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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-11-01 DIRECT TESTIMONY OF 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 2010 through December 2010 test period power supply revenues and expenses, and 2) describe the proposed level of expense and retail revenue credit for The Power Cost

Adjustment (PCA) purposes, using the pro forma costs proposed by the Company in this filing. My testimony also shows the change in power supply expense incorporating the Energy Efficiency Load Adjustment proposed by the Company in this case.

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

A. Yes. I am sponsoring Exhibit 6, Schedules 1 through 5, 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 and short-term purchase and sales by month for each plant. The proposed authorized PCA power supply expense and revenue, transmission expense and revenue, and retail sales are shown in Schedule 4. Schedule 5 identifies the power supply expense and revenue without the Energy Efficiency Load Adjustment, and is provided for information purposes to isolate the impact of the Energy Efficiency Load Adjustment on power supply expense.

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

Schedules. Mr. Ehrbar addresses the Energy Efficiency Load Adjustment in his testimony.

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 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, which is based on an October 2010 through September 2011 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.

Power Supply Expense	
	System
Power Supply Expense in Current Base Rates (Oct 2010 - Sep 2011 pro forma)	$197,453,000
Actual Jan 10 - Dec 10 Power Supply Expense	$190,323,000
Adjustment to Test Period	$700,000
Proposed 2012 Pro forma Power Supply Expense - Unadjusted	$191,023,000
Increase from Expense in Current Rates	-$6,430,000

The net effect of my adjustments to the test year power supply expense is an increase of $700,000 ($191,023,000 - $190,323,000) on a system basis.

The decrease in power supply expense compared to the authorized level in current base rates is $6,430,000 (system) and $2,240,212 (Idaho allocation).

Q. What are the major factors driving the decreased 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 $197,453,000 (system number). This expense level is based on an October 2010 through September 2011 pro forma period. This compares to the proposed 2012 pro forma power supply expense of $191,023,000, a decrease of approximately $6.4 million on a system basis and an Idaho allocation of approximately $2.2 million.

This decrease in pro forma power supply expense over the expense currently in base rates is caused primarily by two factors, lower loads and lower market prices for natural gas and power. Loads are lower by 50.8 aMW from the loads authorized in current based rates, which used a pro forma load projection. The reduction in load is a result of using historical test-year loads and including the Energy Efficiency Load adjustment. The reduction in load due to moving from a pro forma year load to a historical test-year load is 30.7 aMW and the reduction in load due to the Energy Efficiency load adjustment is 20.1 aMW.

Market prices for natural gas and power are both lower than the level included in current base rates. The annual average natural gas price is $4.62/dth in this case versus $5.04/dth in current base rates. The annual average flat power price is $37.11/MWh in this case versus $40.31/MWh in current base rates.

Overall, the pro forma in this case has 17.3 aMW more hydro generation than was in the 2010 general rate case. The cost of the Mid-Columbia purchased generation, however, is higher. This is primarily a result of the expiration of the original Rocky Reach purchase agreement, which was priced at project cost (approximately $11.50/Mwh). The Rocky Reach and Rock Island purchase in this pro forma was acquired through a competitive bid at market prices. The costs for the other Mid-Columbia generation from the Wells project and the Priest Rapids project are also higher.

The net expense of long-term contracts is higher in this case. This is primarily a result of the expiration of the Grant PUD Displacement purchase on September 30, 2011, in which the Company purchases power at a rate equivalent to the BPA Priority Firm price. It also reflects the expiration of some load following sales.

The net (net of generation value) cost of thermal and natural gas-fired generation is higher due to increased fuel expense and reduced value of the power produced.

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

Power Supply Expense Change 2012 Pro forma vs. Oct 2010 - Sep 2011 Authorized		
Factor	2011 to 2012 Pro forma Change $millions	Idaho Allocation $millions
Hydro Generation & Mid C Costs	$4.4	$1.5
Change in System Load	-$14.9	-$5.2
Themal Plant Costs	$2.3	$0.8
CCCT Operating Margin	$6.9	$2.4
Long-Term Contract Changes	$5.4	$1.9
Market Prices (Natural Gas & Power)	-$10.5	-$3.7
2011 to 2012 Power Supply Increase	-$6.4	-$2.2

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 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 current 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 current 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 currently in base rates?

A. No. With the exception of reducing system load due to the use of historical versus pro forma load and the Energy Efficiency Load Adjustment, the process to develop the pro forma net power supply expense in this case is the same as the process used to develop authorized power supply expense in current base rates. The Energy Efficiency Load Adjustment, as further explained later in my testimony, lowers the system load used to develop the pro forma to a level below the weather adjusted test-year load.

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 power purchases or sales in the pro forma that are not in the current base rates?

A. Yes. This pro forma includes the expenses and generation related to the purchase of a 3.0% slice of the output of the Rocky Reach and Rock Island dams owned and operated by Chelan PUD. This purchase was made through a competitive auction and has a term of July 2011 through December 2014. The purchase was made to maintain an adequate level of Mid-Columbia generation to provide load shaping and ramping capabilities at the Mid-Columbia, which allows the Company to operate its own hydro facilities in a more efficient manner.

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

A. Yes. Four 25 aMW long-term market purchases ended December 31, 2010. The Company's long-term purchase of Rocky Reach generation at project cost ends October 31, 2011. The Grant PUD Displacement power purchase ends September 30, 2011. The Black Creek purchase ended March 25, 2011. On the revenue side, the load following contract with Northwestern Energy ended January 9, 2011, and the load following contract with NatuEner ends August 31, 2011.

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

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

A. System balancing 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. The pro forma does not include any of the actual short-term transactions already entered into for the 2012 pro forma period.

<u>Energy Efficiency Load Adjustment</u>

Q. How was the net power supply expense adjusted for the proposed Energy Efficiency Load Adjustment that is explained in Mr. Ehrbar's testimony?

A. The power supply pro forma incorporates the reduction in Idaho retail sales shown in Table 12 of Mr. Ehrbar's direct testimony, which was then grossed up for losses and then divided by Idaho's allocation to create a system load reduction. The power supply pro forma was then developed using the lower system load incorporating the Energy Efficiency Load Adjustment.

Q. What power supply expenses are affected using the Energy Efficiency Load Adjustment?

A. The only accounts affected in the power supply pro forma for the Energy Efficiency Load Adjustment are Account 555, Purchased Power and Account 447, Sales for Resale. Purchased power expense decreased by $3,323,000 on a system basis ($1,150,000 Idaho allocation) and Sales for Resale increased by $3,445,000 on a system basis ($1,200,000 Idaho allocation). All other power supply accounts are unaffected by the Energy Efficiency Load Adjustment. Schedule 5 is provided for information purposes and shows the power supply pro forma excluding the Energy Efficiency Load Adjustment. The difference between net power supply costs in Schedule 5 and Schedule 1 reflects the change in net power supply costs associated with the Energy Efficiency Load Adjustment.

<u>Thermal Fuel Expense</u>

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 current base rates?

A. The only change in transmission expense is the elimination of the Black Creek wheeling expense since that contract ended March 25, 2011.

IV. PCA CALCULATIONS

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 $172,632,863. 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 $17,641,176. The proposed level of Transmission Revenue is $11,524,732.

The level of retail sales MWh and the retail revenue credit is also updated. The proposed authorized level of retail sales to be used in the PCA is the January 2010 through December 2010 weather adjusted retail sales incorporating the Energy Efficiency Load Adjustment. The proposed load change adjustment rate is $26.33/MWh, which is the energy classification of the average cost of production/transmission 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.

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

A. Yes.

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FOR AVISTA CORPORATION

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Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2010 - Dec 2010 Actual and Jan 2012 - Dec 2012 Pro Forma
Historic 2010 Loads w/ Energy Efficiency Load Adjustment, Without Actual ST Transactions

Line No.		Jan 10 - Dec 10 Actuals	Adjustment	Jan 12 - Dec 12 Pro forma
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$21,271	$21,271
2	Actual Short-Term Market Purchases	159,193	-159,193	0
3	Rocky Reach	2,172	-2,172	0
4	Rocky Reach/Rock Island Purchase	0	11,384	11,384
5	Wells - Avista Share	1,400	499	1,899
6	Wells - Colville Tribe's Share	9,496	-9,496	0
7	Priest Rapids Project	5,609	785	6,394
8	Wanapum	-1,228	1,228	0
9	Grant Displacement	5,653	-5,653	0
10	Douglas Settlement	334	246	580
11	Lancaster Capacity Payment	21,475	578	22,053
12	Lancaster Variable O&M Payments	2,689	-223	2,466
13	Lancaster BPA Reserves	824	-824	0
14	WNP-3	13,920	-368	13,552
15	Deer Lake-IP&L	6	0	6
16	Small Power	1,079	13	1,092
17	Stimson	1,964	402	2,366
18	Spokane-Upriver	2,055	884	2,939
19	Black Creek Index Purchase	234	-234	0
20	Non-Monetary	90	-90	0
21	Contract A	6,789	-6,789	0
22	Contract B	6,745	-6,745	0
23	Contract C	6,658	-6,658	0
24	Contract D	7,556	-7,556	0
25	Clearwater Paper Co-Gen Purchase	18,720	-18,720	0
26	Ancillary Services	631	-631	0
27	Stateline Wind Purchase	3,016	530	3,546
28	Total Account 555	277,080	-187,532	89,548
	557 OTHER EXPENSES			
29	Broker Commission Fees	366	0	366
30	REC Purchases (SMUD)	349	1	350
31	Natural Gas Fuel Purchases	119,116	-119,116	0
32	Total Account 557	119,831	-119,115	716
	501 THERMAL FUEL EXPENSE			
33	Kettle Falls - Wood Fuel	10,551	1,534	12,085
34	Kettle Falls - Start-up Gas	30	0	30
35	Colstrip - Coal	15,984	3,803	19,787
36	Colstip - Oil	139	0	139
37	Total Account 501	26,704	5,336	32,040
	547 OTHER FUEL EXPENSE			
38	Coyote Springs Gas	53,491	-15,894	37,597
39	Coyote Springs 2 Gas Transportation	7,891	-58	7,833
40	Lancaster Gas	46,902	-6,544	40,358
41	Lancaster Gas Transportation	5,837	956	6,793
42	Lancaster Gas Transportation Optimization	0	-409	-409
43	Gas Transportation for BP, NE and KFCT	32	0	32
44	Rathdrum Gas	545	-544	1
45	Northeast CT Gas	62	-62	0
46	Boulder Park Gas	505	-472	33
47	Kettle Falls CT Gas	185	-136	49
48	Total Account 547	115,450	-23,163	92,287

REVISED JULY 21, 2011

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Jan 2010 - Dec 2010 Actual and Jan 2012 - Dec 2012 Pro Forma
Historic 2010 Loads w/ Energy Efficiency Load Adjustment, Without Actual ST Transactions

Line No.		Jan 10 - Dec 10 Actuals	Adjustment	Jan 12 - Dec 12 Pro forma
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
49	WNP-3	789	0	789
50	Sand Dunes-Warden	9	0	9
51	Black Creek Wheeling	65	-65	0
52	Wheeling for System Sales & Purchases	321	0	321
53	PTP Transmission for Colstrip & Coyote	8,428	2	8,430
54	PTP Transmission for Lancaster	4,541	-38	4,503
55	BPA Townsend-Garrison Wheeling	1,173	0	1,173
56	Avista on BPA - Borderline	1,253	0	1,253
57	Kootenai for Worley	45	0	45
58	Sagle-Northern Lights	139	0	139
59	Garrison-Burke	337	0	337
60	PGE Firm Wheeling	644	-1	643
61	Total Account 565	17,744	-102	17,642
	536 WATER FOR POWER			
62	Headwater Benefits Payments	853	0	853
	549 MISC OTHER GENERATION EXPENSE			
63	Rathdrum Municipal Payment	160	0	160
64	**TOTAL EXPENSE**	557,822	-324,575	233,247
	447 SALES FOR RESALE			
65	Modeled Short-Term Market Sales	0	30,778	30,778
66	Actual Short-Term Market Sales	219,096	-219,096	0
67	Peaker (PGE) Capacity Sale	1,749	0	1,749
68	Nichols Pumping Sale	1,693	688	2,381
69	Sovereign/Kaiser DES	80	0	80
70	Pend Oreille DES & Spinning	419	0	419
71	Northwestern Load Following	3,257	-3,257	0
72	NaturEner	551	-551	0
73	SMUD Sale - Energy and REC	27,761	-21,926	5,835
74	Ancillary Services	631	-631	0
75	Total Account 447	255,237	-213,995	41,242
	456 OTHER ELECTRIC REVENUE			
76	Renewable Energy Credit Sales	700	0	700
77	Gas Not Consumed Sales Revenue	111,280	-111,280	0
78	Total Account 456	111,980	-111,280	700
	453 SALES OF WATER AND WATER POWER			
79	Upstream Storage Revenue	282	0	282
80	**TOTAL REVENUE**	367,499	-325,275	42,224
81	**TOTAL NET EXPENSE**	190,323	700	191,023

REVISED JULY 21, 2011

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** – No actual transactions are included in the pro forma.

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 2010 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 **Wanapum** – The Wanapum contract ended 10-31-2009. The 2010 test-year included a true-up of 2009 payments.

9 **Grant Displacement** – The 2010 test-year expense included a purchase from Grant PUD that ends 9-30-11.

10 **Douglas Settlement** – Douglas Settlement is for power Avista purchases from Douglas PUD per the 1989 Settlement Agreement.

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

12 **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 times the MWh of Lancaster generation in the pro forma.

13 **Lancaster BPA Reserves** – The pro forma expense is $0 because Lancaster was moved (electronically) into Avista's balancing authority on March 29, 2011 so purchases of generation reserves from BPA are longer required.

14 **WNP-3 -** Pro forma costs are based on the midpoint. The pro forma uses the actual midpoint of the ceiling and floor prices identified in the contract for contract year 2010 through 2011 escalated at the 5-year average escalation rate to the pro forma period.

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

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

17 **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.

18 **Spokane-Upriver** – Pro forma expense is based on a purchase of the net of pumping (at the plant) generation at a contract based on Washington's Schedule 62 avoided cost rates.

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

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

21 **Contract A** – This contract ended 12-31-10.

22 **Contract B** - This contract ended 12-31-10.

23 **Contract C** - This contract ended 12-31-10.

24 **Contract D** - This contract ended 12-31-10.

25 **Clearwater Paper Co-Gen Purchase** – Clearwater Paper purchase is directly assigned in Idaho.

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

27 **Stateline Wind Purchase** – Pro forma expense is $0 because the contract was scheduled to end 12-31-2011. (It was extended to 4-30-2014 on April 20, 2011, after the pro forma expense was developed).

28 **Total Account 555**

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

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

31 **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.

32 **Total Account 557**

33 **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.

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

35 **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.

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

37 **Total Account 501**

38 **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.

39 **CS2 Gas Transportation** – This expense is for transportation of natural gas from AECO to the Coyote Springs 2 plant.

40 **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.

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

42 **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.

43 **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.

44 **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.

45 **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.

46 **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.

47 **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.

48 **Total Account 547**

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

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

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