

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-12_____

DOCKET NO. UG-12_____

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 Demand Side Management (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 of \$40,983,000, or 9.0%, among the Company's electric
5 general service schedules. Incorporating the Company's proposed Energy Recovery
6 Mechanism Schedule 93 Rebate ("ERM Rebate"), reduces the overall increase to 5.9% in
7 billed revenues as explained below. With regard to natural gas service, I will describe the
8 spread of the proposed annual base revenue increase of \$10,088,000, or 7.0%, among the
9 Company's natural gas service schedules. My testimony will also describe the changes to
10 the rates within the Company's electric and natural gas service schedules, as well the
11 proposed increase in the basic charge for electric rate Schedule 1 and natural gas rate
12 Schedule 101. I will also describe the DSM Component of the Attrition Adjustment as well
13 as discuss an issue related to Schedule 95, the Optional Renewable Power Rate program.
14 Later, I will discuss the proposed ERM Rebate. Finally, I will provide an overview of the
15 items required of the Company in Order No. 06, and the related Settlement Stipulation, in
16 Dockets UE-110876 and UG-110877.

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

18 A. Yes. I am sponsoring Exhibit Nos. ____ (PDE-2), ____ (PDE-3), and ____ (PDE-
19 4) related to the proposed electric increase, and Exhibit Nos. ____ (PDE-5), ____ (PDE-6), and
20 ____ (PDE-7) related to the proposed natural gas increase. I am also sponsoring Exhibit No.
21 ____ (PDE-8) relating to the DSM Component of the Attrition Adjustment. These exhibits
22 were prepared by me or under my supervision.

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II. EXECUTIVE SUMMARY

Proposed Electric Increase

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

A. The proposed electric increase is \$40,983,000, or 9.0% over present base tariff rates in effect. The proposed general increase over present billing rates, including all other rate adjustments (DSM and Residential Exchange), as well as the proposed ERM Rebate, is 5.9%. The proposed general base rate increase of \$40,983,000 has been spread by rate schedule on a uniform percentage basis, as has the proposed ERM Rebate. The

1 proposed percentage increase by rate schedule is as follows:

2 **Table 1 - 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 w/ ERM Rebate</u>
Residential Schedule 1	9.0%	9.0%	6.0%
General Service Schedule 11	9.0%	8.6%	5.8%
Large General Service Schedule 21	9.0%	8.6%	5.8%
Extra Large General Service Schedule 25	9.0%	8.6%	5.8%
Pumping Service Schedule 31	9.0%	8.6%	5.8%
Street & Area Lights Schedules	9.0%	8.6%	5.8%
Overall	9.0%	8.8%	5.9%

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

9 **Q. What is the proposed increase for a residential electric customer with**
 10 **average consumption, including the proposed ERM Rebate?**

11 A. The proposed increase for a residential customer using an average of 989
 12 kWhs per month is \$4.94 per month, or a 6.3% increase in their electric bill. The present
 13 bill for 989 kWhs is \$78.97 compared to the proposed level of \$83.91, including all rate
 14 adjustments. The Company is also proposing to change the basic charge from \$6.00 per
 15 month to \$10.00 per month.

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

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

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

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

1 **Proposed Natural Gas Increase**

2 **Q. How is the Company proposing to spread the overall natural gas**
 3 **increase of \$10,088,000, or 7.0% by service schedule?**

4 A. The Company is proposing the following base revenue changes by rate
 5 schedule¹:

6 **Table 2 - 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	7.0%	6.9%
Large General Service Schedule 111	7.0%	6.9%
Ex. Lg. General Service Schedule 121	7.0%	6.8%
Interruptible Sales Service Schedule 131	7.0%	6.6%
Transportation Service Schedule 146	<u>7.0%</u>	<u>7.0%</u>
Overall	7.0%	6.8%

12 This information is also shown on page 1 of Exhibit No.____(PDE-7). The Company has
 13 spread the proposed general base rate increase of \$10,088,000 on a uniform percentage basis
 14 to its natural gas service schedules.

15 **Q. What is the proposed monthly increase for a residential natural gas**
 16 **customer with average usage?**

17 A. The increase for a residential customer using an average of 68 therms of
 18 natural gas per month would be \$4.23 per month, or 6.9%. A bill for 68 therms per month
 19 would increase from the present level of \$61.55 to a proposed level of \$65.78. The
 20 Company is also proposing to change the basic charge from \$6.00 per month to \$10.00 per
 21 month.

¹ For Schedule 146, including an estimate of 40.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 1.1% in those customers' total natural gas bill.

1 **III. PROPOSED ELECTRIC REVENUE INCREASE**

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

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

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

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

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

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

10 A. Exhibit No. ____ (PDE-4) contains information regarding the proposed spread
11 of the electric revenue increase among the service schedules and the proposed changes to the
12 rates within the schedules. Page 1 shows the proposed general revenue and percentage
13 increase by rate schedule compared to the present revenue under base tariff and billing rates.
14 Page 2 shows the rates of return and the relative rates of return for each of the schedules
15 before and after application of the proposed general increase. Page 3 shows the present rates
16 under each of the rate schedules, the proposed changes to the rates within the schedules, and
17 the proposed rates after application of the changes. These pages will be referred to later in
18 my testimony.

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

21 A. Yes. The Company presently provides electric service under Residential
22 Service Schedule 1, General Service Schedules 11 and 12, Large General Service Schedules
23 21 and 22, Extra Large General Service Schedule 25 and Pumping Service Schedules 31 and

1 32. Additionally, the Company provides Street Lighting Service under Schedules 41-46,
 2 and Area Lighting Service under Schedules 47-48. Schedules 12, 22, 32, and 48 exist for
 3 residential and farm service customers who qualify for the Residential Exchange Program
 4 operated by the Bonneville Power Administration. The rates for these schedules are
 5 identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the
 6 Residential Exchange rate credit.

7 The following table shows the type and number of customers served in Washington
 8 (as of December 2011) under each of the service schedules:

9 **Table 3 - Customers by Service Schedule**

<u>Rate Schedule</u>	<u>No. of Customers</u>
Residential Schedule 1	202,664
General Service Schedule 11/12	28,215
Large General Service Schedule 21/22	2,989
Extra Large General Service Schedule 25	22
Pumping Service Schedule 31/32	2,403

13 **Proposed Electric Rate Spread**

14 **Q. How does the Company propose to spread the total general revenue**
 15 **increase request of \$40,983,000 among its various rate schedules?**

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

18 **Table 4 - 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 w/ ERM Rebate</u>
Residential Schedule 1	9.0%	9.0%	6.0%
General Service Schedule 11	9.0%	8.6%	5.8%
Large General Service Schedule 21	9.0%	8.6%	5.8%
Extra Large General Service Schedule 25	9.0%	8.6%	5.8%
Pumping Service Schedule 31	9.0%	8.6%	5.8%
Street & Area Lights Schedules	<u>9.0%</u>	<u>8.6%</u>	<u>5.8%</u>
Overall	9.0%	8.8%	5.9%

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

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

4 A. While the Company believes that the results of the cost of service study
 5 (sponsored by Ms. Knox) should be used as a guide to spread the general increase, the
 6 Company is also aware that, given the size of the overall increase, certain schedules may
 7 have received an even larger rate increase had the Company proposed some movement
 8 closer to the overall rate of return (unity). Therefore, the Company chose to spread the
 9 proposed rate increase on a uniform percentage basis. The table below shows the relative
 10 rates of return (schedule rate of return divided by overall rate of return) before and after
 11 application of the base rate increase on a uniform percentage basis (9.0%) to all rate
 12 schedules:

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

	Present	Uniform
	Relative	Percentage
Rate Schedule	<u>ROR</u>	<u>ROR</u>
Residential Schedule 1	0.58	0.66
General Service Schedule 11	2.09	1.88
Large General Service Schedule 21	1.56	1.45
Extra Large General Service Schedule 25	0.70	0.80
Pumping Service Schedule 31	0.88	0.89
Street & Area Lights Schedules	1.01	0.94
Overall	1.00	1.00

14
 15
 16
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 19
 20 As shown, for those schedules where the present rates are substantially above or
 21 below the cost of service, the proposed rate spread provides some movement towards unity
 22 (1.00).

23

1 **Proposed Rate Design**

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

4 A. Page 3 of Exhibit No. ____ (PDE-4) shows a comparison of the present and
5 proposed rates within each of the schedules, which I will describe below. Column (a) shows
6 the rate/billing components under each of the schedules, column (b) shows the base tariff
7 rates within each of the schedules, column (c) shows the present rate adjustments applicable
8 under each schedule, and column (d) shows the present billing rates. Column (e) shows the
9 proposed general rate increase to the rate components within each of the schedules, column
10 (f) shows the proposed billing rates and column (g) shows the proposed base tariff rates.
11 Finally, column (h) shows the proposed ERM Rebate, and column (i) shows the proposed
12 billing rate including the ERM Rebate.

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

15 A. No, it is not.

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

18 A. Yes. Residential Schedule 1 has a present customer or basic charge of \$6.00
19 per month and three energy rate blocks: 0-600 kWhs, 601-1,300 kWhs and over 1,300
20 kWhs. The present base tariff rate for the first 600 kWhs per month is 6.914 cents per kWh,
21 8.044 cents per kWh for the next 700 kWhs and 9.429 cents for all kWhs over 1,300.

22 **Q. How does the Company propose to spread the proposed revenue increase**
23 **of \$17,867,000 to Schedule 1?**

1 A. The Company is proposing to increase the basic charge from \$6.00 to \$10.00
2 per month, and is proposing to increase the energy rate for all three blocks by 0.343
3 cents/kWh.

4 **Q. Why is the Company proposing to increase the monthly customer charge**
5 **from \$6.00 to \$10.00 per month?**

6 A. A substantial portion of the Company's costs are fixed and do not vary with
7 the amount of energy used by customers. As reflected in this filing, the cost of operating
8 and maintaining our electric system is increasing. The Company believes it is important that
9 rates better reflect these increasing costs to serve customers. Later in my testimony I will
10 provide greater detail as to why the Company believes the monthly customer charge should
11 increase by \$4.00 per month.

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

14 A. The average monthly usage for a residential customer is approximately 989
15 kWhs. Based on the proposed billing rate increase, including the ERM Rebate, the average
16 monthly increase would be \$4.94, or 6.3%. The present monthly bill for 989 kWhs of usage
17 is \$78.97 and the proposed monthly bill would be \$83.91.

18 **Q. Turning to General Service Schedule 11, could you please describe the**
19 **present rate structure and rates under that schedule?**

20 A. Yes. The present rate structure under the schedule includes a monthly
21 customer charge of \$12.00, an energy rate of 10.891 cents per kWh for all usage up to 3,650
22 kWhs per month, and an energy rate of 8.002 cents per kWh for usage over 3,650 kWhs per
23 month. There is also a demand charge of \$5.75 per kW for all demand in excess of 20 kW

1 per month. There is no charge for the first 20 kW of demand.

2 **Q. How is the Company proposing to apply the proposed general revenue**
3 **increase of \$4,999,000 to the rates under Schedule 11?**

4 A. The Company is proposing that the customer charge be increased by \$3.00,
5 from \$12.00 to \$15.00 per month. In addition, the Company is proposing that the demand
6 charge (over 20 kW) be increased \$0.50 per kW, from \$5.75 to \$6.25. The remaining
7 revenue increase for the schedule is proposed to be recovered through a uniform percentage
8 increase of approximately 7.7% applied to the two (block) energy rates. The increase in the
9 first block rate is 0.840 cents per kWh, and 0.617 cents per kWh for the second block rate.
10 Finally, the Company is proposing to increase the minimum charge for 3-phase service from
11 \$19.35 to \$22.35.

12 **Q. Why is the Company proposing a \$0.50 or 9% increase to the demand**
13 **charge for Schedule 11?**

14 A. The system allocated demand cost from the cost of service study is
15 approximately \$17.46 per kilowatt (kW) month². The Company's present monthly demand
16 charges range from \$4.25–\$5.75/kW, depending on service schedule. While the exact level
17 of costs classified as demand-related can be debated, clearly the levels of demand charges
18 will continue to be well below demand-related costs.

19 In addition, the Company's transmission and distribution system is constructed to
20 meet the collective peak demand of its customers. Further, the Company must have
21 adequate resources available to meet peak demand. If customers reduce their peak demand,
22 it will reduce the need for additional investment in these facilities and resources. Customers

² Knox Exhibit No. ____ (TLK-4), at 3 ln.28

1 need to receive the proper price signal to encourage a reduction in their peak demand, i.e.,
2 higher demand charges.

3 For these reasons, the Company believes that it is important to increase the demand
4 charge in this case for Schedule 11, as well as for Schedules 21 and 25, by a percentage
5 equal to or greater than that applied to the energy rates³. If demand charges are not
6 increased at least proportionately with energy charges, customers who have a poor load
7 factor (high peak demand compared to average energy use) would see a lower percentage
8 increase in their bill than a comparable customer with a good load factor (low peak demand
9 compared to average energy use). This result would not send the appropriate price signal to
10 commercial and industrial customers, nor would it reflect the fact that the Company's
11 demand charges are well below the costs associated with meeting customers' peak demand.

12 **Q. Turning to Large General Service Schedule 21, would you please**
13 **describe the present rate structure under that schedule and how the Company is**
14 **proposing to apply the increase of \$11,432,000 to the rates within the schedule?**

15 A. Yes. Large General Service Schedule 21 consists of a minimum monthly
16 charge of \$400.00 for the first 50 kW or less, a demand charge of \$5.25 per kW for monthly
17 demand in excess of 50 kW, and two energy block rates: 6.819 cents per kWh for the first
18 250,000 kWhs per month, and 6.097 cents per kWh for all usage in excess of 250,000 kWhs.

19 The Company is proposing that the present minimum demand charge (for the first 50
20 kW or less) be increased by \$50 per month, from \$400.00 to \$450.00, and the demand
21 charge for kW over 50 per month be increased by \$0.50 per kW, from \$5.25 to \$5.75, for
22 reasons provided previously in my testimony. The remaining revenue increase for the

³ The proposed increase in demand charges of 8.7% is greater than the proposed increase in the variable rates of 7.7%

1 schedule is proposed to be recovered through a uniform percentage increase of
2 approximately 8.5% applied to the two energy block rates. The proposed increase for the
3 first 250,000 kWhs used per month under the schedule is 0.579 cents per kWh, and an
4 increase of 0.517 cents per kWh for usage over 250,000 kWhs per month.

5 **Q. Turning to Extra Large General Service Schedule 25, would you please**
6 **describe the present rate structure under that schedule and how the Company is**
7 **proposing to apply the increase of \$5,241,000 to the rates within the schedule?**

8 A. Yes. Extra Large General Service Schedule 25 consists of a minimum
9 monthly charge of \$14,000.00 for the first 3,000 kVa or less, a demand charge of \$4.25 per
10 kVa for monthly demand in excess of 3,000 kVa, and three energy block rates: 5.373 cents
11 per kWh for the first 500,000 kWhs per month, 4.834 cents per kWh for the next 5.5 million
12 kWhs and 4.391 cents per kWh for all usage in excess of 6 million kWhs.

13 The Company is proposing that the present minimum demand charge under the
14 schedule be increased by \$2,500 per month, from \$14,000 to \$16,500, and the demand
15 charge for kVa over 3,000 per month be increased by \$0.50 per kVa, from \$4.25 to \$4.75.
16 The remaining revenue increase for the schedule is proposed to be recovered through a
17 uniform percentage increase of approximately 7.8% applied to the three energy block rates.
18 The proposed energy rate increase for the first 500,000 kWhs used per month is 0.422 cents
19 per kWh, 0.379 cents per kWh for the next 5.5 million, and 0.345 cents per kWh for all
20 usage over 6 million kWhs per month.

21 **Q. What changes is the Company proposing to the rates under Pumping**
22 **Schedule 31 to recover the proposed general revenue increase of \$850,000?**

23 A. The Company is proposing that the customer charge be increased by \$5.00,

1 from \$10.00 to \$15.00 per month, with the remaining revenue increase spread on a uniform
2 percentage increase of 7.7% to the two energy rate blocks under the schedule. The proposed
3 increase in the first block rate is 0.703 cents per kWh and the increase in the second block
4 rate is 0.503 cents per kWh.

5 **Q. How is the Company proposing to spread the proposed revenue increase**
6 **of \$594,000 applicable to Street and Area Light schedules to the rates contained in**
7 **those schedules (Schedules 41-48)?**

8 A. The Company proposes to increase present street and area light (base) rates
9 on a uniform percentage basis. The proposed increase for all lighting rates is 9.0%. The
10 (base tariff) rates are shown in the tariffs for those schedules, contained in Exhibit
11 No. ____ (PDE-3).

12

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

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

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

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

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

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

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

22 A. Exhibit No. ____ (PDE-7) contains information regarding the proposed spread
23 of the natural gas revenue increase among the service schedules and the proposed changes to

1 the rates within the schedules. Page 1 shows the proposed revenue and percentage increase
2 by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of
3 the schedules before and after the proposed increases. Page 3 shows the present rates under
4 each of the rate schedules, the proposed changes to the rates within the schedules, and the
5 proposed rates after application of the changes. These pages will be referred to later in my
6 testimony.

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

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

20 **Q. The Company also has rate Schedules 112, 122 and 132 on file with the**
21 **Commission. Could you please explain which customers are eligible for service under**
22 **these schedules?**

23 A. Schedules 112, 122 and 132 are in place to provide service to customers who

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

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

13 A. As of December 2011, the Company provided service to the following
 14 number of Washington customers under each of its schedules:

15 **Table 6 - Customers by Service Schedule**

<u>Rate Schedule</u>	<u>No. of Customers</u>
16 General Service Schedule 101	146,618
17 Large General Service Schedule 111/112	2,472
18 Ex. Lg. General Service Schedule 121/122	24
19 Interruptible Sales Service Schedule 131/132	1
20 Transportation Service Schedule 146	39

21 **Proposed Rate Spread**

22 **Q. How does the Company propose to spread the overall revenue increase**
 23 **of \$10,088,000, or 7.0%, among its natural gas general service schedules?**

A. The Company is proposing the following revenue/rate changes by rate

1 schedule:

2 **Table 7 - Proposed % Natural Gas Increase by Schedule**

<u>Rate Schedule</u>	Increase in Base Rates	Increase in Billing Rates
General Service Schedule 101	7.0%	6.9%
Large General Service Schedule 111	7.0%	6.9%
Ex. Lg. General Service Schedule 121	7.0%	6.8%
Interruptible Sales Service Schedule 131	7.0%	6.6%
Transportation Service Schedule 146	<u>7.0%</u>	<u>7.0%</u>
Overall	7.0%	6.8%

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

10 A. No. The proposed percentage increase for Transportation Schedule 146 is not
11 comparable to the proposed increases for the other (sales) service schedules, as Schedule 146
12 revenue does not include an amount for the cost of natural gas or pipeline transportation,
13 whereas the other sales schedules include these costs. Transportation customers acquire their
14 own natural gas and pipeline transportation. Including an estimate of 40.0 cents per therm for
15 the cost of natural gas and pipeline transportation, the proposed increase to Schedule 146
16 rates represents an average increase of 1.1% in those customers' total natural gas bill.

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

19 A. While the Company believes that the results of the natural gas cost of service
20 study (sponsored by Ms. Knox) should be used as a guide to spread the general increase, the
21 Company is also aware that, given the size of the overall increase, certain schedules may
22 have received an even larger rate increase had the Company proposed some movement
23 closer to the overall rate of return (unity). Therefore, the Company chose to spread the

1 proposed rate increase on a uniform percentage basis.

2 **Proposed Rate Design**

3 **Q. Could you please explain the present rate design within each of the**
4 **Company's present natural gas service schedules?**

5 A. Yes. General Service Schedule 101 generally applies to residential and small
6 commercial customers who use less than 200 therms/month. The schedule contains a single
7 rate per therm for all natural gas usage and a monthly customer/basic charge.

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

12 Extra Large General Service Schedule 121 has a five-tier declining-block rate
13 structure with a monthly minimum charge plus a usage charge for the first 500 therms or less,
14 and block rates for the next 500 therms, the next 9,000 therms, the next 15,000 therms, and
15 usage over 25,000 therms/month. There is also an annual minimum requirement of 60,000
16 therms under the schedule and a minimum load factor requirement of approximately 58%.

17 Interruptible Sales Service Schedule 131 has a four-tier declining-block rate structure
18 for the first 10,000 therms, the next 15,000 therms, the next 25,000 therms, and usage over
19 50,000 therms per month. The schedule also has an annual minimum deficiency charge
20 based on a usage requirement of 250,000 therms per year.

21 Transportation Service Schedule 146 contains a \$250 per month customer charge and
22 a five-tier declining-block rate structure for the first 20,000 therms, the next 30,000 therms,
23 the next 250,000 therms, the next 200,000 therms, and usage over 500,000 therms per month.

1 The schedule also has an annual minimum deficiency charge based on a usage requirement of
2 250,000 therms per year.

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

5 A. No, it is not.

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

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

11 **Q. You stated earlier in your testimony that the Company is proposing an**
12 **overall increase of 7.0% to the base rates of General Service Schedule 101. Is the**
13 **Company proposing an increase to the present basic/customer charge of \$6.00/month**
14 **under the schedule?**

15 A. Yes. The Company is proposing to increase the basic/customer charge from
16 \$6.00 to \$10.00 per month, as the Company believes that the customer/basic charge should
17 recover a reasonable portion of the fixed costs of providing service. Later in my testimony I
18 will provide greater detail as to why the Company believes the monthly customer charge
19 should increase by \$4.00 per month.

20 **Q. What is the proposed change to the rate per therm under Schedule 101**
21 **in order to achieve the total proposed revenue increase for the schedule?**

22 A. The Company, as shown in column (e), page 3 of Exhibit No. ____ (PDE-7),
23 has proposed to change the per therm rate for Schedule 101 customers by \$0.00337 per

1 therm, from the current rate (including Schedule 150 natural gas costs) of \$0.79915 per
2 therm to \$0.80252 per therm.

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

5 A. The increase for a residential customer using an average of 68 therms of
6 natural gas per month would be \$4.23 per month, or 6.9%. A bill for 68 therms per month
7 would increase from the present level of \$61.55 to a proposed level of \$65.78.

8 **Q. Could you please explain the proposed changes in the rates for Large and**
9 **Extra Large General Service Schedules 111 and 121?**

10 A. Yes. The present rates for Schedules 101, 111, and 121 provide a clear
11 distinction for customer placement: customers who use less than 200 therms/month should
12 be placed on Schedule 101, customers who use between 200 and 10,000 therms per month
13 should be placed on Schedule 111, and only those customers who generally use over 10,000
14 therms per month should be placed on Schedule 121. Not only do the rates provide guidance
15 for customer schedule placement, they provide a reasonable classification of customers for
16 analyzing the costs of providing service.

17 The Company's proposed rates for Schedules 111 and 121 will maintain the rate
18 structure within the schedules and continue to provide guidance for appropriate schedule
19 placement for customers and a reasonable classification for cost analysis. The proposed
20 increase to the minimum charge for Schedule 111 (for 200 therms or less) of \$4.79 per month
21 is a function of the basic charge increase of \$4.00 under Schedule 101 as well as the

1 increased Schedule 101 variable rate⁴. This methodology maintains the present relationship
 2 between the schedules, and will minimize customer shifting. The remaining proposed
 3 revenue increase for Schedule 111 was then spread on a uniform percentage increase of 7.7%
 4 to the remaining two rate blocks under the schedule, resulting in an overall revenue increase
 5 of 7.0% for the schedule.

6 For Schedule 121, the increase in the minimum charge (for 500 therms or less) is
 7 \$6.33 for a total charge of \$384.96. The minimum charge is derived by adding the proposed
 8 Schedule 101 basic charge of \$10 to the product of 500 therms multiplied by the difference
 9 between the rate in Schedule 101 and the minimum rate under Schedule 121. Below is the
 10 calculation:

11 **Table 8 – Schedule 121 Breakeven Calculation**

	500 Therms	500
	*	
	(101 Rate - 121 Minimum Rate)	
	(0.80252 - 0.05261)	\$0.74991
	+	
	Schedule 101 Basic Charge	\$10.00
	=	\$384.96

17 The second, third, and fourth block rates were increased by a uniform percentage of
 18 approximately 9.0% to maintain consistency between the rates for Schedules 111 and 121.
 19 The fifth block was not adjusted in order to provide a more meaningful spread between the
 20 rate blocks, resulting in an overall revenue increase of 7.0% for the schedule.

⁴ Schedule 111 Minimum Charge increase equals the \$4 increase in Schedule 101 Basic Charge plus 200 therms multiplied by the change in the variable rate (200*\$0.00337 = \$0.67). That total is \$4.67, which is \$0.12 lower than the true breakeven of \$4.79. By adding this small, additional amount, the breakeven bill at 200 therms for Schedules 101 and 111 is \$170.50.

1 **Q. How is the Company proposing to spread the proposed increase of**
2 **\$26,000 to the rates under Interruptible Schedule 131/132?**

3 A. The Company proposes to increase the present four block rates under the
4 schedule by a uniform percentage increase of approximately 7.0%.

5 **Q. Could you please explain the proposed changes in the rates for**
6 **Transportation Schedule 146?**

7 A. Yes. The Company is proposing to adjust the basic charge by \$25 per month,
8 which is an increase from \$250 to \$275 per month. For the remaining revenue requirement,
9 the Company is proposing to spread the increase on a uniform percentage basis of
10 approximately 6.8% to each of the present five block rates under the schedule. The proposed
11 increase to each of the block rates, as well as the present and proposed rates, are shown at the
12 bottom of page 3 of Exhibit No. ____ (PDE-7).

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

15 A. Yes. The rates contained in Purchase Gas Cost Adjustment Schedule 150
16 have been incorporated into the present and proposed rates shown on Page 3 of Exhibit
17 No. ____ (PDE-7). Further, a revised Schedule 150 is filed as part of Exhibit No. ____ (PDE-6),
18 whereby the present rates under the schedule have been zeroed-out and included in the
19 Company's proposed general service tariffs.

1 **V. BASIC CHARGE**

2 **Q. Why is the Company proposing to increase the electric monthly**
3 **customer charge for Schedule 1 from \$6.00 to \$10.00 per month?**

4 A. A significant portion of the Company's costs are fixed and do not vary with
5 customer usage. These costs include distribution plant and operating costs to provide
6 reliable service to customers. Upon evaluation of the total customer allocated costs for
7 Schedule 1, as shown in Knox Exhibit No. ____ (TLK-4), page 4, line 25, those costs are
8 \$12.78 per customer per month. Factoring in distribution demand cost per customer per
9 month of \$22.31, as shown in Knox Exhibit No. ____ (TLK-4), page 4, line 27, the total
10 customer and distribution demand monthly cost is \$35.09. These are essentially fixed costs
11 that are allocated based on the number of customers served. Given the large disparity
12 between the level of customer and demand costs and the present level of the basic charge,
13 the Company believes that it is appropriate to recover a more reasonable level of these fixed
14 customer costs through the basic charge.

15 **Q. Why is the Company now proposing an increase of \$4.00 per month in**
16 **this filing?**

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

1 have become accustomed to paying a relatively constant monthly fee for service or system
2 access.

3 Publicly-owned electric utilities have been charging higher monthly customer
4 charges for years in order to more accurately reflect (and recover) the fixed costs of
5 providing service. For example, Avista's nearest neighbors in Eastern Washington and
6 North Idaho, Inland Power and Light and Kootenai Electric Cooperative, have a monthly
7 basic charge of \$17.81 and \$16.50 respectively.

8 **Q. Turning now to natural gas, why is the Company proposing to increase**
9 **the Schedule 101 monthly customer charge from \$6.00 to \$10.00 per month?**

10 A. Upon evaluation of the Schedule 101 total customer allocated costs, as shown
11 in Knox Exhibit No. ____ (TLK-6), page 4, line 24, those costs are \$16.21 per customer per
12 month. Included in the fixed costs in the \$16.21 noted above are the cost of the meter and
13 service, and the costs associated with billing and providing customer service, which amounts
14 to \$12.08 per customer per month, as shown in Knox Exhibit No. ____ (TLK-6), page 4 line
15 22.

16 **Q. What is the consequence to a customer of a Basic Charge that is priced**
17 **below the cost of providing customer services to that customer?**

18 A. Because rate design is a "zero sum game", if customer charges are set below
19 the cost of providing those services, then other charges are, by definition, set above their
20 cost of service. For residential gas and electric customers, the only other charge is the
21 volumetric charge. When volumetric rates are increased above their cost of service to
22 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 In summary, setting the basic charge at a rate substantially less than an amount that covers
9 annual customer costs can result in rates that are not equitable and are unnecessarily
10 variable.

11 **Q. But won't increasing the Basic Charge send the wrong price signal**
12 **through the energy rates?**

13 A. No. Conservation of electricity and natural gas is important for customers
14 and for the Company, and one might argue that a lower basic charge results in higher
15 commodity prices and a stronger price signal related to volume usage. However, sending a
16 price signal to customers through a residential rate design that contains a three tier
17 increasing block rate for electric (natural gas has just one volumetric rate) was developed for
18 just such a reason. The more electricity that is used, the higher the rate, and therefore the
19 higher the overall customer bill. The important distinction in this filing is that the Company
20 is not requesting to decrease the energy rates. As such, the volumetric pricing components
21 will still send a very clear price signal to conserve.

22 **Q. Do you have any additional comments related to "price signals"?**

1 Table 10 below details the analysis for natural gas customers:

2 **Table 10**

3 **Avista - Bill Impacts for Low, Medium and High Natural Gas Customers**

4	Current	Equal	Avista	Difference		
5	Billed Rate	Percentage	Proposed	Equal % vs.	Percent.	
6	Monthly Bill Impact			Proposed	Difference	
7	50 therms/mo Customer	\$46.85	\$50.06	\$51.01	\$0.95	1.9%
8	68 therms/mo Customer	\$61.55	\$65.77	\$65.78	\$0.01	0.0%
9	80 therms/mo Customer	\$71.35	\$76.25	\$75.62	-\$0.63	-0.8%

10 As you can see, the impact of the Company's proposed change to the basic charge varies
 11 based on monthly consumption. For an electric customer who uses less than the average
 12 989 kWh's and/or 68 therms per month, the percentage impact will be slightly higher than
 13 for those customers who use more than the average. We believe the improvement in
 14 matching customer payment of fixed costs with the fixed costs to serve customers, together
 15 with removing part of the inequity among customers on the amount of fixed costs paid,
 16 warrants this relatively small bill impact.

17 Table 11 below shows a comparison of monthly bills for an electric customer with
 18 average usage for a 12-month period. It shows the difference in the monthly bills with a
 19 uniform percentage increase to the basic charge and a uniform cent increase to the
 20 volumetric rates, versus the Company's proposal. The table illustrates the reduction in
 21 payment of fixed costs in the winter months, and increased payment in the summer, with the
 net result being improved alignment of payment of fixed costs by customers with the fixed
 costs to serve customers, with no significant annual difference in overall payment.

1 **Table 11**

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<u>Monthly Bills of an Average Electric Customer</u>				
Month	kWh's	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	1,356	\$119.27	\$117.98	(\$1.29)
February	1,204	\$105.18	\$104.43	(\$0.75)
March	1,137	\$99.32	\$98.80	(\$0.52)
April	851	\$74.27	\$74.76	\$0.48
May	817	\$71.30	\$71.90	\$0.60
June	758	\$66.13	\$66.94	\$0.81
July	817	\$71.30	\$71.90	\$0.60
August	861	\$75.15	\$75.60	\$0.45
September	727	\$63.42	\$64.33	\$0.92
October	822	\$71.73	\$72.32	\$0.58
November	1,083	\$94.59	\$94.26	(\$0.33)
December	1,423	\$126.06	\$124.54	(\$1.52)
	11,856	\$1,037.71	\$1,037.73	\$0.02

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

Table 12

Monthly Bills of an Average Natural Gas Customer				
Month	Therms	Equal Percentage	Avista Proposed	Higher / Lower Bill
January	141	\$129.49	\$125.66	(\$3.83)
February	115	\$106.80	\$104.33	(\$2.47)
March	94	\$88.47	\$87.11	(\$1.36)
April	66	\$64.03	\$64.14	\$0.11
July	35	\$36.97	\$38.71	\$1.74
August	17	\$21.26	\$23.94	\$2.69
September	15	\$19.51	\$22.30	\$2.79
October	15	\$19.51	\$22.30	\$2.79
November	17	\$21.26	\$23.94	\$2.69
October	50	\$50.06	\$51.01	\$0.95
November	106	\$98.94	\$96.95	(\$1.99)
December	146	\$133.85	\$129.76	(\$4.10)
	817	\$790.15	\$790.16	\$0.01

Q. Has the Commission recently commented on what they believe an appropriate basic charge should be?

A. Yes. In 2007, in Puget Sound Energy Dockets UE-060266 and UG-060267 (consolidated), the Commission approved a \$8.25 natural gas basic charge (subsequently increased to \$10) and stated:

This will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.⁷

Avista's proposed \$10 basic charge is approximately 15% of the proposed average bill for natural gas customers and 12% for electric customers. I believe this is well within the range of reasonableness, especially when viewed as a percentage of base rates.

⁷ Puget Sound Energy Dockets UE-060266 and UG-060267, Order No. 08, ¶139.

1 **Q. Please discuss your view of the impacts of this request on your limited**
2 **income customers.**

3 A. There are two different implications of the Company's proposal. The first
4 implication is for limited income electric customers, many whom would benefit from the
5 Company's proposal. Traditional thinking might lead one to believe that a limited income
6 electric customer would tend to be a low user of electricity. Although the Company has not
7 conducted a demographic survey of its customers in recent years, the limited data that we do
8 have would suggest that just the opposite is true.

9 A majority of our customers have natural gas for space and water heating, and
10 therefore may have low average electric usage during the winter. However, many limited
11 income customers, I believe, tend to still use electricity for space and water heating. These
12 customers, in my view, tend to live in apartments (which in Avista's service territory
13 predominantly have electric space and water heat), live in areas where natural gas is not
14 available, or live in areas with natural gas, but cannot afford to convert. These limited
15 income customers, with electric space and water heat, can have electric usage in the tail-
16 block (above 1,300 kWh's) during the winter months. Having a lower basic charge and
17 higher tail-block rate penalizes these customers, as these customers are more susceptible to
18 use in the tail-block. A higher basic charge, on the other hand, would result in lower
19 volumetric rates (than would otherwise be the case), providing some relief to these high use
20 customers during the winter months.

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

22 A. Average-use limited income natural gas customers would tend to pay slightly
23 higher natural gas bills under the Company's proposed rate design (i.e., \$10 basic charge)

1 than if the basic charge and volumetric rate were increased by a uniform or equal
 2 percentage. Data gathered as part of the review of the Company’s Natural Gas Decoupling
 3 Mechanism showed that limited income natural gas customers tend to use slightly less
 4 natural gas (58 therms per month⁸) than the traditional residential customer (68 therms per
 5 month). As shown in Table 13 below, while there is an impact, it is relatively small both on
 6 a dollar and percentage basis (between 0.1% and 0.9%).

7 **Table 13**

8

Avista - Residential/Limited Income Natural Gas Customer Impact					
	Current Rates	Equal Percentage	Avista Proposed	Difference Equal % vs. Proposed	Percent. Difference
Customer Charge	\$6.00	\$6.42	\$10.00	\$3.58	
Billing Rate	\$0.81690	\$0.87284	\$0.82027	-\$0.05257	
Monthly Bill Impact					
58 Therm/mo Customer	\$53.38	\$57.04	\$57.58	\$0.53	0.9%
68 Therm/mo Customer	\$60.73	\$64.90	\$64.96	\$0.06	0.1%

14

15 **VI. DSM COMPONENT OF THE ATTRITION ADJUSTMENT**

16 **Q. Would you briefly describe the Company's DSM Component of the**
 17 **Attrition Adjustment?**

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

⁸ Avista Docket UG-060518, “Evaluation of Avista Gas Decoupling Mechanism Pilot”, p.81, Table K10.

1 **Q. How did you go about quantifying this component of attrition?**

2 A. As I will describe in further detail later in my testimony, the Company
3 calculated the DSM Component of the Attrition Adjustment using the electric DSM savings
4 for 2011 through 2013. This is consistent with Company witness Mr. Lowry's attrition
5 analysis which covered the 2011 historical test year through the 2013 proforma period.

6 As Mr. Norwood explains in his testimony, in a general rate case we begin with
7 historical test period kWh sales (2011), and then assume that all of those historical retail
8 sales, and revenues, continue into the future rate year. We know with certainty, however,
9 that part of the revenue will not occur, because customers have taken steps to use less energy
10 as the Company is required by law to achieve a certain level of electric energy efficiency
11 savings. This is a known change in revenues following the test year (2011), and if that
12 reduction is not reflected in the ratemaking process, then the Company will face earnings
13 attrition. In essence, without an adjustment to reflect these required savings, you start from
14 “day one,” after new rates are set, knowing that you will not receive the amount of revenue
15 the rates were designed to recover because the kWh sales to existing customers following
16 the test year will be less than they otherwise would have been.

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

18 A. Effective January 1, 2010, the Company was mandated to obtain a certain
19 level of electric energy efficiency savings pursuant to RCW Chapter 19.285, the Energy
20 Independence Act. Under this act, Avista is required to “identify its achievable cost-
21 effective conservation potential through 2019”, and beginning in January 2010, “establish
22 and make publicly available a biennial acquisition target for cost-effective conservation

1 consistent with its identification of achievable opportunities ... and meet that target during
2 the subsequent two-year period”. (RCW Chapter 19.285)

3 **Q. What are the Company’s planned electric energy efficiency savings for**
4 **the period 2011 through 2013?**

5 A. On January 29, 2010, the Company filed with the UTC its first “Ten-year
6 Achievable Conservation Potential and Biennial Conservation Target Report” (Docket UE-
7 100167) which included the Company’s first two-year (2010 – 2011) biennial electric
8 conservation target. On April 16, 2010, “Avista identified a ten-year conservation potential
9 of 873,302 megawatt-hours and a biennial 2010-11 conservation target of 128,603
10 megawatt-hours. On May 13, 2010, the UTC approved Avista’s biennial conservation target
11 as filed on April 16, 2010. Given that the level of savings in 2010 was 52,769 megawatt-
12 hours, the target for 2011 was 75,834 megawatt hours. However, rather than using the
13 estimated 2011 savings for purposes of the DSM Component of the Attrition Adjustment,
14 the Company used the actual, unverified 2011 savings of 79,800 megawatt-hours.

15 On November 1, 2011, the Company filed with the UTC the “2012-2013 Biennial
16 Conservation Plan of Avista Corporation” (Docket UE-111882) which included the
17 Company’s second, two-year biennial electric conservation target. In that report, “Avista
18 identified a ten-year conservation potential in the range of 529,114 to 1,079,345 megawatt-
19 hours and a biennial 2012-13 end-use efficiency target between 76,202 megawatt-hours to
20 137,410 megawatt-hours⁹. Note that the 2012-13 savings targets do not include savings from
21 distribution efficiency nor do they include savings from space and water heat fuel
22 conversions.

⁹ Avista Docket UE-111882, “2012-2013 Biennial Conservation Plan of Avista Corporation”, p. 3.

1 **Q. Can you please provide further details regarding the range of savings for**
2 **2012-2013?**

3 A. Yes. As detailed in the Company’s filing in Docket UE-111882, the
4 Company discussed that a Conservation Potential Assessment (CPA) was completed as a
5 part of Avista’s 2011 electric Integrated Resource Plan. Within the Company’s CPA, two
6 types of achievable conservation potential were established – Realistic Acquirable Potential
7 (“RAP”) and Maximum Acquirable Potential (“MAP”). As shown in the Company’s filing
8 in that docket¹⁰, the RAP for 2012-2013 (excluding distribution efficiency and fuel
9 conversions) is 76,202 megawatt hours. The MAP for 2012-2013, also excluding
10 distribution efficiency and fuel conversions, is 137,410 megawatt hours. For purposes of
11 the DSM Component of the Attrition Adjustment, Avista chose to use the RAP, or lower
12 savings target for 2012-2013.

13 **Q. For the DSM Component of the Attrition Adjustment, the Company is**
14 **using the RAP for 2012-2013 conservation savings. Is the savings target of 76,202**
15 **megawatt hours over the two-year period symmetrical?**

16 A. No, the savings for 2012 will be slightly lower than the savings for 2013. As
17 detailed in the Company’s filing in Docket UE-111882, Avista plans to obtain 34,041
18 megawatt-hours of savings in 2012, and plans to obtain 42,161 megawatt-hours in 2013.¹¹

19 **Q. How is the DSM Component of the Attrition Adjustment calculated?**

20 A. The first step in the calculation of the DSM Component of the Attrition
21 Adjustment is to determine the level of electric energy efficiency savings from the

¹⁰ Id. at 12.

¹¹ Id.

1 Company's DSM programs. In 2011, customers who took part in the Company's DSM
2 programs saved 79,799,610 kWhs. Table 14 below shows the savings by rate schedule:

3 **Table 14 – 2011 Electric Energy Savings by Rate Schedule**

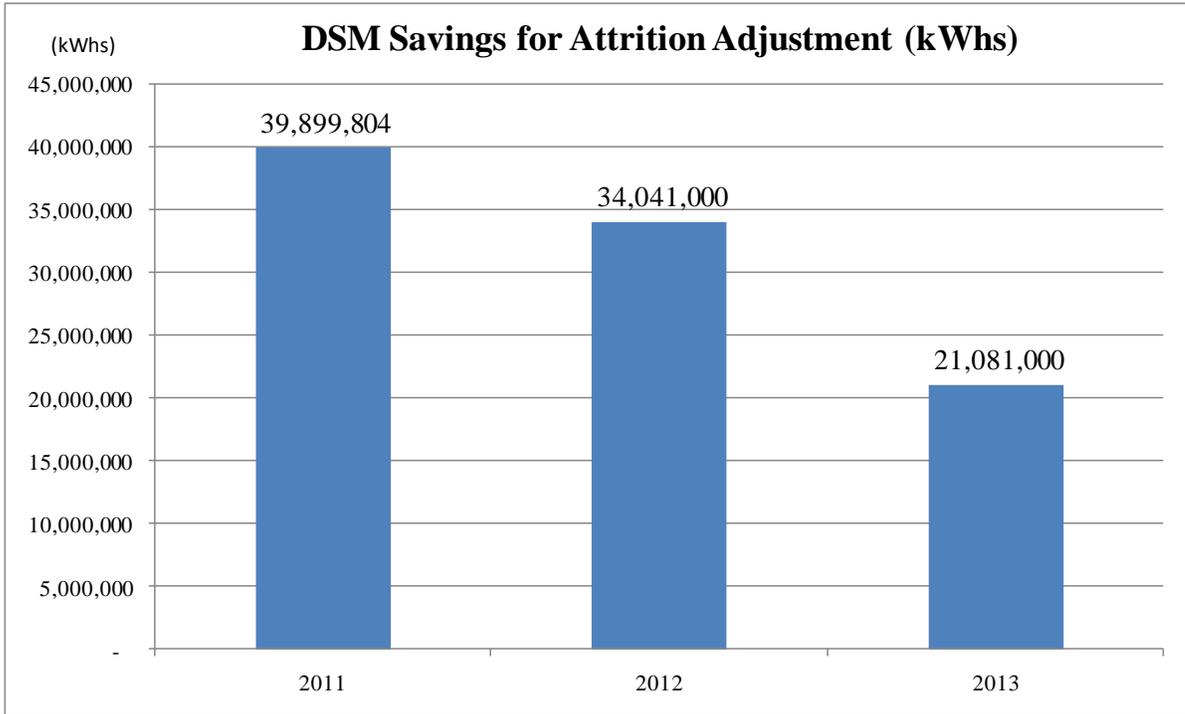
<u>Rate Schedule</u>	<u>2011 Savings (kWhs)</u>
Schedule 1	45,774,436
Schedule 11	4,699,300
Schedule 21	22,520,880
Schedule 25	4,162,173
Schedule 31	2,642,821
	79,799,610

4
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8
9 Because customers installed energy efficiency measures throughout 2011,
10 approximately one-half of the annual savings were already included in the normalized test
11 year usage. Therefore, for the first year, 39,899,804 kWh's were not already included in the
12 normalized test year usage. The lost margin for the approximately one-half of the annual
13 savings not included in the normalized test year usage is included in the DSM Component of
14 the Attrition Adjustment.

15 **Q. How were 2011, 2012 and 2013 electric energy efficiency targets**
16 **determined?**

17 A. As discussed earlier, the Company's electric energy efficiency targets are
18 based on Avista's Ten-Year Achievable Conservation Potential and Biennial Conservation
19 Targets. The targets for 2010-2011 were filed with the Commission in Docket UE-100176,
20 and were later approved in Order No. 01 on May 13, 2010. The targets for 2012-2013 were
21 filed with the Commission in Docket UE-111882, and were later approved in Order No. 01
22 on February 10, 2012. Illustration 1 below is a chart showing the savings included in the
23 DSM Component of the Attrition Adjustment by year:

1 **Illustration No. 1**



12

13 **Q. How were 2012 and 2013 electric energy efficiency savings spread by**

14 **rate schedule?**

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

16 used the same percentage spread as was achieved in 2011, with one major exception.

17 During 2011, Avista conducted a Compact Fluorescent Lighting Program whereby eight

18 compact fluorescent light bulbs were distributed to all Avista residential and small

19 commercial electric customers. Because that was a one-time, non-recurring program, the

20 estimated program savings of 27.3 million kWhs claimed in 2011 were deducted from total

21 year savings in order to normalize annual kWh savings¹². Table 15 below shows the revised

¹² Of the 27.3 million kWhs saved, 5.2% came from Schedule 11 customers and 94.8% came from Schedule 1 customers. See Ehrbar electronic workpapers for calculation.

1 2011 kWh savings used for purposes of developing a revised savings percentage spread
 2 which will be applied to the 2012 and 2013 savings:

3 **Table 15 – 2011 Full Year Savings, Less CFL Program, for Derivation of Normalized**
 4 **Savings by Rate Schedule**
 5

<u>Rate Schedule</u>	<u>2011 Savings (kWhs)</u>	<u>% of Total Savings</u>
Schedule 1	19,894,036	37.9%
Schedule 11	3,279,700	6.3%
Schedule 21	22,520,880	42.9%
Schedule 25	4,162,173	7.9%
Schedule 31	2,642,821	5.0%
	52,499,610	100%

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 7
 8
 9
 10
 11 **Q. Is the use of 2011 results by rate schedule appropriate for purposes of**
 12 **allocating 2012 and 2013 estimated savings?**

13 A. Yes, with the exception noted above relating to the 2011 Compact
 14 Fluorescent Lighting Program. The Company continues to have similar energy efficiency
 15 programs in place, as it had in 2011, and does not have plans to significantly alter the mix of
 16 electric energy efficiency programs as it relates to residential and commercial/industrial
 17 customers. Therefore, the adjusted 2011 actual results provide a reasonable basis upon
 18 which to spread the 2012 and 2013 energy savings.

19 **Q. What are the final DSM kWh savings used in the DSM Component of**
 20 **the Attrition Adjustment?**

21 A. Table 16 below shows the kWh savings by year and by rate schedule (using
 22 the revised 2011 rate schedule spread) which were used in the DSM Component of the
 23 Attrition Adjustment:
 24

Table 16 – Load Adjustment Electric Energy Savings by Rate Schedule

<u>Rate Schedule</u>	<u>2011 kWh Savings (1/2 of Year)</u>	<u>2012 kWh Savings (Full Year)</u>	<u>2013 kWh Savings (1/2 of Total)</u>
Schedule 1	22,887,218	12,901,539	7,989,699
Schedule 11	2,349,650	2,144,583	1,328,103
Schedule 21	11,260,440	14,603,589	9,043,749
Schedule 25	2,081,086	2,689,239	1,665,399
Schedule 31	1,321,410	1,702,050	1,054,050
	39,899,804	34,041,000	21,081,000

Q. Please continue with your discussion of how the DSM Component of the Attrition Adjustment was calculated?

A. Having calculated the reduction in energy (kWh) by rate schedule, the Company then developed the “Revenue Change” as noted on line 8 on Page 1 of Exhibit No.____(PDE-8). As noted in that exhibit, the Company developed an “Average Revenue per kWh”. In order to calculate Average Revenue per kWh, total present revenues by rate schedule, excluding fixed charge revenues, are divided by the pro forma kWhs. The result of the calculation is the Average Revenue per kWh. That rate multiplied by the kWh reduction by rate schedule as shown in Table 18 above, results in the lost revenue by rate schedule (see “Revenue Change” on line 8 on Page 1 of Exhibit No.____(PDE-8)).

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

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

1 **Q. Did the Company include a corresponding power supply cost savings**
2 **reduction in its DSM Component of the Attrition Adjustment?**

3 A. Yes, it did. The Power Cost Savings is shown on line 9 on Page 1 of Exhibit
4 No. ____ (PDE-8).

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

7 A. The appropriate power price to use for the change in power supply cost
8 during the pro forma period due to a decrease in retail load is the average cost of spot market
9 sales and purchases included in the pro forma power supply expense. Any decrease in load
10 will result in decreased spot market purchases and/or increased spot market sales. This price
11 is represented by the average sale and purchase price of \$31.50/MWh¹³ as determined by the
12 AURORA model for the pro forma period.

13 **Q. Can you please summarize the calculation of the DSM Component of the**
14 **Attrition Adjustment?**

15 A. Yes, I can. The DSM Component of the Attrition Adjustment calculation
16 takes the “Revenue Change” on line 8 on Page 1 of Exhibit No. ____ (PDE-8) and subtracts
17 from that “Power Cost Savings” (line 9) as well as Revenue Related Expenses (line 10).
18 The result is shown on line 11, “DSM Component of the Attrition Adjustment” by rate
19 schedule. The final result of this component is a \$3,977,271 increase in net expense (line 11
20 on Page 1 of Exhibit No. ____ (PDE-8)) and was given to Company witness Ms. Andrews for
21 incorporation into the Company’s revenue requirement model.

¹³ Johnson Exhibit No. ____ (WGJ-4). See annual “Average Market Sale and Purchase Price per MWh”.

1 **Q. Does the Company have the necessary funding to obtain the mandated**
2 **conservation targets?**

3 A. Yes, it does. On April 29, 2011, pursuant to Order No. 1 in UE-100176,
4 Avista filed its annual report (Docket UG-110790) related to, among other things, the
5 required funding levels needed for the twelve-month period starting July 1, 2011. In that
6 filing the Company demonstrated that the current level of dedicated funding for electric
7 energy efficiency measures was sufficient, and that there was no need to adjust up or down
8 the current Schedule 91 tariff rider. As stated in the Company's filing at page 4:

9 However, no changes are proposed to Schedule 91 at this time due to expected
10 program expenditures over the next twelve months projected to meet goals
11 associated with the conservation portion of "I-937", also known as WAC 480-109,
12 "Acquisition of minimum quantities of conservation and renewable energy as
13 required by the Energy Independence Act (Chapter 19.285 RCW)."

14
15 **Q. Does the Company have the programs in place in order to meet its**
16 **conservation targets?**

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

24 **Q. What happens if the Company does not meet its targets under the**
25 **Energy Independence Act (EIA)?**

1 (PPA), or purchased on the open market. The separate PPA used to source the majority of this
2 program includes RECs that accompany generation totals from 35MW of wind at the Stateline
3 energy center. The total program RECs are from wind power and other “Green-e Certified”
4 resources such as biomass, geothermal and non-Avista low-impact certified hydro to source the
5 program.

6 **Q. Was there an issue related to the accounting for the Buck-a-Block**
7 **Program that was addressed in the Company’s previous general rate case?**

8 A. Yes. Order No. 07 in Docket UE-100468 required the Company to account
9 for all Buck-a-Block program costs separate from utility operations. As demonstrated in
10 Docket UE-110876, the Company has complied with that requirement.

11 **Q. Please discuss recent changes to the Buck-a-Block program.**

12 A. As noted in Schedule 95, renewable power and associated renewable energy
13 certificates shall be primarily from wind power...but may also come from other certified
14 resources. The Company recently installed at its Rathdrum Clean Energy Test site a 15 kW
15 solar installation, with the cost and benefits of this generating facility being borne by those
16 customers who voluntarily opt to participate in Schedule 95. While the Company will
17 purchase the electrical energy from this facility under PURPA rates, the balance of project
18 annual capital recovery and expenses, including the environmental attributes or RECs, will
19 be funded through Buck-a-Block contributions. This ensures that the costs associated with
20 this resource dedicated to the Buck-a-Block program are not subsidized by other customers.

VIII. SCHEDULE 93 ERM REBATE

Q. Please explain the Company's Schedule 93 ERM Rebate proposal that would go into effect when the general rate increase is implemented.

A. The Company proposes that the ERM deferral balance of \$13,556,306 as of December 31, 2011, be rebated to customers, over a 12 month period, at the time the general rate increase is implemented¹⁵. Table 17 below shows the proposed ERM Rebate by Schedule.

Table 17 – ERM Rebate by Schedule

<u>Rate Schedule</u>	<u>Schedule 93 ERM Rebate (\$000)</u>	<u>Schedule 93 ERM Rebate Billed %</u>
Residential Schedule 1	\$5,912	2.9%
General Service Schedule 11	\$1,654	2.9%
Large General Service Schedule 21	\$3,780	2.9%
Extra Large General Service Schedule 25	\$1,733	2.9%
Pumping Service Schedule 31	\$281	2.9%
Street & Area Lights Schedules	<u>\$196</u>	<u>2.9%</u>
Overall	\$13,556	2.9%

Q. What was the basis for the proposed rate spread of the ERM Rebate balance?

A. Using the Settlement Stipulation approved in the Fifth Supplemental Order in Docket No. UE-011595 as a guide, the Company spread the rebate balance to the various rate schedules on a uniform percentage basis¹⁶. Within each rate schedule, the rate adjustment was applied to the energy charges on a uniform cents per kWh basis using the test year normalized kilowatt-hours.

¹⁵ Includes gross up for revenue related expenses. Actual balance as of 12/31/2011 is \$12,947,628.

¹⁶ Avista Docket UE-011595, Fifth Supplemental Order (June 18, 2002), Settlement Stipulation, p. 8.

1 **Q. Did the Company deviate from the Settlement Stipulation approved in**
2 **Supplemental Order No. 5 in Docket UE-011595 as it relates to the rate spread of the**
3 **proposed ERM Rebate?**

4 A. Yes, in one instance. In the Settlement Stipulation referred to above, any
5 ERM rebate was to be spread to street and area light rates on a uniform percentage basis.
6 The Company believes that spreading a rebate balance that was created, in part, by
7 reductions in the cost to purchase and generate electrical energy should not be used to
8 reduce non-energy costs. Take for instance the rates for street lights detailed on Schedule
9 42. Those rates are made up of three components – capital recovery for the light/pole,
10 maintenance, and energy. If the Company were to spread the ERM Rebate on a uniform
11 percentage basis, then that rebate would reduce all three components, not just the energy
12 component.

13 By way of a simplified example, there are two lights on Schedule 42 that both have
14 100 watt bulbs which operate from dusk until dawn. One light is served overhead (code
15 431), and based on current base rates, is charged \$13.12 per month. The other light is served
16 via underground (code 433) and, based on current base rates, is charged \$23.26 per month.
17 The difference in the monthly cost is due primarily to the difference in capital costs. While
18 the energy usage for these lights is the same, if the ERM Rebate is spread on a uniform
19 percentage basis, the light served overhead would receive a rebate of approximately \$0.38
20 per month while the light served by underground service would receive approximately \$0.67
21 per month.

22 Because of this inequity, the Company proposed to use the implicit energy usage by
23 light for purposes of spreading the ERM Rebate on a uniform cents basis.

1 **Q. When would the proposed rebate go into effect?**

2 A. The Company would file Schedule 93 with its tariff compliance filing at the
3 conclusion of this case to pass through this deferral balance to customers over a 12 month
4 period.

5

6 **IX. SUMMARY OF UE-110876/UG-110877 ORDER No. 06 REQUIREMENTS**

7 **Q. There were several requirements the Commission required of the**
8 **Company to address in this docket based on Order No. 06 (and Settlement Stipulation)**
9 **in Dockets UE-110876 and UG-110877. Would you please provide a summary of those**
10 **items and how they have been addressed by the Company in this rate case?**

11 A. Yes. Detailed below are four items that the Company was required to
12 address based on Order No. 06 in Dockets UE-110876 and UG-110877. Shown below are
13 the requirements, the page number and paragraph where the items are located in the Order,
14 and the witnesses that address the issues in this docket.

15 **Item 1 – Order Page 19, Paragraphs 42-43, addressed by Witness Feltes:**

16 "Accordingly, we order the Company to file with the Commission in this proceeding
17 by February 29, 2012, the following information: A description of current executive
18 compensation, including but not limited to base salary, non-equity incentive pay, and
19 incentive pay. This description should state what elements and amounts are included
20 in rates for the Company and what elements and amounts are not recovered through
21 rates. A description of how levels of executive compensation are set. This
22 description should include discussion of the basis for selecting ostensibly
23 comparable utilities that were surveyed, state what those survey results showed, and
24 explain how the results relate to Avista. Avista is also required to state whether
25 executive compensation paid by any Pacific Northwest investor-owned (e.g., Puget
26 Sound Energy, PacifiCorp, et cetera) or publicly-owned utilities (e.g., Seattle City
27 Light, Tacoma Power, Public Utility District No. 1 of Snohomish County, and the
28 Bonneville Power Administration) were considered and, if not, explain why not. A
29 discussion of Avista's perspective on whether and, if so, why, the existing levels of
30 executive compensation are appropriate for recovery in utility rates. We also
31 require the Company to update this information at the time it files its next general
32 rate case so that the Company's testimony can be evaluated for the prudence of

1 Avista's executive compensation expense both in terms of the levels of
2 compensation and the allocation of its recovery from utility customers."
3

4 **Item 2 – Order Page 8, Paragraphs 17, addressed by Witness Kinney:**

5 Bonneville Power Administration Parallel Operation Agreement – “The Settlement
6 provides that Washington’s share of a certain settlement agreement with the
7 Bonneville Power Administration (BPA), \$767,000, will be reflected in the
8 Company’s transmission revenues over a three-year amortization period.
9 Specifically, the Settlement provides that during the first year, 2012, Avista’s
10 transmission revenues will be increased by \$256,000 to reflect one-third of
11 Washington’s share of the BPA settlement proceeds.”
12

13 **Item 3 – Order Page 9, Paragraphs 18, addressed by Witness Kinney:**

14 Transmission Line Ratings Plan - “The settling parties agree to amortize expenses
15 associated with the Transmission Line Ratings Confirmation Plan (Plan) over a
16 three-year period commencing in 2012. For each of the three years, Avista will
17 amortize approximately \$640,000 and will not apply a carrying charge on the
18 unamortized balance.”
19

20 **Item 4 – Order Page 16, Paragraphs 37, addressed by Witness Andrews:**

21 Deferred Accounting Mechanism for Coyote Springs 2 and Colstrip 3 and 4 - "By
22 providing this limited approval of the mechanism, we caution the parties and,
23 especially Avista, that we will revisit this issue on an expanded basis and in a future
24 proceeding, possibly on an industry-wide basis so that other public utilities affected
25 by the expenses at these units might also participate. If this proceeding has not
26 commenced prior to Avista’s next rate filing, we expect the Company to include a
27 proposal for such a tracker in that initial filing so that we can evaluate whether or not
28 to terminate the provisional mechanism."
29

30 In addition, there are two additional items that the Company committed to as a part
31 of the Settlement Stipulation approved in Order No. 06. Shown below are the requirements,
32 the page number and paragraph where the items are located in the Stipulation, and the
33 witnesses that address the issues in this docket.

34 **Item 1 – Stipulation Page 12, Paragraphs 15, addressed by Witness Andrews:**

35 “Avista agrees to begin separately accounting for all internal and external costs
36 related to preparation, filing, and litigation of Washington general rate cases. The
37 Company will present the overall amount of test year rate case expenses, including
38 but not limited to internal labor costs, administrative and production costs, and costs
39 of outside services, beginning with the 2012 test year.”
40
41

1 **Item 2 – Stipulation Page 12, Paragraphs 15, addressed by Witness Andrews:**

2 “Pursuant to the Commission’s Final Order in Docket UE-100467 and UE-100468,
3 Avista shall perform an annual internal audit for accounting practices in each of the
4 three years following the issuance of that Final Order, and shall prepare a report
5 regarding the results of such audit. The Company shall provide to the Parties the
6 results of its annual audit(s), as well as all internal and external costs associated with
7 performing the audit(s) and preparing the report(s).”
8

9 **Q. Were all the requirements in Order No. 06 and the Settlement**
10 **Stipulation met by the Company prior to filing this general rate case?**

11 A. Yes, all of the items that were required of the Company in Order No. 06 and
12 the Settlement Stipulation were either completed prior to filing this general rate case or are
13 addressed in this docket as required.

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

15 A. Yes it does.