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UTILITIES COMMISSION

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-10-01 DIRECT TESTIMONY OF WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is William G. Johnson. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Resources Department.

Q. What is your educational background?

A. I graduated from the University of Montana in 1981 with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve power contract origination and management and power supply regulatory issues.

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

A. My testimony will 1) identify and explain the proposed normalizing and pro forma adjustments to the January 2009 through December 2009 test period power supply revenues and expenses, and 2) describe the proposed level of authorized expense and retail revenue credit for the Power Cost Adjustment (PCA) calculation purposes, using the pro forma costs proposed by the Company in this filing.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 6, Schedules 1 through 4, which were prepared under my supervision and direction.

Q. Are other company witnesses providing testimony regarding issues you are addressing?

A. Yes. Company witness Mr. Kalich provides detailed testimony on the AURORA model used by the Company to develop short-term power purchase expense, fuel expense and short-term power sales revenue included in my exhibits.

II. OVERIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT

Q. Please provide an overview of the pro forma power supply adjustment.

A. The pro forma power supply adjustment involves the determination of revenues and expenses based on the generation and dispatch of Company resources and expected wholesale market power prices as determined by the AURORA model simulation for the pro forma period. In addition, adjustments are made to reflect contract changes between

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CORRECTED PAGES (3, 6, 7, and 12)

TO WILLIAM G. JOHNSON DIRECT TESTIMONY

(Marked)

the 2009 calendar-year test period and the pro forma period October 2010 to September 2011. The table below shows total net power supply expense during the test period and the pro forma period. For information purposes only, the power supply expense[1] currently in rates, which is based on a July 2009 through June 2010 pro forma period, is also shown.

Power Supply Expense (Not Including Directly Assigned Clearwater Paper Purchase)	System	Idaho Allocation
Power Supply Expense in Current Base Rates	$169,037,000	
Actual Jan 09 - Dec 09 Power Supply Expense	$189,811,000	
Adjustment to Test Period	$29,376,000	$10,319,789
Proposed Pro forma Power Supply Expense	$219,187,000	
Increase from Expense in Current Rates	$50,150,000	$17,617,695

The net effect of my adjustments to the test year power supply expense is an increase of $29,376,000 ($219,187,000 - $189,811,000) on a system basis. The Idaho allocation of this adjustment of $10,319,789 is incorporated into the revenue requirement calculation for the Idaho jurisdiction by Company witness Ms. Andrews.

The increase in power supply expense compared to the authorized level in current base rates is $50,150,000 (system) and $17,617,695 (Idaho allocation).

[1] For the remainder of my testimony, for purposes of the power supply adjustment, I will refer to the net of power supply revenues and expenses as power supply expense for ease of reference.

that end December 31, 2010. Those four purchases have an average rate of $31.68/MWh, well below their replacement costs. The cost of replacement in the pro forma is $48.51/MWh. This leads to an increased expense of $3.6 million (Idaho allocation).

Other expense increases are due to decreased hydro generation, higher net wholesale contract costs and increased fuel prices. Lower retail load reduces power supply expense.

Hydro generation is lower by 43.4 aMW in the pro forma versus the amount in the current base rates. The loss of hydro generation is due to several factors. The first is a reduction in generation from Avista's plants on the Clark Fork River as explained in Mr. Kalich's testimony. The second is a reduction in Mid-Columbia purchased hydro generation. This is due to reduced allocation for Avista of Grant County PUD's Priest Rapids Project, and the expiration of Avista's purchase of the Colville Indian Tribe's share of the Wells project on September 30, 2010. The net impact of reduced hydro generation is an increased expense of $2.5 million (Idaho allocation).

Higher net wholesale contract costs increase power supply expense by $.7 million (Idaho allocation), and is primarily a result of reduced wholesale revenues due to the expiration of a load following contract with NorthWestern Energy along with other contract volume and price changes.

Higher fuel prices increases power supply expense by $5.3 million (Idaho allocation). This impact is the sum of higher natural gas fuel prices ($4.1 million) and higher net costs at Colstrip and Kettle Falls ($1.2 million). Natural gas prices in this pro forma are $6.26/dth (Stanfield) compared to $4.79/dth in the current base rates.

A reduction in retail loads reduces power supply expense by $2.1 million (Idaho allocation). Pro forma system loads are 13.5 aMW lower than loads that current rates are based on. Most of this increase is mitigated by the production property adjustment so the net impact of lower retail loads is small.

The table below shows the primary factors driving the increase in power supply expense compared to the level in current base rates.

Power Supply Expense Change
Oct 10-Sep-11 Pro forma vs. Current Authorized

Factor	Pro Forma to Authorized Change $millions	Idaho Allocation $millions
Lancaster	$21.3	$7.5
Decreased System Load	-$6.0	-$2.1
Low Cost 100 MW Purchase Ends	$10.3	$3.6
Reduced Hydro Generation	$7.1	$2.5
Colstrip and Kettle Falls Fuel	$3.5	$1.2
Purchase Contracts	$2.1	$0.7
Higher Natural Gas Prices	$11.8	$4.1
Total Power Supply Increase	$50.1	$17.6

III. PRO FORMA POWER SUPPLY EXPENSE ADJUSTMENTS

Overview

Q. Please identify the specific power supply cost items that are covered by your testimony and the total adjustment being proposed.

A. Exhibit No. 6, Schedule 1 identifies the power supply expense and revenue items that fall within the scope of my testimony. These revenue and expense items are related to power purchases and sales, fuel expenses, transmission expense, and other miscellaneous power supply expenses and revenues.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. The purpose of the adjustments to the test period is to normalize power supply expenses for normal weather and normal hydroelectric generation and to reflect known and measurable changes for the pro forma period that retail rates will be in effect. Adjustments are also made to reflect contract changes from the test period to the pro forma period.

The AURORA Model, as explained by Mr. Kalich, dispatches Company resources on an hourly basis and calculates the level of generation from the Company's thermal resources, fuel costs for thermal resources, and the short-term purchases and sales necessary to serve system requirements.

Q. Have any changes been made in the calculation of pro forma power supply costs from the last general rate case?

A. No. The process to develop the pro forma net power supply expense in this case is the same as in the 2009 general rate case.

A brief description of each adjustment is provided in Exhibit No. 6, Schedule 2. Detailed workpapers have been provided to the Commission coincident to this filing to support each of the pro forma revenues and expenses. The detailed workpapers for each adjustment show the actual revenue or expense in the test period, and the pro forma revenue or expense.

<u>**Long-Term Contracts**</u>

Q. How are long-term power contracts included in the pro forma?

A. Long-term power contracts are included in the pro forma by including the energy receipt or obligation associated with the contract in the AURORA model and including the cost or revenue in the pro forma net power supply expense.

Q. Are there any new long-term power purchases or sales in the pro forma?

A. Yes. This pro forma includes the expenses and revenues related to the Lancaster power purchase agreement. These expenses and revenues are not in the authorized power supply expense supporting current base rates and are being tracked in the PCA.

Q. Are there any power purchases or sales that are in current base rates but not in this pro forma?

A. Yes. As stated earlier, one of the larger factors driving expenses higher is the expiration of four low cost 25 aMW purchases at the end of 2010. Also as discussed earlier, the company's purchase of the Colville Indian Tribe's share of Wells dam ends September 30, 2010.

On the revenue side, the load following contract with NorthWestern Energy ends January 9, 2011.

Short-Term Power Purchases and Sales

Q. How are short-term transactions included in the pro forma?

A. Short-term electric power purchases and sales are an output of the AURORA model. The model calculates both the volumes and price of short-term purchases and sales that balance the system's generation and long-term purchases with retail load and other obligations. The price of the short-term transactions represents the price of spot market power as determined by the AURORA model.

Thermal Fuel Expense

Q. How are thermal fuel expenses determined in the pro forma?

A. Thermal fuel expenses include Colstrip coal costs, Kettle Falls wood waste costs and natural gas expense for the Company's gas-fired resources consisting of Coyote Springs 2, Lancaster PPA, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion turbine. Unit coal costs at Colstrip are based on the long-term coal supply and transportation agreements. Unit wood fuel costs at Kettle Falls are based on multiple shorter-term contracts with fuel suppliers and inventory. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation as determined by the AURORA model. Exhibit No. 6, Schedule 3 shows the pro forma fuel costs by month for each plant. Mr. Kalich provides details and supporting workpapers regarding the level of generation for the Company's thermal plants, and the fuel costs for the natural gas-fired and thermal plants.

Transmission Expense

Q. What changes in transmission expense are in the pro forma compared to the test year or the current base rates?

The pro forma in this case includes the purchase of 250 MW of BPA point-to-point transmission for the Lancaster plant. The annual cost of this transmission is $4.5 million (system basis).

IV. PCA CALCULATIONS

Proposed Changes to the PCA

Q. Is the Company proposing any changes to the PCA?

A. Yes. The Company is proposing to remove the separate 100% tracking of Lancaster fixed expenses in the PCA as all of Lancaster PPA's related expenses and revenues will be included in the authorized power supply expense in the PCA.

New Authorized Power Supply and Transmission Expense

Q. What is the authorized power supply expense and revenue proposed by the Company for the PCA?

A. The proposed authorized level of annual system power supply expense is $200,570,792. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). The proposed level of Transmission Expense is $17,648,340. The proposed level of Transmission Revenue is $12,388,460.

The level of retail sales and the retail revenue credit will also be updated. The proposed authorized level of retail sales to be used in the PCA is the October 2009 through September 2011 pro forma retail sales. The proposed retail revenue credit is $50.26/MWh, which is the average cost of production/transmission in this filing.

The proposed authorized monthly PCA expense and revenue is shown in Exhibit 6, Schedule 4.

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

A. Yes.

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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-10-01 EXHIBIT NO. 6 WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

REVISED APRIL 6, 2010

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

Line No.		Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$31,363	$31,363
2	Actual ST Market Purchases - Physical	198,063	-198,063	0
3	Rocky Reach	1,658	439	2,097
4	Wanapum	4,989	-4,989	0
5	Wells - Avista Share	1,412	140	1,552
6	Wells - Colville Tribe's Share	11,202	-11,202	0
7	Priest Rapids Project	4,999	692	5,691
8	Grant Displacement	5,333	326	5,659
9	Douglas Settlement	365	219	584
10	Lancaster Capacity Payment	0	20,999	20,999
11	Lancaster Variable O&M Payments	0	2,555	2,555
12	Lancaster BPA Reserves	0	744	744
13	WNP-3	14,078	-1,825	12,253
14	Deer Lake-IP&L	7	0	7
15	Small Power	904	115	1,019
16	Stimson	1,865	300	2,165
17	Spokane-Upriver	1,792	211	2,003
18	Douglas Exchange Capacity	1,511	-1,511	0
19	Seattle Exchange Capacity	1,535	-1,535	0
20	Black Creek Index Purchase	139	-5	134
21	Non-Monetary	-142	142	0
22	Contract A	6,789	-5,077	1,712
23	Contract B	6,745	-5,044	1,701
24	Contract C	6,657	-4,978	1,679
25	Contract D	7,556	-5,651	1,905
26	Northwestern Deviation Energy	1,661	-1,661	0
27	BPA NT Deviation Energy	1,101	-1,101	0
28	Clearwater Paper Co-Gen Purchase	19,413	-19,413	0
29	Spinning Reserve Purchase	622	0	622
30	Ancillary Services	686	-686	0
31	Stateline Wind Purchase	2,846	685	3,531
32	Total Account 555	303,786	-203,811	99,975
	557 OTHER EXPENSES			
33	Broker Commission Fees	124	0	124
34	REC Purchases	350	0	350
35	Natural Gas Fuel Purchases	32,480	-32,480	0
36	Total Account 557	32,954	-32,480	474
	501 THERMAL FUEL EXPENSE			
37	Kettle Falls - Wood Fuel	7,450	2,830	10,280
38	Kettle Falls - Start-up Gas	47	0	47
39	Colstrip - Coal	13,336	7,012	20,348
40	Colstip - Oil	113	85	198
41	Total Account 501	20,946	9,927	30,873
	547 OTHER FUEL EXPENSE			
42	Coyote Springs Gas	57,429	-2,651	54,778
43	CS2 Gas Transportation Charge	6,832	1,052	7,884
44	Lancaster Gas	0	57,669	57,669
45	Lancaster Gas Transportation Charge	0	6,014	6,014
46	Lancaster Gas Transportation Optimization	0	-392	-392
47	Rathdrum Gas	2,628	-2,285	343
48	Northeast CT Gas	3	73	76
49	Boulder Park Gas	1,461	-1,276	185
50	Kettle Falls CT Gas	303	-101	202
51	Total Account 547	68,656	58,102	126,758

Exhibit No. 6
Case No. AVU-E-10-01
W. Johnson, Avista
Schedule 1, p. 1 of 2

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Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

Line No.		Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
52	WNP-3	789	0	789
53	Sand Dunes-Warden	13	0	13
54	Black Creek Wheeling	25	-4	21
55	Wheeling for System Sales & Purchases	332	0	332
56	PTP Transmission for Colstrip & Coyote	8,432	-2	8,430
57	PTP Transmission for Lancaster	0	4,503	4,503
58	Redirected Lancaster Transmission	0	-241	-241
59	BPA Townsend-Garrison Wheeling	1,173	0	1,173
60	Avista on BPA - Borderline	1,530	0	1,530
61	Kootenai for Worley	45	0	45
62	Sagle-Northern Lights	140	0	140
63	Garrison-Burke	226	44	270
64	PGE Firm Wheeling	647	-4	643
65	Total Account 565	13,352	4,296	17,648
	536 WATER FOR POWER			
66	Headwater Benefits Payments	716	7	723
	549 MISC OTHER GENERATION EXPENSE			
67	Rathdrum Municipal Payment	160	0	160
68	**TOTAL EXPENSE**	440,570	-163,960	276,610
	447 SALES FOR RESALE			
69	Modeled Short-Term Market Sales	0	45,214	45,214
70	Actual ST Market Sales - Physical	158,707	-158,707	0
71	Peaker (PGE) Capacity Sale	1,748	0	1,748
72	Nichols Pumping Sale	1,642	1,511	3,153
73	Sovereign/Kaiser DES	511	-432	79
74	Pend Oreille DES & Spinning	613	-154	459
75	Northwestern Load Following	4,554	-3,556	998
76	NaturEner	313	-313	0
77	SMUD Sale	27,648	-22,265	5,383
78	Ancillary Services	686	-686	0
79	BPA NT Deviation Energy	1,233	-1,233	0
80	Total Account 447	197,655	-140,621	57,034
	456 OTHER ELECTRIC REVENUE			
81	Renewable Energy Credit Sales	144	-144	0
82	Gas Not Consumed Sales Revenue	33,137	-33,137	0
83	Total Account 456	33,281	-33,281	0
	453 SALES OF WATER AND WATER POWER			
84	Upstream Storage Revenue	381	-20	361
	454 MISC RENTS			
85	Colstrip Rents	29	0	29
86	**TOTAL REVENUE**	231,346	-173,922	57,424
87	**TOTAL NET EXPENSE**	209,224	9,963	219,187
88	**Clearwater Paper Purchase Assigned to Idaho**		19,413	
89	**Total Adjustment Including Clearwater Paper**		29,376	

Exhibit No. 6
Case No. AVU-E-10-01
W. Johnson, Avista
Schedule 1, p. 2 of 2

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Oct 2010 - Sep 2011 Pro Forma

Line No.		Jan 09 - Dec 09 Actuals	Adjustment	Oct 10 - Sep 11 Pro forma
70	Actual ST Market Sales - Physical	158,707	-158,707	0
71	Peaker (PGE) Capacity Sale	1,748	0	1,748
72	Nichols Pumping Sale	1,642	1,509	3,151
73	Sovereign/Kaiser DES	511	-432	79
74	Pend Oreille DES & Spinning	613	-154	459
75	Northwestern Load Following	4,554	-3,556	998
76	NaturEner	313	-313	0
77	SMUD Sale	27,648	-22,265	5,383
78	Ancillary Services	686	-686	0
79	BPA NT Deviation Energy	1,233	-1,233	0
80	Total Account 447	197,655	-138,945	58,710
	456 OTHER ELECTRIC REVENUE			
81	Renewable Energy Credit Sales	144	-144	0
82	Gas Not Consumed Sales Revenue	33,137	-33,137	0
83	Total Account 456	33,281	-33,281	0
	453 SALES OF WATER AND WATER POWER			
84	Upstream Storage Revenue	381	-20	361
	454 MISC RENTS			
85	Colstrip Rents	29	0	29
86	TOTAL REVENUE	231,346	-172,246	59,100
87	TOTAL NET EXPENSE	209,224	8,679	217,903
88	**Clearwater Paper Purchase Assigned to Idaho**		19,413	
89	**Total Adjustment Including Clearwater Paper**		28,092	

Exhibit No. 6
Case No. AVU-E-10-01
W. Johnson, Avista
Schedule 1, p. 3 of 3

Avista Corp.
Brief Description of Power Supply Adjustments

<u>Line No.</u>

1 **Modeled Short-term Market Purchases** - Short-term purchases from the AURORA Dispatch Simulation Model.

2 **Actual ST Market Purchases-Physical** - Expense of the actual term physical power transactions in the test year.

3 **Rocky Reach** - The Pro forma cost for Rocky Reach is based on Chelan PUD's budgeted expenses. Avista's costs are based on the Company's 2.9% share of total cost. The contract terminates 10-31-11.

4 **Wanapum - The** Wanapum contract expires October 31, 2009. Beginning November 2009 Wanapum becomes part of the Priest Rapids Project and Wanapum costs are included in the Priest Rapids Project costs.

5 **Wells - Avista Share** - Wells' costs are based on the Company's 3.34% share of total cost at project costs.

6 **Wells - Colville Tribe's Share** - The 2009 test year included 4.5% of Well's output purchased from the Colville Indian Tribe that terminates 9-30-10.

7 **Priest Rapids Project** - Priest Rapids Project expense includes the expense related to the purchased power from the Priest Rapids development and power from the Wanapum development.

8 **Grant Displacement** - Grant Displacement is scheduled energy from Grant PUD that is priced at Grant's cost. This contract ends 9-30-11.

9 **Douglas Settlement** - Douglas Settlement is for power Avista purchases from Douglas PUD per the 1989 Settlement Agreement.

10 **Lancaster Capacity Payment** - The Lancaster capacity payment includes a capital payment and a fixed O&M payment.

11 **Lancaster Variable Energy Payment** - The Lancaster variable energy payment is based on the variable energy rate in the Lancaster Power Purchase Agreement multiplied time the MWh of Lancaster generation in the pro forma.

12 **Lancaster BPA Reserves** - Because Lancaster is in BPA's balancing authority, Avista purchases reserves for the plant from BPA. The expense is based on BPA's reserve rate times 7% of Lancaster generation in the pro forma.

13 **WNP-3** - Pro forma costs are based on the lower of actual costs or the midpoint. The pro forma uses the actual rate for contract year 2009 through 2010 escalated at the 5-year average escalation rate to the pro forma period.

14 **Deer Lake-IP&L** - Pro forma expense is for power purchased from Inland Power to serve Avista customers.

15 **Small Power - Pro forma** costs are based on 5-year average generation and an average contract rate.

16 **Stimson** - This purchase is from the cogeneration plant at Plummer, Idaho. Pro forma costs are based on 5-year average generation and pro forma period contract rates.

17 **Spokane-Upriver** - Pro forma expense is based on a purchase on the net of pumping (at the plant) generation at the contract rate.

18 **Douglas Exchange Capacity** - Pro forma is $0 because Avista bids annually for this capacity.

19 **Seattle Exchange Capacity** - Pro forma is $0 because contract terminates 9-30-10.

20 **Black Creek Index Purchase** - Expense is for an October purchase at index prices less transmission expense and a margin.

21 **Non-Monetary** - Expense is normalized to $0 in the Pro forma.

22 **Contract A** - Pro forma expense is for a 2007 through 2010 25 MW power purchase. (Contract details are provided in a CONFIDENTIAL workpaper).

23 **Contract B** - Pro forma expense is for a 2007 through 2010 25 MW power purchase. (Contract details are provided in a CONFIDENTIAL workpaper).

24 **Contract C** - Pro forma expense is for a 2007 through 2010 25 MW power purchase. (Contract details are provided in a CONFIDENTIAL workpaper).

25 **Contract D** - Pro forma expense is for a 2007 through 2010 25 MW power purchase. (Contract details are provided in a CONFIDENTIAL workpaper).

26 **NorthWestern Load Following Deviation Energy** - Pro forma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

27 **BPA NT Deviation Energy** - Pro forma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

28 **Clearwater Paper Co-Gen Purchase** - Pro forma expense is $0 because Clearwater Paper purchase expense is directly assigned to the Idaho jurisdiction and is not included in system power supply expense.

29 **Spinning Reserve Purchase** - Pro forma expense is for a purchase of spinning reserves during the months of May through July that matches the test year purchase expense. The AURORA model does not include reserves.

30 **Ancillary Services** - Pro forma expense is $0 because this is an intra-utility expense (matching revenue in Account 447).

31 **Stateline Wind Purchase** - Pro forma expense is for a 10-year purchase from a Northwest wind project. Expense is based on expected energy amount times the contract rate. (Contract details are provided in a CONFIDENTIAL workpaper).

32 **Total Account 555**

33 **Broker Commission Fees** - Pro forma expense is associated with purchases and sales of electricity and natural gas fuel.

34 **REC Purchases** - Expense is for the purchase of California certifiable renewable Energy Credits to support the SMUD Sale.

35 **Natural Gas Fuel Purchases** - This is the expense for natural gas purchased for but not consumed for generation. Pro forma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

36 **Total Account 557**

37 **Kettle Falls Wood Fuel Cost** – Pro forma fuel expense is based on the generation of the Kettle Falls plant in the AURORA Model and the projected unit cost of fuel.

38 **Kettle Falls-Start-up Gas** - Pro forma expense is for start-up gas at Kettle Falls and is based on the test-year expense.

39 **Colstrip Coal Cost** - Pro forma fuel expense is based on the generation of the Colstrip plant in the AURORA Model and the projected unit cost of fuel.

40 **Colstrip Oil** - Pro forma expense is for start-up oil expense. Pro forma is based on a five year average.

41 **Total Account 501**

42 **Coyote Springs Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

43 **CS2 Gas Transportation** - This expense is for transportation of natural gas to the Coyote Springs 2 plant.

44 **Lancaster Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

45 **Lancaster Gas Transportation** - This expense is for natural gas transportation to the Lancaster plant.

46 **Lancaster Gas Transportation Optimization** - This credit to expense is based on optimizing the gas transportation contracts for Coyote Springs 2 and Lancaster. In general, this involves trading the gas price spread between AECO (Canada) and Malin.

47 **Rathdrum Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

48 **Northeast CT Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

49 **Boulder Park Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

50 **Kettle Falls CT Gas** - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

51 **Total Account 547**

52 **WNP-3 Transmission** - Pro forma WNP-3 transmission is based on 32.22 MW at a rate of $2.04/kW/mo.

53 **Sand Dunes-Warden** - Pro forma expense is for a transmission expense with Grant PUD.

54 **Black Creek Wheeling** - Expense is for wheeling and shaping associated with the Black Creek power purchase. The purchase rate is reduced by the wheeling expense.

55 **Wheeling for System Sales and Purchases** - Pro forma expense is for short-term transmission purchases.

56 **PTP for Colstrip and Coyotes Springs 2** - This wheeling is for the transmission of 196 MW from Colstrip at the Garrison substation and 272 MW from the Coyote Springs 2 plant to Avista's system. Pro forma expense is based on 468 MW of capacity at a rate of $1.501/kW/mo.

57 **PTP for Lancaster** - This wheeling is for the transmission from the Lancaster plant to Avista's system. Pro forma expense is based on 250 MW of capacity at a rate of $1.501/kW/mo.

58 **Redirected Lancaster Transmission** - This credit is for the Lancaster transmission that is redirected and used when the plant is off-line or not operating at full capacity.

59 **BPA Townsend-Garrison Wheeling** - This expense is for the transmission of Colstrip power from the Townsend substation to the Garrison substation.

60 **Avista on BPA Borderline** - This expense is to serve Avista load off of BPA transmission. The expense is based on Avista's borderline loads priced at BPA's NT transmission rates plus ancillary services cost and use of facilities charges.

61 **Kootenai for Worley** - This expense is for Avista load served using Kootenai PUD's facilities.

62 **Sagle-Northern Lights** - Expense is for transmission purchased from Northern Lights Utility to serve Avista customers.

63 **Garrison Burke** - Garrison Burke wheeling is an expense for the transmission of Colstrip energy above 196 MW from the Garrison substation over Northwestern Energy's transmission system to the interconnection of Northwestern Energy and Avista. Expense is based on a 5-year average.

64 **PGE Firm Wheeling** - PGE Firm wheeling reflects the cost of transmission from the John Day substation to COB (Intertie South) purchased from Portland General Electric. The Pro forma expense is based on 100 MW at the current rate of $.53549/kW/mo.

65 **Total Account 565**

66 **Headwater Benefits Expense** - Pro forma expense is based on the expense for contract year September 2009 through August 2010.

67 **Rathdrum Municipal Payment** - This includes a payment in Jan. 2011 of $160,000 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

68 **Total Expenses** - Sum of Accounts 555, 557, 501, 547, 565, 536, and 549.

69 **Modeled Short-Term Market Sales** - Short-term market sales from the AURORA Model simulation.

70 **Actual ST Market Sales-Physical** - Revenue from the actual term transactions in the test year.

71 **Peaker (PGE) Capacity Sale** - This Pro forma revenue is based on 150 MW of capacity at a price of $1/kW/mo less a contract servicing fee.

72 **Nichols Pumping Sale** - This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price less $2.05/MWh. Pro forma revenue is based on approximately 8 MW at the market price (less $2.05/MWh) as determined by the AURORA model.

73 **Sovereign/Kaiser DES** - This contract provides load control services to Kaiser's Trentwood plant. (Contract details are provided in a CONFIDENTIAL workpaper).

74 **Pend Oreille DES & Spinning Reserves** - This contract provides load control and spinning reserves for Pend Oreille PUD. (Contract details are provided in a CONFIDENTIAL workpaper).

75 **Northwestern Load Following** - This contract provides load following capacity to NorthWestern Energy. Contract ends 1-9-11. (Contract details are provided in a CONFIDENTIAL workpaper).

76 **NaturEner** - This contract provides load following capacity to a Montana wind facility. Contract ends 6-30-10.

77 **SMUD Sale** - Pro forma revenue is the expected margin (margin only, not including index priced energy) from the sale of energy and associated renewable energy credits.

78 **Ancillary Services** - Pro forma revenue is $0 because it is intra-utility revenue (matching expense in Account 555).

79 **BPA NT Deviation Energy** - Pro forma revenue is $0 because deviation energy is priced at index and is not included in the AURORA model.

80 **Total Account 447**

81 **Renewable Energy Credit Sales** - Pro forma revenue is $0 because test year revenue was for non-reoccurring renewable energy credit sales.

82 **Gas Not Consumed Sales Revenue** - This is the revenue for natural gas purchased for but not consumed for generation. Pro forma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

83 **Total Account 456**

84 **Upstream Storage Revenue** - Pro forma revenue is based on the revenue for contract year September 2009 through August 2010.

85 **Colstrip Rents** - Pro forma revenue is based on expected revenue.

86 **Total Revenue** – Sum of Accounts 447, 456, 453 and 454.

87 **Total Net Expense** – Total expense minus total revenue.

88 **Clearwater Paper Purchase Assigned to Idaho** - This line shows the Clearwater Paper purchase adjustment. The Clearwater Paper expense is directly assigned to Idaho and is not included in the pro forma system power supply expense. The Clearwater Paper purchase expense is included in the adjustment in line 89 to show the total adjustment from test year actual expense (includes Clearwater Paper) to the Pro forma.

89 **Total Adjustment Including Clearwater Paper** - This is the total adjustment in power supply expense factoring in the Clearwater Paper purchase expense directly assigned to Idaho.

REVISED APRIL 6, 2010

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Idaho Proforma October 2010 - September 2011

		744	672	743	720	744	720	744	744	720	744	721	744
	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Market Sales - Dollars	-$45,213,996	-$1,708,632	-$2,710,358	-$2,372,510	-$2,843,062	-$3,574,964	-$3,712,836	-$5,372,409	-$2,882,435	-$2,829,575	-$3,130,375	-$4,919,886	-$9,156,954
Market Sales - MWh	(1,052,450)	-30,077	-50,062	-48,462	-76,903	-137,772	-148,109	-111,856	-56,782	-58,389	-71,425	-102,001	-160,613
Average Market Sales Price -$/ MWh	$42.96	$56.81	$54.14	$48.96	$36.97	$25.95	$25.07	$48.03	$50.76	$48.46	$43.83	$48.23	$57.01
Market Purchases - Dollars	$31,362,977	$5,074,814	$3,347,531	$5,022,944	$2,385,237	$1,324,753	$1,390,446	$2,124,545	$4,257,903	$2,854,514	$2,019,367	$1,109,426	$451,498
Market Purchases - MWh	587,172	90,962	57,233	95,321	53,022	32,580	34,197	39,725	67,839	46,663	41,647	20,029	7,954
Average Market Purchase Price - $/MWh	$53.41	$55.79	$58.49	$52.70	$44.99	$40.66		$53.48	$62.76	$61.17	$48.49	$55.39	$56.77
Net Market Purchases (Sales) MWh	-465,279	60,885	7,171	46,859	-23,881	-105,192	-113,912	-72,131	11,057	-11,726	-29,778	-81,972	-152,660
Net Market Purchases (Sales) aMW	-53.1	82	11	63	-33	-141	-158	-97	15	-16	-40	-114	-205
Average Sale and Purchase Price - $/MWh	$46.70	$56.04	$56.46	$51.43	$40.24	$28.76	$27.99	$49.46	$57.30	$54.11	$45.54	$49.41	$57.00
Colstrip MWh	1,639,080	147,656	135,220	146,716	129,388	104,967	97,758	142,191	149,634	144,878	148,496	144,879	147,298
Colstrip Fuel Cost $/MWh	$12.41	$12.66	$12.64	$12.67	$12.82	$13.23	$13.27	$12.72	$12.64	$12.64	$11.43	$11.42	$11.44
Colstrip Fuel Cost	$20,348,004	$1,869,131	$1,708,979	$1,858,854	$1,659,011	$1,388,227	$1,297,336	$1,808,201	$1,891,254	$1,831,040	$1,696,985	$1,654,016	$1,684,970
Kettle Falls MWh	294,847	34,068	31,085	33,887	0	0	0	27,776	33,888	32,009	34,416	33,305	34,411
Kettle Falls Fuel Cost $/MWh	$34.87	$35.45	$35.44	$35.44	#DIV/0!	#DIV/0!		$35.57	$35.45	$35.45	$33.74	$33.74	$33.74
Kettle Falls Fuel Cost	$10,280,029	$1,207,849	$1,101,680	$1,201,137	$0	$0	$0	$987,912	$1,201,309	$1,134,647	$1,161,026	$1,123,574	$1,160,895
Coyote Springs MWh	1,275,000	129,533	126,369	101,223	32,206	17,202	30,345	122,112	154,605	150,022	122,493	139,921	148,972
Coyote Springs Fuel Cost $/MWh	$42.96	$46.36	$45.91	$44.96	$41.54	$41.70	$42.42	$41.95	$41.36	$41.78	$39.20	$41.96	$44.43
Coyote Springs Fuel Cost	$54,777,628	$6,005,019	$5,801,319	$4,550,956	$1,337,710	$717,287	$1,287,142	$5,122,948	$6,395,211	$6,267,859	$4,801,647	$5,871,626	$6,618,903
	$6.14												
Lancaster MWh	1,267,003	133,225	127,403	102,880	29,907	17,546	19,425	110,092	152,557	149,154	117,577	152,840	154,398
Lancaster Fuel Cost $/MWh	$45.52	$48.04	$47.72	$46.75	$43.65	$45.22	$46.71	$45.71	$44.91	$44.84	$41.46	$44.06	$46.60
Lancaster Fuel Cost	$57,669,371	$6,400,139	$6,079,308	$4,809,725	$1,305,350	$793,448	$907,367	$5,032,234	$6,850,808	$6,687,660	$4,875,149	$6,733,921	$7,194,263
Boulder Park MWh	3,121	237	101	40	9	42	104	1,635	897	49	0	7	1
Boulder Park Fuel Cost $/MWh	$59.13	$65.38	$64.58	$62.61	$57.36	$56.57	$56.41	$58.01	$59.33	$56.71		$62.88	$62.73
Boulder Park Fuel Cost	$184,551	$15,470	$6,504	$2,488	$504	$2,362	$5,867	$94,842	$53,243	$2,775	$0	$447	$49
Kettle Falls CT MWh	3,438	598	269	162	0	0	4	950	1,125	132	23	75	101
Kettle Falls CT Fuel Cost $/MWh	$58.63	$63.00	$63.08	$60.94			$68.47	$56.31	$57.26	$54.83	$52.29	$57.23	$61.53
Kettle Falls CT Fuel Cost	$201,578	$37,664	$16,945	$9,895	$0	$0	$257	$53,470	$64,389	$7,226	$1,213	$4,276	$6,244
Rathdrum MWh	4,375	0	0	0	0	0	43	2,568	1,740	24	0	0	0
Rathdrum Fuel Cost $/MWh	$78.38						$76.45	$77.70	$79.48	$75.68			
Rathdrum Fuel Cost	$342,946	$0	$0	$0	$0	$0	$3,305	$199,505	$138,282	$1,854	$0	$0	$0
Northeast MWh	905	0	0	0	0	0	0	483	419	4	0	0	0
Northeast Fuel Cost $/MWh	$83.66							$82.37	$85.19	$78.74			
Northeast Fuel Cost	$75,743	$0	$0	$0	$0	$0	$0	$39,763	$35,670	$310	$0	$0	$0
Total Fuel Expense	$143,879,849	$15,535,272	$14,714,736	$12,433,054	$4,302,574	$2,901,324	$3,501,275	$13,338,874	$16,630,166	$15,933,371	$12,536,020	$15,387,860	$16,665,324

Net Fuel and Purchase Expense	$130,028,831

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Avista Corp
Pro forma October 2010 - September 2011
PCA Authorized Expense and Retail Sales

PCA Authorized Power Supply Expense

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Account 555 - Purchased Power	$99,973,476	$11,958,638	$9,648,897	$10,369,141	$7,674,915	$5,715,996	$5,803,342	$6,304,182	$8,147,437	$6,632,169	$8,287,612	$9,889,639	$9,541,506
Account 501 - Thermal Fuel	$30,872,641	$3,097,364	$2,831,043	$3,080,375	$1,679,395	$1,408,611	$1,317,720	$2,816,497	$3,112,947	$2,986,072	$2,878,395	$2,797,974	$2,866,249
Account 547 - Natrual Gas Fuel	$126,757,248	$13,546,803	$12,999,479	$10,452,412	$3,804,091	$2,673,625	$3,364,467	$11,703,289	$14,698,131	$14,128,211	$10,802,604	$13,689,033	$14,895,103
Account 447 - Sale for Resale	$57,032,573	$2,669,417	$3,467,055	$3,243,324	$3,910,764	$4,624,204	$4,731,723	$6,260,937	$3,880,607	$3,715,656	$4,194,226	$6,070,898	$10,263,761
Power Supply Expense	$200,570,792	$25,933,388	$22,012,364	$20,658,604	$9,247,636	$5,174,028	$5,753,806	$14,563,031	$22,077,908	$20,030,797	$17,774,384	$20,305,748	$17,039,097
Transmission Expense	$17,648,340	$1,469,612	$1,469,612	$1,469,612	$1,469,612	$1,469,612	$1,469,612	$1,469,612	$1,482,612	$1,469,612	$1,469,612	$1,469,612	$1,469,612
Transmission Revenue	$12,388,460	$901,304	$825,004	$1,002,240	$898,431	$1,029,104	$1,371,347	$1,379,878	$1,150,203	$1,025,629	$1,041,304	$939,334	$824,682

PCA Authorized Idaho Retail Sales

	Total	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-10	Nov-10	Dec-10
Total Retail Sales, MWh	3,520,611	344,110	305,499	306,081	271,677	271,340	270,297	287,198	287,002	265,380	283,088	300,962	327,976

Retail Revenue Credit Rate $50.26 /MWh

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