

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-15_____

DIRECT TESTIMONY OF

WILLIAM G. JOHNSON

REPRESENTING AVISTA CORPORATION

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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 October 2013 through September 2014 test period power supply revenues and expenses, 2) describe proposed changes to the Energy Recovery Mechanism (ERM), and 3) describe the proposed level of expense and load change adjustment rate

1 (LCAR)¹ for ERM purposes, using the pro forma costs proposed by the Company in this
2 filing.

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

4 A. Yes. I am sponsoring Exhibit Nos.____ (WGJ-2) through ____ (WGJ-5),
5 which were prepared under my supervision and direction. Exhibit No. ____ (WGJ-2)
6 identifies the power supply expense and revenue items that fall within the scope of my
7 testimony. A brief description of each adjustment is provided in Exhibit No. ____ (WGJ-3).
8 Exhibit No. ____ (WGJ-4) shows the pro forma fuel costs for each thermal plant and short-
9 term purchase and sales by month. The proposed authorized ERM power supply expense
10 and revenue, transmission expense and revenue, broker fees, Colstrip and Coyote Spring 2
11 O&M expense, and retail sales are shown in Exhibit No.__(WGJ-5).

12 **Q. Are there other Company witnesses providing testimony regarding**
13 **issues you are addressing?**

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

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18 **II. OVERVIEW OF PRO FORMA POWER SUPPLY ADJUSTMENT**

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

20 A. The pro forma power supply adjustment involves the determination of
21 revenues and expenses based on the generation and dispatch of Company resources and
22 expected wholesale market power prices as determined by the AURORA model simulation

¹ In previous filings, the load change adjustment rate was referred to as the retail revenue credit.

1 for the pro forma rate period (calendar year 2016) under normal weather and hydro
 2 generation conditions. In addition, adjustments are made to reflect contract changes
 3 between the historical test period and the pro forma period. Table No. 1 below shows total
 4 net power supply expense during the test period and the pro forma period. For information
 5 purposes only, the power supply expense² currently in base retail rates, which are based on a
 6 calendar 2015 pro forma period, is also shown.

7 **Table No. 1:**

Power Supply Expense		
	<u>System</u>	<u>Washington Allocation</u>
Power Supply Expense in Current Rates (2015 pro forma)	\$191,152,000	\$124,611,989
Actual Oct 2013 - Sep 2014 Power Supply Expense with O&M Expense	\$207,185,000	\$135,063,902
Actual Oct 2013 - Sep 2014 Power Supply Expense w/o O&M Expense	\$187,993,000	\$122,552,637
Proposed 2016 Pro forma Power Supply Expense with O&M Expense	\$214,108,000	\$139,577,005
Proposed 2016 Pro forma Power Supply Expense w/o O&M Expense	\$189,768,000	\$123,709,759
Proposed 2016 with O&M vs Oct 2013 - Sep 2014 Test Period	\$6,923,000	\$4,513,104
Proposed 2016 w/o O&M vs Oct 2013 - Sep 2014 Test Period	\$1,775,000	\$1,157,123
Proposed 2016 w/o O&M vs Current Rates	-\$1,384,000	-\$902,230

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 9 The net effect of my adjustments to the test year power supply expense is an increase
 10 of \$6,923,000 (\$214,108,000 - \$207,185,000) on a system basis and \$4,513,104 Washington
 11 allocation. As I explain later in my testimony the Company is proposing to include
 12 operations and maintenance (O&M) expense at Colstrip and Coyote Springs 2 as part of
 13 base power supply expense used for the Energy Recovery Mechanism (ERM). The
 14 approved level of base power supply expense currently does not include this O&M expense.

² 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.

1 Absent the O&M expense at Colstrip and Coyote Springs 2, base power supply expense
2 decreased \$902,230 (Washington allocation) from the current approved level.

3 The Colstrip and Coyote Springs 2 O&M expense is currently included in the
4 determination of retail rates, but in a cost category separate from base power supply
5 expense. We are proposing to consolidate these O&M expenses with base power supply
6 expenses for rate making purposes, because they are interrelated with the level of base
7 power supply expense.

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9 **III. PRO FORMA POWER SUPPLY ADJUSTMENTS**

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

12 A. Exhibit No. ____ (WGJ-2) identifies the power supply expense and revenue
13 items that fall within the scope of my testimony. These revenue and expense items are
14 related to power purchases and sales, fuel expenses, transmission expense, Colstrip and
15 Coyote Springs 2 O&M expense, and other miscellaneous power supply expenses and
16 revenues.

17 **Q. Are there any changes in how the pro forma in this case was developed**
18 **versus the authorized power supply expense currently in base rates?**

19 A. Yes. As noted above, and explained later in my testimony, power supply
20 expense now includes O&M expense at Colstrip and Coyote Springs 2. Other than the
21 inclusion of the O&M expense, the process to develop the pro forma net power supply
22 expense in this case is the same as the process used to develop authorized power supply
23 expense in current base rates.

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

3 A. The purpose of the adjustments to the test period is to normalize power
4 supply expenses for normal weather and normal hydroelectric generation and to reflect
5 current forward natural gas prices and other known and measurable changes for the pro
6 forma period.

7 The AURORA Model, as explained by Mr. Kalich, dispatches Company resources
8 using the current forward natural gas prices and calculates the level of generation from the
9 Company's thermal resources, fuel costs for thermal resources, and the short-term purchases
10 and sales necessary to balance system requirements and resources.

11 A brief description of each adjustment is provided in Exhibit No. ____ (WGJ-3).
12 Detailed workpapers have been provided to the Commission with this filing to support each
13 of the pro forma revenues and expenses. The detailed workpapers for each adjustment show
14 the actual revenue or expense in the test period, and the pro forma revenue or expense.

15 **Long-Term Contracts**

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

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

20 **Q. Are there any new long-term power purchases or sales in the pro forma**
21 **that are not in the current base rates?**

22 A. No. However, the volume of the Rocky Reach/Rock Island purchase has
23 changed. The Rocky Reach/Rock Island purchase is included in the 2016 pro forma as a 5

1 percent share. The Company has been in discussion with Chelan PUD about purchasing a 5
2 percent share in 2016. Current base rates include a 4 percent share of Rocky Reach/Rock
3 Island. A new contract is expected to be finalized sometime in early 2015.

4 The purchase of the Colville Tribe's share of the Wells dam is not included in the
5 2016 pro forma. It was in the 2015 pro forma for the first quarter only. The Company has
6 been purchasing this product on a shorter term basis lately and may make a purchase for a
7 portion of 2016. If so, the Company would propose to include the purchase in a power
8 supply update later in 2015.

9 The 2016 pro forma includes a full year of Portland General Electric capacity sale
10 revenue. Current bases rates only include 11 months of revenue because the monetization
11 period ended January 2015 and the full revenue from the contract returned to the Company
12 beginning February 2015.

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

15 A. Yes. As mentioned above, current base rates include a three months purchase
16 of the Colville Tribe's share of the Wells dam that is not included in the 2016 pro forma.

17 **Short-Term Power Purchases and Sales**

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

19 A. After including the actual physical forward short-term transactions as
20 resources and obligations in the AURORA model, the balance of the short-term electric
21 power purchases and sales are an output of the AURORA model. The model calculates both
22 the volumes and price of short-term purchases and sales that balance the system's generation
23 and long-term purchases with retail load and other obligations. The price of the short-term

1 transactions represents the price of spot market power as determined by the AURORA
2 model. Short-term fixed price financial electric and natural gas transactions are included as
3 a mark-to-model price line item in the pro forma.

4 **Q. What actual forward short-term transactions are included in the pro**
5 **forma?**

6 A. The pro forma includes transactions entered into through late 2014 for the
7 2016 pro forma period. These transactions include fixed-price financial electric and natural
8 gas transactions. The AURORA model is used to mark-to-model the financial electric
9 transactions. A mark-to-modeled gas price calculation is performed outside the AURORA
10 model and details of these gas transactions are provided in workpapers.

11 **Thermal Fuel Expense**

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

13 A. Thermal fuel expenses include Colstrip coal costs, Kettle Falls wood-waste
14 costs, and natural gas expense for the Company's gas-fired resources including Coyote
15 Springs 2, Lancaster, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion
16 turbine. Unit coal costs at Colstrip are based on the long-term coal supply and
17 transportation agreements. Unit wood fuel costs at Kettle Falls are based on multiple
18 shorter-term contracts with fuel suppliers and inventory. Total fuel costs for each plant are
19 based on the unit fuel cost and the plant's level of generation as determined by the
20 AURORA model.

21 Exhibit No. ____ (WGJ-4) shows the pro forma fuel costs by month for each plant.
22 Mr. Kalich provides details and supporting workpapers regarding the level of generation for
23 the Company's thermal plants, and the fuel cost for thermal and natural gas-fired plants.

1 **Transmission Expense**

2 **Q. What changes in transmission expense are in the pro forma compared to**
3 **the test-year and the expense in current base rates?**

4 A. The biggest change from the test-year is the reduction in transmission
5 purchased for the Lancaster plant. Through August 2014 the Company purchased 250 MW
6 of BPA point-to-point transmission to move Lancaster Generation to the Company's system.
7 On December 13, 2013, the Lancaster substation became a point of interconnection to
8 Avista's transmission system, eliminating the need for BPA transmission for Lancaster.
9 Avista's Lancaster transmission contracts with BPA allowed for the termination of 150 MW
10 of the 250 MW of transmission with a two-year notice. The termination notice was given to
11 BPA on August 31, 2012, and the contract ended August 31, 2014. There is only a \$9,000
12 difference in transmission expense from the level in current base rates.

13 **Summary**

14 **Q. Please summarize your proposed pro forma power supply expense that is**
15 **provided to witness Andrews for the Company's electric attrition study.³**

16 A. The proposed pro forma power supply expense as shown in Exhibit No. ____
17 (WGJ-2) is a \$6,923,000 increase in expense on a system basis and \$4,513,104 for the
18 Washington allocation from the October 2013 through September 2014 test-year expense.
19 Part of the increase in expense is related to consolidating the Colstrip and Coyote Springs 2
20 O&M expense with base power supply expense.

³ The pro forma power supply expense was also provided to Company witness Ms. Smith for the electric pro forma cross check study.

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IV. MODIFICATIONS TO THE ERM

Q. Is the Company proposing any modification to the ERM?

A. Yes. The Company is proposing three changes to the ERM. These three changes are: 1) a proposal to annually clear the deferral balance with a rebate or a surcharge rather than waiting until a \$30 million trigger balance is reached, 2) change the load change adjustment rate (LCAR) to the average market price of energy rather than the ERM-related FERC accounts in dollars per MWh, and 3) track the changes in operation and maintenance expenses for Colstrip and Coyote Springs 2 in the ERM.

ERM Deferral Balance Trigger

Q. What is the current rate adjustment trigger for the ERM?

A. The rate adjustment trigger was originally set at 10% of base revenues per the Settlement Stipulation approved by the Fifth Supplemental Order in Docket UE-011595, dated June 18, 2002. The multiparty settlement stipulation in Docket No. UE-120436 reduced the rate adjustment trigger amount from 10 percent of base revenues to \$30 million. While this substantially reduced the trigger amount, the Company believes that allowing deferrals to grow to \$30 million needlessly delays the recovery or rebate of variations in power supply related costs.

Q. What is the Company’s proposed modification to the trigger mechanism?

A. The Company is proposing to replace the trigger mechanism with annual ERM rate adjustments. These annual rate adjustments would occur with rates effective July 1 each year, based on the deferrals from the previous calendar year. The Company would continue to file its annual deferral report on or before April 1 of each year, accompanied by

1 a proposed rate adjustment to recover or rebate the deferral balance over a twelve-month
2 period beginning July 1. Commission Staff and other interested parties would have 90 days
3 to review the filing prior to the July 1 effective date of the tariff.

4 **Q. Do annual rate adjustments result in smaller rate adjustments as**
5 **compared to the existing trigger mechanism?**

6 A. Yes, the Company's proposal would likely result in smaller surcharge or
7 rebate rate adjustments, than adjusting rates when the \$30 million trigger is reached. The
8 rate adjustments would also be more understandable to customers since the costs being
9 recovered or rebated relate to a recent period. Annual rate adjustments would result in a
10 more timely recovery of costs when deferrals are in the surcharge direction, and a timelier
11 pass-through of refunds when deferrals are in the rebate direction. The proposal of annual
12 rate adjustments also fits within the existing 90-day review process.

13 **Load Change Adjustment Rate**

14 **Q. What is the issue in this case regarding the Load Change Adjustment**
15 **Rate?**

16 A. In the Multi-Party Settlement Agreement in Docket No. UE-140188, the
17 parties agreed to change the load change adjustment rate (LCAR) from the energy classified
18 production and transmission revenue requirement to the approved ERM-related FERC
19 accounts in dollars per MWh. This reduced the LCAR from \$32.15/MWh to \$22.80/MWh.
20 Although the Company agreed to this rate for settlement purposes, it now believes the
21 average wholesale market price of energy is the more appropriate LCAR as further
22 explained below.

23 **Q. Please describe how the LCAR works within the ERM.**

1 A. When retail loads are higher than authorized loads, there is a higher power
2 supply expense to serve the increase in load. In the ERM there is an LCAR adjustment that
3 multiplies the LCAR times the increase in sales to take into account that there is an increase
4 in retail revenue to correspond with the increase in power supply expense. Absent the
5 LCAR adjustment, customers would be overcharged through the ERM for the increase in
6 power supply expense.

7 Likewise, when retail loads are lower than authorized loads, there is a lower net
8 power supply expense to serve the decrease in load. The LCAR is applied to the decrease in
9 sales to take into account that there is a decrease in retail revenue that corresponds with the
10 decrease in power supply expense. Absent the LCAR adjustment, customers would receive
11 an undue benefit through the ERM, since the net reduction in power supply expense is
12 directly related to a reduction in retail revenue.

13 **Q. What change is the Company proposing to the LCAR?**

14 A. The Company is proposing that the LCAR be set at the average purchase and
15 sale price as determined by the AURORA model in the power supply pro forma. This value
16 represents the average market price of energy. That number is \$30.68/MWh based on the
17 filed power supply pro forma. This is the average wholesale market price in the pro forma
18 at which short-term (hourly) purchases and/or sales are made.

19 **Q. Why is the market price of power a more appropriate value for the**
20 **LCAR?**

21 A. The market price of power is more representative of the actual increased or
22 decreased cost that will occur with a change in load from the authorized level. For example,
23 if loads are higher than the authorized level, costs will increase because of either increased

1 power purchase or decreased power sales. Those power transactions occur at a market
 2 power price which is likely to be higher than the existing \$22.80 LCAR. This results in an
 3 ERM surcharge because the LCAR adjustment does not offset the increased power expense.
 4 The same is true with the opposite situation when loads are lower than the authorized level.
 5 Power costs decrease because of increased sales or decreased purchases at market power
 6 prices. The LCAR adjustment will likely be less than the decreased power costs and an
 7 ERM rebate deferral will result. If the LCAR, however, is at the market price of power at
 8 which purchases or sales are made, then any deferral will be reduced or eliminated.

9 Table No. 2 and Table No. 3 below show the impact to the ERM for different
 10 LCARs for a month with higher loads and a month with lower loads. In these two examples
 11 I have used actual load changes and market power prices that occurred in November and
 12 December 2014 and the current and proposed LCAR.

13 **Table No. 2:**

Impact of Load Change Adjustment Rate Loads Above Authorized Level		
	Load Change Adjustment Rate	
	ERM Related FERC Accounts	Avg Market Power Price
Increased Washington Sales, MWh (1)	15,912	15,912
Average Wholesale Market Purchase Price, \$/MWh (1)	\$30.65	\$30.65
Increased Power Supply Expense	\$487,703	\$487,703
Load Change Adjustment Rate, \$/MWh	\$22.80	\$30.68
LCAR Adjustment	-\$362,794	-\$488,180
ERM Surcharge (Rebate)	\$124,909	-\$477
1) Based on actual November 2014 load increase and market power price.		

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1 **Table No. 3:**

Impact of Load Change Adjustment Rate Loads Below Authorized Level		
	Load Change Adjustment Rate	
	ERM Related FERC Accounts	Avg Market Power Price
Decreased Washington Sales, MWh (1)	(23,884)	(23,884)
Average Wholesale Market Sale Price, \$/MWh (1)	\$29.37	\$29.37
Decreased Power Supply Expense	-\$701,473	-\$701,473
Load Change Adjustment Rate, \$/MWh	\$22.80	\$30.68
LCAR Adjustment	\$544,555	\$732,761
ERM Surcharge (Rebate)	-\$156,918	\$31,288
1) Based on actual December 2014 load decrease and market power price.		

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4 As shown in these examples, using the modeled average market price of power as the

5 LCAR results in much lower deferrals than using the rate based on the ERM FERC-related

6 accounts. In these two months the actual market price of power was close to the modeled

7 market power price resulting in very small load change related deferrals. That may not be

8 true in every month since the actual market price of power varies and could be substantially

9 different than the modeled price, which would result in larger load change related deferrals.

10 However, in that case, the ERM is capturing the actual change in expense because the

11 difference in the actual price of power and the modeled price of power represents the real

12 change of expense related to a change in load. The change in power supply expense due to a

13 change in load is directly related to the short-term market price of power, and this market

1 price of power is more representative of the actual change in costs than the current LCAR
2 based on ERM-related FERC accounts.

3 **Q. Should the same LCAR be used in the decoupling mechanism?**

4 A. Yes. As explained above, the LCAR should be a value that most
5 appropriately represents the change in power supply expense resulting from a change in
6 load.

7 **Colstrip and Coyote Springs 2 Operation and Maintenance Expense**

8 **Q. What is the Company proposing related to Colstrip and Coyote**
9 **Springs 2 O&M expense?**

10 A. The Company is proposing to track the difference between the authorized
11 level of O&M expense and actual O&M costs in the ERM.

12 **Q. Why does the Company believe it is appropriate to include such costs in**
13 **the ERM?**

14 A. Including the O&M expense in the ERM better captures the total variation in
15 power supply costs. O&M at the Colstrip and Coyote Springs 2 plants is a significant
16 expense and both plants have highly variable maintenance schedules that are dependent on
17 factors outside the Company's control. The real issue is primarily maintenance and not
18 operation expense. Major maintenance is done every 2 out of 3 years at Colstrip (each unit
19 every 3 years) and is known in advance. Avista does not control this maintenance cycle as it
20 is a jointly owned plant. Coyote Springs 2's major maintenance is dependent on fired-run
21 hours on the gas turbine. Major maintenance occurs every 24,000 hours. It is expected that
22 the turbine will reach 72,000 hours of run time sometime in 2016. Run time is dependent on

1 market conditions and Avista cannot be certain when major maintenance will occur because
2 market conditions and therefore run hours vary.

3 In 2016 both Colstrip and Coyote Springs 2 are expected to incur major maintenance
4 expense and that expense level is \$3,105,745 higher than the expense level in the test-year
5 (Washington allocation). Avista will significantly under recover its O&M expense for
6 Colstrip and Coyote Springs 2 in 2016 if it does not have some means to include these costs
7 in retail rates.

8 **Q. Why include operation expense?**

9 A. Operation expense is included because it may be lower in years with major
10 maintenance expense because the plant will run less time. It would be unfair to customers to
11 charge them for higher maintenance expense but not credit them for lower operation
12 expense.

13 **Q. What accounts would be tracked?**

14 A. The accounts that would be tracked are FERC accounts 500 through 507 and
15 510 through 514 for Colstrip, and 546 through 554 and 562 for Coyote Springs 2. The test-
16 year and pro forma expenses for these accounts are shown in workpapers included with this
17 filing.

18 **Q. How would the difference in O&M be included in the ERM deferrals?**

19 A. The difference between actual and pro forma O&M costs would be treated
20 the same as any other power supply expense variation, and be subject to the dead band and
21 the sharing bands.

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V. ERM AUTHORIZED VALUES

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

A. The proposed authorized level of annual system power supply expense is \$197,770,559. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). It also includes the O&M accounts noted above related to its Colstrip and Coyote Springs 2 plants, transmission expense, transmission revenue and broker fee expense.

Q. What is the level of retail sales and the proposed LCAR for the ERM?

A. The proposed authorized level of retail sales to be used in the ERM is the October 2013 through September 2014 weather adjusted Washington retail sales. The proposed LCAR is \$30.68MWh, which is the average spot market purchase and sales rate in the power supply pro forma.

The proposed authorized ERM power supply expense and revenue, transmission expense and revenue, and retail sales are shown in Exhibit No.____ (WGJ-5).

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

A. Yes.