly  
 13 exceeded depreciation expense. Because of this, rate base in the rate year is significantly greater  
 14 than the historical test period AMA rate base. This is shown in Illustration 1 below.

15 **Illustration 1:**



<sup>2</sup> Recognizing that a portion of the costs associated with certain capital additions are offset by additional revenues.

1           The only way to ensure that retail rates are fair, just, reasonable, and sufficient is for the  
2 utility plant investment that is being used to serve customers be properly reflected in retail rates,  
3 net of appropriate offsets. This makes it necessary for the Company to pro form plant investment  
4 that is in service after the historical test year, and will be in service during the rate year so that  
5 rate base for the pro forma rate year is representative of the level of investment used to serve  
6 customers. The Company's pro forma adjustments in this case properly reflect any offsets, and  
7 include adjustments to ensure a proper matching with test period loads.

8           **Q.    What is the historical and projected level of annual capital spending for**  
9 **Avista?**

10          A.    Avista's annual capital requirements have steadily increased from approximately  
11 \$130 million in 2005 to approximately \$250 million in 2011. Capital expenditures of  
12 approximately \$482 million are planned for 2011-2012 for customer growth, investment in  
13 generation upgrades and transmission and distribution facilities, as well as necessary  
14 maintenance and replacements of our natural gas utility systems. Capital expenditures of  
15 approximately \$1.2 billion are planned for the five year period ending December 31, 2015.  
16 Exhibit No. \_\_\_\_ (DBD-2) reflects this trend that Avista has experienced and what is planned for  
17 in the near future.

18          **Q.    What is driving the significant investment in new utility plant?**

19          A.    As Company witnesses Mr. Kinney and Mr. Lafferty, in particular, explain in their  
20 testimony, the Company is being required to add or upgrade new generation facilities, expand  
21 transmission and distribution facilities due in part to customer growth in our service area,  
22 reliability requirements, and needed capacity upgrades. Other issues driving the need for capital

1 investment include an aging infrastructure, physical degradation, and municipal compliance  
2 issues (e.g., street/highway relocations), etc.

3 While the rate of increases experienced in recent years for the cost of materials (concrete,  
4 copper, steel, etc.) has subsided, the cost of materials and equipment is still orders of magnitude  
5 higher than what they were even a few years ago, causing the cost of these new facilities to be  
6 significantly higher than in the past. Accordingly, the annual costs associated with the new  
7 facilities will be significantly higher than the annual costs of the Company's older, existing  
8 facilities.

9 **Q. What data is available that depicts the significant increase in the cost of**  
10 **utility plant assets that have been added in recent years as compared to the cost of the**  
11 **facilities being replaced?**

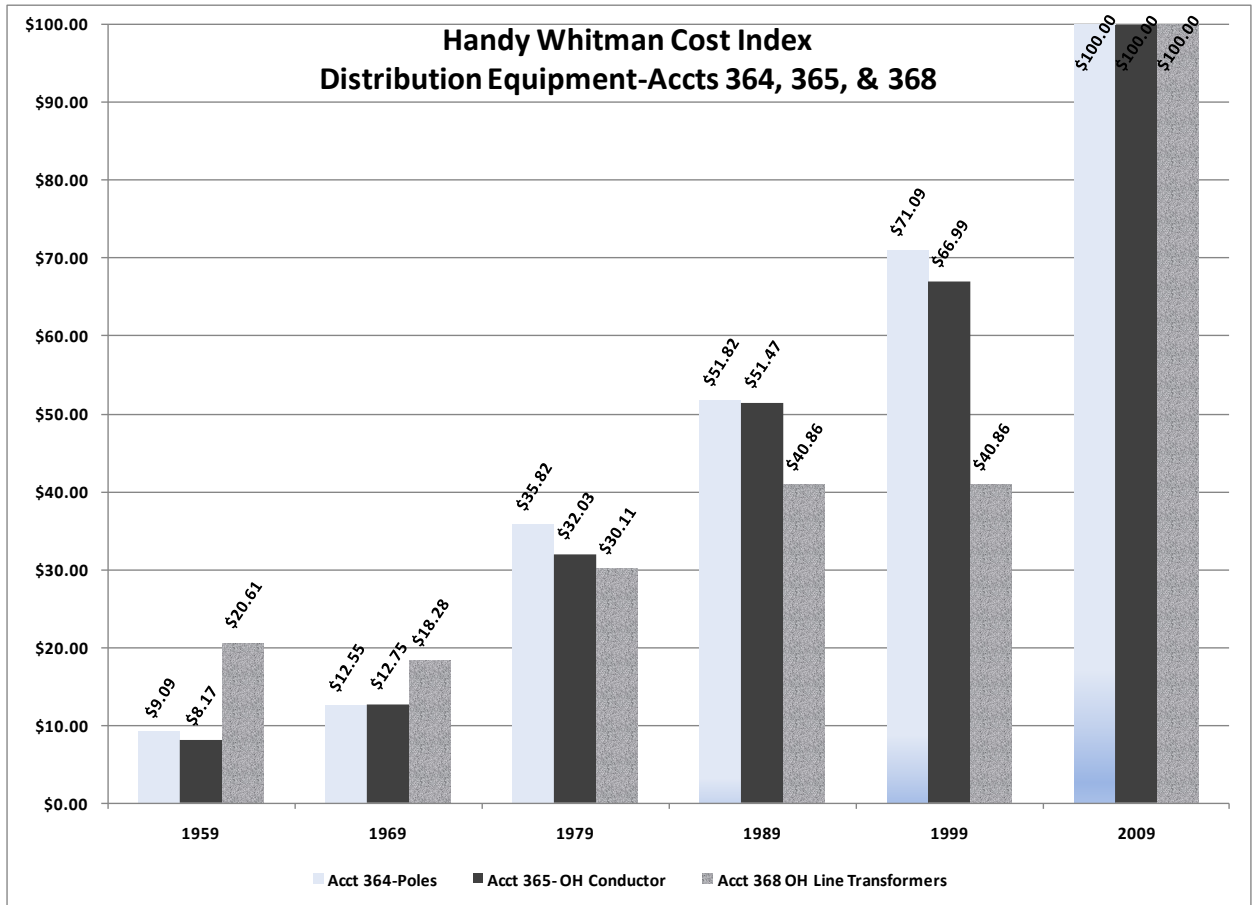
12 A. Using the Handy-Whitman Index Manual<sup>3</sup>, the Company analyzed several major  
13 categories of plant. Exhibit No. \_\_\_\_ (DBD-3) depicts the increases in costs of transmission  
14 substations, transmission equipment, distribution substations, and distribution equipment that the  
15 utility industry has experienced over the past fifty years. These charts show what these  
16 categories of plant have cost historically on a relative scale. For example, on Page 4 of Exhibit  
17 No. \_\_\_\_ (DBD-3), and also shown in Illustration 2 below, distribution poles fifty years ago would  
18 have a cost of only 9% of the current replacement cost.

19

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<sup>3</sup> "The Handy-Whitman Index of Public Utility Construction Costs", published by Whitman, Requardt and Associates, Baltimore, Maryland; all rights reserved. The Handy-Whitman Indexes of Public Utility Construction Costs show the level of costs for different types of utility construction. Separate indices are maintained for general items of construction, such as reinforced concrete, and specific items of material or equipment, such as pipe or turbo-generators. Handy-Whitman Index numbers are used to trend earlier valuations and original cost at prices prevailing at a certain date.

**Illustration 2:**



The charts on Exhibit No. \_\_\_(DBD-3), show that the cost of the same equipment and facilities that are being added today are multiple times more expensive than those facilities installed in the past.

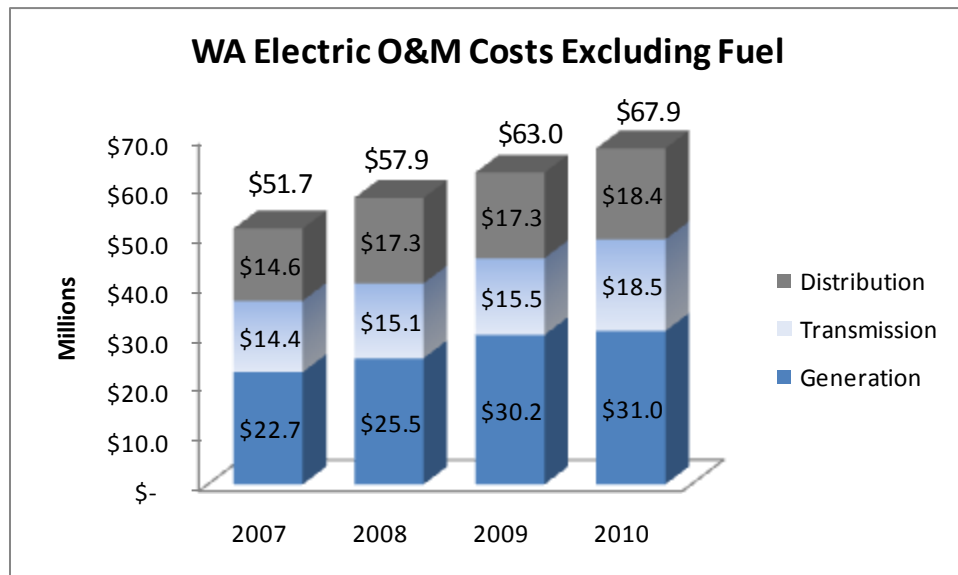
**Q. With respect to Avista’s proposed pro forma capital additions, would there be some operation and maintenance (O&M) savings associated with the replacement of some of the aging equipment with new equipment?**



1 A. Not when you look at the total utility as a whole, which is how ratemaking is  
 2 done.<sup>4</sup> At some point our facilities approach the end of their useful lives and need to be replaced  
 3 before they fail. Our general practice is to attempt to replace our aging equipment before it fails,  
 4 because it is not only less costly to replace this equipment on a structured, planned basis, but it  
 5 also results in more reliable service to customers, which is expected by all utility stakeholders. If  
 6 our practice were to avoid replacing utility equipment until it failed, the reliability of our system  
 7 would suffer.

8 Therefore, it is imperative that we continue every year to reinvest and upgrade a portion  
 9 of our utility system, in addition to the investments to meet mandatory reliability requirements,  
 10 so that our system will continue to provide reliable service. On a net basis, we will continue to  
 11 experience O&M costs to maintain a system that continues to age. Our O&M costs are  
 12 continuing to go up over time, not down, as shown in Illustration 3 below.

13 **Illustration 3:**



<sup>4</sup> As described below, all of the capital that was pro formed was reviewed for any offsets and any specific offset that was identified was included in the pro forma adjustment as a reduction to O&M costs.

1           The reinvestment and upgrades actually serve, to a large extent, to allow the Company to  
2 avoid additional costs in the future associated with maintenance – not to reduce the overall level  
3 of existing O&M costs. Mr. Kinney provides additional testimony in this area.

4           **Q. Will the additional revenue from load growth that the Company will**  
5 **experience in 2012 over the test year loads, cover the additional costs from the capital**  
6 **investment that the Company will make in 2011 and 2012?**

7           A. No. Because of the design of the Retail Revenue Credit that is included in the  
8 Company's Energy Recovery Mechanism (ERM), load growth does not provide additional  
9 revenues to offset increased costs associated with new capital additions and increased operation  
10 and maintenance expenses.

11           As load growth occurs over time there is a higher power supply expense to serve the  
12 increase in load. The amount of power supply expense that is above the amount authorized in  
13 rates is captured and deferred in the ERM. The Retail Revenue Credit takes into account the fact  
14 that there is also an increase in retail revenue from the increase in retail load. Hence, a Retail  
15 Revenue Credit amount is credited to the ERM deferral account.

16           The rate used to calculate the Retail Revenue Credit is based on the fixed and variable  
17 production and transmission costs authorized in the Company's last rate case. Company witness  
18 Ms. Knox shows the calculation of the Retail Revenue Credit in her Exhibit No. \_\_\_\_ (TLK-2).  
19 So, there is no new production and transmission related revenue from load growth available to  
20 offset costs associated with new capital additions and increased, non-power supply, operation  
21 and maintenance expenses, since the new revenue is deferred as a credit in the ERM.

1           Load growth also causes increased costs associated with distribution capital additions  
2 from hooking up new customers. Hence, the distribution portion of the new revenue from load  
3 growth is necessary to offset the new, direct, distribution costs necessary to bring service to new  
4 customers, and is not available to offset capital additions necessary to replace aging production,  
5 transmission, and back-bone distribution infrastructure, or increased operation and maintenance  
6 expenses.

7           **Q.     Does the Company have a Retail Revenue Credit as a component of its Power**  
8 **Cost Adjustment (PCA) in its Idaho jurisdiction, and how does it compare to the Retail**  
9 **Revenue Credit in the Washington ERM?**

10           A.     Yes. The Company does have a Retail Revenue Credit as a component of its PCA  
11 in Idaho. The Retail Revenue Credit in Idaho was recently modified. (See Idaho Public Utilities  
12 Commission, Case No. GNR-E-10-03, Order No. 32206, March 15, 2011.) The previous Idaho  
13 Retail Revenue Credit rate was calculated in the same manner as the Washington Retail Revenue  
14 Credit rate is currently calculated. The Credit included fixed and variable production and  
15 transmission costs authorized in the Company's last rate case.

16           Effective April 1, 2011, the new Retail Revenue Credit in Idaho was changed to be based  
17 upon the energy classified portion of embedded production revenue requirement as established in  
18 the Company's cost of service study from its last rate case. The new methodology lowers the rate  
19 that is applied to changes in load in the PCA, and allows the Company to retain the appropriate  
20 revenue from load growth to offset increased capital and O&M costs of providing service. As  
21 long as the Retail Revenue Credit in Washington is designed to give back to customers the new  
22 revenue from load growth related to the production and transmission capital investment and

1 O&M costs, it is necessary to pro form in the production and transmission capital additions and  
 2 O&M costs for the rate year, in order to allow Avista to recover these costs in rates.

3 **Q. If Avista were to be granted 100% of its rate relief request in this case, would**  
 4 **the increase in revenues provide full recovery of the costs associated with the capital**  
 5 **additions that are in place serving customers?**

6 A. No. Because of the design of the Retail Revenue Credit in the ERM and because  
 7 only limited capital investment in 2011 and 2012 was pro formed in this case, Avista will not  
 8 fully recover its costs in 2012 related to the capital additions that will be in place serving  
 9 customers. Approval of the capital additions pro formed into this case, however, will allow  
 10 Avista to make some progress in moving Avista's actual return on equity (ROE) closer to the  
 11 ROE authorized by the UTC.

12 **Q. Please summarize the capital additions made in 2010 through 2012 and the**  
 13 **capital additions that the Company has included in this filing?**

14 A. Table 1 below summarizes this data.

15 **Table 1:**

<b>Summary of Capital Additions Washington Electric Service (\$000s)</b>			
<b><u>Line Description</u></b>	<b><u>2010</u></b>	<b><u>2011</u></b>	<b><u>2012</u></b>
1 Capital Additions, excluding New Customer Growth Plant	\$ 100,600	\$ 107,500	\$ 92,500
2 New Customer Growth Plant Capital Additions	13,100	15,000	13,100
3 Total Capital Additions	<u>\$ 113,700</u>	<u>\$ 122,500</u>	<u>\$ 105,600</u>
4 Depreciation Expense	<u>\$ 53,200</u>	<u>\$ 55,000</u>	<u>\$ 58,000</u>
5 Capital Additions Authorized in 2010 GRC	<u>\$ 7,732</u>	<u>\$ 3,796</u>	
6 Capital Additions Restated/Pro Formed in Current Filing	<u>\$ 17,230</u>	<u>\$ 32,600</u>	<u>\$ 3,400</u>

1

2 Line 3 of the table shows that the Company has or will invest between \$105 million and  
3 \$123 million each year in Washington for electric service. Depreciation expense on Line 4 is  
4 between \$53 million and \$58 million each year, which is considerably less than the investment.  
5 Line 5 of the table also shows that in our last general rate case, the additions in 2010 and 2011  
6 that were authorized did not come close to the non-revenue producing investment that the  
7 Company made in excess of depreciation expense. And finally, Line 6 shows that the capital  
8 additions pro formed in this case are also significantly less than the investment that will be made,  
9 and that will be providing service to customers during the rate year.

10 **Q. What 2011 and 2012 capital additions were pro formed into rate base in this**  
11 **case?**

12 A. The Company included major electric generation plant additions, major  
13 transmission plant, including those that were required by laws, regulations, or directives from  
14 regulatory bodies, and major, non-revenue producing distribution plant that is part of the  
15 Company's Asset Management Program described by Mr. Kinney, that will be in service by  
16 December 31, 2011. In addition, the Company included the 2012 Noxon Unit #4 generation  
17 plant upgrade. The additional generation from this upgrade was factored into the Company's  
18 power supply model. All of the plant investment pro formed in this filing was stated at the 2012  
19 AMA basis.

20 Although there is a strong case to be made that all of the new capital investment in 2011  
21 and 2012 will be used to serve customers during the 2012 rate year, and should be reflected in  
22 this case, the Company has only included certain 2011 new investment and only the 2012 Noxon

1 Unit #4 Upgrade in this filing. By excluding most of the 2011 new investment and almost all of  
 2 the 2012 new investment, the rate base used to serve customers in 2012 will not be recovered in  
 3 rates, i.e., we have understated our costs to serve customers in 2012. As such, this represents a  
 4 conservative portrayal of our plant-in-service during the rate year. And as I explained earlier,  
 5 because of the current design of the Retail Revenue Credit in the ERM, which credits back to  
 6 customers the additional revenue from load growth that would otherwise cover the new  
 7 investment, Avista will not recover the cost of the new capital investment unless it is pro formed  
 8 into rate base in a general rate case.

### 9 10 **III. DESCRIPTION OF CAPITAL PROJECTS**

11 **Q. Please provide a description of the 2010 capital projects that were annualized**  
 12 **in this filing.**

13 A. A short description of the capital projects and their costs<sup>5</sup> that transferred to plant  
 14 in service in 2010 and that are included in this filing follows:

15 **Generation (\$16.7 million - system):**

16 **Hydro – 2010 Noxon Unit #3 Upgrade - \$8,491,924**

17 As described by Mr. Lafferty, the Company is nearing the end of a multi-year program to  
 18 upgrade the Noxon Rapids generating units which are currently using 1950's era  
 19 technology. The upgrades on the four units are expected to improve efficiency by adding  
 20 an additional 30 MW of capacity and approximately 6 aMW of energy to the Noxon  
 21 Rapids project, as well as improve reliability. The upgrade work on Unit 3 was  
 22 completed in 2010, Unit #2 in 2011 and Unit #4 will be completed in 2012. The Unit #3  
 23 upgrade, completed in April 2010, increased energy efficiency by 4.15%, and boosted the  
 24 unit rating 7.5 MW. The costs and additional generation for Unit #3 were also pro

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<sup>5</sup> The costs shown for the 2010 capital projects that were annualized are system costs for generation and transmission additions and Washington's direct or allocated share of costs for the distribution and general plant capital additions. It should be noted that this does not represent the amount included in the restating adjustment. The restating adjustment represents the difference between the net plant at the end of 2010 and the net plant that was included in the test period.

1 formed, and approved for recovery, in Docket Nos. UE-090134 and UE-100467. A  
 2 restating adjustment was made in this case to adjust the 2010 test year AMA basis to an  
 3 end-of-period basis.

4  
 5 Thermal – Kettle Falls Capital Projects - \$1,180,687

6 Two projects were completed in 2010 at the Kettle Falls Generating Station. The  
 7 replacement of the air heater in July 2010 for approximately \$940,000 recovered some of  
 8 the capacity that had been lost over the past several years because of corrosion of air  
 9 heater tubes and it reduced the overall load of the Fan Motor. The modernization of the  
 10 elevator for approximately \$240,000 was completed in October 2010.

11  
 12 Thermal - Colstrip Capital Additions- \$1,696,138

13 Colstrip capital additions in 2010 included a major waste water treatment plant project for  
 14 Units 3 and 4. This project was an environmental requirement to reduce excess water  
 15 inventory in order to help reduce the water level in the ponds, which in turn helped reduce  
 16 the potential for seepage and improved groundwater protection. A number of other  
 17 smaller capital projects were completed, including mercury control for Units 3 and 4 and  
 18 the replacement of an existing boiler retract with a new model that has a more effective  
 19 soot blower.

20  
 21 Hydro – Nine Mile Upgrade - \$4,734,043

22 In November 2010, a new pneumatically operated spill gate was installed on the Nine  
 23 Mile spillway section. This improved operational performance of the facility by not  
 24 requiring extended operation at lower head as well as eliminated the annual downstream  
 25 risk associated with releasing wooden flashboards. This project was a FERC license  
 26 requirement.

27  
 28 Hydro – Noxon Capital Project - \$614,900

29 In September 2010, the remodel of the HED control room was completed. The remodel  
 30 included removal of existing control board and relocation of controls, installation of a  
 31 raised floor, installation of new control board for emergency spill gates and propane  
 32 generator, installation of new lighting system, sound proofing, other office remodeling,  
 33 and updating conference room and audio visual equipment.

34  
 35  
 36 **Electric Transmission (\$11.1 million - system):**

37  
 38 Nez Perce 115 kV Substation Rebuild and Capacitor Bank - \$3,749,115

39 The complete reconstruction of the Nez Perce substation due to its degraded condition  
 40 was completed in December 2010. The project also included the addition of a shunt  
 41 capacitor bank to provide voltage support to the area for critical contingencies to ensure  
 42 compliance with NERC Standards: TOP-004-2 R1-R4, TPL-002-0a R1-R3, TPL-003-0a  
 43 R1-R3.

1 Noxon Rapids A Bank GSU Replacements - \$7,311,685

2 Replacements of the Generator Step up Transformers (GSU) were needed to  
3 accommodate the additional capacity from the turbine upgrades. These transformers were  
4 50 years old and were reaching the end of their useful life, without the additional capacity  
5 requirements. This project completed in 2010 was the first phase of a two-year project at  
6 the facility. B Bank GSU Transformers will be replaced in 2011.

7  
8  
9 **Electric Distribution (\$6.270 million – WA share):**

10 Wood Pole Replacement Program and Capital Distribution Feeder Repair - \$3,183,532

11 The distribution wood pole management program evaluates wood pole strength of a  
12 certain percentage of the wood pole population each year such that the entire system is  
13 inspected every 20 years. Avista has over 240,000 distribution wood poles and 33,000  
14 transmission wood poles in its electric system. Depending on the test results for a given  
15 pole, the pole is either considered satisfactory, needing to be reinforced with a steel stub,  
16 or needing to be replaced. As feeders are inspected as part of the wood pole management  
17 program, issues are identified unrelated to the condition of the pole. This project also  
18 funds the work required to resolve those issues (i.e. potentially leaking transformers,  
19 transformers older than 1981, failed arrestors, missing grounds, damaged cutouts, and  
20 dated high resistance conductor). Transformers older than 1981 have oil that potentially  
21 contain polychlorinated biphenyls (PCBs). There is increased risk in these older  
22 transformers because of the potential to leak oil that contains PCBs. Poles installed  
23 during the pre-World War II buildup have reached the end of their useful life. Avista's  
24 Wood Pole Management program was put into place to prevent the pole-rotten events and  
25 crossarm-rotten events from increasing. So far, the Wood Pole Management Program  
26 has helped keep pole-rotten and crossarm-rotten events in check.

27  
28 Electric Underground Replacement - \$3,087,237

29 This effort involves replacing the first generation of Underground Residential District  
30 (URD) cable, which has been ongoing for the past several years. This program focuses  
31 on replacing a vintage and type of cable that has reached its end of life and contributes  
32 significantly to URD cable failures. This replacement program will be completed in  
33 2012.

34  
35  
36 **General (\$5.0 million - system):**

37 HVAC Renovation Project - \$5,003,884

38 The heating, ventilating, and air conditioning systems throughout the Spokane Central  
39 Operating Facilities are approximately fifty years old and are in need of replacement. In  
40 2007, the Company initiated a multi-year HVAC renovation project that involves  
41 replacing central air handling units and distribution systems in three buildings - the  
42 Spokane Service Center, the general office building, and the cafeteria auditorium



1 building. The building envelope of the general office building was also renovated with  
 2 high efficiency glass and insulation. The project will also achieve asbestos abatement and  
 3 life safety (fire sprinkler) additions. New controls will also be installed which will enable  
 4 energy conservation. The costs annualized in this filing are for the fourth floor  
 5 renovation that was completed in September 2010.  
 6

7 **Natural Gas Distribution (\$3.4 million – WA share):**

8 Replace Deteriorated Pipe – \$573,102

9 This annual project replaced sections of existing natural gas piping that were suspected  
 10 for failure or had deteriorated within the gas system. This project addressed the  
 11 replacement of sections of gas main that no longer operated reliably and/or safely.  
 12 Sections of the natural gas system required replacement due to many factors including  
 13 material failures, environmental impact, increased leak frequency, or coating problems.  
 14 This project identified and replaced sections of main to improve public safety and system  
 15 reliability.  
 16

17 Regulator Station Reliability Projects - \$522,883

18 This annual project upgraded or replaced various regulator stations within the natural gas  
 19 distribution system improving station reliability and reducing operation and maintenance  
 20 costs. Existing stations required upgrade due to many factors such as replacement of  
 21 obsolete equipment and improvement in regulation technology.  
 22

23 Natural Gas Replacement Street and Highways – \$419,021

24 This annual project replaced sections of existing natural gas piping that required  
 25 replacement due to relocation or improvement of streets or highways in areas where  
 26 natural gas piping was installed. Avista installs many of its facilities in public right-of-  
 27 way under established franchise agreements. Avista is required under the franchise  
 28 agreements, in most cases, to relocate its facilities when they are in conflict with road or  
 29 highway improvements.  
 30

31 Cathodic Protection Projects - \$464,652

32 This annual project upgraded, replaced, or installed cathodic protection systems required  
 33 to ensure compliance with PHMSA regulations regarding proper cathodic protection  
 34 levels of steel mains.  
 35

36 Natural Gas Non-Revenue Projects – \$1,408,711

37 This annual project replaced sections of existing natural gas piping that required  
 38 replacement to improve the operation of the natural gas system that are not directly linked  
 39 to new revenue. This project included relocation of main related to overbuilds [customer  
 40 constructed improvements (i.e. decks, driveways, etc.) that restricted the Company's  
 41 access to pipe], improvement in equipment and/or technology that improved system  
 42 operation and/or maintenance, replacement of obsolete facilities, replacement of main to

1 improve cathodic performance, and projects that improved public safety and/or improved  
2 system reliability.

3  
4 **Q. Please provide a listing of the 2011 capital projects that were pro formed in**  
5 **this filing.**

6 A. A listing of the capital projects and their system costs that will transfer to plant in  
7 service in 2011 and that are included in this filing follows:

8  
9 **Generation (\$21.437 million - system):**

10  
11 The major electric generation projects that will transfer to plant in service are described in  
12 detail in Mr. Lafferty's direct testimony. A listing of these projects follows:

- 13  
14 Thermal - Colstrip Capital Additions- \$5,886,000  
15 Hydro – Cabinet Gorge Upgrade - \$1,490,000  
16 Hydro – 2011 Noxon Unit #2 Upgrade - \$9,110,000  
17 Hydro – Post Falls Capital Project - \$1,240,000  
18 Hydro – Clark Fork/Spokane Implement PME Agreements - \$3,711,000  
19

20  
21 **Electric Transmission (\$18.756 million - system):**

22 The electric transmission projects that will transfer to plant in service are described in  
23 detail in Mr. Kinney's direct testimony. A listing of these projects and system costs  
24 follows:

25  
26 Major Transmission Projects:

- 27 Power Transformer Transmission - \$3,250,000  
28 Noxon Rapids B Bank GSU Replacements - \$5,874,000  
29

30 Compliance Projects:

- 31 Spokane-CDA 115 kV Line Relay Upgrades - \$1,000,000  
32 Bronx Cabinet 115 kV Substation Rebuild - \$2,000,000  
33 SCADA Replacement - \$625,000  
34 West Plains Transmission Reinforcement - \$2,300,000  
35 System-Replace/Install Capacitor Banks - \$400,000  
36 Moscow Sub Rebuild - \$400,000  
37

38 Environmental Regulation Project:

- 39 Beacon Storage Yard Oil Containment - \$1,020,000

1  
2 Transmission Asset Management Projects - \$1,887,000

3  
4 **Electric Distribution (\$12.4 million - system):**

5  
6 The electric distribution projects that were pro formed in this case include those projects  
7 that are part of the Company's Asset Management Program that are described in detail in  
8 Mr. Kinney's direct testimony. A listing of these projects and system costs follows:

9  
10 Wood Pole Replacement Program & Capital Distribution Feeder Repair - \$8,900,000  
11 (WA Share - \$5,809,920)

12 Electric Underground Replacement - \$3,500,000 (WA Share - \$2,284,800)

13  
14 **Natural Gas Distribution (\$0.615 million – WA share):**

15  
16 The Isolated Steel Replacement Program for \$615,000 that will transfer to plant in service  
17 in 2011 is described in detail in Company witness Mr. Kopczyński's direct testimony.

18  
19 **Q. What is the 2012 capital project that was pro formed in this filing?**

20 A. The Company pro formed the upgrade of unit #4 at the Noxon hydro facility with  
21 a cost of \$8,757,000 that will be completed in May 2012. Mr. Lafferty describes this upgrade in  
22 his testimony.

23  
24 **IV. SUMMARY OF ADJUSTMENTS**

25  
26 **Q. Please summarize the restating adjustment for the 2010 investment in capital  
27 projects?**

28 A. As I mentioned earlier, the Company adjusted the 2010 capital additions identified  
29 above from the 2010 average-of-monthly-averages (AMA) basis to the end-of-period (EOP)  
30 basis. The adjustment included depreciation expense and net rate base (capital costs net of  
31 accumulated depreciation and deferred federal income taxes). None of the projects that were  
32 annualized included any distribution capital that was for customer growth or to generate new  
33 revenue.

1 Table 2 below provides a summary of the capital projects at the AMA and the EOP basis,  
2 the restating net rate base adjustment and the resulting revenue requirement.

3 **Table 2:**

<b>2010 Restating Capital Additions Summary</b>				
(\$000's)				
<b>Electric</b>				
	<u>2010 AMA</u>	<u>2010 EOP</u>	<u>Restating Net Rate</u>	<u>Revenue</u>
			<u>Base Adjustment</u>	<u>Requirement (1)</u>
Generation	\$ 4,407	\$ 10,868	\$ 6,461	\$ 1,028
Transmission	1,491	7,187	5,696	896
Distribution	2,896	6,251	3,355	579
General Plant	710	2,428	1,718	279
	<u>\$ 9,504</u>	<u>\$ 26,734</u>	<u>\$ 17,230</u>	<u>\$ 2,782</u>
<b>Natural Gas</b>				
	<u>2010 AMA</u>	<u>2010 EOP</u>	<u>Restating Net Rate</u>	<u>Revenue</u>
			<u>Base Adjustment</u>	<u>Requirement (1)</u>
Distribution	\$ 1,102	\$ 3,379	\$ 2,277	\$ 356
General Plant	184	631	447	73
	<u>\$ 1,286</u>	<u>\$ 4,010</u>	<u>\$ 2,724</u>	<u>\$ 429</u>

(1) Revenue Requirement is shown before impact of the restate debt adjustment.

15  
16 **Q. Please summarize the pro forma adjustments for the 2011 and 2012**  
17 **investment in capital projects?**

18 A. Table 3 below provides a summary of the 2011 and 2012 pro forma rate base  
19 adjustments, the revenue and expense offsets, and the resulting net revenue requirement.

**Table 3:**

<b>2011 &amp; 2012 Pro Forma Capital Additions Summary</b>			
(\$000's)			
<b>Electric</b>			
	<u>Pro Forma Net Rate</u>	<u>Revenue/Expense</u>	<u>Revenue</u>
	<u>Base Adjustment</u>	<u>Offsets</u>	<u>Requirement (1)</u>
Generation (2)	\$ 7,734	\$ 10	\$ 1,296
2011/2012 Noxon (2)	8,697	-	1,488
Transmission	11,817	314	1,641
Distribution	7,740	22	1,332
	<u>\$ 35,987</u>	<u>\$ 346</u>	<u>\$ 5,757</u>
<b>Natural Gas</b>			
	<u>Pro Forma Net Rate</u>	<u>Revenue/Expense</u>	<u>Revenue</u>
	<u>Base Adjustment</u>	<u>Offsets</u>	<u>Requirement (1)</u>
Distribution	\$ 595	\$ -	\$ 104

(1) Revenue Requirement is shown before impact of the restate debt adjustment.

(2) These assets are included in the power cost model (Aurora) and any Aurora-related offsets from these investments are already included in the power costs adjustment, therefore, those offsets are not summarized and included in this table.

**Q. How were the offsets determined for the pro formed plant investment?**

A. Each capital addition was analyzed to determine any offsets (e.g. reduced O&M costs, reduced load losses, etc.). Maintenance records were reviewed to determine whether any specific maintenance costs were incurred in the test period that would be reduced or eliminated by the investment at the facility. For transmission projects, analyses were conducted to determine the amount of potential load loss savings that would be achieved. Those costs were quantified and included as a reduction to O&M costs in the pro forma adjustment.

1 In addition, the output from generation assets is included in the Aurora power cost model.  
2 Therefore, to the extent that the additional investments serve to either preserve or increase  
3 generation from the generation projects, the benefits are reflected in the Aurora model.

4 **Q. Please summarize the pro forma adjustment related to the upgrades to the**  
5 **Noxon units.**

6 A. A pro forma adjustment was made to include the 2011 Noxon Unit #2 generation  
7 plant upgrade (approved in the 2010 rate case) and the 2012 Noxon Unit #4 generation plant  
8 upgrade at a 2012 AMA basis.

9 As explained by Mr. Lafferty, the Company has been upgrading one turbine each year at  
10 its Noxon generating facility. The upgrade for Unit #2 will be completed in April 2011 and was  
11 approved in rates in the most recent general rate case on a 2011 AMA basis. This adjustment pro  
12 forms this same upgrade on a 2012 AMA basis.

13 The upgrade for Unit #4, which will be completed in May 2012 is also pro formed into  
14 this case and is the only 2012 capital addition that the Company has included in its electric case.  
15 Sixty-seven percent of the additional generation and costs have been included in the power cost  
16 model to provide a proper matching of revenues and costs. The Company included sixty-seven  
17 percent of the additional generation and costs because it represents the eight months that it will  
18 be in service during 2012.

19 **Q. Please summarize the pro forma adjustments for new capital investment in**  
20 **2011 for the natural gas system.**

21 A. The Company has pro formed the capital costs associated with the Isolated Steel  
22 Program for \$615,000 that will transfer to plant in service in 2011 as described in Mr.

1 Kopczynski's direct testimony. No other natural gas plant additions for 2011 were pro formed  
2 into this case.

3 **VI. CONCLUSION**

4 **Q. What is the impact of the restating and pro forma capital investment**  
5 **adjustments?**

6 A. The proposed adjustments will result in a closer matching of revenues to cost of  
7 service at the time new rates go into effect at the conclusion of this general rate proceeding.  
8 Without the proposed adjustments, the Company will not have the opportunity to make  
9 meaningful progress in earning its allowed rate of return on investment during the rate year.  
10 Avista only proposed to reflect certain new investment in utility plant through December 31,  
11 2011, even though rates from this case will remain in place throughout 2012. Therefore, if the  
12 Commission were to approve Avista's proposed pro forma capital adjustments as filed, the  
13 revenues received from customers would still not reflect all costs associated with total capital  
14 investment in place to serve customers.

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

16 A. Yes, it does.