

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-14_____

DOCKET NO. UG-14_____

DIRECT TESTIMONY OF
PATRICK D. EHRBAR
REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Patrick D. Ehrbar and my business address is 1411 East Mission Avenue, Spokane, Washington. I am presently assigned to the State and Federal Regulation Department as Manager of Rates and Tariffs.

Q. Would you briefly describe your duties?

A. Yes. My primary areas of responsibility include electric and natural gas rate design, customer usage and revenue analysis, and tariff administration.

Q. Please briefly describe your educational background and professional experience?

A. I am a 1995 graduate of Gonzaga University with a Bachelors degree in Business Administration. In 1997 I graduated from Gonzaga University with a Masters degree in Business Administration. I started with Avista in April 1997 as a Resource Management Analyst in the Company's DSM Department. Later, I became a Program Manager, responsible for energy efficiency program offerings for the Company's educational and governmental customers. In 2000, I was selected to be one of the Company's key Account Executives. In this role I was responsible for, among other things, being the primary point of contact for numerous commercial and industrial customers, including delivery of the Company's site specific energy efficiency programs.

I joined the State and Federal Regulation Department as a Senior Regulatory Analyst in 2007. Responsibilities in this role included being the discovery coordinator for the Company's rate cases, line extension policy tariffs, as well as miscellaneous regulatory

1 issues. In November 2009, I was promoted to my current role.

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

3 A. My testimony in this proceeding will cover the spread of the proposed annual
4 electric base revenue increase over 2014 base revenues of \$18,201,000, or 3.8%, among the
5 Company's electric general service schedules. The change in billing revenues is an increase
6 of \$26,308,000 or 5.5% which reflects the following items which will, or are proposed to, go
7 into effect on January 1, 2015:

8 Expiration of ERM Rebate – as a part of the Settlement Stipulation approved by the
9 Commission in the Company's last general rate case¹, during 2014 the Company is
10 rebating to customers approximately \$9.0 million from the Energy Recovery
11 Mechanism ("ERM") balancing account. That rebate expires on January 1, 2015.

12 Expiration of BPA Transmission Rebate – Pursuant to Order No. 01 in Docket UE-
13 130536, the Company is also rebating to customers in 2014 certain BPA
14 transmission revenues representing the entire 2013 and 2014 revenue associated with
15 the Bonneville settlement agreement (approximately \$4.3 million).

16 New Renewable Energy Credit ("REC") Revenue Mechanism – As discussed in
17 Company witness Mr. Johnson's testimony, the Company is proposing a REC
18 Revenue Mechanism to rebate to customers the actual and projected net REC
19 revenues for the 2012 through June 2016 time period. The amortization period for
20 this rebate, which is approximately \$7.8 million (Washington allocation), will be 18
21 months, January 2015 through June 2016. The 2015 annualized rebate amount is
22 approximately \$5.2 million.

23 Below is a table and an illustration summarizing the various rate changes noted

¹ Dockets UE-120436 and UG-120437, Order No. 09.
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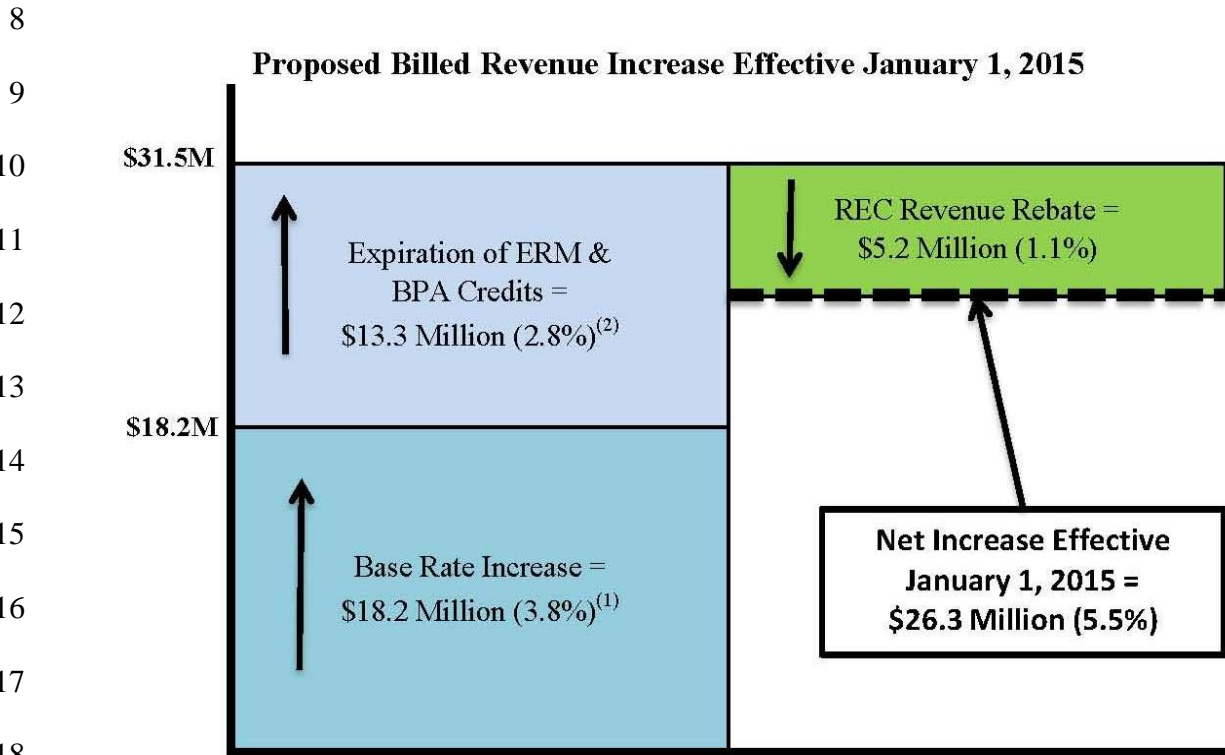
1 above:

2 **Table No. 1:**

3

Billed Revenue Changes Effective January 1, 2015		
	<u>Revenue Change</u>	<u>% Change</u>
4 Proposed Base Revenue Increase	\$ 18,201,000	3.8%
5 Expiration of 2014 ERM & BPA Offsets	\$ 13,344,000	2.8%
REC Revenue Proposed Rebate	\$ (5,237,000)	-1.1%
6 Net Billing Revenue Change 1/1/15	<u>\$ 26,308,000</u>	5.5%

7 **Illustration No. 1**



19 (1) Increase in Base Rate Revenue over 2014 levels.
 20 (2) Reflects expiration of \$9.0 Million rebate from ERM balancing account per UE-120436, and expiration of \$4.3 Million rebate of 2013/14 BPA Settlement revenues from Docket UE-130536.

21 With regard to natural gas service, I will describe the spread of the proposed annual
 22 base revenue increase over 2014 base revenues of \$12,135,000, or 8.1%, among the
 23 Company's natural gas service schedules. The proposed increase on a billing basis is 7.8%.

1 My testimony will also describe the changes to the rates within the Company's
 2 electric and natural gas service schedules, as well the proposed increase in the basic charge
 3 for residential electric rate Schedule 1 and natural gas rate Schedule 101. I will describe the
 4 DSM Component of the Attrition Adjustment and the Company's request for an Electric and
 5 Natural Gas Decoupling Mechanism. Later, I will discuss changes to the Company's street
 6 lighting tariffs, and the proposed REC Revenue Mechanism. Finally, I will provide an
 7 overview of the items required of the Company in Order No. 09, and the related Settlement
 8 Stipulation, in Dockets UE-120436 et. al.

9 **Q. Are you sponsoring any Exhibits that accompany your testimony?**

10 A. Yes. I am sponsoring Exhibit Nos. ____ (PDE-2), ____ (PDE-3), and ____ (PDE-
 11 4) related to the proposed electric increase, and Exhibit Nos. ____ (PDE-5), ____ (PDE-6), and
 12 ____ (PDE-7) related to the proposed natural gas increase. I am also sponsoring Exhibit No.
 13 ____ (PDE-8) relating to the DSM Component of the Attrition Adjustment. Exhibit
 14 Nos. ____ (PDE-9) and ____ (PDE-10) are related to the Company's proposed Electric and
 15 Natural Gas Decoupling Mechanisms. These exhibits were prepared by me or under my
 16 supervision. A table of contents for my testimony is as follows:

17

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II. EXECUTIVE SUMMARY

Proposed Electric Increase

13
14 **Q. What is the proposed electric revenue increase in this case and how is the**
15 **Company proposing to spread the total increase by rate schedule?**

16 A. The proposed electric increase is \$18,201,000, or 3.8% over present 2014
17 base tariff revenues. Elsewhere, the Company has demonstrated the need for a continuation
18 of the existing rate relief provided in 2014 of \$14.038 million, as well as an additional
19 increase in base rates of \$18.2 million to take effect January 1, 2015. The proposed general
20 increase over present billing revenues², including all other rate adjustments (DSM and
21 Residential Exchange), and including the new and expiring credits discussed earlier is 5.5%.
22 We are proposing that the general base rate increase of \$18,201,000 be spread by rate
23 schedule on a uniform percentage basis, and the proposed REC Revenue Mechanism rebate
24 be spread to the schedules on a uniform cents per kWh basis. The proposed percentage
25 increase by rate schedule is as follows:

² Included in present billing rates is a refund of approximately \$9.0 million from the Energy Recovery Mechanism Schedule 93 (as approved in Docket UE-120436), and a refund of approximately \$4.3 million from the Bonneville Power Settlement (Docket UE-130536). Effective January 1, 2015, the rebates associated with the ERM and BPA Settlement will expire.

Table 2 - Proposed % Electric Increase by Schedule

Rate Schedule	Increase in Base Rates	Increase in Billing Rates	Increase in Billed Revenues Net of New & Expiring Credits
Residential Schedule 1	3.8%	3.8%	5.6%
General Service Schedules 11/12	3.8%	3.7%	5.4%
Large General Service Schedules 21/22	3.8%	3.7%	5.4%
Extra Large General Service Schedule 25	3.8%	3.8%	5.2%
Pumping Service Schedules 31/32	3.8%	3.8%	5.3%
Street & Area Lights Schedules 41-48	<u>3.8%</u>	<u>3.6%</u>	<u>5.4%</u>
Overall	<u>3.8%</u>	<u>3.8%</u>	<u>5.5%</u>

This information is shown with more detail on page 1, of Exhibit No. ____ (PDE-4).

Q. What is the proposed increase for a residential electric customer with average consumption, including the proposed changes in rebates?

A. The proposed increase for a residential customer using an average of 965 kWhs per month is \$4.89 per month, or a 6.1% increase in their electric bill. The present bill for 965 kWhs is \$80.09 compared to the proposed level of \$84.98, including all rate adjustments. The Company is also proposing to change the basic charge from \$8.00 per month to \$15.00 per month.

Q. Is the Company proposing any changes to the present rate structures within its electric service schedules?

A. No. The Company is not proposing any changes to the present rate structures within its electric schedules.

Q. Where do you show the proposed changes in rates within the electric service schedules?

A. This information is shown in detail on page 3 of Exhibit No. ____ (PDE-4).

1 **Proposed Natural Gas Increase**

2 **Q. What is the proposed natural gas revenue increase in this case and how**
 3 **is the Company proposing to spread the total increase by rate schedule?**

4 A. The proposed natural gas increase is \$12,135,000 or 8.1% over present 2014
 5 base tariff revenues³. Elsewhere, the Company has demonstrated the need for a continuation
 6 of the existing rate relief provided in 2014 of \$1.4 million, as well as an additional increase
 7 in base rates of \$12.1 million to take effect January 1, 2015. The proposed general increase
 8 over present billing rates, including all other rate adjustments (Purchased Gas Cost
 9 Adjustment, DSM, etc.) is 7.8%. The Company utilized the results of the natural gas cost of
 10 service study, sponsored by Company witness Mr. Miller, as a guide in spreading the overall
 11 revenue increase. The Company is proposing the following base and billing revenue changes
 12 by rate schedule⁴:

13 **Table 3 - Proposed % Natural Gas Increase by Schedule**

<u>Rate Schedule</u>	<u>Increase in Base Rates</u>	<u>Increase in Billing Rates</u>
General Service Schedule 101	8.7%	8.3%
Large General Service Schedules 111/112	6.4%	6.1%
Ex. Lg. General Service Schedules 121/122	5.2%	4.9%
Interrupt. Sales Service Schedules 131/132	3.8%	3.7%
Transportation Service Schedule 146	<u>17.0%</u>	<u>17.0%</u>
Overall	8.1%	7.8%

19 This information is also shown on page 1 of Exhibit No. ____ (PDE-7).

20 **Q. What is the proposed monthly increase for a residential natural gas**

³ The proposed increase in natural gas revenues of 8.1% includes revenues from base tariffs as well as the current cost of natural gas included in Schedule 150.

⁴ For Schedule 146, including an estimate of 50.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 2.3% in those customers' total natural gas bill.

1 **customer with average usage?**

2 A. The increase for a residential customer using an average of 65 therms of
3 natural gas per month would be \$5.23 per month, or 8.5%. A bill for 65 therms per month
4 would increase from the present level of \$61.19 to a proposed level of \$66.42. The
5 Company is also proposing to change the basic charge from \$8.00 per month to \$12.00 per
6 month.

7

8 **III. PROPOSED ELECTRIC REVENUE INCREASE**

9 **Summary of Electric Rate Schedules and Tariffs**

10 **Q. Would you please explain what is contained in Exhibit No. ____ (PDE-2)?**

11 A. Yes. Exhibit No. ____ (PDE-2) contains a copy of the Company's present
12 electric tariffs/service schedules.

13 **Q. Could you please describe what is contained in Exhibit No. ____ (PDE-3)?**

14 A. Yes. Exhibit No. ____ (PDE-3) contains the proposed electric tariff sheets
15 incorporating the proposed changes included in this filing.

16 **Q. What is contained in Exhibit No. ____ (PDE-4)?**

17 A. Exhibit No. ____ (PDE-4) contains information regarding the proposed spread
18 of the electric revenue increase among the service schedules and the proposed changes to the
19 rates within the schedules. Page 1 shows the proposed general revenue and percentage
20 increase by rate schedule compared to the present revenue under base tariff and billing rates.
21 Page 2 shows the rates of return and the relative rates of return for each of the schedules
22 before and after application of the proposed general increase. Page 3 shows the present rates
23 under each of the rate schedules, the proposed changes to the rates within the schedules, and

1 the proposed rates after application of the changes. These pages will be referred to later in
 2 my testimony.

3 **Q. Would you please describe the Company's present rate schedules and the**
 4 **types of electric service offered under each?**

5 A. Yes. The Company presently provides electric service under Residential
 6 Service Schedule 1, General Service Schedules 11 and 12, Large General Service Schedules
 7 21 and 22, Extra Large General Service Schedule 25, and Pumping Service Schedules 31
 8 and 32. Additionally, the Company provides Street Lighting Service under Schedules 41-
 9 46, and Area Lighting Service under Schedules 47-48. Schedules 12, 22, 32, and 48 exist
 10 for residential and farm service customers who qualify for the Residential Exchange
 11 Program operated by the Bonneville Power Administration. The rates for these schedules
 12 are identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the
 13 Residential Exchange rate credit.

14 Table 4 below shows the type and number of customers served in Washington (as of
 15 June 2013) under each of the service schedules:

16

<u>Table 4 - Customers by Service Schedule</u>	
<u>Rate Schedule</u>	<u>No. of Customers</u>
Residential Schedule 1	203,022
General Service Schedules 11/12	29,592
Large General Service Schedules 21/22	1,993
Extra Large General Service Schedule 25	20
Pumping Service Schedules 31/32	2,423

21

22 **Proposed Electric Rate Spread**

23 **Q. How does the Company propose to spread the total general revenue**

1 **increase request of \$18,201,000 among its various rate schedules?**

2 A. The Company is proposing that the overall requested revenue increase be
3 spread on a uniform percentage basis:

4 **Table 5 - Proposed % Electric Increase by Schedule**

<u>Rate Schedule</u>	<u>Increase in Base Rates</u>	<u>Increase in Billing Rates</u>	<u>Increase in Billing Rates Net of New & Expiring Credits</u>
Residential Schedule 1	3.8%	3.8%	5.6%
General Service Schedules 11/12	3.8%	3.7%	5.4%
Large General Service Schedules 21/22	3.8%	3.7%	5.4%
Extra Large General Service Schedule 25	3.8%	3.8%	5.2%
Pumping Service Schedules 31/32	3.8%	3.8%	5.3%
Street & Area Lights Schedules 41-48	<u>3.8%</u>	<u>3.6%</u>	<u>5.4%</u>
Overall	3.8%	3.8%	<u>5.5%</u>

10

11 This information is shown with more detail on Page 1 of Exhibit No. ____ (PDE-4).

12 **Q. What rationale did the Company use in developing the proposed general**
13 **increase by rate schedule?**

14 A. The Company believes that the results of the cost of service study (sponsored
15 by Company witness Ms. Knox) should be used as a guide to spread the general increase.
16 The Company also reviewed the results of the Company's cost of service study from its
17 original filing in its 2012 general rate case (updated for the final approved retail revenue
18 credit rate determination assumptions), and looked at the impact to the cost of service study
19 results incorporating the 2013 agreed-upon revenue requirement. Those study results along
20 with the cost of service study results in this case demonstrate that all rate schedules, with the
21 exception of the Street and Area Lights rate schedules, have had steady movement closer to
22 the overall rate of return (unity). Therefore, the Company chose to spread the proposed rate
23 increase on a uniform percentage basis which continues the progress towards unity.

1 Table 6 below shows the relative rates of return (schedule rate of return divided by
 2 overall rate of return) before and after application of the base rate increase on a uniform
 3 percentage basis (3.8%) to all rate schedules:

4 **Table 6 - Present & Proposed Relative Rates of Return**

Rate Schedule	Present Relative <u>ROR</u>	Uniform Percentage <u>ROR</u>
Residential Schedule 1	0.65	0.68
General Service Schedules 11/12	1.92	1.85
Large General Service Schedules 21/22	1.37	1.34
Extra Large General Service Schedule 25	0.85	0.88
Pumping Service Schedules 31/32	0.91	0.91
Street & Area Lights Schedules	0.92	0.90
Overall	1.00	1.00

11 As shown, for those schedules where the present rates are substantially above or
 12 below the cost of service, the proposed rate spread provides some movement towards unity
 13 (1.00).

14

15 **Proposed Rate Design**

16 **Q. Where in your Exhibit do you show a comparison of the present and**
 17 **proposed rates within each of the Company’s electric service schedules?**

18 A. Page 3 of Exhibit No.____(PDE-4) shows a comparison of the present and
 19 proposed rates within each of the schedules, which I will describe below. Column (a) shows
 20 the rate/billing components under each of the schedules, column (b) shows the base tariff
 21 rates within each of the schedules, column (c) shows the present rate adjustments applicable
 22 under each schedule, and column (d) shows the present billing rates. Column (e) shows the
 23 proposed general rate increase to the rate components within each of the schedules. Column

1 (f) shows the proposed REC Revenue Mechanism rebate, and column (g) shows the
2 expiration of the 2014 ERM and BPA credits. Finally, column (h) shows the proposed
3 billing rates and column (i) shows the proposed base tariff rates.

4 **Q. Is the Company proposing any changes to the existing rate structures**
5 **within its rate schedules?**

6 A. No, it is not.

7 **Q. Turning to Residential Service Schedule 1, could you please describe the**
8 **present rate structure under this schedule?**

9 A. Yes. Residential Schedule 1 has a present customer or basic charge of \$8.00
10 per month and three energy rate blocks: 0-800 kWhs, 801-1,500 kWhs and over 1,500
11 kWhs. The present base tariff rate for the first 800 kWhs per month is 7.369 cents per kWh,
12 8.573 cents per kWh for the next 700 kWhs and 10.050 cents for all kWhs over 1,500.

13 **Q. How does the Company propose to spread the proposed revenue increase**
14 **of \$7,844,000 to Schedule 1?**

15 A. The Company is proposing to increase the basic charge from \$8.00 to \$15.00
16 per month, and is proposing to decrease the energy rate for all three blocks by approximately
17 4.9 percent.

18 **Q. Why is the Company proposing to increase the monthly customer charge**
19 **from \$8.00 to \$15.00 per month?**

20 A. A substantial portion of the Company's costs are fixed and do not vary with
21 the amount of energy used by customers. As reflected in this filing, the fixed costs of
22 operating and maintaining our electric system are increasing. The Company believes it is
23 important that rates better reflect these increasing costs to serve customers. Later in Section

1 V. of my testimony I will provide greater detail as to why the Company believes the monthly
2 customer charge should increase by \$7.00 per month.

3 **Q. What is the average monthly electric usage for a residential customer,**
4 **and what is the effect of the proposed increase on a customer's bill?**

5 A. The average monthly usage for a residential customer is approximately 965
6 kWhs. Based on the proposed billing rate increase, including the proposed REC Revenue
7 rebate, the average monthly increase would be \$4.89, or 6.1%. The present bill for 965
8 kWhs is \$80.09 compared to the proposed level of \$84.98, including all rate adjustments.

9 **Q. Turning to General Service Schedule 11, would you please describe the**
10 **present rate structure and rates under that schedule?**

11 A. Yes. The present rate structure under the schedule includes a monthly
12 customer charge of \$15.00, an energy rate of 11.391 cents per kWh for all usage up to 3,650
13 kWhs per month, and an energy rate of 8.370 cents per kWh for usage over 3,650 kWhs per
14 month. There is also a demand charge of \$6.00 per kW for all demand in excess of 20 kW
15 per month. There is no charge for the first 20 kW of demand.

16 **Q. How is the Company proposing to apply the proposed general revenue**
17 **increase of \$2,500,000 to the rates under Schedule 11?**

18 A. The Company is proposing that the customer charge be increased by \$3.00,
19 from \$15.00 to \$18.00 per month. In addition, the Company is proposing that the demand
20 charge (over 20 kW) be increased \$0.50 per kW, from \$6.00 to \$6.50. The remaining
21 revenue increase for the schedule is proposed to be recovered through a uniform percentage
22 increase of approximately 2.2% applied to the two (block) energy rates. The increase in the
23 first block rate is 0.247 cents per kWh, and 0.182 cents per kWh for the second block rate.

1 Finally, the Company is proposing to increase the minimum charge for 3-phase service from
2 \$22.35 to \$25.35 per month.

3 **Q. Why is the Company proposing a \$0.50 or 8.3% increase to the demand**
4 **charge for Schedule 11?**

5 A. The system allocated demand cost from the cost of service study is \$17.46
6 per kilowatt (kW) month⁵. The Company's present monthly demand charges range from
7 \$5.25–\$6.00/kW, depending on service schedule. While the exact level of costs classified as
8 demand-related can be debated, clearly the levels of demand charges will continue to be well
9 below demand-related costs.

10 In addition, the Company's transmission and distribution system is constructed to
11 meet the collective peak demand of its customers. Further, the Company must have
12 adequate resources available to meet peak demand. If customers reduce their peak demand,
13 it will reduce the need for additional investment in these facilities and resources. Customers
14 need to receive the proper price signal to encourage a reduction in their peak demand, i.e.,
15 higher demand charges.

16 For these reasons, the Company believes that it is important to increase the demand
17 charge in this case for Schedule 11, as well as for Schedules 21 and 25, by a percentage
18 equal to or greater than that applied to the energy rates. If demand charges are not increased
19 at least proportionately with energy charges, customers who have a poor load factor (high
20 peak demand compared to average energy use) would see a lower percentage increase in
21 their bill than a comparable customer with a good load factor (low peak demand compared
22 to average energy use). This result would not send the appropriate price signal to

⁵ Knox Exhibit No. ____ (TLK-4), at 3 ln. 28
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1 commercial and industrial customers, nor would it reflect the fact that the Company's
2 demand charges are well below the costs associated with meeting customers' peak demand.

3 **Q. Turning to Large General Service Schedule 21, would you please**
4 **describe the present rate structure under that schedule and how the Company is**
5 **proposing to apply the increase of \$4,830,000 to the rates within the schedule?**

6 A. Yes. Large General Service Schedule 21 consists of a minimum monthly
7 charge of \$450.00 for the first 50 kW or less, a demand charge of \$6.00 per kW for monthly
8 demand in excess of 50 kW, and two energy block rates: 7.099 cents per kWh for the first
9 250,000 kWhs per month, and 6.349 cents per kWh for all usage in excess of 250,000 kWhs.

10 The Company is proposing that the present minimum demand charge (for the first 50
11 kW or less) be increased by \$50 per month, from \$450.00 to \$500.00, and the demand
12 charge for kW over 50 per month be increased by \$0.50 per kW, from \$6.00 to \$6.50, for the
13 reasons provided previously in my testimony. The remaining revenue increase for the
14 schedule is proposed to be recovered through a uniform percentage increase of
15 approximately 2.2% applied to the two energy block rates. The proposed increase for the
16 first 250,000 kWhs used per month under the schedule is 0.156 cents per kWh, and an
17 increase of 0.140 cents per kWh for usage over 250,000 kWhs per month.

18 **Q. Turning to Extra Large General Service Schedule 25, would you please**
19 **describe the present rate structure under that schedule and how the Company is**
20 **proposing to apply the increase of \$2,358,000 to the rates within the schedule?**

21 A. Yes. Extra Large General Service Schedule 25 consists of a minimum
22 monthly charge of \$15,000.00 for the first 3,000 kVa or less, a demand charge of \$5.25 per
23 kVa for monthly demand in excess of 3,000 kVa, and three energy block rates: 5.708 cents

1 per kWh for the first 500,000 kWhs per month, 5.135 cents per kWh for the next 5.5 million
2 kWhs and 4.391 cents per kWh for all usage in excess of 6 million kWhs.

3 The Company is proposing that the present minimum demand charge under the
4 schedule be increased by \$1,500 per month, from \$15,000 to \$16,500, and the demand
5 charge for kVa over 3,000 per month be increased by \$0.50 per kVa, from \$5.25 to \$5.75.
6 The remaining revenue increase for the schedule is proposed to be recovered through a
7 uniform percentage increase of approximately 2.6% applied to the three energy block rates.
8 The proposed energy rate increase for the first 500,000 kWhs used per month is 0.145 cents
9 per kWh, 0.131 cents per kWh for the next 5.5 million, and 0.112 cents per kWh for all
10 usage over 6 million kWhs per month.

11 **Q. What changes is the Company proposing to the rates under Pumping**
12 **Schedule 31 to recover the proposed general revenue increase of \$409,000?**

13 A. The Company is proposing that the customer charge be increased by \$3.00,
14 from \$15.00 to \$18.00 per month, with the remaining revenue increase spread on a uniform
15 percentage increase of 3.1% to the two energy rate blocks under the schedule. The proposed
16 increase in the first block rate is 0.296 cents per kWh and the increase in the second block
17 rate is 0.212 cents per kWh.

18 **Q. How is the Company proposing to spread the proposed revenue increase**
19 **of \$260,000 applicable to Street and Area Light schedules to the rates contained in**
20 **those schedules (Schedules 41-48)?**

21 A. The Company proposes to increase present street and area light (base) rates
22 on a uniform percentage basis. The proposed increase for all lighting rates is 3.8%. The
23 (base tariff) rates are shown in the tariffs for those schedules, contained in Exhibit

1 No. ____ (PDE-3).

2 **Q. Is the Company proposing any other changes to its Street and Area**
3 **Light schedules?**

4 A. Yes, it is. For Schedule 42 (Company-owned street lights), the Company is
5 proposing two changes. First, the Company has added additional lighting codes for 100 watt
6 and 200 watt LED equivalent street lights. These rates will be applicable for those lights
7 converted to LED technology.

8 Second, the Company is proposing a methodology for calculating new Street and
9 Area Light rates for customer-requested lighting in between general rate cases. In some
10 instances customers may request that the Company install a particular street light; however,
11 that street light may be different than the lights included in the tariff. The Company is
12 proposing to use the methodology summarized below and described more fully in Schedule
13 42 to update new lighting standards outside of the context of a general rate case⁶.

14 **Q. Please describe the basic methodology for calculating the capital**
15 **component of a new street or area light rate?**

16 A. The basic methodology for calculating any new rate for Schedule 42 is to
17 determine the capital, maintenance, and energy components to develop a monthly rate. For
18 the capital component, an engineering estimate of the installed cost for a new Street Light
19 component would be multiplied by a Capital Recovery Factor⁷ to determine the annual
20 revenue requirement. Illustration No. 2 below shows an example of the annual and monthly
21 rate calculation methodology:

⁶ The components would be updated with the final approved capital structure, gross-up factor, and depreciation factor as ordered by the Commission at the culmination of this general rate case.

⁷ The Capital Recovery Factor is derived by adding together the Company's approved weighted Cost of Capital, grossed up for revenue related expenses, and the effective depreciation rate for all Street and Area Lights (FERC Account 373) from the Company's Cost of Service study.

1 **Illustration No. 2 – Calculation of Monthly Capital Recovery**

	Example
	<u>100 Watt Light</u>
3 Luminaire & Lamp	\$500.00
4 Service	\$117.00
4 Total	\$617.00
5	
6 Multiply by Capital Recovery Factor	13.45%
7	
7 Annual Capital Recovery	\$83.01
7 Monthly Capital Recovery	\$6.92

8 The maintenance component for an existing light offering will be the same rate that is
 9 embedded in present rates today⁸. For the energy component, the energy rate for a similar
 10 wattage light under Schedule 46 would be used. The energy component of any new light
 11 offering will be derived in the same manner as described in the changes to Schedule 46
 12 below. Any new rates developed would be included in the Company's next rate case filing.

13 **Q. What other changes are being proposed to the Street and Area Light**
 14 **Schedules.?**

15 A. Under Schedule 44, the Company provides energy and O&M services to
 16 customer-owned street lights. Customer-owned lights are governed, electrically, by the
 17 National Electric Code ("NEC"). Utility owned property, however, is governed by the
 18 National Electric Safety Code ("NESC"). While the Company traditionally works on
 19 customer-owned street lights, adoption of the NESC 2012 Edition has created a conflict
 20 between the Company's tariff and the NESC. Specifically, Section 1.011.A.2 states that
 21 street lights maintained by a utility must be under the exclusive control of the utility, i.e.,

⁸ The maintenance component for an existing light can be derived by subtracting the Schedule 46 (energy) light code monthly charge from the same Schedule 44 light code monthly charge (maintenance and energy). The maintenance component for a new lighting standard that is outside of what is in the Company's present offerings will be based on an engineering estimate of the monthly maintenance cost grossed up for revenue related expenses.

1 Company-owned lights. Under Schedule 44, Avista provides maintenance on customer-
2 owned lights, thus creating the conflict between the schedule and the rule. Closing the
3 schedule to new customers will help to resolve this conflict. The Company is proposing
4 close Schedule 44 to new customers effective January 1, 2015, with existing customers
5 being allowed to continue to take service.

6 For Schedule 46, the Company is proposing to modify its tariff to reflect a new
7 prescriptive energy rate calculation for lights where an existing code does not exist. The
8 rate would be determined using the following formula:

9 **Custom Rate = Wattage of Customers Street Light * 365 Hours * Energy Rate**

10 The wattage of the street light would be provided by the Customer and verified by the
11 Company. As for the hours of operation, the Company is basing that on dusk-to-dawn
12 service (4,380 annual hours, or 365 hours per month). Finally, the energy rate was
13 determined by dividing the proposed revenue for Schedule 46 by total kWh usage for
14 Schedule 46.

15

16 **IV. PROPOSED NATURAL GAS REVENUE INCREASE**

17 **Summary of Natural Gas Rate Schedules and Tariffs**

18 **Q. Would you please explain what is contained in Exhibit No. ____ (PDE-5)?**

19 A. Yes. Exhibit No. ____ (PDE-5) contains a copy of the Company's present
20 natural gas tariffs presently on file with the Commission.

21 **Q. Please describe what is contained in Exhibit No. ____ (PDE-6)?**

22 A. Exhibit No. ____ (PDE-6) contains the proposed natural gas tariff sheets
23 incorporating the proposed changes included in this filing.

1 **Q. Please explain what is contained in Exhibit No. ____ (PDE-7)?**

2 A. Exhibit No. ____ (PDE-7) contains information regarding the proposed spread
3 of the natural gas revenue increase among the service schedules and the proposed changes to
4 the rates within the schedules. Page 1 shows the proposed revenue and percentage increase
5 by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of
6 the schedules before and after the proposed increases. Page 3 shows the present rates under
7 each of the rate schedules, the proposed changes to the rates within the schedules, and the
8 proposed rates after application of the changes. These pages will be referred to later in my
9 testimony.

10 **Q. Would you please review the Company's present rate schedules and the**
11 **types of natural gas service offered under each?**

12 A. Yes. The Company's present Schedules 101, 111 and 121 offer firm sales
13 service. Schedule 101 generally applies to residential and small commercial customers who
14 use less than 200 therms/month. Schedule 111 is generally for customers who consistently
15 use over 200 therms/month, and Schedule 121 is generally for customers who use over
16 10,000 therms/month and have a high annual load factor. Schedule 131 provides
17 interruptible sales service to customers whose annual requirements exceed 250,000 therms.
18 Schedule 146 provides transportation/distribution service for customer-owned natural gas
19 for customers whose annual requirements exceed 250,000 therms. Schedule 148 is a
20 banded-rate transportation tariff that allows for a negotiated service rate with large
21 customers that have an economic alternative to taking natural gas distribution service from
22 the Company.

23 **Q. The Company also has rate Schedules 112, 122 and 132 on file with the**

1 **Commission. Would you please explain which customers are eligible for service under**
 2 **these schedules?**

3 A. Yes. Schedules 112, 122 and 132 are in place to provide service to
 4 customers, who, at one time, were provided natural gas service under Transportation Service
 5 Schedule 146. The rates under these schedules are the same as those under Schedules 111,
 6 121 and 131 respectively, except for the application of Temporary Gas Rate Adjustment
 7 Schedule 155. Schedule 155 is a temporary rate adjustment used to amortize the deferred
 8 natural gas costs approved by the Commission in the prior PGA. Because of their size,
 9 transportation service customers are analyzed individually to determine their appropriate
 10 share of deferred natural gas costs. If those customers switch back to sales service, the
 11 Company continues to analyze those customers individually; otherwise, those customers
 12 would receive natural gas costs deferrals which are not due them, thus the need for
 13 Schedules 112, 122 and 132. There are presently only four customers served under these
 14 schedules.

15 **Q. How many Washington customers does the Company serve under each**
 16 **of its natural gas rate schedules?**

17 A. As of June 2013, the Company provided service to the following number of
 18 Washington customers under each of its schedules:

<u>Table 7 - Customers by Service Schedule</u>	
<u>Rate Schedule</u>	<u>No. of Customers</u>
General Service Schedule 101	147,321
Large General Service Schedules 111/112	2,476
Ex. Lg. General Service Schedules 121/122	28
Interruptible Sales Service Schedules 131/132	2
Transportation Service Schedule 146	45

1 **Proposed Rate Spread**

2 **Q. How does the Company propose to spread the overall revenue increase**
 3 **of \$12,135,000, or 8.1%, among its natural gas general service schedules?**

4 A. The Company is proposing the following revenue/rate changes by rate
 5 schedule:

6 **Table 8 - Proposed % Natural Gas Increase by Schedule**

<u>Rate Schedule</u>	<u>Increase in</u> <u>Base Rates</u>	<u>Increase in</u> <u>Billing Rates</u>
General Service Schedule 101	8.7%	8.3%
Large General Service Schedules 111/112	6.4%	6.1%
Ex. Lg. General Service Schedules 121/122	5.2%	4.9%
Interrupt. Sales Service Schedules 131/132	3.8%	3.7%
Transportation Service Schedule 146	<u>17.0%</u>	<u>17.0%</u>
Overall	8.1%	7.8%

12 **Q. Is the proposed percentage increase for Transportation Schedule 146**
 13 **comparable to the increase for the other service schedules?**

14 A. No. The proposed percentage increase for Transportation Schedule 146 is not
 15 comparable to the proposed increases for the other (sales) service schedules, as Schedule 146
 16 revenue does not include an amount for the cost of natural gas or pipeline transportation,
 17 whereas the other sales schedules include these costs. Transportation customers acquire their
 18 own natural gas and pipeline transportation. Including an estimate of 50.0 cents per therm for
 19 the cost of natural gas and pipeline transportation, the proposed increase to Schedule 146
 20 rates represents an average increase of 2.3% in those customers' total natural gas bill.

21 **Q. What information did the Company use to develop the proposed spread**
 22 **of the overall increase to the various rate schedules?**

23 A. The Company used the results of the cost of service study sponsored by Mr.

1 Miller as a guide to spread the general increase. The spread of the proposed increase
 2 generally results in the rates of return for the various service schedules moving
 3 approximately one-third (33%) closer to the overall rate of return (unity). The relative rates
 4 of return before and after application of the proposed increases by schedule are as follows:

5 **Table 9 - Present & Proposed Relative Rates of Return**

6		Present	Proposed
7		Relative	Relative
8	Rate Schedule	<u>ROR</u>	<u>ROR</u>
9	General Service Schedule 101	0.91	0.94
10	Large General Service Schedules 111/112	1.36	1.24
11	Ex. Lg. General Service Schedules 121/122	1.46	1.31
12	Interruptible Sales Service Schedules 131/132	1.73	1.49
13	Transportation Service Schedule 146	0.81	0.87
14	Overall	1.00	1.00

15 **Proposed Rate Design**

16 **Q. Would you please explain the present rate design within each of the**
 17 **Company's present natural gas service schedules?**

18 A. Yes. General Service Schedule 101 generally applies to residential and small
 19 commercial customers who use less than 200 therms/month. The schedule contains two
 20 energy rate blocks; 0-70 therms, and over 70 and a monthly customer/basic charge.

21 Large General Service Schedules 111/112 has a three-tier declining-block rate
 22 structure and is generally for customers who consistently use over 200 therms/month. The
 23 schedule consists of a monthly minimum charge plus a usage charge for the first 200 therms
 or less, and block rates for 201-1,000 therms/month, and over 1,000 therms/month.

Extra Large General Service Schedules 121/122 has a five-tier declining-block rate
 structure with a monthly minimum charge plus a usage charge for the first 500 therms or less,

1 and block rates for the next 500 therms, the next 9,000 therms, the next 15,000 therms, and
2 usage over 25,000 therms/month. There is also an annual minimum requirement of 60,000
3 therms under the schedule and a minimum load factor requirement of approximately 58%.

4 Interruptible Sales Service Schedules 131/132 has a four-tier declining-block rate
5 structure for the first 10,000 therms, the next 15,000 therms, the next 25,000 therms, and
6 usage over 50,000 therms per month. The schedule also has an annual minimum deficiency
7 charge based on a usage requirement of 250,000 therms per year.

8 Transportation Service Schedule 146 contains a monthly customer charge and a five-
9 tier declining-block rate structure for the first 20,000 therms, the next 30,000 therms, the next
10 250,000 therms, the next 200,000 therms, and usage over 500,000 therms per month. The
11 schedule also has an annual minimum deficiency charge based on a usage requirement of
12 250,000 therms per year.

13 **Q. Is the Company proposing any changes to the present rate structures**
14 **contained in its natural gas service schedules?**

15 A. No, it is not.

16 **Q. Where in your Exhibits do you show the present and proposed rates for**
17 **the Company's natural gas service schedules?**

18 A. Page 3 of Exhibit No. ____ (PDE-7) shows the present and proposed rates under
19 each of the rate schedules, including all present rate adjustments (adders). Column (e) on that
20 page shows the proposed changes to the rates contained in each of the schedules.

21 **Q. You stated earlier in your testimony that the Company is proposing an**
22 **overall increase of \$12,135,000 or 8.1% to the base rates of General Service Schedule**
23 **101. Is the Company proposing a \$4.00 per month increase to the present**

1 **basic/customer charge of \$8.00/month under the schedule?**

2 A. Yes. The Company is proposing to increase the basic/customer charge from
3 \$8.00 to \$12.00 per month, as the Company believes that the customer/basic charge should
4 recover a reasonable portion of the fixed costs of providing service. Later in Section V. of
5 my testimony I will provide greater detail as to why the Company believes the monthly
6 customer charge should increase by \$4.00 per month.

7 **Q. What is the proposed change to the volumetric rates under Schedule 101**
8 **in order to achieve the total proposed revenue increase for the schedule?**

9 A. The Company, as shown in column (e), page 3 of Exhibit No. ____ (PDE-7), has
10 proposed to increase the per therm rate for the two volumetric blocks on a uniform
11 percentage basis. The first block (0-70 therms) would increase from \$0.78022 to \$0.79925
12 (including Schedule 150 natural gas costs), and the second block (over 70 therms) would
13 increase from \$0.88130 per therm to \$0.90279 per therm.

14 **Q. What would be the increase in a residential customer's bill with average**
15 **usage based on the proposed increase for Schedule 101?**

16 A. The increase for a residential customer using an average of 65 therms of
17 natural gas per month would be \$5.23 per month, or 8.5%. A bill for 65 therms per month
18 would increase from the present level of \$61.19 to a proposed level of \$66.42.

19 **Q. Please explain the proposed changes in the rates for Large and Extra**
20 **Large General Service Schedules 111/112 and 121/122**

21 A. Yes. The present rates for Schedules 101, 111/112, and 121/122 provide a
22 clear distinction for customer placement: customers who use less than 200 therms/month
23 should be placed on Schedule 101, customers who use between 200 and 10,000 therms per

1 month should be placed on Schedules 111/112, and only those customers who generally use
 2 over 10,000 therms per month should be placed on Schedules 121/122. Not only do the rates
 3 provide guidance for customer schedule placement, they provide a reasonable classification
 4 of customers for analyzing the costs of providing service.

5 The Company’s proposed rates for Schedules 111/112 and 121/122 will maintain the
 6 rate structure within the schedules and continue to provide guidance for appropriate schedule
 7 placement for customers and a reasonable classification for cost analysis. The proposed
 8 minimum charge of \$85.70 per month⁹ for Schedules 111/112 (for 200 therms or less)
 9 maintains the present relationship between the Schedule 101 and 111/112, and will minimize
 10 customer shifting. The remaining proposed revenue increase for Schedules 111/112 was then
 11 spread on a uniform percentage increase of 7.7% to the remaining two rate blocks under the
 12 schedule, resulting in an overall revenue increase of 6.4% for the schedule.

13 For Schedules 121/122, in order to maintain the present relationship between the
 14 schedules, the minimum monthly charge is set at \$207.13 per month. The minimum charge is
 15 derived by adding the proposed Schedule 101 basic charge of \$12 to the product of 500
 16 therms multiplied by the proposed Schedule 101 rates. The calculation is shown below:

17 **Table 10 – Schedules 121/122 Breakeven Calculation**

18	500 Therms	
19	*	
20	Melded Schedule 101 Rate	
	\$0.39026	\$195.13
21	+	
	Schedule 101 Basic Charge	\$12.00
22	=	\$207.13

⁹ The calculation of the minimum charge for Schedule 111 is equal to the total bill for 200 therms priced at Schedule 101 base rates (excluding Schedule 150 gas costs).

1 The second, third, and fourth block rates were increased by a uniform percentage of
2 approximately 6.3% to maintain consistency between the rates for Schedules 111/112 and
3 121/122. The fifth block was not adjusted in order to provide a more meaningful spread
4 between the rate blocks, resulting in an overall revenue increase of 5.2% for the schedule.

5 **Q. How is the Company proposing to spread the proposed increase of**
6 **\$28,000 to the rates under Interruptible Schedule 131/132?**

7 A. The Company proposes to increase the present four block rates under the
8 schedule by a uniform percentage increase of approximately 3.8%.

9 **Q. Please explain the proposed changes in the rates for Transportation**
10 **Schedule 146.**

11 A. The Company is proposing to adjust the basic charge by \$50 per month, which
12 is an increase from \$400 to \$450 per month. For the remaining revenue requirement, the
13 Company is proposing to spread the increase on a uniform percentage basis of approximately
14 17.4% to each of the present five block rates under the schedule. The proposed increase to
15 each of the block rates, as well as the present and proposed rates, are shown at the bottom of
16 page 3 of Exhibit No. ____ (PDE-7).

17 **Q. Is the Company proposing any other changes to its natural gas service**
18 **schedules?**

19 A. No, it is not.
20

21 **V. BASIC CHARGE FOR SCHEDULES 1 & 101**

22 **Q. Why is the Company proposing to increase the electric monthly**
23 **customer charge for Schedule 1 from \$8.00 to \$15.00 per month?**

1 A. A significant portion of the Company's costs are fixed and do not vary with
2 customer usage. These costs include distribution plant and operating costs to provide
3 reliable service to customers. Upon evaluation of the total customer allocated costs for
4 Schedule 1, as shown in Knox Exhibit No. __ (TLK-4), page 4, line 25, those costs are
5 \$12.81 per customer per month. Factoring in distribution demand cost per customer per
6 month of \$23.92, as shown in Knox Exhibit No. __ (TLK-4), page 4, line 27, the total
7 customer and distribution demand monthly cost is \$36.73. These are essentially fixed costs
8 that are allocated based on the number of customers served. Given the large disparity
9 between the level of customer and demand costs and the present level of the basic charge,
10 the Company believes that it is appropriate to recover a more reasonable level of these fixed
11 customer costs through the basic charge.

12 **Q. Why is the Company now proposing an increase of \$7.00 per month in**
13 **this filing?**

14 A. One of the arguments against higher residential basic charges in the past was
15 one of customer understandability and acceptance. We believe it is increasingly important
16 that our charges to customers more accurately reflect the actual costs to serve customers.
17 With regard to fixed charges, many other utility assessments (phone, water, sewer, solid
18 waste, television, internet, etc.) are generally a flat monthly fee. Typically, there is little
19 correlation between the level of use and the monthly amount paid for service related to these
20 other utilities/services. Consumers understand that most of the costs associated with these
21 other utilities/services are fixed, and have become accustomed to paying a relatively
22 constant monthly fee for service.

1 Publicly-owned electric utilities have been charging higher monthly customer
2 charges for years in order to more accurately reflect (and recover) the fixed costs of
3 providing service. For example, Avista’s nearest neighbor in Eastern Washington, Inland
4 Power and Light, has a residential monthly basic charge of \$17.81 per month. Avista’s
5 nearest neighbor in North Idaho, Kootenai Electric Cooperative, has a residential monthly
6 basic charge of \$19.50, and a minimum charge of \$25.00 per month.

7 **Q. Turning now to natural gas, why is the Company proposing to increase**
8 **the Schedule 101 monthly customer charge from \$8.00 to \$12.00 per month?**

9 A. Upon evaluation of the Schedule 101 total customer allocated costs, as shown
10 in Mr. Miller’s Exhibit No. __ (JDM-3), page 4, line 24, those costs are \$20.02 per customer
11 per month. Included in the fixed costs in the \$20.02 noted above are the cost of the meter
12 and service, and the costs associated with billing and providing customer service, which
13 amounts to \$12.50 per customer per month, as shown in Miller Exhibit No. __ (JDM-3),
14 page 4 line 22.

15 **Q. What is the consequence to an electric or natural gas customer of a Basic**
16 **Charge that is priced below the cost of providing customer services to that customer?**

17 A. Because rate design is a “zero sum game”, if customer charges are set below
18 the cost of providing those services, then other charges are, by definition, set above their
19 cost of service. For residential gas and electric customers, the only other charge is the
20 volumetric charge. When volumetric rates are increased above their cost of service to
21 include customer costs that are not in the Basic Charge, several consequences ensue:

- 1 • It results in almost all customers paying more “per-customer” related costs in the
2 winter, even though their customer costs are not higher in the winter, and vice
3 versa in the summer.
- 4 • It results in the amount of customer costs a customer pays being unpredictable,
5 even though customer costs are actually very predictable.
- 6 • A portion of fixed costs of providing service to low usage customers is actually
7 recovered from other higher usage customers served under the same schedule.

8 Ideally, to properly match revenues with the cost of service, the fixed costs of providing
9 service would be recovered through a fixed monthly charge, paid by each customer
10 irrespective of actual usage. The rationale for that type of rate design is that a utility’s
11 facilities and support functions are made available to its customers irrespective of how much
12 energy they use. In summary, setting the basic charge at a rate substantially less than an
13 amount that covers annual customer costs can result in rates that are not equitable, and
14 monthly bills that are unnecessarily volatile.

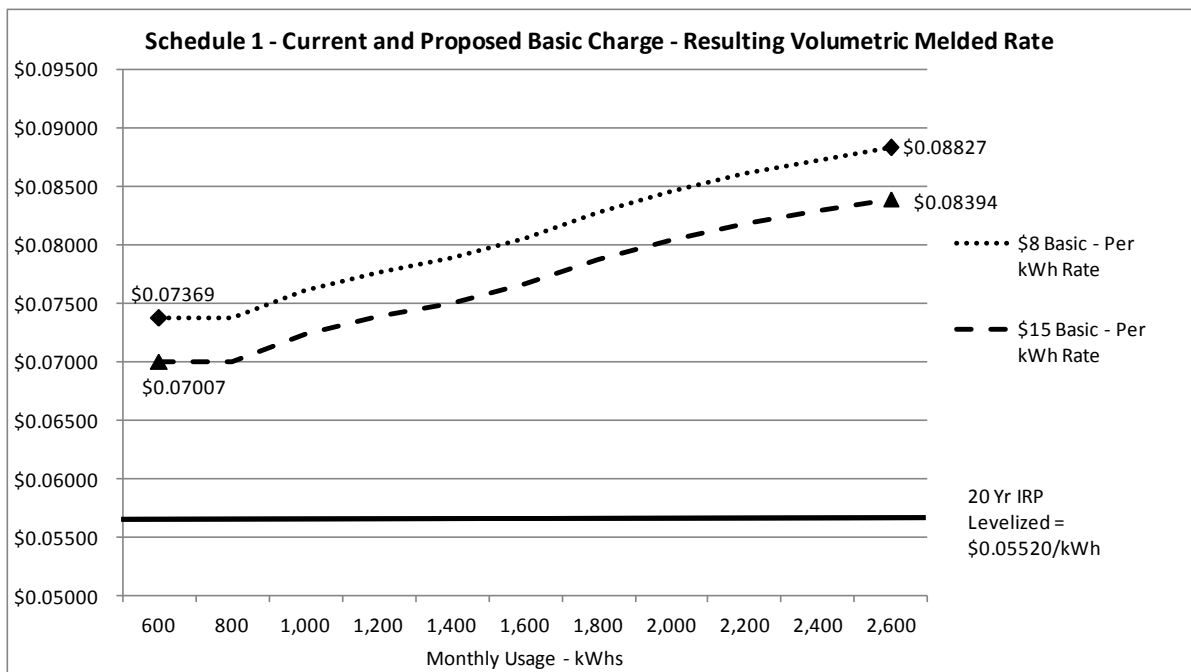
15 **Q. But won’t increasing the Basic Charge send the wrong price signal**
16 **through the energy rates?**

17 A. No. Conservation of electricity and natural gas is important for customers
18 and for the Company, and one might argue that a lower basic charge results in higher
19 commodity charges and a stronger price signal related to volume usage. However, sending a
20 price signal to customers through a residential rate design that contains a three-tier
21 increasing block rate for electric (natural gas has two volumetric tiers) was developed for
22 just such a reason. The more electricity that is used, the higher the rate, and therefore the
23 higher the overall customer bill. The volumetric pricing components even with the

1 Company's proposed basic charge increase will still send a very clear price signal to
 2 conserve.

3 One measure of this it to look to the Company's Integrated Resource Plans to see
 4 what the incremental cost of electricity and natural gas is on a forward looking basis, as
 5 compared to retail rates. Illustration No. 3 below shows the average or melded Schedule 1
 6 volumetric rate per kWh, at varying usage levels, and with varying basic charges.

7 **Illustration No. 3**



18 The dotted line at the top of the graph shows the current melded volumetric rate per
 19 kWh with an \$8 per month basic charge. The second dashed line shows the proposed
 20 melded volumetric rate per kWh with a \$15 basic charge. At the bottom of the graph is a
 21 solid line which shows the levelized 20-year avoided cost from the Company's 2013 electric
 22 Integrated Resource Plan (\$0.05520 per kWh). Demonstrated in this line graph is that, by
 23 adjusting the basic charge from its current \$8 per month level to \$15 per month, the resulting

1 melded volumetric rate, both current and proposed, are well above the 20-year levelized
 2 avoided cost. With a basic charge of \$15 per month, customers will still pay a volumetric
 3 rate, regardless of usage, that exceeds the Company’s avoided cost and therefore sends a
 4 very clear price signal.

5 For natural gas, the Company included several forecasts in its 2012 Integrated
 6 Resource Plan which, for the most part, all showed forecasted natural gas prices at Henry
 7 Hub over the next fifteen years being lower than Avista’s retail rate¹⁰.

8 **Q. Have you prepared an analysis to show what impact the proposed rate**
 9 **design changes would have on customers on electric Schedule 1 and natural gas**
 10 **Schedule 101, including the proposed increases to the monthly basic charges?**

11 A. Yes. The Company completed an analysis showing the impact on low,
 12 average, and high use electric and natural gas customers. The comparison shows the
 13 difference in a customer’s bill (only including base rates) based on the Basic Charge and
 14 volumetric rates being increased on a uniform percentage basis, versus the Company’s
 15 proposed changes. Table 11 below details results of that analysis for residential electric
 16 customers on Schedule 1:

17 **Table 11**

18 **Avista - Bill Impacts for Low, Medium and High Electric Customers on Schedule 1**

Monthly Bill Impact	Current Billed Rate	Equal Percentage	Avista Proposed	Difference Equal % vs. Proposed	Percent. Difference
750 kWh/mo Customer	\$62.49	\$66.03	\$67.92	\$1.89	2.9%
965 kWh/mo Customer	\$80.09	\$84.64	\$84.98	\$0.34	0.4%
1600 kWh/mo Customer	\$135.35	\$142.99	\$138.47	-\$4.52	-3.2%

19 ¹⁰ Harper, Exhibit No. ____ (SAH-2), p 1.5.
 20 Direct Testimony of Patrick D. Ehrbar
 21 Avista Corporation
 22 Docket Nos. UE-14____ and UG-14____

1 Table 12 below details the analysis for natural gas customers on Schedule 101:

2 **Table 12**

3 **Avista - Bill Impacts for Low, Medium and High Gas Customers on Schedule 101**

4	Current	Equal		Difference	Percent.	
5	Billed Rate	Percentage	Avista Proposed	Equal % vs.	Difference	
6	Monthly Bill Impact			Proposed		
7	46 therms/mo Customer	\$45.64	\$49.45	\$50.51	\$1.07	2.2%
	65 therms/mo Customer	\$61.19	\$66.28	\$66.42	\$0.14	0.2%
	90 therms/mo Customer	\$83.66	\$90.62	\$89.43	-\$1.19	-1.3%

8 The impact of the Company's proposed change to the basic charge varies based on monthly
 9 consumption. For an electric customer who uses less than the average 965 kWh's and/or 65
 10 therms per month, the percentage impact will be slightly higher than for those customers
 11 who use more than the average. That makes sense in that, with fixed costs being recovered
 12 in variable energy rates, customers with higher use are subsidizing lower use customers. We
 13 believe the improvement in matching customer payment of fixed costs with the fixed costs
 14 to serve customers, together with removing part of the inequity among customers on the
 15 amount of fixed costs paid, warrants this relatively small bill impact.

16 Table 13 below shows a comparison of monthly bills for an electric customer with
 17 average usage for a 12-month period. It shows the difference in the monthly bills with a
 18 uniform percentage increase to the basic charge and a uniform cents/kWh increase to the
 19 volumetric rates, versus the Company's proposal. The table illustrates the reduction in
 20 payment of fixed costs in the winter months, and increased payment in the summer, with the
 21 net result being improved alignment of payment of fixed costs by customers with the fixed
 22 costs to serve customers, with a 0.4% annual difference in overall payment.

23

1 **Table 13 – Monthly Bills for a Residential Schedule 1 Electric Customer using an**
 2 **Average of 965 kWhs per Month**
 3

Month	kWh's	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	1,306	\$115.18	\$112.98	(\$2.20)
February	1,238	\$109.06	\$107.37	(\$1.69)
March	994	\$87.23	\$87.36	\$0.13
April	879	\$76.94	\$77.93	\$0.98
May	823	\$71.93	\$73.33	\$1.40
June	713	\$63.18	\$65.31	\$2.13
July	788	\$68.95	\$70.60	\$1.65
August	940	\$82.40	\$82.93	\$0.53
September	736	\$64.95	\$66.93	\$1.98
October	795	\$69.49	\$71.10	\$1.60
November	1,037	\$91.08	\$90.89	(\$0.19)
December	1,329	\$117.21	\$114.84	(\$2.37)
Total Annual	11,578	\$1,017.62	\$1,021.57	\$3.95
Total % Bill Change				0.4%

14 Table 14 below provides a similar comparison for a 12-month period for a natural
 15 gas customer with average usage. The net result is similar to the electric results above,
 16 namely a better alignment of payment of fixed costs by customers with the fixed costs to
 17 serve customers.

Table 14 – Monthly Bills for a Schedule 101 Natural Gas Customer using an Average of 65 therms per Month

Month	Therms	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	134	\$134.43	\$131.23	(\$3.20)
February	117	\$117.50	\$115.30	(\$2.20)
March	92	\$92.61	\$91.88	(\$0.73)
April	58	\$60.08	\$60.56	\$0.48
May	33	\$37.93	\$39.63	\$1.70
June	19	\$25.53	\$27.91	\$2.38
July	15	\$21.99	\$24.56	\$2.57
August	14	\$21.10	\$23.72	\$2.62
September	16	\$22.87	\$25.40	\$2.52
October	48	\$51.22	\$52.19	\$0.97
November	96	\$96.59	\$95.63	(\$0.96)
December	137	\$137.42	\$134.04	(\$3.38)
Total Annual	779.0	\$819.28	\$822.04	\$2.77
Total % Bill Change				0.3%

Q. How will the proposed change in the residential basic charge affect limited income customers?

A. Traditional thinking might lead one to believe that a limited income electric customer would tend to be a low user of electricity. Although the Company has not conducted a demographic survey of its customers in recent years, the data that we do have available suggests that just the opposite is true.

A majority of our customers have natural gas for space and water heating, and therefore may have, on average, lower electric usage during the winter. However, many limited income customers still use electricity for space and water heating. Many of these customers live in apartments (which in Avista's service territory predominantly have electric space and water heat), live in areas where natural gas is not available, or live in areas where

1 natural gas is available, but cannot afford to convert. These limited income customers, with
2 electric space and water heat, can have electric usage in the tail-block (above 1,500 kWh's)
3 during the winter months.

4 **Q. Does the Company have any analysis showing that limited income**
5 **customers tend to use more electricity than other residential customers?**

6 A. Yes. The Company recently conducted an analysis which shows that limited
7 income customers, on average, do use more electricity than other residential customers. For
8 the analysis, the Company looked at those limited income customers who received a
9 LIHEAP or LIRAP grant during the July 2012 through June 2013 time period, and
10 compared their annual usage to the usage of all other residential customers.¹¹ The results of
11 the analysis are shown in the Table 15 below:

¹¹ Customer usage extracted from the Company's billing system were from Schedule 1 customers that had their account open during the entire test year, i.e., from July 1, 2012 through June 30, 2013. Any accounts opened for a partial year were excluded. Further, the Company is aware that the limited income population used for this analysis is not comprehensive, however the Company does not track customer incomes and therefore could only rely upon LIHEAP and LIRAP participants to be the proxy group for the limited income population.

Table 15

Washington Residential Electric Usage Analysis (Billed Usage - Not Weather Corrected)*			
Year: July 2012 through June 2013			
		<u>Average Annual kWh Usage</u>	<u>Average Monthly kWh Usage</u>
Electric Only Customer - Limited Income Population		14,307	1,192
Electric Only Customer - All Other Residential Customers		13,324	1,110
Difference		983	82
Dual Fuel Customer - Limited Income Population		11,331	944
Dual Fuel Customer - All Other Residential Customers		11,286	941
Difference		45	4
Total Limited Income		13,088	1,091
Total All Other Residential Customers		12,067	1,006
Difference		1,021	85
* Schedule 1 Customers that had accounts open throughout the entire test period of July 1, 2012 through June 30, 2013			

The analysis shows that limited income customers who only have electric service use 983 kWhs more per year than the residential population. For those limited income customers who have electric and natural gas service, they tend to use more electricity on an annual basis.

This analysis shows that limited income customers may be harmed by having a rate design with a lower basic charge and a higher tail-block rate, as these customers are more susceptible to use in the tail-block. A higher basic charge, on the other hand, would result in lower volumetric rates (than would otherwise be the case), providing some relief to these high use customers during the winter months (as demonstrated earlier in Table 10 where higher use customers would have less of an overall bill impact with a \$15 basic charge).

1 **Q. What are the implications for limited income natural gas customers?**

2 A. Average-use limited income natural gas customers would tend to pay slightly
 3 higher natural gas bills under the Company’s proposed rate design (i.e., \$12 basic charge)
 4 than if the basic charge and volumetric rate were increased by a uniform or equal
 5 percentage. Data gathered as part of the review of the Company’s Natural Gas Decoupling
 6 Mechanism showed that limited income natural gas customers tend to use slightly less
 7 natural gas (58 therms per month¹²) than the residential customer population (65 therms per
 8 month). As shown in Table 16 below, while there is an impact, it is relatively small both on
 9 a dollar and percentage basis (between 0.2% and 0.8%).

10 **Table 16**

11 **Avista - Residential/Limited Income Natural Gas Customer Impact**

	Current Rates	Equal Percentage	Avista Proposed	Difference Equal % vs. Proposed	Percent. Difference
Monthly Bill Impact					
58 Therm/mo Customer	\$55.46	\$60.08	\$60.56	\$0.48	0.8%
65 Therm/mo Customer	\$61.19	\$66.28	\$66.42	\$0.14	0.2%

15

16 **VI. DSM COMPONENT OF THE PRO FORMA CROSS CHECK STUDY**

17 **Q. Would you briefly describe the Company's DSM Component of the Pro**
 18 **Forma Cross Check Study?**

19 A. Yes. One of the reasons Avista is experiencing attrition is due to our success
 20 in assisting our customers with electric energy efficiency through our Demand Side
 21 Management (DSM) programs. This portion of my testimony will quantify how much of
 22 Avista’s attrition problem is being caused by electric energy savings through DSM.

¹² Avista Docket UG-060518, “Evaluation of Avista Gas Decoupling Mechanism Pilot”, p. 81, Table K-10.
 Direct Testimony of Patrick D. Ehrbar
 Avista Corporation
 Docket Nos. UE-14____ and UG-14____

1 Avista's proposed electric and natural gas revenue increases in this filing are based
2 on its Attrition Study, and the resulting Attrition Adjustment. As we have explained in our
3 filing, Avista is experiencing attrition because investment in plant and operating costs are
4 growing at a faster rate than revenue. One of the reasons for slow revenue growth is the
5 reduced sales from our DSM programs. Ms. Andrews explains the Pro Forma Cross Check
6 Study the Company has provided in this filing, which identifies the various components of
7 the changes in rate base, operating costs, and revenues from the historical test year to the
8 2015 rate year. This calculation of DSM lost margin represents one of the components of
9 the Pro Forma Cross Check analysis, and is part of the explanation of why utility costs are
10 growing faster than revenues.

11 **Q. How did you go about quantifying this component?**

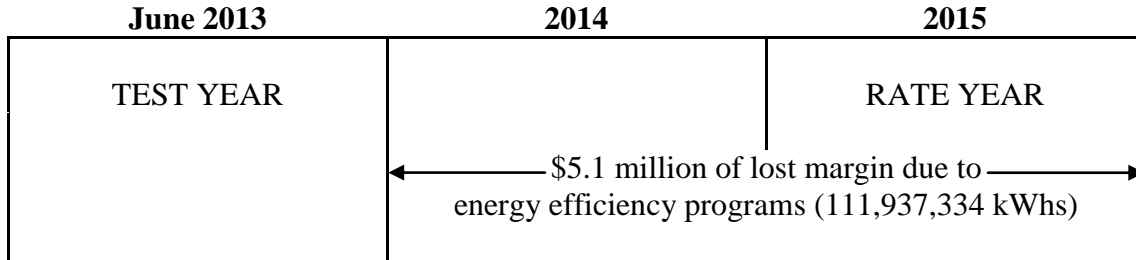
12 A. As I will describe in further detail later in my testimony, the Company
13 calculated the DSM Component of the Pro Forma Cross Check Study using the electric
14 DSM savings for 2012 through 2015. This is consistent with Company witness Ms.
15 Andrews' attrition analysis which covered the 12-months ending June 2013 historical test
16 year through the 2015 rate period.

17 In a general rate case we begin with historical test period kWh sales (12-months
18 ending June 2013), and then assume that all of those historical retail sales, and revenues,
19 continue into the future rate year. We know with certainty, however, that part of that
20 revenue will not occur, because customers have taken steps to use less energy. This is a
21 known change in revenues following the test year (12-months ending June 2013), and if that
22 reduction is not reflected in the ratemaking process, then the Company will face earnings
23 attrition. In essence, without an adjustment to reflect these required savings, you start from

1 “day one,” after new rates are set, knowing that you will not receive the amount of revenue
 2 the rates were designed to recover, because the kWh sales to existing customers following
 3 the test year will be less than they otherwise would have been.

4 **Illustration No. 4:**

TIMELINE



5

6 **Q. How did you quantify these DSM energy efficiency savings?**

7 A. Effective January 1, 2010, the Company was mandated to obtain a certain
 8 level of electric energy efficiency savings pursuant to RCW Chapter 19.285, the Energy
 9 Independence Act. Under this act, Avista is required to “identify its achievable cost-
 10 effective conservation potential through 2019”, and beginning in January 2010, “establish
 11 and make publicly available a biennial acquisition target for cost-effective conservation
 12 consistent with its identification of achievable opportunities ... and meet that target during
 13 the subsequent two-year period”. (RCW Chapter 19.285)

14 **Q. What were the Company’s electric energy efficiency savings for 2012**
 15 **and 2013?**

16 A. In 2012, the electric energy efficiency savings resulting from the Company’s
 17 energy efficiency programs were 64,192,378 kWhs. For 2013, the Company is estimating
 18 that customers will further reduce their usage by 43,497,456 kWhs. This is based on actual,
 19 unverified electric savings from January through October 2013, and an estimate for the

1 November-December 2013 time period. Verification of the savings for the 2012-2013 two-
2 year period will be completed in April 2014.

3 **Q. What are the Company's planned electric energy efficiency savings for**
4 **the period 2014 through 2015?**

5 A. On November 1, 2013, the Company filed with the UTC the "2014-2015
6 Biennial Conservation Plan" (Docket UE-132045) which included the Company's third,
7 two-year biennial electric conservation target. In the Biennial Conservation Plan ("BCP"),
8 Avista identified a ten-year conservation potential of approximately 394,200 megawatt-
9 hours, and for the 2014-2015 biennium, a target of 65,131 megawatt-hours. Including the
10 estimated savings from the Northwest Energy Efficiency Alliance ("NEEA"), the estimated
11 kWh savings for 2014-2015 is 82,972 megawatt-hours. This two-year target does not
12 include the 5% increase in the 2015 kWh savings target related to the Company's Electric
13 Decoupling Mechanism request discussed later in my testimony. Including the 5% adder in
14 2015, the two-year target becomes 85,046 megawatt-hours.

15 **Q. Prior to the application of the additional 5% electric savings for 2015**
16 **related to the Company's decoupling mechanism request, are the electric energy**
17 **efficiency savings of 82,972 megawatt-hours for the 2014-2015 time period**
18 **symmetrical?**

19 A. Yes, the savings for 2014 and 2015 are expected to be symmetrical. Avista
20 plans to obtain 41,486 megawatt-hours of savings in 2014 and in 2015. The proposed level
21 in 2015, after application of the 5% adder related to the proposed decoupling mechanism, is
22 43,560 megawatt-hours.

1 **Q. How is the DSM Component of the Pro Forma Cross Check Study**
2 **calculated?**

3 A. The first step in the calculation is to determine the level of electric energy
4 efficiency savings from the Company's DSM programs. In 2012, customers who took part
5 in the Company's DSM programs saved 64,192,378 kWhs. Table 17 below shows the
6 savings by rate schedule:

7 **Table 17 – 2012 Electric Energy Savings by Rate Schedule**

<u>Rate Schedule</u>	<u>2012 kWh Savings</u>
Schedule 1	24,174,618
Schedule 11	10,682,909
Schedule 21	23,078,081
Schedule 25	4,843,908
Schedule 31	1,412,862
	64,192,378

8
9
10
11
12
13 Because customers installed energy efficiency measures throughout 2012,
14 approximately three-quarters of the annual savings were already included in the normalized
15 test year usage. Therefore, for 2012, approximately 16,048,093 kWhs were not already
16 included in the normalized test year (July 2012 – June 2013) usage. The lost margin for the
17 approximately one-quarter of the annual savings not included in the normalized test year
18 usage is included in the DSM Component of the Pro Forma Cross Check Study.

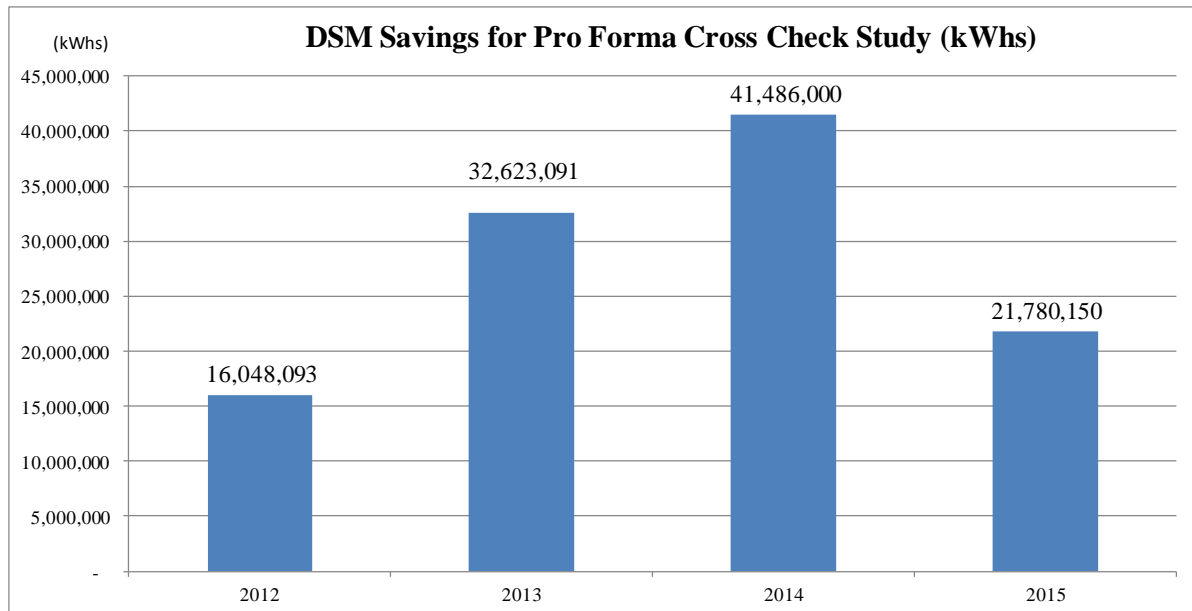
19 **Q. Please describe the level of savings included in the DSM Component of**
20 **the Pro Forma Cross Check Study for 2013, 2014, and 2015?**

21 A. The kWh savings for 2013 is approximately 43,497,456. Because customers
22 installed energy efficiency measures throughout 2013 (but only six months of 2013 is
23 included in the test year), approximately one-quarter of the annual savings, or 10,874,365

1 kWhs were already included in the normalized test year usage. Therefore, for the test year,
2 32,623,091 kWhs were not already included in the normalized test year usage. The lost
3 margin for the approximately three-quarters of the annual savings not included in the
4 normalized test year usage is included in the DSM Component of the Pro Forma Cross
5 Check Study.

6 For 2014, the entire level of estimated annual savings, approximately 41,486,000
7 kWhs, were included in the Adjustment. For the 2015 rate year, the Company included one-
8 half, or 20,743,000 kWhs, of the estimated annual savings. Illustration No. 5 below is a
9 chart showing the savings included in the DSM Component of the Pro Forma Cross Check
10 Study by year:

1 **Illustration No. 5**



11

12 From the 12-months ended June 2013 test year to the 2015 rate year, there is a total

13 of 111,937,334 kWhs of reduced energy usage through Avista's DSM efforts that need to be

14 accounted for in the ratemaking process.

15 **Q. How were 2014 and 2015 electric energy efficiency savings spread by**

16 **rate schedule?**

17 A. For purposes of spreading the energy savings by rate schedule, the Company

18 used the same percentage spread as was achieved in 2013. Table 18 below shows the kWh

19 savings for 2013, by rate schedule, and the average savings by schedule over the that time

20 period:

Table 18 – 2013 Electric Energy Savings by Rate Schedule

<u>Rate Schedule</u>	<u>2013 1st Year Savings (kWh)</u>	<u>% of Total</u>
1	31,724,087	72.9%
11/12	6,629,046	15.2%
21/22	2,208,613	5.1%
25	2,917,062	6.7%
31/32	18,648	0.0%
Grand Total	43,497,456	100.0%

For 2014 for example, the estimated annual kWh savings is 41,486,000 kWhs. Using the “% of Total” from Table 17 above, 72.9% of 41,486,000 kWhs was allocated to Schedule 1 (30,255,740 kWhs).

Table 19 below shows the kWh savings by year and by rate schedule (using the Average energy efficiency savings by rate schedule spread discussed above) which were used in the DSM Component of the Pro Forma Cross Check Study:

Table 19 – Load Adjustment Electric Energy Savings by Rate Schedule

<u>Rate Schedule</u>	<u>2012 kWh Savings (1/4 of Year)</u>	<u>2013 kWh Savings (3/4 of Year)</u>	<u>2014 kWh Savings (Full Year)</u>	<u>2015 kWh Savings (Half Year)</u>
Schedule 1	6,043,654	23,793,065	30,255,740	15,884,263
Schedule 11	2,670,727	4,971,784	6,322,466	3,319,295
Schedule 21	5,769,520	1,656,460	2,107,489	1,106,432
Schedule 25	1,210,977	2,187,796	2,783,711	1,461,448
Schedule 31	353,215	13,986	16,594	8,712
	16,048,093	32,623,091	41,486,000	21,780,150

Q. Please continue with your discussion of how the DSM Component of the Pro Forma Cross Check Study was calculated?

A. Having calculated the reduction in energy (kWh) by rate schedule, the Company then developed the “Revenue Change” shown on line 11 on Page 1 of Exhibit

1 No. ____ (PDE-8). As shown in that exhibit, the Company developed an “Average Revenue
2 per kWh”. In order to calculate Average Revenue per kWh, total present revenues by rate
3 schedule, excluding fixed charge revenues, are divided by the test-period normalized kWhs.
4 The result of the calculation is the Average Revenue per kWh. That rate multiplied by the
5 kWh reduction by rate schedule as shown in Table 19 above, results in the lost revenue by
6 rate schedule (see “Revenue Change” on line 11 on Page 1 of Exhibit No. ____ (PDE-8)).

7 **Q. Why are revenues from fixed charges excluded from the Average**
8 **Revenue per kWh equation?**

9 A. Fixed charge revenues, such as the Basic Charge for Schedule 1, do not vary
10 based on customer usage. Had that revenue been included in the calculation, the Average
11 Revenue per kWh would have been overstated.

12 **Q. Did the Company include a corresponding power supply cost savings**
13 **reduction in its DSM Component of the Pro Forma Cross Check Study?**

14 A. Yes, it did. The Power Cost Savings is shown on line 12 on Page 1 of
15 Exhibit No. ____ (PDE-8).

16 **Q. What is the appropriate power price to use for the change in power**
17 **supply cost due to a decrease in retail load?**

18 A. The appropriate power price to use for the change in power supply cost
19 during the 2015 rate year due to a decrease in retail load is the average cost of spot market
20 sales and purchases included in the pro forma power supply expense. Any decrease in load
21 will result in decreased spot market purchases and/or increased spot market sales. This price

1 is represented by the average sale and purchase price of \$31.26/MWh¹³ as determined by the
2 AURORA^{XMP} model for the 2015 rate year.

3 **Q. Would you please summarize the calculation of the DSM Component of**
4 **the Pro Forma Cross Check Study?**

5 A. Yes. The DSM Component of the Pro Forma Cross Check Study calculation
6 takes the “Revenue Change” on line 11 on Page 1 of Exhibit No. ____ (PDE-8) and subtracts
7 from that “Power Cost Savings” (line 12) as well as Revenue Related Expenses (line 13).
8 The result is shown on line 14, “DSM Component of the Pro Forma Cross Check Study” by
9 rate schedule. The final result of this component is a \$5,112,118 increase in net expense
10 (line 14 on Page 1 of Exhibit No. ____ (PDE-8)) and was given to Company witness Ms.
11 Andrews for incorporation into her Pro Forma Cross Check Study.

12 **Q. Does the Company have the necessary funding to obtain the mandated**
13 **conservation targets?**

14 A. Yes, it does. As part of the conditions approved by the Commission in
15 Docket No. UE-111882, Order 01 at Paragraph 30 (d), Avista must file with the
16 Commission on an annual basis a cost recovery tariff by June 1 of each year, with a
17 requested effective date of August 1. The Company made such a filing on May 31, 2013 in
18 Docket UE-131213. The Company’s tariff rider mechanism is designed to match future
19 revenue with budgeted expenditures. To ensure appropriate recovery, the mechanism
20 includes a true-up feature that reconciles the previous period’s actual expenditures and
21 collections.

22 **Q. Does the Company have the programs in place in order to meet its**
23 **conservation targets?**

¹³ Johnson Exhibit No. ____ (WGJ-4). See annual “Average Market Sale and Purchase Price per MWh”.
Direct Testimony of Patrick D. Ehrbar
Avista Corporation
Docket Nos. UE-14____ and UG-14____

1 A. Yes. Avista offers a wide range of electric and natural gas efficiency
2 programs to our customers as well as supports outreach, infrastructure and educational
3 programs. These programs are comprehensively reviewed on an annual basis as part of a
4 business planning process, a process which established an operational plan for achieving all
5 cost-effective conservation through available or contemplated tools. In short, the Company
6 has the necessary funding and program offerings in place in order to meet its electric
7 conservation targets.

8 **Q. The Company is requesting an electric and natural gas decoupling**
9 **mechanism in this case. Is the DSM Component of the Pro Forma Cross Check Study**
10 **duplicative to a decoupling mechanism?**

11 A. No, it is not duplicative. The DSM Component is an adjustment in Ms.
12 Andrews' Pro Forma Cross Check Study. This analysis is being used to support, or as a
13 cross-check on, the Company's rate request through its Attrition Analysis. The Company
14 did not otherwise adjust its test year billing determinants as a part of this adjustment.

15 The proposed decoupling mechanisms, on the other hand, are mechanisms that
16 would go into effect after new rates go into effect. The decoupling mechanisms would
17 ensure that the Company would recover an agreed upon revenue per customer going forward
18 - no more and no less.

1 **VII. ELECTRIC AND NATURAL GAS DECOUPLING MECHANISMS**

2 **Q. Is the Company requesting an electric and natural gas decoupling**
3 **mechanism in this general rate case?**

4 A. Yes, the Company is requesting both an Electric Decoupling Mechanism, as
5 well as a Natural Gas Decoupling Mechanism that would replace the Company’s existing
6 limited natural gas decoupling mechanism. The Company believes, for reasons stated
7 below, that the mechanisms would provide benefits to both the Company and its customers,
8 and therefore are in the public interest and should be approved effective January 1, 2015.

9 **Q. What has been the Company’s view on decoupling in the past?**

10 A. Avista has had a limited natural gas decoupling mechanism since 2007, and
11 has provided comments both through workshops and in testimony where it has expressed its
12 support of decoupling in general, as long as such mechanisms were designed and
13 implemented in a way that truly “fixes” the problem that necessitates a need for a
14 decoupling-type mechanism in the first place. The traditional problem is that rates are
15 established in a general rate case to provide revenue to recover the fixed costs to provide
16 service to customers. However, the majority of that revenue is received on a volumetric
17 basis, i.e., based on the volume of kWh and therm sales.

18 At the same time, Avista is obligated by law to pay its customers to use fewer kWhs
19 through the implementation of energy efficiency measures, and, if unsuccessful, would incur
20 stiff penalties. After new retail rates are established in a rate case, all other things being
21 equal, Avista’s customers will, in fact, consume a lower volume of kWh than that included
22 in designing the rates, and therefore revenues will not be sufficient to cover Avista’s costs.
23 As discussed earlier and shown on Illustration No. 4, if the ratemaking process does not

1 account for the known reduction in kWh sales related to energy efficiency, rates set based on
2 historical test period loads are actually designed to not provide recovery of the Company's
3 costs under normal operating conditions.

4 Further, to the extent there is any growth in net revenue from new customers, or
5 through growth in use-per-customer, if that revenue is captured to offset the known
6 reduction in revenue from energy efficiency savings, it would undermine the use of
7 historical test-year ratemaking, since those revenues would not be available to offset the
8 growth in utility costs following the test year.

9 **Q. Why is the Company requesting full electric and natural gas decoupling**
10 **mechanisms in this filing?**

11 A. In preparing this general rate case, the Company reviewed the Commission's
12 "Report And Policy Statement On Regulatory Mechanisms, Including Decoupling, To
13 Encourage Utilities To Meet Or Exceed Their Conservation Targets" in Docket U-100522
14 ("Policy Statement") as well as the decoupling mechanisms that the Commission recently
15 approved for Puget Sound Energy ("PSE") in 2013 (Dockets UE-121697 and UG-121705).
16 In short, the decoupling mechanisms approved by the Commission for PSE help to solve the
17 ratemaking problem discussed earlier, and also provides benefits to customers by fixing the
18 overall revenue per customer that the Company is allowed to collect. The mechanisms are
19 designed to benefit both the Company and customers. The mechanisms also meet the
20 objectives outline in the Policy Statement which stated "that a properly constructed full
21 decoupling mechanism that is intended, between general rate cases, to balance out both lost

1 and found margin from any source can be a tool that benefits both the Company and its
2 ratepayers”.¹⁴

3 **Q. Before describing the mechanisms, would you please provide further**
4 **details on how the mechanisms benefit the Company and its customers?**

5 A. Yes. To the extent use per customer declines from programmatic and non-
6 programmatic DSM between general rate cases, the decoupling mechanisms would provide
7 recovery of the fixed costs of providing service to its customers. These are the same fixed
8 costs, on a revenue per customer basis, that the Commission approves for recovery in a
9 general rate case. The mechanisms would also ensure that, to the extent there is customer
10 growth in the rate year and beyond, the revenues from those new customers would not be
11 used to offset the known reduction in revenue from energy efficiency savings, but rather
12 would be available to offset the growth in utility costs following the test year.

13 Customers also benefit from the proposed mechanisms. By decoupling sales from
14 revenues, the disincentive to promote conservation would be removed, as would any
15 incentive for the utility to increase throughput. Customers benefit if the overall actual
16 revenue collected by the Company on a per-customer basis is greater than that approved by
17 the Commission. For example, if a winter is colder than normal, leading to loads that are
18 higher than normal, the Company would rebate to customers all of the revenue collected
19 above the allowed revenue. In addition, as I will discuss later in my testimony, if the
20 Company’s request for an electric decoupling mechanism is approved, it agrees to increase
21 its electric energy efficiency target by 5% with implementation of the mechanism.

¹⁴ Docket U-100522, Report And Policy Statement On Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet Or Exceed Their Conservation Targets, p. 27.

1 Finally, the mechanisms have an Earnings Test. Should the Company have a
2 surcharge balance, but has an actual earned return in excess of its authorized return, the
3 proposed surcharge would be reduced or eliminated to bring the rate of return down to the
4 authorized level.

5 In summary, the Company's proposed decoupling mechanisms would ensure that it
6 would be able to recover the fixed costs of providing service to customers, on a revenue per
7 customer basis. In a colder than normal winter or hotter than normal summer, if the
8 Company collects revenues that are greater than the amount authorized, those revenues
9 would be returned to customers.

10 **Q. What is the Company's view on proposals to reduce the allowed return**
11 **on equity (ROE) or adjust the equity layer in the Company's capital structure in the**
12 **event the Commission were to adopt decoupling?**

13 A. The Company agrees with the Commission's recent order that there is no
14 empirical evidence that demonstrates that utilities with decoupling mechanisms have a
15 reduced cost of capital. The Commission in Order No. 7 in PSE's decoupling Dockets (UE-
16 121697 et. al.) stated at paragraph 104:

17 In terms of the arguments that implementing decoupling reduces the Company's cost
18 of equity there again is no empirical evidence to show this is so. Indeed, the record
19 does not even fully support the proposition that equity markets recognize and
20 respond to the forms of risk reduction that accompany the implementation of
21 decoupling mechanisms. While this cannot be said to disprove the theory that
22 decoupling reduces risk and, therefore, cost of capital, the more important point from
23 the Commission's perspective is that absent evidence actually demonstrating the
24 theory's effect in practice on either the debt or equity markets there is no evidentiary
25 basis upon which the Commission can order a reduction in the Company's cost of
26 capital. (emphasis added)
27

1 The primary reason Avista is considering decoupling in the first place is there is
2 recognition that energy efficiency kWh savings eliminates revenue from the utility intended
3 to cover utility costs. That is, the ratemaking process assumes the revenues are there, but
4 because kWh sales are eliminated through the energy efficiency programs after retail rates
5 are set, the revenues actually do not occur. So decoupling represents a “fix” or “patch” to
6 the ratemaking process to restore the revenue related to energy efficiency. The revenue
7 provided to Avista through a decoupling mechanism would not represent additional revenue
8 to the Company over and above what is needed to recover its costs; it represents restoration
9 of revenues that the Commission has already determined should be provided to the utility
10 from the last rate case. Therefore, it does not represent reduced risk to the utility or a shift
11 of risk from the utility to its customers; it is a replacement of revenue that the ratemaking
12 process assumes is present, when in fact the revenue is not realized. Furthermore, customers
13 can expect to see rebates as well as surcharges over time with the decoupling mechanisms.

ELEMENTS OF THE ELECTRIC DECOUPLING MECHANISM

16 **Q. Would you please provide a summary of how the proposed decoupling**
17 **mechanisms would function?**

18 A. Yes. First, it is important to note that Avista is generally using the same
19 methodology as employed by PSE in its approved decoupling mechanisms. As I will
20 explain in more detail below, essentially the Company is proposing a Revenue Per Customer
21 decoupling mechanism for its electric and natural gas operations. The proposed decoupling
22 mechanisms compare the actual, non-weather adjusted revenues per customer to the allowed
23 revenue per customer, with any differences deferred for later rebate or surcharge. In

1 addition, the Company is proposing to group customers into three Rate Groups –
2 Residential, Non-Residential, and Industrial. More discussion on the three Rate Groups will
3 follow later in my testimony.

4 **Q. For the Electric Decoupling Mechanism, would you please describe how**
5 **the Allowed Non-Power Supply Revenue per Customer is determined?**

6 A. Yes. Provided on Page 1 of Exhibit No. ____ (PDE-9) is information that
7 calculates the Allowed Non-Power Supply Revenue. This is the revenue that the Company
8 collects in its variable energy and demand charges to cover the fixed costs of providing
9 service to customers. It excludes revenues associated with power supply, and revenues that
10 are collected in fixed basic, demand and minimum charges.

11

12 • Step 1 – Determine the Total Proposed Revenue - Lines 1 through 3 on Page 1 of
13 Exhibit No. ____ (PDE-9) shows the Total Normalized Revenue from the test period
14 (\$480.9 million) and adds to that total the Proposed Revenue Increase (\$18.2
15 million). The resulting calculation is the Total Proposed Revenue that the Company
16 has requested in this case (\$499.1 million) effective January 1, 2015.

17

18 • Step 2 – Determine Amount of Revenue related to Power Supply – The Normalized
19 kWhs by rate schedule for the test year are detailed on Line 4. On Line 5, those
20 kWhs are multiplied by the proposed Retail Revenue Credit¹⁵ of \$0.03518 to
21 determine the total Power Supply Related Revenue. Lines 12-14 show the
22 calculation of the Retail Revenue Credit grossed up for revenue related expenses.

¹⁵ See Exhibit No. ____ (WGJ-7) for the Retail Revenue Credit of 0.03360/kWh. As shown on page 1 of Exhibit No. ____ (PDE-9), the Retail Revenue Credit has been grossed up for revenue related expenses to \$0.03518/kWh.

1

2 • Step 3 – Determine Non-Power Supply Related Revenue – To determine the Non-
3 Power Supply Related Revenue, the mechanism subtracts the Power Supply Related
4 Revenue on Line 6 from the Total Proposed Revenue on Line 3.

5

6 • Step 4 – Remove Fixed Revenues – included in the Non-Power Supply Revenue on
7 Line 7 are revenues that are recovered from customers in Basic and Fixed Demand
8 charges (“Fixed Charges”). Because the proposed decoupling mechanism only track
9 revenues that vary with customer usage, the revenue from Fixed Charges must be
10 removed. Line 8 shows the number of Customer Bills in the test period, and Line 9
11 shows the proposed Fixed Charges in this case. Line 10 is the total Fixed Charge
12 revenue which is calculated by taking the number of customer bills and multiplying
13 those by the associated Fixed Charges, by rate schedule.

14

15 • Step 5 – Determine Allowed Non-Power Supply Revenue – The final step to
16 calculate the Allowed Non-Power Supply Revenue, as shown on Line 11, is to
17 subtract the Fixed Charge Revenue (Line 10) from the Non-Power Supply Revenue
18 (Line 7).

19

20 Steps 1 through 5 above subtract from the Total Proposed Revenue the revenues
21 associated with Power Supply and Fixed Charges in order to develop the Allowed Non-
22 Power Supply Revenue. The next step will be to determine the Allowed Non-Power Supply
23 Revenue per customer.

1 **Q. Would you please describe how the Allowed Non-Power Supply Revenue**
2 **per Customer is determined?**

3 A. Yes. Provided on Page 2 of Exhibit No.____(PDE-9) are the inputs and
4 calculations to determine the Allowed Non-Power Supply Revenue per Customer. Line 1 on
5 Page 2 of Exhibit No.____(PDE-9) shows the Allowed Non-Power Supply Revenue, by Rate
6 Group, that was calculated earlier. Note that the information on Page 2 now shows the
7 revenues by Rate Group rather than by individual rate schedule. More discussion related to
8 the Rate Groups will follow later in my testimony. Line 2 shows the Test Year Customers,
9 by Rate Group. Finally, Line 3 divides the Allowed Non-Power Supply Revenue by the
10 Test Year number of Customers to determine the annual Allowed Non-Power Supply
11 Revenue per Customer.

12 Page 3 of Exhibit No.____(PDE-9) calculates the monthly Allowed Non-Power
13 Supply Revenue per Customer. To determine the monthly Allowed Non-Power Supply
14 Revenue per customer, which is required for the monthly deferral calculations discussed
15 later in my testimony, the annual Allowed Non-Power Supply Revenue per customer is
16 shaped based on the monthly kWh usage from the test year, as shown on Page 3 of Exhibit
17 No.____(PDE-9). For example, the Residential Group used 11.31% of its annual usage in
18 January 2013 (266,050 MWh / 2,352,012 MWh). The Company used the resulting monthly
19 percentage of usage by month and multiplied that by the annual Allowed Non-Power Supply
20 Revenue per Customer to determine the 12 monthly values.

21 **Q. Please describe how deferrals for the Electric Decoupling Mechanism**
22 **would be calculated?**

1 A. In the rate year, the Company would track the Actual Non-Power Supply
2 Revenue it receives and defer any difference between that amount and the Allowed Non-
3 Power Supply Revenue. Deferrals would be tracked separately for each Rate Group. A
4 sample calculation, provided for illustrative purposes, is included on Page 4 of Exhibit
5 No.____(PDE-9). Detailed below are the steps outlined on Page 4 to calculate the deferral.
6 For purposes of describing the deferral calculation, I will only refer to the calculation of the
7 deferral for the Residential Group; there is no difference in the calculations for the Non-
8 Residential and Extra Large Non-Residential Groups.

- 9
- 10 • Step 1 – Determine Allowed Non-Power Supply Revenue Opportunity - The first
11 step is to pull from the Company’s billing system the actual number of customers
12 each month. The actual number of customers are used in the calculation with all
13 customers assuming the same level of Monthly Allowed Non-Power Supply
14 Revenue per Customer. Line 1 on Page 4 of Exhibit No. ____ (PDE-9) shows an
15 illustrative Residential Group level of customers for the Rate Year of 2015. Line 2
16 shows the Monthly Allowed Non-Power Supply Revenue per Customer for that
17 group. Multiplying those values together results in an Allowed Non-Power Supply
18 Revenue for each month, shown on Line 3. The calculated values on Line 3 show,
19 by month, the total amount of revenue that the Company would be allowed.

- 20
- 21 • Step 2 – Determine Period “Actuals” - The next step is to pull from the Company’s
22 billing system the Actual Monthly revenue (Line 4 on Page 4 of Exhibit

1 No. ____ (PDE-9)), Actual Fixed Charge Revenue (Line 5) and Actual Usage (Line 6).
2 These “actuals” would not be weather normalized.

3

4 • Step 3 – Calculation of Revenue Related to Power Supply – the next step in the
5 deferral calculation multiplies the approved Retail Revenue Credit (Line 7 on Page 4
6 of Exhibit No. ____ (PDE-9)) by the Actual Usage (kWhs) shown on Line 6. The
7 result is the level of revenues associated with power supply that will be deducted in
8 Step 4.

9

10 • Step 4 – Calculation of Actual Non-Power Supply Revenue – Line 9 on Page 4 of
11 Exhibit No. ____ (PDE-9) shows the calculation of the Actual Non-Power Supply
12 Revenue. This calculation subtracts from Actual Monthly Revenue on Line 4 the
13 Actual Fixed Charge Revenue (Line 5) and the Monthly Revenue Related to Power
14 Supply (Line 8). The calculated values on Line 9 show, by month, the total amount
15 of revenue that the Company actually received.

16

17 • Step 5 – Deferral Calculation – In order to determine if the Company over- or under-
18 recovered its fixed costs, Actual Non-Power Supply Revenues (Line 9 on Page 4 of
19 Exhibit No. ____ (PDE-9)) is subtracted from Non-Power Supply Revenue Opportunity
20 (Line 3). Line 10 shows the calculation. If the number is positive (surcharge
21 direction), then the Company under-recovered its allowed revenue. If the number is
22 negative, then the Company over-recovered its allowed revenue. The monthly

1 deferrals are tracked monthly, and accrue interest at the FERC rate (as shown on
2 Line 11)¹⁶. Finally, Line 12 shows the Cumulative Deferral.¹⁷

3
4 In summary, the calculations shown on Page 4 of Exhibit No. ____ (PDE-9) provide an
5 example of how the Electric Decoupling Mechanism would work. It shows the use of the
6 Monthly Allowed Non-Power Supply Revenue per Customer and how that value is applied
7 to the actual level of customers to determine the Allowed Non-Power Supply Revenue
8 Opportunity. Further the example shows how actual revenues from Fixed Charges and
9 revenues associated with Power Supply are removed from actual revenues to determine the
10 amount of revenues the Company actually received that are non-power supply related.
11 Finally, the example shows the monthly and cumulative deferral calculations, including the
12 effect of interest.

13 **Q. Please provide information related to when the Company would file for a**
14 **rate adjustment under the proposed Decoupling Mechanism.**

15 A. On or before September 1, the Company would file a proposed rate
16 adjustment surcharge or rebate based on the amount of deferred revenue recorded for the
17 prior July – June time period¹⁸. The rate adjustment would be calculated separately for each
18 Rate Group. The results of the “earnings” and “3% Rate Increase Limitation” tests would
19 also be included with the filing and used to determine the amount of the rate adjustment.

¹⁶ Interest would be accrued on the unamortized balance in the decoupling balancing accounts at the quarterly rate published by the Federal Energy Regulatory Commission (“FERC”)

¹⁷ Note that the deferral calculations would be completed at the revenue level. The actual deferral would have an additional calculation to remove revenue related expenses. The final deferred balance which the Company would file for later rebate or recovery from customers would then be grossed up for revenue related expenses.

¹⁸ The proposed effective date for rates in this general rate case is January 1, 2015. The Company proposes that the first deferral period would be the six-month time period of January 1, 2015 through June 30, 2015, and would then be based on a July – June deferral period thereafter.

1 The “earnings” and “3% Rate Increase Limitation” tests will be discussed later in my
2 testimony.

3 The proposed tariff included with that filing would include a rate adjustment that
4 recovers/rebates the appropriate deferred revenue amount over a twelve-month period
5 effective on November 1st. The deferred revenue amount approved for recovery or rebate
6 would be transferred to a balancing account and the revenue surcharged or rebated during
7 the period would reduce the deferred revenue in the balancing account. Any deferred
8 revenue remaining in the balancing account at the end of the July - June year would be
9 added to the new revenue deferrals to determine the amount of the proposed
10 surcharge/rebate for the following year.

11 After determining the amount of deferred revenue that can be recovered through a
12 surcharge (or refunded through a rebate) by Rate Group, the proposed rates under this
13 Schedule would be determined by dividing the deferred revenue to be recovered by Rate
14 Group by the estimated kWh sales (Electric Decoupling Mechanism) or therm sales (Natural
15 Gas Decoupling Mechanism) for each Rate Group during the twelve month recovery period.

16 Interest would be accrued on the unamortized balance in the decoupling balancing
17 accounts at the quarterly rate published by the Federal Energy Regulatory Commission
18 (“FERC”)¹⁹.

¹⁹ 18 CFR 35.19a.

1 **Q. For the Natural Gas Decoupling Mechanism, would you please describe**
2 **how the Allowed Non-PGA Revenue is determined?**

3 A. Yes, and it is very similar to the calculation for the Electric Decoupling
4 Mechanism. Provided on Page 1 of Exhibit No. ____ (PDE-10) is information that calculates
5 the Allowed Non-PGA Revenue. This is the revenue that the Company collects in its
6 variable energy rates to cover the fixed costs of providing service to customers. It excludes
7 revenues associated with natural gas commodity and revenues that are collected in fixed
8 basic charges. Below are the steps to calculated the Allowed Non-PGA Revenue.

9

10 • Step 1 – Determine the Total Proposed Revenue - Lines 1 through 3 on Page 1 of
11 Exhibit No. ____ (PDE-10) shows the Total Normalized Revenue from the test period
12 (\$150.0 million) and adds to that total the Proposed Revenue Increase (\$12.1
13 million). The resulting calculation is the Total Proposed Revenue that the Company
14 has requested in this case (\$162.2 million) effective January 1, 2015.

15

16 • Step 2 – Determine Amount of Revenue related to Natural Gas/PGA Costs – The
17 Normalized therms by rate schedule for the test year are detailed on Line 4. On Line
18 5, those therms are multiplied by the current approved Schedule 150 PGA rates to
19 determine the total PGA Revenue.

20

21

1 • Step 3 – Determine Total Revenue Excluding Gas Costs – To determine the Total
2 Revenue Excluding Gas Costs, the mechanism subtracts the PGA Revenue on Line 6
3 from the Total Proposed Revenue on Line 3.

4

5 • Step 4 – Remove Fixed Revenues – included in the Total Revenue Excluding Gas
6 Costs on Line 7 are revenues that are recovered from customers in Basic and
7 Monthly Minimum charges (“Fixed Charges”). Because the proposed decoupling
8 mechanism only track revenues that vary with customer usage, the revenue from
9 Fixed Charges must be removed. Line 8 shows the number of Customer Bills in the
10 test period, and Line 9 shows the proposed Fixed Charges in this case. Line 10 is the
11 total Fixed Charge revenue which is calculated by taking the number of customer
12 bills and multiplying those by the associated Fixed Charges, by rate schedule.

13

14 • Step 5 – Determine Allowed Non-PGA Revenue – The final step to calculate the
15 Allowed Non-PGA Revenue, as shown on Line 11, is to subtract the Fixed Charge
16 Revenue (Line 10) from the Non-PGA Revenue Excluding Gas Costs (Line 7).

17

18 Steps 1 through 5 above subtract from the Total Proposed Revenue the revenues
19 associated with the PGA and Fixed Charges to develop the Allowed Non-PGA Revenue.

20 The next step will be to determine the Allowed Non-PGA Revenue per customer.

1 **Q. Would you please describe how the Allowed Non-PGA Revenue per**
2 **Customer is determined?**

3 A. Yes. Provided on Page 2 of Exhibit No.____(PDE-10) are the inputs and
4 calculations to determine the Allowed Non-PGA Revenue per Customer. Line 1 on Page 2
5 of Exhibit No.____(PDE-10) shows the Allowed Non-PGA Revenue, by Rate Group, that
6 was calculated earlier. Note that the information on Page 2 now shows the revenues by Rate
7 Group rather than by individual rate schedule. More discussion related to the Rate Groups
8 will follow later in my testimony. Line 2 shows the Test Year Customers, by Rate Group.
9 Finally, Line 3 divides the Allowed Non-PGA Revenue by the Test Year number of
10 Customers to determine the annual Allowed Non-PGA Revenue per Customer.

11 Page 3 of Exhibit No.____(PDE-10) calculates the monthly Allowed Non-PGA
12 Revenue per Customer. To determine the monthly Allowed Non-PGA Revenue per
13 customer, which is required for the monthly deferral calculations discussed later in my
14 testimony, the annual Allowed Non-PGA Revenue per customer is shaped based on the
15 monthly therm usage from the test year as shown on Page 3 of Exhibit No.____(PDE-10).
16 For example, the Residential Group used 17.33% of its annual usage in January 2013
17 (19,888,327 therms / 114,766,242 therms). The Company used the resulting monthly
18 percentage of usage by month and multiplied that by the annual Allowed Non-PGA Revenue
19 per Customer to determine the 12 monthly values.

20 **Q. Please describe how deferrals for the Natural Gas Decoupling**
21 **Mechanism would be calculated?**

22 A. In the rate year, the Company would track the Actual Non-PGA Revenue it
23 receives and defer any difference between that amount and the Allowed Non-PGA Revenue.

1 Deferrals would be tracked separately for each Rate Group. A sample calculation, provided
2 for illustrative purposes, is included on Page 4 of Exhibit No. ____ (PDE-10). Detailed below
3 are the steps outlined on Page 4 to calculate the deferral. For purposes of describing the
4 deferral calculation, I will only refer to the calculation of the deferral for the Residential
5 Group; there is no difference in the calculations for the Non-Residential Group.

- 6
- 7 • Step 1 – Determine Allowed Non-PGA Revenue Opportunity - The first step is to
8 pull from the Company’s billing system the actual number of customers each month.
9 The actual number of customers are used in the calculation with all customers
10 assuming the same level of Monthly Allowed Non-PGA Revenue per Customer.
11 Line 1 on Page 4 of Exhibit No. ____ (PDE-10) shows an illustrative Residential Group
12 level of customers for the Rate Year of 2015. Line 2 shows the Monthly Allowed
13 Non-PGA Revenue per Customer for that group. Multiplying those values together
14 results in an Allowed Non-PGA Revenue for each month, shown on Line 3. The
15 calculated values on Line 3 show, by month, the total amount of revenue that the
16 Company would be allowed.

- 17
- 18 • Step 2 – Determine Period “Actuals” - The next step is to pull from the Company’s
19 billing system the Actual Monthly Revenue excluding natural gas costs (Line 4 on
20 Page 4 of Exhibit No. ____ (PDE-10)), and Actual Fixed Charge Revenue (Line 5).
21 These “actuals” would not be weather normalized.

22

1 • Step 3 – Calculation of Actual Non-PGA Revenue – Line 6 on Page 4 of Exhibit
 2 No. ____ (PDE-10) shows the calculation of the Actual Non-PGA Revenue. This
 3 calculation subtracts from Actual Monthly Revenue on Line 4 the Actual Fixed
 4 Charge Revenue (Line 5). The calculated values on Line 6 show, by month, the total
 5 amount of revenue that the Company actually received.

6
 7 • Step 4 – Deferral Calculation – In order to determine if the Company over- or under-
 8 recovered its fixed costs, Actual Non-PGA Revenues (Line 6 on Page 4 of Exhibit
 9 No. ____ (PDE-10)) is subtracted from Allowed Non-PGA Revenue (Line 3). Line 7
 10 shows the calculation. If the number is positive (surcharge direction), then the
 11 Company under-recovered its allowed revenue. If the number is negative, then the
 12 Company over-recovered its allowed revenue. The monthly deferrals are tracked
 13 monthly, and accrue interest at the FERC rate (as shown on Line 8)²⁰. Finally, Line
 14 9 shows the Cumulative Deferral.²¹

15
 16 In summary, the calculations shown on Page 4 of Exhibit No. ____ (PDE-10) provide
 17 an example of how the Natural Gas Decoupling Mechanism would work. It shows the use
 18 of the Monthly Allowed Non-PGA Revenue per Customer and how that value is applied to
 19 the actual level of customers to determine the Allowed Non-PGA Revenue Opportunity.
 20 Further the example shows how actual revenues from Fixed Charges are removed from
 21 actual revenues to determine the amount of revenues the Company actually received that are

²⁰ Interest would be accrued on the unamortized balance in the decoupling balancing accounts at the quarterly rate published by the Federal Energy Regulatory Commission (“FERC”)

²¹ Note that the deferral calculations would be completed at the revenue level. The actual deferral would have an additional calculation to remove revenue related expenses. The final deferred balance which the Company would file for later rebate or recovery from customers would then be grossed up for revenue related expenses.

1 non-PGA related. Finally, the example shows the monthly and cumulative deferral
2 calculations, including the effect of interest.

3 **Q. Earlier in your testimony you mentioned that customers will be**
4 **combined into Rate Groups. Please explain?**

5 A. Similar to what PSE did with their decoupling mechanisms, Avista has
6 combined customers into Rate Groups. For the Electric Decoupling Mechanism customers
7 would be included in one of three Rate Groups:

- 8 1. Residential – Schedule 1
- 9 2. Commercial – Schedules 11, 12, 21, 22, 31, and 32
- 10 3. Industrial – Schedule 25

11 Using the PSE grouping as a model, the Company made one adjustment to PSE's
12 original groups and removed Schedule 25 from the non-residential group. The customer
13 base and usage levels for Schedule 25 customers are substantially different from the
14 remaining non-residential customers. Further, there has been limited rate schedule shifting
15 between Schedule 21 and Schedule 25 in the past, as opposed to the schedule shifting that
16 has and continues to occur between Schedules 11 and 21. Keeping the remaining non-
17 residential customers as its own group strikes a reasonable balance between a desire to
18 minimize cross-subsidization between customer groups (i.e., customers switching rate
19 schedules to avoid potential surcharges or to enjoy potential rebates) and the administrative
20 complexity that could result from greater delineation of non-residential customers.

21 For the Natural Gas Decoupling Mechanism customers would be included in one of
22 two Rate Groups:

- 24 1. Residential – Schedule 101
- 25 2. Commercial – Schedules 111, 112, 121, 122, 131, and 132

26

1 Schedule 146 transportation customers were not included in the design of the Natural
2 Gas Decoupling Mechanism. This is consistent with the treatment of transportation
3 customers in the decoupling portion of the PSE Settlement recently approved by the
4 Commission in Docket No. UE-121697 and UG-121705.

5 **Q. Would you describe the accounting for the proposed Electric and**
6 **Natural Gas Decoupling Mechanisms?**

7 A. Yes. The Company would record the deferral in account 186 –
8 Miscellaneous Deferred Debits. The amount approved for recovery or rebate would then be
9 transferred into a Regulatory Asset or Regulatory Liability account for amortization. On the
10 income statement, the Company would record both the deferred revenue and the
11 amortization of the deferred revenue through Account 407 - Regulatory Debits and Credits,
12 in separate sub-accounts. The Company would file quarterly reports with the Commission
13 showing pertinent information regarding the status of the current deferral. This report would
14 include a spreadsheet showing the monthly revenue deferral calculation for each month of
15 the deferral period (July - June), as well as the current and historical monthly balance in the
16 deferral account.

17 **Q. In its Policy Statement, the Commission outlined a number of items that**
18 **a utility should include, at a minimum, in requests seeking a Decoupling Mechanism.**
19 **Briefly, what are those items?**

20 A. The Commission set forth their “Criteria for Approval” at Page 18 of its
21 Policy Statement²². The criteria consist of:

- 22 1. Application to Customer Classes
23 2. Weather Adjustment Mechanism

²² Docket U-100522 – “Report And Policy Statement On Regulatory Mechanisms, Including Decoupling, To Encourage Utilities To Meet Or Exceed Their Conservation Targets”.

- 1 3. Incremental Conservation
- 2 4. Limited-income Impacts/Benefits
- 3 5. Duration of Program
- 4 6. Reports
- 5 7. Other Factors Impacting the Public Interest
- 6
- 7

7 In addition to the seven criteria noted above, the Commission elsewhere in its Policy
8 Statement set forth additional conditions that need to be addressed in order to evaluate, and
9 potentially approve, a full decoupling mechanism. Those items include:

- 10 8. Address Management's Incentive to Control Costs
- 11 9. True-up Mechanism
- 12 10. Impact on Rate of Return
- 13 11. Earnings Test
- 14 12. Accounting for Off-System Sales and Avoided Costs
- 15

16 **Q. Before you address the 12 items noted above, is it your understanding**
17 **that the decoupling mechanisms proposed by the Company do not necessarily need to**
18 **meet all of the Commission's criteria?**

19 A. Yes, that is my understanding. The Commission stated the following in its
20 Order No. 7 approving PSE's decoupling mechanisms:

21 A number of the arguments raised by those opposed to the decoupling mechanisms
22 that PSE and NWECA propose are couched in terms of the failure of one aspect or
23 another of the proposals to meet the "requirements" set out in the Commission's
24 2010 Decoupling Policy Statement. While we address these arguments individually
25 below, it is appropriate to emphasize that interpretive and policy statements are
26 advisory only. They are "advisory statements" and "have no legal or regulatory
27 effect." Such statements generally set forth the Commission's preferences or clear
28 guidelines in certain policy-related matters after extensive deliberation in a workshop
29 setting. We recognize that the proposed decoupling mechanisms vary in certain
30 respects from the Decoupling Policy Statement but this is not a sufficient legal basis
31 for rejecting the mechanisms. Moreover, as the Commission stated in its Final Order
32 in PSE's 2011/2012 GRC, the Decoupling Policy Statement did not set forth
33 "immutable doctrine" on the issue of decoupling.²³ (footnotes omitted) (emphasis
34 added)

²³ Docket Nos. UE-121697 and UG-121705, Order No. 7, ¶95.
Direct Testimony of Patrick D. Ehrbar
Avista Corporation
Docket Nos. UE-14____ and UG-14____

1

2

Q. Please address the Company's decoupling proposals in relation to Criteria #1, Application to Customer Classes.

3

4

A. As I mentioned earlier in my testimony, the Company is proposing three Rate Groups for the electric mechanism, and two Rate Groups for the natural gas mechanism. For the Electric Decoupling Mechanism, the Company believes that the Non-Residential Group, consisting primarily of our commercial customers, is a somewhat homogenous grouping in terms of their usage. As I stated earlier, keeping the non-residential customers, excluding Schedule 25, as its own group strikes a reasonable balance between a desire to minimize cross-subsidization between customer groups (i.e., customers switching rate schedules to avoid potential surcharges or to enjoy potential rebates) and the administrative complexity that could result from greater delineation of non-residential customers. Finally, Street and Area Light rate schedule customers are billed on a flat monthly rate. As such, the fixed costs of providing service to those customers are being recovered by the nature of their rate design and, therefore, have been excluded from the mechanism.

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For the Natural Gas Decoupling Mechanism, for similar reasons noted for the Electric Non-Residential Group, the Company believes it is appropriate to combine all of the non-Schedule 101 customers into its own group. As stated earlier, Transportation Schedule 146 customers were excluded from the mechanism, just as they are under the PSE mechanism. Finally, Special Contract customers served under Schedule 148 have been excluded, as the terms of service, including their rates, are fixed by contract.

22

Q. As for item #2, "Weather Adjustment Mechanism", please reiterate the Company's proposal as it relates to excluding the effects of weather and why.

23

1 A. As I discussed earlier in my testimony, the proposed decoupling mechanism
2 does not have a weather normalization adjustment. The Company has a certain level of
3 fixed costs that are recovered in its variable energy and demand rates. To the extent weather
4 is incorporated into the mechanism and revenues are adjusted, the mechanism would not
5 provide the same level of fixed cost recovery as determined in the last general rate case.
6 With the Company's proposed mechanisms, should sales be higher due to colder than
7 normal winter weather, or hotter than normal summer weather, those additional revenues as
8 calculated in the mechanisms would be deferred and returned to customers.

9 **Q. Please address item #3, the amount of incremental conservation the**
10 **Company plans to obtain if this proposed mechanism is approved.**

11 A. The Company has demonstrated in a number of filings before this
12 Commission that it has been aggressively pursuing cost-effective conservation for a number
13 of years. In addition, the Commission states in its Policy Statement that the Washington's
14 Energy Independence Act (EIA), enacted by the voters as Initiative 937 and codified as
15 RCW 19.285, requires electric utilities to "pursue all available conservation that is cost-
16 effective, reliable, and feasible"²⁴. Simply stated, the Company is already aggressively
17 seeking all available cost-effective conservation in order to meet its required savings targets.
18 The Company is actively promoting all technologies that are cost-effective, reliable, and
19 feasible, with the goal of meeting and exceeding its required targets.

20 While the Company believes that the adoption of decoupling should not be
21 conditioned upon the Company achieving an incremental level of energy efficiency, the
22 Company would increase its electric energy efficiency targets by 5% with the

²⁴ Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, November 2010, Page 3.

1 implementation of the Electric Decoupling Mechanism. This is consistent with what PSE
2 committed to as a part of its electric decoupling mechanism.

3 The Company is not proposing to increase its natural gas energy efficiency targets.
4 As the Commission is aware, the drop in wholesale natural gas prices in recent years has put
5 substantial downward pressure on natural gas avoided costs. Lower avoided costs have
6 likewise reduced the cost-effectiveness of the Company's natural gas DSM programs.
7 Further, the reduction in wholesale natural gas prices has been reflected in customers' retail
8 rates, which make energy efficiency projects less cost-effective from a customer standpoint.
9 As such, the Company has had difficulties in meeting the DSM targets included in its natural
10 gas Integrated Resource Plan. While the Company continues to work hard in acquiring as
11 much cost-effective natural gas DSM as it can, the Company is not confident that it can cost-
12 effectively obtain additional natural gas savings.

13 **Q. For item #4, please address whether or not the Company's conservation**
14 **programs provide benefits to limited-income ratepayers that are roughly comparable**
15 **to other ratepayers.**

16 A. Overall, we believe the Company's conservation programs do provide
17 benefits to limited-income ratepayers that are comparable to other ratepayers. By far the
18 largest benefit that accrues to all of our retail customers is that, through Avista's energy
19 efficiency efforts, the Company has been able to reduce the need for higher cost incremental
20 sources of energy. The total levelized cost of the Company's electric energy efficiency
21 programs is approximately \$55.71 per MWh based on 2012 actual, unverified savings,
22 which is less expensive than incremental natural gas turbines and wind energy. By avoiding
23 higher cost power sources, the Company's overall power supply costs are lower than they

1 otherwise would have been. Those savings would especially benefit limited-income
2 customers whose energy burdens as a percentage of income is higher than that for non-
3 limited-income customers.

4 As it relates to the Company's residential energy efficiency programs, all residential
5 customers irrespective of income can participate. Analysis prepared for the Company's
6 limited-income collaborative shows there is evidence that limited-income customers, and/or
7 their landlords, do participate²⁵. Actual participation levels cannot be accurately measured
8 as the Company does not track the income levels of its customers.

9 Finally, the Company's energy efficiency tariff rider, through Community Action
10 Partnership ("CAP") Agencies, funds limited-income weatherization programs that fund not
11 only 100% of the measure cost, but also an additional 15% for health and human safety
12 investments to preserve the habitability of the residence and preserve the energy efficiency
13 measure. In addition, Avista provides the CAP agencies with an additional payment, equal
14 to 15% of the project cost, to support the CAP agencies administrative costs. Customers
15 who otherwise participate in the Company's regular residential programs typically only
16 receive funding of approximately 50% for the whole cost of the energy efficiency measure,
17 significantly lower than the 100% of the whole cost of the measure limited-income
18 customers receive²⁶.

19 Finally it should be noted that the electric limited-income DSM budget accounts for
20 47% of the overall residential DSM budget for 2014. In my view that percentage is in

²⁵ Avista Utilities Low Income Energy Efficiency Report, Dockets UE-090134, UG-090135 and UG-060518 (consolidated), Compliance Filing, September 2010.

²⁶ 2010 Triple E Report.

1 excess of the percentage of the Company's residential customer base that is considered to be
2 limited-income²⁷.

3 **Q. Please address Item #5, the proposed duration of the program, and Item**
4 **#6, the reports that will be filed with the Commission.**

5 A. The Company believes that a mechanism should not be short-term. The
6 Company believes that the mechanism should have at least a five-year duration in order to
7 allow for a proper assessment over time of its effectiveness. Similar to the current Natural
8 Gas Decoupling Mechanism, the Company would file quarterly reports with the
9 Commission showing pertinent information regarding the status of the current deferral.

10 **Q. Is the Company proposing to facilitate a third-party evaluation of the**
11 **proposed decoupling mechanisms?**

12 A. Yes, the Company proposes to have a third-party evaluation of the
13 mechanisms completed at the end of the third full-year (ending June 30, 2018). Any
14 proposed modifications or findings resulting from the evaluation would be incorporated into
15 the mechanisms after the end of the fifth full-year (ending June 30, 2020). The cost of the
16 evaluation would be limited to \$150,000, similar to the evaluation agreed upon by the
17 parties in the PSE decoupling dockets. The cost of the evaluation would be included in the
18 decoupling balancing accounts.²⁸

19 **Q. With Respect to Item #7, are there any other factors impacting the**
20 **public interest that the Company wants to address?**

²⁷ Avista Utilities Low Income Energy Efficiency Report, Dockets UE-090134, UG-090135 and UG-060518 (consolidated), Compliance Filing, September 2010, Page 4.

²⁸ The cost of the evaluation would be allocated to the mechanisms using the total Allowed Non-Power Supply (\$236.6 million) and Allowed Non-PGA (\$51.3 million) revenues. Within the mechanism, the cost would be spread to the Rate Groups based on each group's share of the total revenue.

1 A. For the reasons discussed elsewhere, the Company believes that the design of
2 the mechanisms are properly constructed to balance out both lost and found margin,
3 providing benefits to both the Company and its customers.

4 **Q. With Respect to Item #8, what is the Company’s response to possible**
5 **concerns that without “the risk of recovery of declines in revenue...the utility could**
6 **lose some of its incentive to manage the company in a manner that constantly looks to**
7 **reduce costs”?**

8 A. The adoption of decoupling would not result in a reduction of efforts by the
9 Company to operate efficiently. The proposed Decoupling Mechanism would provide
10 recovery of fixed costs, on a revenue per customer basis, that were previously approved by
11 the Commission in a prior general rate case for recovery. To the extent those fixed costs
12 increase, or escalate, over time, the Mechanism would not provide for recovery of the
13 change in costs above the approved level already embedded in the allowed revenue per
14 customer. The Company would continue to bear the risk of changes in costs between
15 general rate cases, and therefore must manage the business in a prudent manner. Further,
16 the Commission in a general rate case can always make the determination that any of the
17 Company’s expenditures were not prudent. This potential for disallowance together with
18 management’s desire to provide attractive earnings for shareholders provides enough
19 incentive for management to control costs, and the proposed Decoupling Mechanism does
20 not change that.

21 **Q. With Respect to Item #9, “True-up Mechanism”, the Company**
22 **previously laid out in substantial detail the elements of the Decoupling Mechanism. Do**
23 **you have any additional points you would like to make regarding this item?**

1 A. No, it is fully discussed elsewhere in my testimony.

2 **Q. With respect to Item #10, what is the Company’s position as it relates to**
3 **the potential for an adjustment to the Company’s rate of return with the Decoupling**
4 **Mechanism?**

5 A. An adjustment to the Company’s rate of return or equity layer is not
6 warranted. As I explained earlier, revenue provided to Avista through a decoupling
7 mechanism would not represent additional revenue to the Company over and above what is
8 needed to recover its costs. Decoupling would provide a replacement of revenue that the
9 ratemaking process assumes is already present, when in fact the revenue is not realized
10 because of energy efficiency or other decreases in use per customer. The fact that retail
11 sales are not normalized actually provides a benefit to the Company and its customers. For
12 customers, should a winter be colder than normal, or a summer hotter than normal, and
13 revenues on a per customer basis exceed authorized levels, those additional revenues would
14 be deferred and returned to customers. Moreover, the Commission addressed this issue,
15 when approving PSE’s decoupling mechanisms, and did not order an adjustment to the rate
16 of return.

17 **Q. Item #11 from the Commission’s Policy Statement refers to an Earnings**
18 **Test? Is the Company proposing an Earnings Test as a part of the mechanism?**

19 A. Yes, the Company has included an earnings-test, individually applied for its
20 electric and natural gas mechanism so as to prevent cross-subsidization. The “earnings-test”
21 is based on the Company’s annual “Commission-basis” operating results, which are filed
22 with the Commission by April 30 for the previous calendar year results. If the Commission-
23 basis rate of return for the Company’s Washington electric and natural gas operations

1 (individually) exceeds the most recently authorized rate of return, the amount of the
2 proposed surcharge (amount transferred to the balancing account) is reduced or eliminated
3 to move the rate of return down to, or toward, the Commission-authorized level.

4 **Q. Is the Company proposing a DSM test a part of its Decoupling**
5 **Mechanisms?**

6 A. No, it is not. As it relates to the electric mechanism, to the extent the
7 Company fails to meet its savings targets required under the Energy Independence Act
8 (RCW 19.285), Avista would face stiff penalties. Failure to meet energy efficiency targets
9 should not penalize the Company in terms of its ability to recover its Commission approved
10 costs.

11 **Q. Should there be a 3% limit on any annual rate increases?**

12 A. Yes, Avista proposes that there would a 3% Rate Increase test, and that there
13 would be no limit on any annual rate reductions.

14 **Q. Please describe the 3% Rate Increase Limitation Test.**

15 A. After applying the “earnings” test, the amount of the rate increase resulting
16 from the adjustment is subject to an annual incremental limit of 3%, i.e., the annual increase
17 in the surcharge cannot exceed a 3% rate increase each year, with unrecovered balances
18 carried forward to future years for recovery. The incremental surcharge (percentage)
19 increase is determined by subtracting the annual revenue amount recovered by the present
20 surcharge rate from deferred revenue to be recovered through the proposed surcharge rate,
21 and dividing that net amount by the total “normalized” revenue by Rate Group for the most
22 recent July – June period (with the first period being January 2015 – June 2015). The
23 normalized revenue is determined by multiplying the weather-corrected usage for the

1 period²⁹ by the present billing rates in effect. If the incremental surcharge exceeds a 3% rate
2 increase, only a 3% increase is implemented and any additional deferred revenue remains in
3 the deferred revenue account and could be recovered the following year, subject to the 3%
4 limitation. Again, the 3% limitation is not applicable if the Company is in a rebate position.

5 **Q. Please address Item #12, Accounting for electric Off-System Sales and**
6 **Avoided Costs.**

7 A. The Company's Energy Recovery Mechanism (ERM) is designed to capture
8 any change in Off-System Sales and Purchased Power expense that may arise due to
9 changes in retail load. The Retail Revenue Credit ("RRC") rate is applied to the change in
10 retail sales to take into account that there would be a corresponding change in retail revenue.
11 The RRC rate multiplied by actual retail sales (kWhs) represents the embedded volumetric
12 retail revenue accounted for in the ERM. As demonstrated earlier in my testimony and as
13 shown in Exhibit No. ____ (PDE-9), the Company's proposed Electric Decoupling Mechanism
14 specifically excludes that embedded volumetric retail revenue accounted for in the ERM,
15 because the same Retail Revenue Credit rate determines the amount of power supply
16 revenue excluded from both the allowed and actual revenues measured in the decoupling
17 mechanism. In short, the Company would not be double counting in the ERM and Electric
18 Decoupling Mechanism as it relates to power supply costs.

19 **Q. Has the Company prepared electric and natural gas tariffs that would**
20 **administer the decoupling mechanisms?**

21 A. Yes, included in Exhibit No. ____ (PDE-3) and Exhibit No. ____ (PDE-6) are
22 new tariff Schedules 99 (electric) and 199 (natural gas). These tariffs outline the mechanics
23 of the decoupling mechanisms and will serve as the rate adjustment tariffs.

²⁹ Inclusive of booked billed revenue, booked unbilled revenue and the weather adjustment.
Direct Testimony of Patrick D. Ehrbar
Avista Corporation
Docket Nos. UE-14____ and UG-14____

1 **Q. What is the Company proposing to do with its existing limited natural**
2 **gas decoupling mechanism administered under rate Schedule 159?**

3 A. The Company is proposing to terminate its current partial natural gas
4 decoupling mechanism effective January 1, 2015 and substitute the proposed mechanism in
5 its place. If the Company’s request for the new Natural Gas Decoupling Mechanism is
6 approved, the Company would transfer any remaining deferral balance into the new
7 mechanism (Residential Rate Group).

8

9 **VIII. RENEWABLE ENERGY CREDIT (“REC”) REVENUE MECHANISM**

10 **Q. Please describe the Company’s proposal for returning REC revenue to**
11 **customers.**

12 A. As discussed by Mr. Johnson, the Company proposes to implement a REC
13 revenue rebate effective January 1, 2015, coinciding with any change in base rates. This
14 rebate will be based on actual and projected net REC revenues from 2012 through June
15 2016. The amortization period for this rebate will be 18 months, January 2015 through June
16 2016 (see Exhibit No. ____ (WGJ-5) which includes a schematic of the proposed REC revenue
17 mechanism).

18 REC revenue will be based on the actual REC revenue in excess of the amount in
19 base rates for 2012 and 2013, the estimated REC revenue in excess of the amount in base
20 rates for 2014, and the total estimated REC revenue for the period January 2015 through
21 June 2016. The Company proposes that the rebate be implemented on a uniform
22 cents/kWh basis across all rate classes.

1 **Q. What is the estimated REC revenue rebate to go into effect on January 1,**
2 **2015?**

3 A. Based on actual 2012 and 2013 REC revenue plus the estimated REC
4 revenue for the period 2014 through June 2016, the total rebate amount is \$7,841,726
5 (Washington allocation). Amortized over an 18 month period the rebate is \$0.00094/kWh,
6 or approximately a 1.1% reduction in rates. A table showing net REC revenues, both actual
7 and projected, by year is shown in Exhibit No. ____ (WGJ-6).

8 **Q. Has the Company developed a tariff to administer the proposed**
9 **mechanism?**

10 A. Yes, the Company has developed electric rate Schedule 98, “Renewable
11 Energy Credit Revenue Mechanism”, and has included this tariff sheet in its proposed
12 tariffs, Exhibit No. ____ (PDE-3).

13

14 **IX. SUMMARY OF UE-120436/UG-120437 ORDER No. 09 REQUIREMENTS**

15 **Q. Has the Company complied with the requirements of the Commission’s**
16 **Order No. 09 (and Settlement Stipulation) in Dockets UE-120436 and UG-120437?**

17 A. Yes. Detailed below are four items that the Company was required to
18 address based on Order No. 09 in Dockets UE-120436 and UG-120437. Shown below, in
19 no particular order, are the requirements, the page number and paragraph where the items
20 are located in the Order, and the witnesses that address the issues in this docket.

21 **Item 1 – REC Mechanism (Order Page 32, Paragraphs 83-85):**

22 *"The Commission orders Avista to defer the difference between the REC sale*
23 *proceeds in base rates and actual REC sale proceeds to a separate tracking account*
24 *not subject to the trigger mechanism of the ERM. At the time of its next filed rate*
25 *case, Avista will propose a mechanism for returning any such accumulated*
26 *difference of REC sale proceeds in a true-up. The Commission recognizes that the*

1 *balance in this account at the time of the next general rate case may be a credit or*
2 *debt to customers. To simplify the treatment of REC sale proceeds in the next*
3 *general rate case, the Commission orders Avista to remove REC sale proceeds from*
4 *the ERM account and base rates, to project the revenues expected in the rate year,*
5 *and to defer such revenues to a tracking account established by the Company. The*
6 *REC sale proceeds will be returned to ratepayers via a mechanism consistent with*
7 *those used by Puget Sound Energy and PacifiCorp and presented for approval in the*
8 *next general rate case. For the 2012 REC sale proceeds currently accounted for in*
9 *the ERM, the Commission orders that all such revenues in excess of the \$4,077,485*
10 *million now credited to customers be deferred into the tracking account established*
11 *by this Order without being subject to the ERM deadbands or sharing bands.”*

12
13 This item is addressed by Mr. Johnson in Exhibit No. ____ (WGJ-1T).

14
15 **Item 2 – Changes to the Retail Revenue Credit (Order Page 32, Paragraph 86):**

16 *“The Settlement also alters the retail revenue credit in the ERM. The Commission*
17 *accepts the Settlement as a non-precedent setting agreement. To extend this*
18 *modification to the ERM, the Company must seek approval in the next general rate*
19 *case and provide more extensive testimony in support of its request. We expect the*
20 *parties to contribute to our determination as to whether extending the change to the*
21 *retail revenue credit is in the public interest.”*

22
23 This item is addressed by Mr. Johnson in Exhibit No. ____ (WGJ-1T).

24
25 **Item 3 – Planned Capital Additions (Order Page 38, Paragraphs 114 & 115):**

26 *With regard to its planned capital expenditures for calendar year 2013, Avista must*
27 *file: (1) a progress report on its 2013 capital expenditures on or before September*
28 *30, 2013; and (2) a comprehensive report on the final totals for 2013 capital*
29 *expenditures on or before March 1, 2014. As to the capital expenditures Avista plans*
30 *to make in calendar year 2014, the Company must file: (1) its capital expenditure*
31 *plan for 2014 on or before September 30, 2013; and (2) updates on changes in*
32 *meeting its capital expenditure plan for 2014 and reports on progress in making*
33 *such capital improvements on June 1, September 1, and December 1, 2014,*
34 *respectively, for the previous quarters.*

35
36 This item is addressed by Company witness Mr. De Felice in Exhibit No. ____ (DBD-
37 1T).

38
39 **Item 4 – Allocation Methods (Stipulation Page 7, Paragraph 17):**

40 *“Avista will provide justification for the service and jurisdictional cost allocation*
41 *methodologies it employs in its next general rate case filing.”*

42
43 This item is addressed by Ms. Andrews in Exhibit No. ____ (EMA-1T).

1 **Q. Were all the requirements in Order No. 09 and the Settlement**
2 **Stipulation met by the Company prior to filing, or included in, this general rate case?**

3 A. Yes, all of the items that were required of the Company in Order No. 09 and
4 the Settlement Stipulation were either completed prior to filing this general rate case or are
5 addressed in this docket as required. This includes the capital expenditure reports that are
6 due during the pendency of this general rate case.

7 **Q. Does this conclude your pre-filed, direct testimony?**

8 A. Yes it does.