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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-12-08
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	DIRECT TESTIMONY
AND NATURAL GAS CUSTOMERS IN THE	)	OF
STATE OF IDAHO	)	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 July

2011 through June 2012 test period power supply revenues and expenses, and 2) describe the proposed level of expense and load change adjustment rate for Power Cost Adjustment (PCA) 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 6, including Schedules 1 through 4, which were prepared under my supervision and direction. Schedule 1 identifies the power supply expense and revenue items that fall within the scope of my testimony. A brief description of each adjustment is provided in Schedule 2. Schedule 3 shows the pro forma fuel costs for each thermal plant and short-term purchase and sales by month. The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, and retail sales are shown in Schedule 4.

Q. Are there 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. OVERVIEW 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 under normal weather and hydro generation conditions. In addition, adjustments are made to reflect contract changes between the historical test period and the pro forma period. 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 base retail rates[2], which is based on a calendar 2012 pro forma period, is also shown.

[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.

[2] The last general rate case was resolved through a "black-box" settlement. My figures represent an estimate of the change from the last case, based on the Power Supply information presented in that case.

Power Supply Expense	
	System
Power Supply Expense in Current Rates (2012 pro forma)	$192,715,000
Actual July 2011 - June 2012 Power Supply Expense (excluding Clearwater)	$186,026,000
Proposed 2013 Pro forma Power Supply Expense	$179,160,000
Proposed 2013 Pro forma vs July 2011 - June 2012 Test Period	-$6,866,000
Proposed 2013 Pro forma vs Current Rates	-$13,555,000

The net effect of my adjustments to the test year power supply expense is a decrease of $6,866,000 ($186,026,000 - $179,160,000) on a system basis (excluding Clearwater power purchase expense in test year). The decrease in power supply expense compared to the authorized level in current base rates is $13,555,000 (system) and $4,711,718 (Idaho allocation).

Q. Why is the power supply expense for the pro forma year lower than the level of power supply expense currently in the last rate case?

A. The decrease in pro forma power supply expense from the expense included in the last rate case is primarily a result of lower natural gas and power prices. The natural gas price included in the AURORA model has decreased from an annual average of $4.62/dth to $3.44/dth.

The average modeled power purchase price has decreased from $40.45/MWh to $28.33/MWh[3].

Pro forma system load (July 2011 through June 2012 weather adjusted loads) is 3.2 average megawatts (aMW) lower (before the Energy Efficiency Load Adjustment[4]) than the system load included in the last rate case (2010 weather adjusted loads).

Other than the addition of the power purchase from the Palouse Wind Project and the Spokane Waste to Energy plant, which I will address later, the contracts and resources in this pro forma are the same as those included in the last rate case.

III. PRO FORMA POWER SUPPLY ADJUSTMENTS

Overview

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

A. Schedule 1 of Exhibit 6, identifies the power supply expense and revenue items that fall within the scope

[3] The natural gas price included in the AURORA model and the modeled power purchase price does not include the actual natural gas and power transactions that have been entered into for the 2013 pro forma period.

[4] The Energy Efficiency Load Adjustment is described by Company witness Ehrbar. The reduction in load was not included in the AURORA model in this filing, but was calculated outside the model and is included as a reduction in power supply expense for purposes of the Power Cost Adjustment.

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 recent forward natural gas prices and other known and measurable changes for the pro forma period.

The AURORA Model, as explained by Mr. Kalich, dispatches Company resources using the recent forward natural gas prices 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 balance system requirements and resources.

Q. Are there any changes in how the pro forma in this case was developed versus the authorized power supply expense proposed in the last rate case?

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

A brief description of each adjustment is provided in 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.

Long-Term Contracts

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 that were not included in the last rate case?

A. Yes. This pro forma includes the expenses and generation related to the purchase from the Palouse Wind Project, a 105 MW capacity (39 aMW energy) wind facility located 30 miles south of Spokane. Additional information regarding this purchase is contained in Mr. Lafferty's testimony. The pro forma also includes a purchase from the Spokane Waste-to-Energy plant located on the west side of

Spokane. The plant produces approximately 15 aMW of energy.

Q. Why did the Company enter into a power purchase agreement with the City of Spokane's Waste-to-Energy plant?

A. The output from the Waste-to-Energy plant had been purchased by Puget Sound Energy for the past 20 years. That contract with Puget expired December 31, 2011. As a PURPA resource, Avista is required to purchase the output if the generator so requests, which they did. The purchase price is at the avoided cost rates in Avista's 2011 Integrated Resource Plan.

Q. Are there any long-term power purchases or sales that were included in the last rate case, but are not in this pro forma?

A. No.

<u>Short-Term Power Purchases and Sales</u>

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

A. After including the actual physical forward long-term transactions as resources and obligations in the AURORA model, the balance of the 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.

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

A. No. The AURORA 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.

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, Lancaster, 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.

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 cost for thermal and natural gas-fired plants.

Transmission Expense

Q. What changes in transmission expense are in the pro forma compared to the expense in the last rate case?

A. The only change in transmission expense are some increases in all BPA transmission expenses beginning October, 1, 2013 based on BPA's proposed rate increases.

Summary of Power Supply Expense

Q. Please summarize your proposed pro forma power supply expense that is provided to witness Andrews.

A. The proposed pro forma power supply expense as shown in Schedule is a $25,953,000 reduction in expense on a system basis ($9,021,263 Idaho allocation) from the July 2011 through June 2012 actual test-year expense and a $13,555,000 (system)/$4,711,718 (Idaho allocation) reduction in expense from the power supply expense in the last rate case.

PCA Related Revenues and Expenses, Retail Sales and Proposed Load Change Adjustment Rate

Q. What is Avista's proposed authorized power supply expense and revenue for the PCA?

A. The proposed authorized level of annual system power supply expense is $157,095,545. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale) less $2,806,911 for the Energy Efficiency Load Adjustment[5]. The proposed level of Transmission Expense is $17,970,479. The proposed level of Transmission Revenue is $14,192,399.

Q. What is the level of retail sales and the proposed load change adjustment rate for the PCA?

A. The proposed authorized level of retail sales to be used in the PCA is the July 2011 through June 2012 weather adjusted retail sales adjusted for the Energy Efficiency Load Adjustment. The proposed load change adjustment rate is $27.68/MWh, which is the energy classified portion of the fixed and variable production and transmission revenue requirement in this filing developed by Company witness Ms. Knox.

The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, and retail sales is shown in Schedule 4.

[5] The reduction in power supply expense for the Energy Efficiency Load Adjustment is explained by Company witness Ehrbar.

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

A. Yes.

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OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 6
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	WILLIAM G. JOHNSON
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jul 2011 - Jun 2012 Actual and Jan 2013 - Dec 2013 Pro Forma
July 2011 - June 2012 Weather Normalized Load

Line No.		Jul 11 - Jun 12 Actuals	Adjustment	Jan 13 - Dec 13 Pro forma
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$12,450	$12,450
2	Actual ST Market Purchases	122,152	-122,152	0
3	Rocky Reach	875	-875	0
4	Rocky Reach/Rock Island Purchase	10,915	910	11,825
5	Wells - Avista Share	1,616	184	1,800
6	Wells - Colville Tribe's Share	4,287	-4,287	0
7	Priest Rapids Project	5,712	1,122	6,834
8	Grant Displacement	1,437	-1,437	0
9	Douglas Settlement	998	-204	794
10	Lancaster Capacity Payment	21,413	647	22,060
11	Lancaster Variable O&M Payments	2,382	663	3,045
12	Palouse Wind	0	19,217	19,217
13	WNP-3	15,663	-2,033	13,630
14	Deer Lake-IP&L	6	0	6
15	Small Power	1,295	-231	1,064
16	Stimson	1,865	169	2,034
17	Spokane-Upriver	2,213	201	2,414
18	Spokane Waste-to-Energy	2,918	3,367	6,285
19	Black Creek Index Purchase	118	-118	0
20	Non-Monetary	84	-84	0
21	Clearwater Paper Co-Gen Purchase (1)	0	0	0
22	Ancillary Services	628	-628	0
23	Stateline Wind Purchase	3,435	-187	3,248
24	Total Account 555	200,012	-93,306	106,706
	557 OTHER EXPENSES			
25	Broker Commission Fees	828	0	828
26	Non WA EIA REC Purchase	348	-174	174
27	Optional Renewable Power Expense Offset	-141	141	0
28	Natural Gas Fuel Purchases	153,292	-153,292	0
29	Total Account 557	154,327	-153,325	1,002
	501 THERMAL FUEL EXPENSE			
30	Kettle Falls - Wood Fuel	9,014	1,041	10,055
31	Kettle Falls - Start-up Gas	6	0	6
32	Colstrip - Coal	17,625	2,940	20,565
33	Colstrip - Oil	291	0	291
34	Total Account 501	26,936	3,980	30,916
	547 OTHER FUEL EXPENSE			
35	Coyote Springs Gas	23,454	14,569	38,023
36	Coyote Springs 2 Gas Transportation	6,785	429	7,214
37	Lancaster Gas	26,826	8,428	35,254
38	Lancaster Gas Transportation	5,764	387	6,151
39	Gas Transportation Optimization	0	-3,501	-3,501
40	Gas Transportation for BP, NE and KFCT	20	0	20
41	Rathdrum Gas	260	2,249	2,509
42	Northeast CT Gas	20	28	48
43	Boulder Park Gas	252	183	435
44	Kettle Falls CT Gas	74	405	479
45	Total Account 547	63,455	23,176	86,631
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
46	WNP-3	789	15	804
47	Black Creek Wheeling	39	-39	0

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jul 2011 - Jun 2012 Actual and Jan 2013 - Dec 2013 Pro Forma
July 2011 - June 2012 Weather Normalized Load

Line No.		Jul 11 - Jun 12 **Actuals**	Adjustment	Jan 13 - Dec 13 **Pro forma**
48	Wheeling for System Sales & Purchases	197	0	197
49	BPA PTP for Colstrip, Coyote & Lancaster	12,826	260	13,086
50	BPA Townsend-Garrison Wheeling	1,424	84	1,508
51	Avista on BPA - Borderline	1,216	9	1,225
52	Kootenai for Worley	45	0	45
53	Sagle-Northern Lights	134	0	134
54	Northwestern for Colstrip	328	0	328
55	PGE Firm Wheeling	643	0	643
56	Total Account 565	17,641	329	17,970
	536 WATER FOR POWER			
57	Headwater Benefits Payments	1,034	-99	935
	549 MISC OTHER GENERATION EXPENSE			
58	Rathdrum Municipal Payment	160	0	160
59	**TOTAL EXPENSE**	463,565	-219,245	244,320
	447 SALES FOR RESALE			
60	Modeled Short-Term Market Sales	0	38,401	38,401
61	Actual Short-Term Market Sales	109,163	-109,163	0
62	Peaker (PGE) Capacity Sale	1,751	0	1,751
63	Nichols Pumping Sale	1,060	438	1,498
64	Sovereign/Kaiser DES	80	0	80
65	Pend Oreille DES & Spinning	412	0	412
66	Northwestern Load Following	335	-335	0
67	NaturEner	222	-222	0
68	SMUD Sale - Energy and REC	20,291	1,919	22,210
69	Ancillary Services	628	-628	0
70	Total Account 447	133,942	-69,590	64,352
	456 OTHER ELECTRIC REVENUE			
71	Non WA EIA REC Sales	2,366	-1,988	378
72	Gas Not Consumed Sales Revenue	140,649	-140,649	0
73	Total Account 456	143,015	-142,637	378
	453 SALES OF WATER AND WATER POWER			
74	Upstream Storage Revenue	582	-152	430
75	**TOTAL REVENUE**	277,539	-212,379	65,160
76	**TOTAL NET EXPENSE**	186,026	-6,866	179,160

(1) Directly assigned to Idaho $19.087 million

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

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 entered into for the pro forma period as of 01-20-12**.**

3 **Rocky Reach** - The pro forma cost for Rocky Reach is $0 because the contract ends 10-31-11.

4 **Rocky Reach/Rock Island Purchase** – The pro forma expense is based on a purchase of a portion of Rocky Reach and Rock Island generation beginning July 1, 2011.

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 2011 test-year included 4.5% of Well's output purchased from the Colville Indian Tribe.

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** – The 2011 test-year expense included a purchase from Grant PUD that ended 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 O&M Payments** – the Lancaster variable O&M payment is based on the variable O&M rate in the Lancaster Power Purchase Agreement multiplied time the MWh of Lancaster generation in the pro forma.

12 **Palouse Wind** – Pro forma expense is based on expected generation and the pro forma period contract rate including the adder for apprenticeship credit.

13 **WNP-3 -** Pro forma costs are based on the midpoint. The pro forma uses the actual price identified in the contract for contract year 2011 through 2012 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 of the net of pumping (at the plant) generation at the pro forma contract rate.

18 **Spokane Waste-to-Energy** - Pro forma expense is based on a purchase of the plant generation at the pro forma contract rate. This purchase began 1-1-12.

19 **Black Creek Index Purchase** - Pro forma expense is $0 because the contract ended March 25, 2011, with the power received in October 2011.

20 **Non-Monetary** - Expense is normalized to $0 in the pro forma.

21 **Clearwater Paper 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.

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

23 **Stateline Wind Purchase** – Pro forma expense based on 5-year average generation and the pro forma period contract rate less $1/MWh for the Renewable Energy Credit, which is assigned to the Buck-a-Block.

24 **Total Account 555**

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

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

27 **Optional Renewable Power Expense Offset** – This test year credit was to remove the REC cost of the Stateline Wind purchase that was assigned to the Buck-a-Block program. The pro forma credit is $0 because the Stateline Wind purchase expense already removes the REC expense.

28 **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.

29 **Total Account 557**

30 **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 unit cost of available fuel.

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

32 **Colstrip Coal Cost** – Pro forma fuel expense is based on the generation of the Colstrip plant in the AURORA Model and the unit cost of fuel under the contract.

33 **Colstrip Oil** – Pro forma expense is for start-up oil expense. Pro forma is based on the test-year expense.

34 **Total Account 501**

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

36 **CS2 Gas Transportation** – This expense is for natural gas transportation for the Coyote Springs 2 plant.

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

38 **Lancaster Gas Transportation** – This expense is for natural gas transportation for the Lancaster plant.

39 **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.

40 **Gas Transportation for BP, NE and KFCT –** This expense is for transportation of natural gas to serve Boulder Park, Northeast and Kettle Falls Combustion Turbine gas-fired plants.

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

42 **Northeast CT Gas** – Pro forma expense is an output of the AURORA Model based on the pro forma unit cost of fuel and the dispatch of the plant (including test firing), which determines the volume of fuel consumed.

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

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

45 **Total Account 547**

46 **WNP-3 Transmission** – Pro forma WNP-3 wheeling is based on 32.22 MW at a rate of $2.04/kW/mo through 9-30-13 and $2.20/kW/mo 10-1-13 through 12-31-13 based on BPA's proposed rate increase.

47 **Black Creek Wheeling –** Pro forma expense is $0 because the contract ended March 25, 2011.

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

49 **PTP for Colstrip and Coyotes Springs 2 and Lancaster–** This wheeling is for the transmission of 196 MW from Colstrip, 272 MW from Coyote Springs 2 and 250 MW from Lancaster. Pro forma expense is based on 718 MW of capacity at a rate of $1.501/kW/mo. through 9-30-13 and $1.622/kW/mo 10-1-13 through 12-31-13 based on BPA's proposed rate increase.

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

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

Pro from expense is based on test-year expense through 9-30-13 and is increased by 2.89% for 10-1-13 through 12-31-13 based on BPA's proposed rate increase.

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

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

54 **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.

55 **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.

56 **Total Account 565**

57 **Headwater Benefits Expense** – Pro forma expense is based on the expense for contract year September 2011 through August 2012.

58 **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.

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

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

61 **Actual ST Market Sales - Physical** – Revenue from the actual term transactions entered into for the pro forma period as of 01-20-12.

62 **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. This contract is related to the sales of capacity to Portland General Electric, which was monetized in 1998.

63 **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 aMW through 10-31-13 at the market price (less $2.05/MWh) as determined by the AURORA model.

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

65 **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).

66 **Northwestern Load Following** – Pro forma revenue is $0 because there is no contract for the pro forma period.

67 **NaturEner** – This contract provides load following capacity to a Montana wind facility. Pro forma revenue is $0 because there is no contract for the pro forma period.

68 **SMUD Sale –** Pro forma revenue is the sale of energy and associated renewable energy credits.

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

70 **Total Account 447**

71 **Non WA EIA REC Sales –** Pro forma revenue is based on contracted REC sales during the pro forma period.

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

73 **Total Account 456**

74 **Upstream Storage Revenue** – Pro forma revenue is based on the revenue for contract year September 2011 through August 2012.

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

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

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Idaho Pro forma January 2013 - December 2013

		744	672	743	720	744	720	744	744	720	744	721	744
	Total	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Market Sales - Dollars	**-$38,400,506**	-$2,501,590	-$2,378,831	-$2,818,487	-$3,736,394	-$3,309,704	-$1,701,010	-$4,482,036	-$1,289,603	-$2,967,290	-$3,319,771	-$4,659,989	-$5,235,801
Market Sales - MWh	(1,374,609)	-77,745	-73,627	-95,646	-138,204	-179,880	-159,594	-145,487	-40,746	-92,766	-104,660	-131,530	-134,724
Average Market Sales Price -$/ MWh	$27.94	$32.18	$32.31	$29.47	$27.04	$18.40	$10.66	$30.81	$31.65	$31.99	$31.72	$35.43	$38.86
Market Purchases - Dollars	**$12,449,764**	$2,199,825	$1,612,815	$1,359,776	$511,810	$270,045	$371,442	$675,189	$2,986,828	$771,565	$670,315	$451,910	$568,245
Market Purchases - MWh	439,497	79,078	56,093	54,967	33,758	17,464	27,363	17,515	83,550	22,198	18,952	12,260	16,299
Average Market Purchase Price - $/MWh	$28.33	$27.82	$28.75	$24.74	$15.16	$15.46		$38.55	$35.75	$34.76	$35.37	$36.86	$34.86
Net Market Purchases (Sales) MWh	-935,112	1,333	-17,534	-40,678	-104,446	-162,416	-132,231	-127,973	42,804	-70,568	-85,708	-119,270	-118,426
Net Market Purchases (Sales) aMW	-106.7	2	-26	-55	-145	-218	-184	-172	58	-98	-115	-165	-159
Average Sale and Purchase Price - $/MWh	**$28.03**	$29.98	$30.77	$27.74	$24.70	$18.14	$11.09	$31.64	$34.41	$32.52	$32.28	$35.55	$38.43
Colstrip MWh	1,511,799	133,671	128,234	134,083	100,622	87,653	77,256	131,031	141,337	141,739	147,735	143,119	145,320
Colstrip Fuel Cost $/MWh	$13.60	$13.56	$13.54	$13.61	$13.79	$13.83	$14.01	$13.68	$13.56	$13.50	$13.49	$13.49	$13.49
Colstrip Fuel Cost	**$20,564,618**	$1,812,553	$1,736,715	$1,825,240	$1,387,575	$1,212,631	$1,082,479	$1,792,781	$1,916,323	$1,913,921	$1,992,935	$1,930,445	$1,961,020
Kettle Falls MWh	333,613	31,741	29,278	31,305	21,208	16,653	10,072	28,429	32,921	32,458	33,594	32,522	33,433
Kettle Falls Fuel Cost $/MWh	$30.14	$30.12	$30.11	$30.16	$30.33	$30.34		$30.19	$30.10	$30.07	$30.07	$30.06	$30.07
Kettle Falls Fuel Cost	**$10,054,701**	$956,027	$881,653	$944,048	$643,254	$505,242	$305,986	$858,326	$990,970	$975,952	$1,010,021	$977,750	$1,005,470
Coyote Springs MWh	1,538,453	143,469	134,119	132,442	77,518	50,844	34,312	127,341	154,918	161,724	170,561	171,537	179,669
Coyote Springs Fuel Cost $/MWh	$24.72	$24.22	$24.22	$24.03	$23.47	$23.77	$24.27	$24.37	$24.44	$24.28	$24.47	$25.75	$27.00
Coyote Springs Fuel Cost	**$38,023,143**	$3,474,829	$3,248,722	$3,183,149	$1,818,986	$1,208,316	$832,649	$3,103,629	$3,786,146	$3,926,418	$4,172,972	$4,416,450	$4,850,877
Lancaster MWh	1,498,508	149,055	136,302	140,599	87,258	31,202	23,307	112,631	139,868	158,164	174,476	170,402	175,245
Lancaster Fuel Cost $/MWh	$23.53	$22.73	$22.67	$22.68	$22.52	$22.84	$23.47	$23.60	$23.37	$23.05	$23.22	$24.56	$25.98
Lancaster Fuel Cost	**$35,253,634**	$3,388,553	$3,089,494	$3,188,899	$1,965,061	$712,587	$547,122	$2,658,120	$3,268,848	$3,645,657	$4,050,861	$4,185,537	$4,552,896
Boulder Park MWh	11,807	2,553	2,137	1,451	1,037	531	47	226	507	434	149	1,205	1,530
Boulder Park Fuel Cost $/MWh	$36.81	$36.11	$36.25	$35.99	$35.15	$35.38	$35.71	$36.13	$36.33	$36.36	$36.70	$38.36	$40.34
Boulder Park Fuel Cost	**$434,561**	$92,209	$77,468	$52,214	$36,440	$18,799	$1,673	$8,151	$18,412	$15,761	$5,476	$46,245	$61,712
Kettle Falls CT MWh	13,456	1,859	1,680	1,232	1,173	859	273	703	1,012	1,231	958	1,060	1,415
Kettle Falls CT Fuel Cost $/MWh	$35.56	$35.01	$35.14	$34.90	$34.08	$34.30	$34.62	$35.03	$35.22	$35.25	$35.58	$37.19	$39.11
Kettle Falls CT Fuel Cost	**$478,540**	$65,076	$59,058	$43,002	$39,986	$29,479	$9,461	$24,611	$35,657	$43,402	$34,074	$39,417	$55,319
Rathdrum MWh	58,431	10,482	5,660	2,109	3,816	679	16	7,447	10,066	2,531	23	3,857	11,743
Rathdrum Fuel Cost $/MWh	$42.95	$41.53	$41.96	$41.92	$40.47	$41.78	$43.14	$41.75	$41.98	$42.15	$43.15	$44.39	$47.03
Rathdrum Fuel Cost	**$2,509,445**	$435,352	$237,499	$88,418	$154,440	$28,381	$706	$310,927	$422,520	$106,690	$1,013	$171,209	$552,290
Northeast MWh	933	216	127	97	291	47	1	15	47	18	2	29	45
Northeast Fuel Cost $/MWh	$51.26	$51.32	$51.51	$51.15	$49.95	$50.27	$50.75	$51.34	$51.62	$51.66	$52.15	$54.52	$57.32
Northeast Fuel Cost	**$47,847**	$11,061	$6,529	$4,968	$14,553	$2,370	$37	$753	$2,428	$914	$81	$1,572	$2,581
Total Fuel Expense	**$107,366,488**	$10,235,660	$9,337,139	$9,329,939	$6,060,294	$3,717,804	$2,780,112	$8,757,299	$10,441,304	$10,628,715	$11,267,433	$11,768,625	$13,042,165
Net Fuel and Purchase Expense	**$81,415,746**												

Avista Corp
Pro forma January 2013 - December 2013
PCA Authorized Expense and Retail Sales (with Energy Efficiency Load Adjustment)
July 2011 - June 2012 Normalized Loads

PCA Authorized Power Supply Expense - System Numbers (1)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Account 555 - Purchased Power	$106,706,470	$12,526,478	$10,806,995	$10,336,714	$8,592,752	$6,927,512	$6,593,636	$6,791,045	$8,867,711	$6,752,418	$7,236,266	$10,357,318	$10,917,624
Account 501 - Thermal Fuel	$30,916,732	$2,789,917	$2,632,215	$2,785,057	$2,031,330	$1,718,372	$1,405,767	$2,715,972	$2,948,383	$2,925,528	$3,051,784	$2,909,636	$3,002,771
Account 547 - Natural Gas Fuel	$86,631,151	$8,264,229	$7,537,533	$7,376,233	$4,927,841	$2,851,219	$2,201,285	$6,893,937	$8,303,984	$8,561,441	$9,099,171	$9,713,701	$10,900,577
Account 447 - Sale for Resale	$64,351,897	$5,243,329	$4,871,731	$5,375,103	$5,885,551	$5,398,583	$3,447,153	$6,470,154	$3,363,867	$5,136,150	$5,299,000	$6,549,513	$7,311,763
Energy Efficiency Load Adjustment	-$2,806,911	-$273,886	-$250,672	-$242,982	-$212,229	-$209,628	-$200,167	-$234,185	-$231,449	-$211,558	-$201,508	-$254,873	-$283,773
Power Supply Expense	$157,095,545	$18,063,408	$15,854,340	$14,879,918	$9,454,142	$5,888,892	$6,553,367	$9,696,616	$16,524,762	$12,891,679	$13,886,714	$16,176,270	$17,225,436
Transmission Expense	$17,970,479	$1,495,284	$1,530,877	$1,480,538	$1,427,248	$1,371,518	$1,420,882	$1,432,251	$1,480,124	$1,483,239	$1,547,809	$1,665,262	$1,635,447
Transmission Revenue	$14,192,399	$1,181,058	$975,106	$1,088,154	$1,016,354	$1,087,976	$1,266,618	$1,420,627	$1,296,313	$1,218,435	$1,355,084	$1,151,351	$1,135,323

PCA Authorized Idaho Retail Sales (2)

	Total	January	February	March	April	May	June	July	August	September	October	November	December
Total Retail Sales (w/o Clearwater), M	2,920,316	288,551	259,938	251,710	220,893	215,129	211,357	242,246	239,640	218,704	210,033	262,811	299,304
Clearwater Paper Gen/Load	444,563	39,257	35,848	26,604	38,658	38,512	33,557	38,814	38,992	35,735	38,447	38,899	41,240
Load Change Adjustment Rate	$27.87	/MWh											

1) Multiply system numbers by 34.76% to determine Idaho share.
2) 2011 weather normalized Idaho retail sales. (with Energy Efficiency Load Adjustment)

Exhibit No. 6
Case No. AVU-E-12-08
W. Johnson, Avista
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