DAVID J. MEYER
VICE PRESIDENT, GENERAL COUNSEL, REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

RECEIVED
2008 APR -3 PM 12:56
IDAHO PUBLIC
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-08-01 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 2007 test period power supply revenues and expenses, and 2) describe the new base level of power supply costs for 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. SUMMARY

Q. Please provide an overview of your direct testimony.

A. My testimony will identify and explain the proposed normalizing and pro forma adjustments to the 2007 test period power supply revenues and expenses, and describe the new base level of power supply costs for Power Cost Adjustment (PCA) calculation purposes, using the pro forma costs proposed by the Company in this filing. This 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. In addition, adjustments are made to reflect contract changes between the 2007 test period and the 2009 pro forma period. The table below shows total net power supply expense during the 2007 test period and the proposed 2009 pro forma period. For information only purposes, the power supply expense currently in rates, which is based on a September 2004 through August 2005 pro forma period, is also shown.

Power Supply Expense
(Not Including Directly Assigned Potlatch Purchase)

	System	Idaho Allocation
Power Supply Expense in Current Base Rates (Sep 04 - Aug 05 pro forma)	$82,643,000	
Actual 2007 Power Supply Expense	$175,939,000	
Adjustment to Test Period	$971,000	$343,831
2009 Pro forma Power Supply Expense	$176,910,000	

The net effect of my adjustments to the 2007 test year power supply expense is an increase of $971,000 ($176,910,000 - $175,939,000) on a system basis. The Idaho allocation of this adjustment of $343,831 is incorporated into the revenue requirement calculation for the Washington jurisdiction by Company witness Ms. Andrews.

Q. What are the major factors driving the increased power supply expense in the pro forma year over the level of power supply expense currently in base rates?

A. The level of power supply expense currently in base rates is $82,643,000 (system number). This expense level is based on a September 2004 through August 2005 pro forma period and 2002 retail loads. This compares to the proposed 2009 pro forma power supply expense of $176,910,000, an increase of approximately $94.3 million on a system basis and an Idaho allocation of approximately $33.4 million.

This significant increase in pro forma power supply expense over the expense currently in base rates is based on numerous factors, including higher retail loads, reduced hydro generation, increased fuel costs and increased transmission expense.

Higher retail loads are the most significant factor contributing to higher power supply expense. Pro forma retail loads are 128.6 aMW higher than 2002 loads that current rates are based on. Hydro generation is also lower than the level in current base rates. Pro forma hydro generation is 546.3 aMW compared to 553.1 aMW in current base rates, a reduction of 6.8 aMW. The pro forma hydro generation includes the "hydro rate mitigation adjustment" of 26.5 aMW. Without the "rate mitigation adjustment" (described later in my testimony), the reduction in hydro generation would be 33.3 aMW. This reduction in hydro generation is due to the reduction in Mid Columbia purchased hydro generation resulting from the expiration of the Priest Rapids contract in 2005 and the Wanapum contract in 2009.

Fuel expense is significantly higher in the 2009 pro forma compared to the fuel expense in current base rates. Total thermal fuel expense for coal, wood fuel and natural gas is approximately 50 percent higher on a dollars per MWh basis in the 2009 pro forma, increasing from $20.26 per MWh in current base rates to $30.33 per MWh in the 2009 pro forma.

Finally, transmission expense has increased by approximately $2.9 million on a system basis, approximately $1.0 million Idaho allocation. This is primarily due to the purchase of an additional 125 MW of BPA point-to-point transmission for Coyote Springs 2.

Q. What are the major factors driving the increased power supply expense in the pro forma year over the 2007 test year?

A. The primary factors increasing power supply expense from the 2007 test year to the 2009 pro forma year are the cost of serving additional retail load, fuel costs and increased purchased power costs.

Retail loads in the 2009 pro forma period are approximately 27 aMW higher than 2007 weather adjusted retail load. Increased retail load creates higher power supply expense and also puts upward pressure on retail rates because the marginal cost of power exceeds the embedded cost of power. The increase in power supply expense due to increased retail loads is approximately $4.8 million (Idaho allocation).

In addition to higher loads, some of the Company's purchased power contract costs have increased, particularly the Company's Mid-Columbia purchases from the Priest Rapids and Wanapum hydro generation developments. The cost for the Company's share of Wanapum and Priest Rapids is approximately $1.7 million (Idaho allocation) higher in 2009 than in 2007. The Company's contract for Priest Rapid's power expired October 31, 2005. While the Company still gets power from Priest Rapids, the majority of the power is now priced at market prices rather than the low project cost. The Wanapum contract expires October 31, 2009. Beginning November 1, 2009 the Company will receive approximately half of much energy from these two plants as before the expiration of the contracts, and only a small portion of the power will be priced at project cost. Under the new contract for these plants, the plant's owner, Grant County PUD, gets more of the physical output of the plants and also keeps more of the financial value of the purchaser's share of the plants. Effectively, as Grant's loads grow they keep some of the financial value of the purchasers' share of the plants in order to serve their loads with project cost power. Due to the very high load growth in Grant County, less of the value of Priest Rapid's power is going to the purchasers, and with the expiration of the Wanapum contract in October 2009, less of the value of that plant will go to the purchasers.

Finally, thermal fuel expense for Colstrip and Kettle Falls has also increased significantly, increasing by approximately $2.2 million (Idaho allocation) from 2007 to 2009. This is based primarily on increasing unit costs for coal and wood fuel.

Q. Given the increased costs describe above, please explain why there is almost no increase in the overall power supply expense between the 2009 pro forma year and the 2007 test year.

A. The reason that the overall increase in power supply expense from the 2007 year to the 2009 pro forma year is very small is because the hydro generation "rate mitigation adjustment" offsets almost all of the increased power supply expense. The hydro generation "rate mitigation adjustment", explained by Mr. Kalich, decreases system power supply expense by approximately $12.8 (system), $4.5 million (Idaho allocation).

After incorporating the "rate mitigation adjustment", the total power supply adjustment from 2007 actual to 2009 pro forma power supply expense is only $343,831 (Idaho allocation), as shown in the previous table.

<u>III. PRO FORMA POWER SUPPLY COSTS</u>

<u>Overview</u>

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 2007 test period power supply revenues and expenses?

A. The purpose of the adjustments to the 2007 test period is to normalize power supply expenses for normal weather and hydroelectric generation and to reflect known and measurable changes for the 2009 pro forma period that rates will be in effect. Adjustments are also made to reflect contract changes from 2007 to 2009.

The AURORA Model 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 power supply costs from the prior general rate case?

A. Yes. The primary change made in this general rate case is the use of loads that match the pro forma period. The use of pro forma retail loads together with a production property adjustment, provides a better matching of revenues and expenses, and properly reflects the costs of providing services to retail customers during the pro forma period that rates will be in effect. Mr. Kalich describes the pro forma retail loads used in this case, and Company witness Ms. Knox explains the production property adjustment.

The power supply pro forma in this case also includes a "rate mitigation adjustment" to hydroelectric generation to decrease pro forma power supply expense. This adjustment increased hydro generation above normal generation levels, which decreased power supply expense by $12.8 million (system number). This adjustment was made in the AURORA model and is explained in Mr. Kalich's testimony.

Other than the use of pro forma retail loads and the hydro rate mitigation adjustment, the process to develop the pro forma net power supply expense in this case is the same as in the 2004 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 2007, and the pro forma revenue or expense for 2009.

<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 power purchases or sales in the pro forma that were not in place during the 2007 test year?

A. Yes, there is one new long-term purchase. The Company has entered into a 10-year purchase agreement with Thompson River Cogen, a cogeneration plant in Thompson Falls, Montana. The plant is expected to be on-line sometime during early 2008 and produce approximately 11 average megawatts. The purchase price of $58.50 per MWh is very close to the forward power market prices in the AURORA model for the 2009 pro forma period, so the contract has minimal impact on power supply expense.

__**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 long-term 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 including Coyote Springs 2, 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 fuel costs for the Company's thermal plants.

Transmission Expense

Q. What changes in transmission expense are in the 2009 pro forma compared to the actual 2007 transmission expense?

A. Transmission expense in the 2009 pro forma is approximately $.5 million (system) higher than the 2007 actual expense. The primary reason for this increase is that beginning August 1, 2007 the Company began purchasing an additional 50 MW of transmission for Coyote Springs 2 (CS2).

Q. What is the change in transmission for CS2 between the 2007 test year and the 2009 pro forma period?

A. Until August 1, 2007 the Company purchased 222 MW of firm point-to-point (PTP) transmission from BPA and had a 125 MW exchange agreement to meet the remaining transmission requirements for CS2. The exchange agreement expired at the end of 2007. To meet the transmission requirements of CS2 the Company purchased an additional 50 MW of firm PTP transmission from BPA, for a total of 272 MW of firm transmission for CS2. This results in total PTP purchases of 468 MW (196 MW for Colstrip and 272 MW for CS2).

Q. Are there any new transmission contracts?

A. Yes, there is a new transmission expense, labeled Sagle-Northern Lights, for the purchase of transmission from Northern Lights Utility to serve Avista customers in northern Idaho. This transmission purchase began May 1, 2007. Purchasing transmission from Northern Lights was less expensive then building what would have been a duplicative transmission line.

IV. PCA CALCULATIONS

Q. What effect will this case have on the PCA?

A. This case will update the authorized power supply expenses and revenues, retail load, and the retail revenue credit. PCA entries will continue to be calculated in the same manner as current calculations. The final order in this case will determine the new authorized level of power supply expense, retail load and the retail revenue credit, and Potlatch generation and revenues used in the PCA calculation.

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

A. The proposed authorized level of annual system power supply expense is $161,669,734. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale) in the Company's filed pro forma.

The level of retail sales and the retail revenue credit will also be updated. Because the Company has included a Production Property Adjustment in its revenue requirement the proposed authorized level of retail sales to be used in the PCA is the 2009 pro forma retail sales

Q. What value is the Company proposing as the retail revenue credit in the PCA?

A. Because the Company is using pro forma retail load to develop pro forma power supply expense, the Company is proposing to use the marginal power cost from the AURORA model as the value for the retail revenue credit in the PCA. The proposed retail revenue credit is $53.63/MWh. This is the average market purchases and sales price shown on line 9 of Exhibit No. 6, Schedule 3. This value is the average market price for short-term transaction, which represents the marginal cost of power in the pro forma period.

Absent the use of pro forma retail loads in the development of power supply expense the Company would propose that the correct value to use as the retail revenue credit in the PCA is the average production cost. The average production cost represents the power commodity component of retail rates and is the revenue collected from customers to recover power costs. Using the average cost of production as the retail revenue credit in the PCA ensures that the actual revenue collected from customers when retail sales increase is credited back against the increased power supply expense and only the difference between the actual cost of power and the amount of revenue collected from customers is included in the PCA.

The use of pro forma retail loads in the development of power supply expense, however, makes the choice of what value to use as the retail revenue credit less critical. This is because the difference in actual sales and authorized sales in 2009 is expected to be small since the load is for the same year. The use of pro forma loads in developing the pro forma power supply expense mitigates the potential impact of load growth in the PCA.

The proposed PCA authorized monthly power supply expense, retail sales, and Potlatch generation that determines the Potlatch power purchase expense and revenue related to the portion of Potlatch's load equal to their generation is shown in Exhibit No. 6, Schedule 4.

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

A. Yes.

RECEIVED
2008 APR -3 PM 12:56
IDAHO PUBLIC
UTILITIES COMMISSION

DAVID J. MEYER
VICE PRESIDENT, GENERAL COUNSEL, REGULATORY &
GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

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-08-01 EXHIBIT NO. 6 WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - 2007 Actual and 2009 Pro forma (Hydro Adjusted)
2009 Loads

Line No.		Jan 07 - Dec 07 Actuals	Adjustment	Jan 09 - Dec 09 Pro forma
	555 PURCHASED POWER			
1	Short-Term Market Purchases	$94,024	-$42,627	$51,397
2	Rocky Reach	2,181	119	2,300
3	Wanapum	4,430	1,238	5,668
4	Wells	1,275	78	1,353
5	Priest Rapids Project	3,924	3,459	7,383
6	Grant Displacement	5,610	-190	5,420
7	Douglas Settlement	617	16	633
8	WNP-3	11,870	1,708	13,578
9	Deer Lake-IP&L	8	0	8
10	Small Power	1,091	58	1,149
11	Stimson	1,990	107	2,097
12	Spokane-Upriver	1,913	104	2,017
13	Douglas Exchange Capacity	1,536	-1,536	0
14	Seattle Exchange Capacity	1,681	-1,681	0
15	Black Creek Index Purchase	144	46	190
16	Non-Monetary	241	-241	0
17	Contract A	6,789	0	6,789
18	Contract B	6,745	0	6,745
19	Contract C	6,658	0	6,658
20	Contract D	7,556	0	7,556
21	CS2 Exchange	1,533	-1,533	0
22	TRC Purpa Purchase	0	5,403	5,403
23	NWestern Load Following Deviation Energy	1,286	-1,286	0
24	BPA NT Deviation Energy	3,074	-3,074	0
25	Grant Transmission Losses	276	-276	0
26	Potlatch Co-Gen Purchase	19,861	-19,861	0
27	BPA Spinning Reserve	980	0	980
28	Ancillary Services	662	-662	0
29	PPM Wind Purchase	3,173	-123	3,050
30	Total Account 555	191,128	-60,754	130,374
	557 OTHER EXPENSES			
31	Broker Commission Fees	52	0	52
32	REC Purchases	301	49	350
33	Bankruptcy Write-Off	23	-23	0
34	Natural Gas Fuel Purchases	16,575	-16,575	0
35	Total Account 557	16,951	-16,549	402
	501 THERMAL FUEL EXPENSE			
36	Kettle Falls - Wood Fuel	8,714	3,097	11,811
37	Kettle Falls - Gas	38	-38	0
38	Colstrip - Coal	16,207	3,181	19,388
39	Colstip - Oil	308	0	308
40	Total Account 501	25,267	6,240	31,507
	547 OTHER FUEL EXPENSE			
41	Coyote Springs Gas	88,084	-18,687	69,397
42	Gas Transportation Charge	7,729	0	7,729
43	Rathdrum Gas	1,774	-401	1,373
44	Northeast CT Gas	238	-238	0
45	Boulder Park Gas	1,811	-1,343	468
46	Kettle Falls CT Gas	140	214	354
47	Total Account 547	99,776	-20,456	79,320

565 TRANSMISSION OF ELECTRICITY BY OTHERS

Exhibit No.6
Case No. AVU-E-08-01
W. Johnson, Avista
Schedule 1, p. 1 of 2

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - 2007 Actual and 2009 Pro forma (Hydro Adjusted)
2009 Loads

Line No.		Jan 07 - Dec 07 Actuals	Adjustment	Jan 09 - Dec 09 Pro forma
48	WNP-3	790	3	793
49	Grant Transmission	512	-512	0
50	Sand Dunes-Warden	11	0	11
51	Black Creek Wheeling	18	4	22
52	Wheeling for System Sales & Purchases	1,278	0	1,278
53	PTP for Colstrip & Coyote	7,822	653	8,475
54	BPA Townsend-Garrison Wheeling	1,173	0	1,173
55	Avista on BPA - Borderline	1,098	237	1,335
56	Kootenai for Worley	32	48	80
57	Sagle-Northern Lights	89	45	134
58	Garrison-Burke	388	0	388
59	PGE Firm Wheeling	643	0	643
60	Total Account 565	13,854	478	14,332
	536 WATER FOR POWER			
61	Headwater Benefits Payments	651	8	659
	549 MISC OTHER GENERATION EXPENSE			
62	Rathdrum Municipal Payment	155	5	160
63	**TOTAL EXPENSE**	347,782	-91,027	256,755
	447 SALES FOR RESALE			
64	Short-Term Market Sales	87,895	-22,845	65,050
65	Peaker (PGE) Capacity Sale	1,800	0	1,800
66	Nichols Pumping Sale	2,900	996	3,896
67	Sovereign/Kaiser DES	536	-475	61
68	Pend Oreille DES & Spinning	709	-319	390
69	Northwestern Load Following	3,138	-324	2,814
70	SMUD Sale	39,393	-33,816	5,577
71	Ancillary Services	662	-662	0
72	Spokane Energy Service Fee - Peaker Sale	-57	0	-57
73	BPA NT Deviation Energy	1,634	-1,634	0
74	Total Account 447	138,610	-59,079	79,531
	456 OTHER ELECTRIC REVENUE			
75	Renewable Energy Credit Sales	11	-11	0
76	Gas Not Consumed Sales Revenue	13,031	-13,031	0
77	Total Account 456	13,042	-13,042	0
	453 SALES OF WATER AND WATER POWER			
78	Upstream Storage Revenue	309	-19	290
	454 MISC RENTS			
79	Colstrip Rents	21	2	23
80	**TOTAL REVENUE**	151,982	-72,138	79,844
81	**TOTAL NET EXPENSE**	195,800	-18,890	176,910
82	**Potlatch Purchase Assigned to Idaho**		19,861	
83	**Total Adjustment Including Potlatch**		971	

Exhibit No.6
Case No. AVU-E-08-01
W. Johnson, Avista
Schedule 1, p. 2 of 2

Avista Corp.
Brief Description of Power Supply Adjustments

<u>Line No.</u>

1 **Short-term Market Purchases** - Short-term purchases are normalized through use of the AURORA Dispatch Simulation Model. The proforma value reflects the short-term purchases during the proforma period from the dispatch simulation study.

2 **Rocky Reach** - The proforma 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.

3 **Wanapum** - Proforma costs are based on Grant County PUD's Power Cost Forecast for Wanapum. Avista's costs are based on the Company's 8.2% share of total Wanapum costs for January 2009 through October 2009. 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 for November and December 2009.

4 **Wells** - Wells' costs are based on Douglas PUD's Power Purchaser's Pro-Forma Statement. Avista's costs are based on the Company's 3.5% share of total cost.

5 **Priest Rapids Project** - Priest Rapids Project expense includes the expense related to the purchased power from the Priest Rapids development for the entire pro forma year and purchased power from the Wanapum development for the months of November and December 2009.

6 **Grant Displacement** - Grant Displacement is scheduled energy from Grant PUD that is priced at the Grant's cost.

7 **Douglas Settlement** – Douglas Settlement is for a small (approx. 4 aMW) of power Avista purchases from Douglas PUD.

8 **WNP-3** - Pro forma costs are based on the amount of energy and the lesser of the actual rate or the midpoint. The pro forma uses the actual rate for contract year 2007 through 2008 escalated at the 5-year average escalation rate to the pro forma period.

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

10 **Small Power** - Proforma costs are based on an expected generation and proforma period contract rates. (Contract details are provided in a CONFIDENTIAL workpaper).

11 **Stimson** – This purchase is from the cogeneration plant at Plummer, Idaho. Proforma costs are based on expected generation and proforma period contract rates.

12 **Spokane-Upriver** - Proforma expense is based on the new contract effective July 2004. Proforma expense is based on a purchase on the net of pumping (at the plant) generation at a rate equal to the 8 year levelized avoided cost included in the Company's 2003 Integrated Resource Plan.

13 **Douglas Exchange Capacity** – Proforma is $0 because Avista bids annually for this capacity.

14 **Seattle Exchange Capacity** – Proforma is $0 because contract terminates Sep. 30, 2008.

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

16 **Non-Monetary** - Expense is normalized to $0 in the proforma.

17 **Contract A** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

18 **Contract B** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

19 **Contract C** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

20 **Contract D** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

21 **CS2 Exchange** – Proforma is $0 because contract terminates Dec. 31, 2007.

22 **TRC Purpa Purchase** – The TRC (Thompson River Cogen) purchase is an agreement to purchase power from a qualifying cogeneration facility.

23 **NorthWestern Load Following Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

24 **BPA NT Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

25 **Grant Transmission Losses** - Proforma expense is $0 because losses energy is priced at market and is not included In AURORA model. Contract ended October 2007.

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

27 **BPA Spinning Reserve** – Pro forma expense is for a purchase of spinning reserves from BPA during the months of May and June that matches the test year purchase expense.

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

29 **PPM-Stateline Wind Purchase** - Proforma 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).

30 **Total Account 555**

31 **Broker Commission Fees** – Proforma expense is associated with purchases and sales of electricity and natural gas fuel.

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

33 **Bankruptcy Write-Off** – Expense was for revenue the Company accounted for but never received. Proforma expense is $0.

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

35 **Total Account 557**

36 **Kettle Falls Wood Fuel Cost** - Proforma fuel expense is based on the generation of the Kettle Falls plant in the AURORA Model and the projected unit cost of fuel.

37 **Kettle Falls Gas Fuel Cost** - Proforma expense is $0 because natural gas is not a Kettle Falls fuel option in the AURORA model.

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

39 **Colstrip Oil** – Proforma expense is for start-up oil expense.

40 **Total Account 501**

41 **Coyote Springs Gas** - Proforma 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.

42 **Gas Transportation Charge** – This expense is for transportation of natural gas from AECO to the Coyote Springs 2 plant. Proforma expense is based on transportation charges in Canada and from the Canadian Border (Kingsgate) and for the Coyote Springs lateral.

43 **Rathdrum Gas** - Proforma 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.

44 **Northeast CT Gas** – Proforma 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 **Boulder Park Gas** – Proforma 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.

46 **Kettle Falls CT Gas** – Proforma 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.

47 **Total Account 547**

48 **WNP-3 Transmission** - Proforma WNP-3 wheeling is based on 32.22 MW at a rate of $2.05/kW/mo.

49 **Grant Transmission** – Pro forma expense is $0 because contract ended October 2007.

50 **Sand Dunes-Warden** - Pro forma expense is $0 because contract ended October 2007.

51 **Black Creek Wheeling** – Expense is for wheeling and shaping associated with the Black Creek power purchase.

52 **Wheeling for System Sales and Purchases** – Proforma expense is short-term transmission purchases.

53 **BPA PTP Wheeling 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. Proforma expense is based on 468 MW of capacity at a rate of $1.509/kW/mo.

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

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

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

57 **Sagle-Northern Lights** – Expense is for transmission purchased from Northern Light Utility to serve Avista customers in northern Idaho.

58 **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.

59 **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 Proforma expense is based on 100 MW at the current rate of $.53549/kW/mo.

60 **Total Account 565**

61 **Headwater Benefits Expense** - Proforma expense is based on the expense for contract year September 2007 through August 2008

62 **Rathdrum Municipal Payment** – This includes a payment in Jan. 2009 of $160,000 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

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

64 **Short-Term Market Sales** - Short-term sales volumes and market prices are normalized through use of the AURORA Model simulation. The pro forma revenue reflects the short-term sales during the pro forma period from the dispatch simulation study.

65 **Peaker (PGE) Capacity Sale** – This proforma revenue is based on 150 MW of capacity at a price of $1/kW/mo.

66 **Nichols Pumping Sale** – This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price. Proforma revenue is based on approximately 8 MW at the market price as determined by the AURORA model.

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

68 **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).

69 **Northwestern Load Following** – This contract provides load following capacity to Northwestern Energy. (Contract details are provided in a CONFIDENTIAL workpaper).

70 **SMUD Sale** – Proforma revenue is the expected margin (margin only, not including index priced energy) from the sale of energy and associated renewable energy credits.

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

72 **Spokane Energy Service Fee** – Peaker Sale – Expense is for the scheduling of the Peaker (Portland General) capacity sales. Most of the expense is offset with Account 456 revenue.

73 **BPA NT Deviation Energy** – Proforma revenue is $0 because deviation energy is priced at index and is not included in the AURORA model.

74 **Total Account 447**

75 **Renewable energy Credit Sales** – Proforma revenue is $0 because 2007 revenue was only for short-term renewable energy credit sales.

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

77 **Total Account 456**

78 **Upstream Storage Revenue** – Proforma revenue is based on the revenue for contract year September 2007 through August 2008.

79 **Colstrip Rents** – Proforma revenue is based on expected revenue.

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

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

82 **Potlatch Purchase Assigned to Idaho** – This line shows the Potlatch purchase adjustment. The Potlatch expense is directly assigned to Idaho and is

not included in the pro forma system power supply expense. The Potlatch purchase expense is included in the adjustment in line 83 to show the total adjustment from 2007 actual expense (includes Potlatch) to the proforma.

83 **Total Adjustment Including Potlatch** – This is the total adjustment in power supply expense factoring in the Potlatch purchase expense directly assigned to Idaho.

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Idaho Jurisdiction Proforma January 2009 - December 2009

Line No		Total	744 Jan-09	672 Feb-09	743 Mar-09	720 Apr-09	744 May-09	720 Jun-09	744 Jul-09	744 Aug-09	720 Sep-09	744 Oct-09	721 Nov-09	744 Dec-09
1	Market Sales - Dollars	-$65,050,117	-$2,045,731	-$3,381,922	-$4,426,342	-$8,206,993	-$12,494,044	-$10,413,701	-$8,430,600	-$3,643,219	-$3,055,943	-$2,496,273	-$3,771,432	-$2,683,917
2	Market Sales - MWh	(1,426,458)	-37,579	-57,467	-81,807	-179,049	-300,330	-299,985	-174,900	-69,030	-62,945	-49,787	-66,327	-47,253
3	Average Market Sales Price -$/ MWh	$45.60	$54.44	$58.85	$54.11	$45.84	$41.60	$34.71	$48.20	$52.78	$48.55	$50.14	$56.86	$56.80
4	Market Purchases - Dollars	$51,396,868	$8,817,237	$4,175,373	$4,463,950	$1,274,016	$296,019	$334,487	$2,133,722	$5,110,344	$5,585,617	$7,105,463	$5,625,083	$6,475,556
5	Market Purchases - MWh	744,719	137,772	61,169	67,867	19,685	4,130	5,300	25,885	61,555	75,832	107,001	82,643	95,882
6	Average Market Purchase Price - $/MWh	$69.02	$64.00	$68.26	$65.78	$64.72	$71.67		$82.43	$83.02	$73.66	$66.41	$68.07	$67.54
7	Net Market Purchases (Sales) MWh	-681,739	100,193	3,702	-13,940	-159,364	-296,200	-294,685	-149,015	-7,476	12,887	57,214	16,316	48,629
8	Net Market Purchases (Sales) aMW	-77.8	135	6	-19	-221	-398	-409	-200	-10	18	77	23	65
9	Average Sale and Purchase Price - $/MWh	$53.63	$61.95	$63.70	$59.40	$47.71	$42.01	$35.21	$52.62	$67.03	$62.27	$61.24	$63.08	$63.99
10	Colstrip MWh	1,729,693	155,524	142,868	152,223	126,011	105,815	115,942	154,668	158,126	152,929	156,893	153,073	155,619
11	Colstrip Fuel Cost $/MWh	$11.21	$11.20	$11.20	$11.20	$11.20	$11.24	$11.28	$11.21	$11.20	$11.20	$11.20	$11.20	$11.20
12	Colstrip Fuel Cost	$19,388,379	$1,742,394	$1,600,133	$1,705,441	$1,411,354	$1,189,359	$1,307,346	$1,733,784	$1,771,054	$1,712,918	$1,757,216	$1,714,428	$1,742,955
13	Kettle Falls MWh	333,536	32,105	31,148	33,991	32,252	1,116	0	31,754	34,775	33,088	34,952	33,887	34,468
14	Kettle Falls Fuel Cost $/MWh	$35.41	$35.59	$35.37	$35.35	$35.52	$36.42		$35.59	$35.32	$35.39	$35.30	$35.30	$35.37
15	Kettle Falls Fuel Cost	$11,810,746	$1,142,747	$1,101,660	$1,201,701	$1,145,422	$40,647	$0	$1,130,074	$1,228,343	$1,170,890	$1,233,951	$1,196,182	$1,219,129
16	Coyote Springs MWh	1,298,463	77,241	88,735	84,548	67,292	46,935	51,172	120,158	166,228	159,887	153,864	159,240	123,164
17	Coyote Springs Fuel Cost $/MWh	$53.45	$58.33	$57.97	$56.54	$50.63	$50.33	$51.22	$51.78	$51.54	$51.44	$51.79	$54.00	$56.81
18	Coyote Springs Fuel Cost	$69,397,110	$4,505,141	$5,143,803	$4,780,021	$3,407,158	$2,362,138	$2,620,882	$6,221,339	$8,567,095	$8,224,226	$7,968,855	$8,599,436	$6,997,015
19	Boulder Park MWh	6,483	173	246	82	535	522	185	1,233	1,798	1,368	170	86	84
20	Boulder Park Fuel Cost $/MWh	$72.22	$79.79	$80.86	$80.36	$70.34	$69.79	$69.05	$71.36	$71.99	$71.66	$71.79	$75.64	$81.25
21	Boulder Park Fuel Cost	$468,160	$13,820	$19,874	$6,574	$37,662	$36,442	$12,798	$87,973	$129,427	$98,061	$12,173	$6,517	$6,839
22	Kettle Falls CT MWh	5,000	120	141	115	287	307	178	857	1,289	1,081	257	241	127
23	Kettle Falls CT Fuel Cost $/MWh	$70.71	$77.88	$78.96	$78.04	$68.70	$68.16	$68.01	$69.60	$70.07	$69.98	$69.33	$74.24	$79.00
24	Kettle Falls CT Fuel Cost	$353,536	$9,337	$11,111	$9,007	$19,744	$20,909	$12,074	$59,668	$90,300	$75,615	$17,850	$17,893	$10,029
25	Rathdrum MWh	15,710	0	32	0	64	223	89	6,645	7,654	465	494	43	0
26	Rathdrum Fuel Cost $/MWh	$87.37		$97.99		$85.49	$84.70	$81.06	$86.92	$88.31	$87.22	$80.52	$93.64	
27	Rathdrum Fuel Cost	$1,372,646	$0	$3,121	$0	$5,497	$18,859	$7,227	$577,650	$675,868	$40,599	$39,795	$4,030	$0
28	Northeast MWh	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Northeast Fuel Cost $/MWh	#DIV/0!												
30	Northeast Fuel Cost	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Total Fuel Expense	$102,790,577	$7,413,438	$7,879,702	$7,702,744	$6,026,837	$3,668,354	$3,960,326	$9,810,488	$12,462,086	$11,322,309	$11,029,839	$11,538,487	$9,975,967
32	Net Fuel and Purchase Expense	$89,137,328												

Exhibit No.6
Case No. AVU-E-08-01
W. Johnson, Avista
Schedule 3, p. 1 of 1

Avista Corp
Pro forma Januray 2009 - December 2009, Idaho Jurisdiction
PCA Authorized Expense and Retail Sales

PCA Authorized Power Supply Expense

	Total	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Account 555 - Purchased Power	130,373,613	17,246,176	11,815,778	11,232,497	7,855,247	6,023,371	5,932,392	7,566,547	10,331,648	10,588,478	12,490,788	14,023,629	15,267,063
Account 501 - Thermal Fuel	31,507,125	2,910,807	2,727,459	2,932,808	2,582,443	1,255,673	1,333,012	2,889,525	3,025,063	2,909,474	3,016,833	2,936,277	2,987,751
Account 547 - Natrual Gas Fuel	79,320,453	5,172,381	5,821,993	5,439,685	4,114,144	3,082,431	3,297,063	7,590,714	10,106,773	9,082,585	8,682,756	9,271,960	7,657,967
Account 447 - Sale for Resale	79,531,456	3,261,944	4,590,314	5,648,433	9,379,926	13,648,568	11,526,382	9,646,527	4,900,262	4,281,137	3,718,684	5,005,546	3,923,733
Power Supply Expense	161,669,734	22,067,421	15,774,916	13,956,558	5,171,908	-3,287,094	-963,915	8,400,258	18,563,222	18,299,400	20,471,693	21,226,319	21,989,047

PCA Authorized Idaho Retail Sales and Potlatch Generation

	Total	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Total Retail Sales, MWh	3,120,008	305,198	269,181	274,330	240,497	237,579	230,879	254,119	242,680	232,668	259,470	269,684	303,723
Potlatch Generation, MWh	462,755	40,053	35,982	25,909	38,217	39,430	40,149	43,017	44,432	35,902	35,755	42,576	41,333

Exhibit No.6
Case No. AVU-E-08-01
W. Johnson, Avista
Schedule 4, p. 1 of 1