DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-15-05 CASE NO. AVU-G-15-01 DIRECT TESTIMONY OF PATRICK D. EHRBAR

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

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, the development of line extension policy tariffs, as well as addressing miscellaneous regulatory issues. In November 2009, I was promoted to my current role.

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

A. My testimony in this proceeding will cover the spread of the proposed 2016 and 2017 electric and natural gas revenue increases among the Company’s electric and natural gas general service schedules. My testimony will also describe the changes to the rates within the Company’s electric and natural gas service schedules, as well the proposed increase in the basic charge for residential electric rate Schedule 1 and natural gas rate Schedule 101. Finally, I will describe the Company’s request for an electric and natural gas Fixed Cost Adjustment Mechanism.

Q. Would you please provide an overview of the Company’s electric and natural gas rate requests?

A. Yes. As discussed by Company witness Mr. Morris, the Company is proposing a two-year rate plan for calendar years 2016 and 2017, with proposed increases effective January 1 of each year. The Company is proposing a two-year rate plan, to once again, avoid annual rate cases in its Idaho jurisdiction, providing benefits to all stakeholders. A two-year rate plan, with increases in 2016 and 2017, would provide benefits to its customers by providing rate certainty to customers over this two-year period, a two-year window also provides Avista with the opportunity to manage its business in order to achieve a fair rate of return within known price changes; and finally relief is provided to all stakeholders (customers, the Commission and its Staff, intervenors, and the Company) from the administrative burdens and costs of litigation of annual general rate cases.

Accordingly, the Company has filed two sets of tariffs for each of the electric and natural gas service schedules. The first tariff for each rate schedule provides for an effective date of July 3, 2015; however, in the Company's Application in this case, Avista has requested that the tariffs related to the 2016 rate request be suspended for 30 days plus 5 months from the proposed effective date. This was done to ensure that new rates for 2016 would not go into effect prior to January 1, 2016 pursuant to Order 33130. The second set of tariffs filed for each of the electric and natural gas service schedules has an effective date of January 1, 2017, consistent with the Company's second-step increase proposal.

Provided below in Tables A & B is a summary of the proposed increase, by rate schedule, on a billing basis (inclusive of all base and billing rate components, including the effect of the new and expiring rebates discussed later in my testimony):

Table A: 2016 & 2017 Electric Rate Request by Rate Schedule			
Rate Schedule	**Description**	**2016 Billing Increase**	**2017 Billing Increase**
Residential Service	Schedule 1	6.9%	6.7%
General Service	Schedules 11 & 12	3.5%	3.5%
Large General Service	Schedules 21 & 22	4.5%	4.5%
Extra Large General Service	Schedule 25	4.5%	4.5%
Clearwater Paper	Schedule 25P	2.6%	2.7%
Pumping Service	Schedules 31 & 32	5.2%	5.1%
Street & Area Lights	Schedules 41 - 49	6.1%	5.9%
Total		**5.2%**	**5.1%**

Table B: 2016 & 2017 Natural Gas Rate Request by Rate Schedule			
Rate Schedule	**Description**	**2016 Billing Increase**	**2017 Billing Increase**
General Service	Schedule 101	6.5%	2.9%
Large General Service	Schedules 111 & 112	3.5%	1.3%
Interruptible Service	Schedules 131 & 132	5.5%	2.0%
Transportation Service	Schedule 146*	4.5%	5.4%
Total		**5.8%**	**2.5%**
** excludes commodity and interstate pipeline transportation costs*			

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

A. Yes. I am sponsoring Exhibit No. 15, Schedules 1 through 3 related to the proposed electric increase, and Schedules 4 through 6 related to the proposed natural gas increase. I am also sponsoring Schedules 7 and 8 which are related to the Company’s proposed Electric and Natural Gas Fixed Cost Adjustment mechanisms. These exhibits were prepared by me or under my supervision. A table of contents for my testimony is as follows:

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II. PROPOSED ELECTRIC REVENUE INCREASE

Summary of Electric Rate Schedules and Tariffs

Q. Would you please explain what is contained in Schedule 1 of Exhibit No. 15?

A. Yes. Schedule 1 is a copy of the Company's present and proposed electric tariffs for 2016 and 2017, showing the changes (strikeout and underline) proposed in this filing.

Q. Would you please describe what is contained in Schedule 2 of Exhibit No. 15?

A. Yes. Schedule 2 contains the proposed (clean) electric tariff sheets for 2016 and 2017 incorporating the proposed changes included in this filing.

Q. What is contained in Schedule 3 of Exhibit No. 15?

A. Schedule 3 contains information regarding the proposed spread of the electric revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the 2016 and 2017 proposed general revenue and percentage increases by rate schedule compared to the present revenue under base tariff and billing rates. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after application of the proposed 2016 general increase. Pages 3 and 4 show the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the 2016 and 2017 rate changes. These pages will be referred to later in my testimony.

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

A. Yes. The Company presently provides electric service under Residential Service Schedule 1, General Service Schedules 11 and 12, Large General Service Schedules 21 and 22, Extra Large General Service under Schedule 25 and Schedule 25P (Clearwater Paper’s Lewiston Plant), and Pumping Service Schedules 31 and 32. Additionally, the Company provides Street Lighting Service under Schedules 41-46, and Area Lighting Service under Schedules 47-49. Schedules 12, 22, 32, and 48 cover residential and farm service customers who qualify for the Residential Exchange Program operated by the Bonneville Power Administration. The rates for these schedules are identical to the rates for Schedules 11, 21, 31, and 47, respectively, except for the Residential Exchange rate credit.

The following table shows the type and number of customers served in Idaho (as of December 2014) under each of the electric service schedules:

Table No. 1 - Customers by Service Schedule

Rate Schedule	No. of Customers
Residential Schedule 1	103,747
General Service Schedules 11/12	20,669
Large General Service Schedules 21/22	1,156
Extra Large General Service Schedule 25	9
Clearwater Paper Schedule 25P	1
Pumping Service Schedules 31/32	1,406

Proposed Electric Rate Spread

Q. For 2016, what is the proposed electric revenue increase, and how is the Company proposing to spread the increase by rate schedule?

A. For 2016, the proposed electric increase is $13,230,000, or 5.4% over present base tariff rates in effect. The proposed general increase over present billing rates, including all other rate adjustments (such as DSM and Residential Exchange), is 5.2%. The proposed percentage increase by rate schedule is as follows:

Table No. 2 - Proposed % Electric Increase by Schedule - 2016

Rate Schedule	Increase in Base Rates	Increase in Billing Rates
Residential Schedule 1	7.0%	6.9%
General Service Schedules 11/12	3.7%	3.5%
Large General Service Schedules 21/22	4.7%	4.5%
Extra Large General Service Schedule 25	4.8%	4.5%
Clearwater Paper Schedule 25P	2.8%	2.6%
Pumping Service Schedules 31/32	5.5%	5.2%
Street & Area Lights Schedules 41-48	6.3%	6.1%
Overall	**5.4%**	**5.2%**

This information is shown with more detail on page 1 of Exhibit No. 15, Schedule 3.

Q. What is the Company's proposal related to the current rebate customers are receiving in 2015?

A. Through rate Schedule 97, customers are receiving a rebate of $0.00091 per kWh for 2015 (approximately $2.8 million). This rebate rate was first approved in the Company's 2012 general rate case, Case No. AVU-E-12-08.[1] As a part of the settlement stipulation approved by the Commission in Case No. AVU-E-14-05, the rebate rate was extended through December 31, 2015 using the 2013 electric earnings sharing deferral.[2]

For 2014, Avista deferred approximately $5.6 million under the electric earnings sharing.[3] The Company is proposing in this case to use the $5.6 million deferral balance from 2014 and extend the Schedule 97 rebate rate for 2016 and 2017, and has filed tariff sheet Schedule 97 with revised language reflecting the two-year extension.[4]

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[1] This rebate was related to a prior settlement with the Bonneville Power Administration for their prior use of Avista's transmission system, and was rebated to customers between October 1, 2013 and December 31, 2014.

[2] In Case No. AVU-E-12-08/AVU-G-12-07, the settlement stipulation approved by the Commission contained an earnings test. Under the settlement, the Company agreed to an after-the-fact earnings test, where it would share with customers one-half of any earnings in excess of the 9.8% ROE for each of the years 2013 and 2014.

[3] Id.

[4] Consistent with the provisions of Schedule 97, any over- or under-amortization of the $5.6 million would be trued up in a future PCA filed by the Company.

Q. How did the Company spread the total 2016 general revenue increase request of $13,230,000 among its various rate schedules?

A. The Company used the results of the electric cost of service study (sponsored by Ms. Knox) as a guide to spread the general increase. The spread of the proposed increase generally results in the rates of return for the various electric service schedules moving approximately one-quarter closer to the overall rate of return (unity). While we believe it is reasonable and appropriate to use the cost of service study results as the basis for rate spread, we have tempered the amount of movement toward unity proposed in this case due primarily to the impact such movement would have between the rate schedules. The Company may propose additional movement toward unity in future proceedings.

Table No. 3 below shows the relative rates of return before and after application of the proposed general increase:

Table No. 3 - Present & Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR
Residential Schedule 1	0.76	0.82
General Service Schedules 11/12	1.34	1.26
Large General Service Schedules 21/22	1.16	1.12
Extra Large General Service Schedule 25	1.03	1.02
Clearwater Paper Schedule 25P	1.41	1.31
Pumping Service Schedules 31/32	1.09	1.06
Street & Area Lights Schedules	1.01	1.01
Overall	**1.00**	**1.00**

This information is shown in detail on Page 2, Schedule 3 of Exhibit No. 15.

Q. For 2017, what is the proposed electric revenue increase, and how is the Company proposing to spread the increase by rate schedule?

A. For 2017, the proposed electric increase is $13,713,000, or 5.3% over base tariff rates. The proposed general increase over billing rates, including all other rate adjustments (such as DSM and Residential Exchange), is 5.1%. The Company used a pro-rata allocation of the Company's 2016 electric rate spread percentages for purposes of spreading the proposed 2017 electric revenue increase to its electric service schedules. The proposed percentage increase by rate schedule is as follows:

Table No. 4 - Proposed % Electric Increase by Schedule - 2017

Rate Schedule	**Increase in Base Rates**	**Increase in Billing Rates**
Residential Schedule 1	6.8%	6.7%
General Service Schedules 11/12	3.7%	3.5%
Large General Service Schedules 21/22	4.7%	4.5%
Extra Large General Service Schedule 25	4.7%	4.5%
Clearwater Paper Schedule 25P	2.8%	2.7%
Pumping Service Schedules 31/32	5.4%	5.1%
Street & Area Lights Schedules 41-48	6.1%	5.9%
Overall	**5.3%**	**5.1%**

This information is shown with more detail on page 1 of Exhibit No. 15, Schedule 3.

Proposed Rate Design

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

A. Pages 3 (for 2016) and 4 (for 2017) of Schedule 3 in Exhibit No. 15 shows a comparison of the present and proposed rates within each of the schedules, which I will describe below. Column (a) shows the rate/billing components under each of the schedules, column (b) shows the present base tariff rates within each of the schedules, column (c) shows the present rate adjustments applicable under each schedule, and column (d) shows the present billing rates. Column (e) shows the proposed general rate increase to the rate components within each of the schedules, column (f) shows the proposed billing rates and column (g) shows the proposed base tariff rates.

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

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

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

A. Yes. Residential Schedule 1 has a present customer or basic charge of $5.25 per month and two energy rate blocks: 0-600 kWhs and over 600 kWhs. The present base tariff rate for the first 600 kWhs per month is 8.146 cents per kWh and 9.096 cents for all kWhs over 600.

Q. How does the Company propose to spread Schedule 1's proposed 2016 general revenue increase of $7,349,000 to the rates within that schedule?

A. The Company proposes to increase the monthly customer charge from $5.25 per month to $8.50 per month. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 3.4% applied to the two energy block rates. The proposed increase for the first 600 kWhs used per month under the schedule is 0.276 cents per kWh, and an increase of 0.308 cents per kWh for usage over 600 kWhs per month.

Q. Why is the Company proposing to increase the monthly customer charge from $5.25 to $8.50 per month?

A. A substantial portion of the Company's costs are fixed and do not vary with the amount of energy used by customers. As reflected in this filing, the fixed costs of operating and maintaining our electric system are increasing. The Company believes it is important that rates better reflect these increasing costs to serve customers. Later in Section IV of my testimony I will provide greater detail as to why the Company believes the monthly customer charge should increase to $8.50 per month.

Q. How does the Company propose to spread Schedule 1's proposed <u>2017</u> general revenue increase of $7,617,000 to the rates within that schedule?

A. The Company proposes to keep the monthly customer charge at $8.50 per month. The revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 7.5% applied to the two energy block rates. The proposed increase for the first 600 kWhs used per month under the Schedule is 0.630 cents per kWh, and an increase of 0.704 cents per kWh for usage over 600 kWhs per month.

Q. For <u>2016</u>, What is the proposed increase for a residential electric customer with average consumption?

A. The proposed increase for a residential customer using an average of 929 kWhs per month is $5.92 per month, or a 6.9% increase in their electric bill. The present bill for 929 kWhs is $85.24 compared to the proposed level of $91.16, including all rate adjustments.

Q. For <u>2017</u>, What is the proposed increase for a residential electric customer with average consumption?

A. The proposed increase for a residential customer using an average of 929 kWhs per month is $6.10 per month, or a 6.7% increase in their electric bill, resulting in an overall bill of $97.26, including all rate adjustments.

Q. Turning to General Service Schedules 11/12, could you please describe the present rate structure and rates under those schedules?

A. Yes. General Service Schedules 11/12 are the service schedules typically applicable to customers with an average demand of less than 20 kW per month, such as small retail establishments (Schedule 11), or shops for residential customers which requires a separate service (Schedule 12). The present rate structure under the schedules includes a monthly customer charge of $10.00, an energy rate of 9.634 cents per kWh for all usage up to 3,650 kWhs per month, and an energy rate of 7.178 cents per kWh for usage over 3,650 kWhs per month. There is also a demand charge of $5.25 per kW for all demand in excess of 20 kW per month. There is no charge for the first 20 kW of demand.

Q. How is the Company proposing to apply Schedule 11/12's proposed <u>2016</u> general revenue increase of $1,338,000 to the rates within those schedules?

A. The Company is proposing that the customer charge increase by $3.00 per month, from $10.00 to $13.00. The Company is also proposing that the variable demand rate increase from $5.25/kW to $5.50/kW. The remaining revenue increase for those schedules is proposed to be recovered through a 0.203 cent per kWh, or 2.1%, increase to the first energy block (the first 3,650 kWhs used per month). The Company is proposing to leave the second energy block unchanged in order to provide a more meaningful separation between the blocks, and to ensure that the higher load factor customers served on those schedules do not pay a melded rate per kWh that is higher than customers with poor load factors.

Q. How is the Company proposing to apply Schedule 11/12's proposed <u>2017</u> general revenue increase of $1,388,000 to the rates within those schedules?

A. The Company is proposing that the customer charge increase by $3.00 per month, from $13.00 to $16.00. The Company is also proposing that the variable demand rate increase from $5.50/kW to $6.00/kW. The remaining revenue increase for the schedules is proposed to be recovered through a 0.199 cent per kWh, or 1.9%, increase to the first energy block (the first 3,650 kWhs used per month). Similar to 2016, the Company is proposing to leave the second energy block unchanged in order to provide a more meaningful separation between the blocks, and to ensure that the higher load factor customers served on the schedules do not pay a melded rate per kWh that is higher than customers with poor load factors.

Q. Why is the Company proposing to increase the demand charges for Schedules 11, 21, 25 and 25P?

A. The system allocated demand cost from the cost of service study is $17.53 per kilowatt (kW) month.[5] The Company's present monthly demand charges range from $4.50/kVA to $5.25/kW. While the exact level of costs classified as demand-related can be debated, clearly the levels of demand charges will continue to be well below demand-related costs.

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

Q. Turning to Large General Service Schedules 21/22, would you please describe the present rate structure under those schedules and how the Company is proposing to apply Schedule 21/22's 2016 increase of $2,563,000 to the rates

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[5] See Schedule 3 of Exhibit No. 13, p. 3, ln 28.

within the schedules?

A. Yes. Large General Service Schedules 21/22 are the service schedules applicable to customers with monthly demands over 50 kW, but less than 3,000 kW. Typical customers served under Schedule 21 are grocery stores, schools, and office buildings, and retirement homes and other qualified residential load for Schedule 22.

These schedules consist of a minimum monthly charge of $350.00 for the first 50 kW or less, a demand charge of $4.75 per kW for monthly demand in excess of 50 kW, and two energy block rates: 6.297 cents per kWh for the first 250,000 kWhs per month, and 5.373 cents per kWh for all usage in excess of 250,000 kWhs.

The Company is proposing to increase the present minimum demand charge (for the first 50 kW or less) by $25 per month, from $350.00 to $375.00, and increase the demand charge from $4.75/kW to $5.50/kW for reasons previously discussed. The remaining revenue increase for the schedules is proposed to be recovered through a uniform percentage increase of approximately 2.8% applied to the two energy block rates. The proposed increase for the first 250,000 kWhs used per month under the schedules is 0.176 cents per kWh, and an increase of 0.151 cents per kWh for usage over 250,000 kWhs per month.

Q. Would you please describe how the Company is proposing to apply Schedule 21/22's <u>2017</u> increase of $2,654,000 to the rates within the schedule?

A. Yes. The Company is proposing to increase the minimum demand charge (for the first 50 kW or less) by $25 per month, from $375.00 to $400.00, and increase the demand charge from $5.50/kW to $6.00/kW. The remaining revenue increase for the schedules is proposed to be recovered through a uniform percentage increase of approximately 3.7% applied to the two energy block rates. The proposed increase for the first 250,000 kWhs used per month under the schedules is 0.239 cents per kWh, and an increase of 0.204 cents per kWh for usage over 250,000 kWhs per month.

Q. Turning to Extra Large General Service Schedule 25, would you please describe the present rate structure under that schedule, and how the Company is proposing to apply Schedule 25's <u>2016</u> increase of $820,000 to the rates within the schedule?

A. Yes. Schedule 25 is applicable for customers with demands in excess of 3,000 kVa per month, such as large industrial customers and universities. Extra Large General Service Schedule 25 consists of a minimum monthly charge of $12,500 for the first 3,000 kVa or less, a demand charge of $4.50 per kVa for monthly demand in excess of 3,000 kVa, and two energy block rates: 5.212 cents per kWh for the first 500,000 kWhs per month and 4.414 cents per kWh for all usage in excess of 500,000 kWhs.

The Company is proposing that the present minimum demand charge of $12,500 be increased by $1,250 to $13,750 per month. Further, the Company is proposing to increase the volumetric demand charge from $4.50/kVA to $5.50/kVA for reasons discussed earlier in my testimony. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 2.4% applied to the two energy block rates. The proposed energy rate increase for the first 500,000 kWhs used per month is 0.124 cents per kWh and the increase for usage over 500,000 per month is 0.105 cents per kWh.

Q. Would you please describe how the Company is proposing to apply Schedule 25's 2017 increase of $851,000 to the rates within the schedule?

A. Yes. The Company is proposing that the minimum demand charge of $13,750 be increased by $1,250 to $15,000 per month. Further, the Company is proposing to increase the volumetric demand charge from $5.50/kVA to $6.00/kVA. The remaining revenue increase for the schedule is proposed to be recovered through a uniform percentage increase of approximately 3.7% applied to the two energy block rates.

The proposed energy rate increase for the first 500,000 kWhs used per month is 0.197 cents per kWh and the increase for usage over 500,000 per month is 0.167 cents per kWh.

Q. Please describe the service the Company provides to Clearwater Paper's Lewiston Plant under Schedule 25P.

A. Yes. In Commission Order No. 32841, dated June 28, 2013, the Commission approved a five-year Electric Service Agreement (Agreement) between Avista and Clearwater, applicable to its Lewiston Plant. The Agreement became effective July 1, 2013 and expires June 30, 2018.[6] The Agreement provides for Clearwater to use its on-site generation to serve its own load, and for Clearwater to purchase from Avista all of the electric power requirements that exceed the electric power generated by Clearwater. Avista serves Clearwater's load requirements under Schedule 25P.

Q. Please describe the application of the proposed Schedule 25P <u>2016</u> increase of $653,000 to the rates within the schedule.

A. Like Schedule 25, the Company is proposing that the present minimum demand charge of $12,500 be increased by $1,250 to $13,750 per month. Further, the Company is

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[6] On May 13, 2015, Avista and Clearwater filed with the Commission a Joint Petition requesting, among other things, approval of a contract amendment which would extend the length of the Agreement to June 30, 2021 (Case No. AVU-E-15-06).

proposing to increase the volumetric demand charge from $4.50/kVA to $5.50/kVA for all kVA between 3,000 and 55,000 for reasons discussed earlier in my testimony.[7] The remaining revenue increase for the schedule is proposed to be recovered through an increase of 0.003 cents per kWh to the energy charge.

Q. Please describe the application of the proposed Schedule 25P 2017 increase of $678,000 to the rates within the schedule.

A. Like Schedule 25, the Company is proposing that the minimum demand charge of $13,750 be increased by $1,250 to $15,000 per month. Further, the Company is proposing to increase the volumetric demand charge from $5.50/kVA to $6.00/kVA. The remaining revenue increase for the schedule is proposed to be recovered through an increase of 0.074 cents per kWh to the energy charge.

Q. Turning to Pumping Schedules 31/32, would you please describe how the Company is proposing to apply Schedule 31/32's 2016 increase of $288,000 to the rates within the schedules?

A. The Company is proposing that the customer charge of $8.00 per month be increased by $2.00, to $10.00 per month, and that the remaining revenue increase be spread on

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[7] All kVA over 55,000 is priced at $2.00 per the terms of the Electric Service Agreement.

a uniform percentage basis of approximately 4.9% to the two energy rate blocks under the schedules. The proposed increase in the first block rate is 0.460 cents per kWh and the increase in the second block rate is 0.392 cents per kwh.

Q. Please describe how the Company is proposing to apply Schedule 31/32's <u>2017</u> increase of $298,000 to the rates within the schedules.

A. The Company is proposing that the customer charge of $10.00 per month be increased by $2.00, to $12.00 per month, and that the remaining revenue increase be spread on a uniform percentage basis of approximately 4.9% to the two energy rate blocks under the schedules. The proposed increase in the first block rate is 0.478 cents per kWh, and the increase in the second block rate is 0.408 cents per kwh.

Q. How is the Company proposing to spread the proposed <u>2016</u> revenue increase of $219,000 applicable to Street and Area Light (Schedules 41-49)?

A. The Company proposes to increase present street and area light (base) rates on a uniform percentage basis. The proposed increase for all lighting rates is 6.3%. The (base tariff) rates are shown in the tariffs for those schedules, in Exhibit No. 15, Schedule 2.

Q. How is the Company proposing to spread the proposed <u>2017</u> revenue increase of $227,000 applicable to Street and Area Light (Schedules 41-49)?

A. The Company proposes to increase present street and area light (base) rates on a uniform percentage basis. The proposed increase for all lighting rates is 6.1%. The (base tariff) rates are shown in the tariffs for those schedules, in Exhibit No. 15, Schedule 2.

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

A. Yes, it is. For Schedule 42 (Company-owned street lights) and Schedule 47 (Area Lighting), the Company has added additional lighting codes for 100 watt and 200 watt LED equivalent lights. These rates will be applicable for those lights converted to LED technology.

Second, for Schedule 42, the Company is proposing a methodology for calculating new Street Light rates for customer-requested lighting that occurs in-between general rate cases. On occasion customers may request that the Company install a particular type of street light; however, that street light may be different than the lights included in the tariff. The Company is proposing to use the methodology summarized below, and described more fully in Schedule 42, to update new lighting standards outside of the context of a general rate case.[8]

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

A. The basic methodology for calculating any new rate for Schedule 42 is to determine the capital, maintenance, and energy components to develop a monthly rate. For the capital component, an engineering estimate of the installed cost for a new Street Light component would be multiplied by a Capital Recovery Factor[9] to determine the annual revenue requirement.

Illustration No. 1 below shows an example of the annual and monthly rate calculation methodology:

Illustration No. 1 – Calculation of Monthly Capital Recovery

	Example 100 Watt Light
Luminaire & Lamp	$500.00
Electrical Service	$117.00
Total	$617.00
Multiply by Capital Recovery Factor	13.622%
Annual Capital Recovery	$84.05
Monthly Capital Recovery	$7.00

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

[9] The Capital Recovery Factor is derived by adding together the Company's 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.

The <u>maintenance component</u> for a similar existing light embedded in present rates today would be used for purposes of the custom rate calculation.[10] For the <u>energy component</u>, the energy rate for a similar wattage light under Schedule 46 would be used. The energy component of any new light offering will be derived in the same manner as described in the changes to Schedule 46 below. Any new rates developed would be included in the tariffs filed in the Company's next rate case filing.

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

A. First, the Company is proposing to cancel Schedule 43, "Customer Owned Street Light Energy & Maintenance Service". This schedule was closed to new customers effective November 24, 1981, and only customers served on that schedule could continue to take service. As of May 2015, there are no customers taking service under the schedule.

Next, under Schedule 44, the Company provides energy and O&M services to <u>customer-owned</u> street lights. Customer-owned lights are governed, electrically, by the National

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[10] The maintenance component for an <u>existing</u> 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 <u>new</u> 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.

Electric Code ("NEC"). Utility-owned property, however, is governed by the National Electric Safety Code ("NESC"). While the Company traditionally works on customer-owned street lights, adoption of the NESC 2012 Edition has created a conflict between the Company's tariff and the NESC. Specifically, Section 1.011.A.2 states that street lights maintained by a utility must be under the exclusive control of the utility, i.e., Company-owned lights. Under Schedule 44, Avista provides maintenance on customer-owned lights, thus creating the conflict between the schedule and the rule. Closing the schedule to new customers will help to resolve this conflict. The Company is proposing to close Schedule 44 to new customers effective January 1, 2016, with existing customers being allowed to continue to take service.

For Schedule 46 (Customer-Owned Street Light Energy Service), the Company is proposing to modify its tariff to reflect a new prescriptive energy rate calculation for lights where an existing code does not exist. The rate would be determined using the following formula:

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

The wattage of the street light would be provided by the Customer and verified by the Company. As for the hours of operation, the Company is basing that on dusk-to-dawn service (4,380 annual hours, or 365 hours per month). Finally, the energy rate was determined by dividing the final revenue requirement for Schedule 46 by total kWh usage for Schedule 46 included in the final approved billing determinants.

III. PROPOSED NATURAL GAS REVENUE INCREASE

Q. Would you please explain what is contained in Schedule 4 of Exhibit No. 15?

A. Yes. Schedule 4 of Exhibit No. 15 is a copy of the Company's present and proposed natural gas tariffs for 2016 and 2017, showing the changes (strikeout and underline) proposed in this filing.

Q. Would you please describe what is contained in Schedule 5 of Exhibit No. 15?

A. Schedule 5 of Exhibit No. 15 contains the proposed (clean) natural gas tariff sheets for 2016 and 2017 incorporating the proposed changes included in this filing.

Q. Would you please explain what is contained in Schedule 6 of Exhibit No. 15?

A. Schedule 6 of Exhibit No. 15 contains information regarding the proposed spread of the natural gas revenue increase among the service schedules and the proposed changes to the rates within the schedules. Page 1 shows the proposed general revenue and percentage increase by rate schedule. Page 2 shows the rates of return and the relative rates of return for each of the schedules before and after the proposed 2016 increase. Pages 3 and 4 show the present rates under each of the rate schedules, the proposed changes to the rates within the schedules, and the proposed rates after application of the 2016 and 2017 rate changes. These pages will be referred to later in my testimony.

Summary of Natural Gas Rate Schedules and Tariffs

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

A. Yes. The Company's present Schedules 101 and 111 offer firm sales service. Schedule 101 generally applies to residential and small commercial customers who use less than 200 therms/month. Schedule 111 is generally for customers who consistently use over 200 therms/month and Schedule 131 provides interruptible sales service to customers whose annual requirements exceed 250,000 therms. Schedule 146 provides transportation/distribution service for customer-owned natural gas for customers whose annual requirements exceed 250,000 therms.

Q. The Company also has rate Schedules 112 and 132 on file with the Commission. Would you please explain which customers are eligible for service under these schedules?

A. Yes. Schedules 112 and 132 are in place to provide service to customers who at one time were provided service under Transportation Service Schedule 146. The rates under these schedules are the same as those under Schedules 111 and 131 respectively, except for the application of Temporary Gas Rate Adjustment Schedule 155. Schedule 155 is a temporary rate adjustment used to amortize the deferred natural gas costs approved by the Commission in the prior Purchased Gas Cost Adjustment ("PGA") filing. Because of their size, transportation service customers are analyzed individually to determine their appropriate share of deferred natural gas costs. If those customers switch back to sales service, the Company continues to analyze those customers individually; otherwise, those customers would receive natural gas costs deferrals which are not due them, thus the need for Schedules 112 and 132. There are only six customers served under these schedules as of December 31, 2014.

Q. How many customers does the Company serve under each of its natural gas rate schedules in Idaho?

A. As of December 31, 2014, the Company provided service to the following number of customers under each of its schedules in Idaho:

Table No. 5 - Customers by Service Schedule

Rate Schedule	No. of Customers
General Service Schedule 101	76,642
Large General Service Schedules 111/112	1,411
Interruptible Sales Service Schedules 131/132	1
Transportation Service Schedule 146	5

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

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

Proposed Rate Spread

Q. For 2016, what is the proposed natural gas revenue increase, and how is the Company proposing to spread the increases by rate schedule?

A. For 2016, the proposed base revenue increase is $3,205,000, or 8.8% in base margin[11] revenue (on a billed revenue basis, the increase is 4.5%). In addition, effective January 1, 2016, a rebate of approximately $1.2

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[11] Base margin revenue refers to the base revenue associated with the Company's ownership and operation of its natural gas distribution operations. It is the revenue related to delivering natural gas to customers, and does not include the cost of natural gas, upstream third-party owned transportation, or the effect of other tariffs.

million that is being credited to customers in 2015 will expire. The Company is proposing to replace a portion of that rebate, approximately $0.2 million, in 2016 to partially offset the expiring rebate.

Q. What is the Company's proposal related to the current natural gas rebate customers are receiving in 2015?

A. Through rate Schedule 197, customers are receiving a rebate of $0.01489 per therm through December 31, 2015 (approximately $1.2 million). This rebate rate was first approved in the Company's 2012 general rate case, Case No. AVU-G-12-07.[12] As a part of the settlement stipulation approved by the Commission in Case No. AVU-G-14-01, the rebate rate was extended for 2015 using the 2013 electric earnings sharing deferral.[13] For 2014, Avista deferred approximately $0.2 million under the natural gas earnings sharing. The Company is proposing to use the $0.2 million natural gas deferral balance from 2014 to partially offset the expiration of the $1.2 million rebate that will occur on January 1, 2016.[14] Effective January 1, 2017, the rebate

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[12] This rebate was related to certain deferral balances from the 2012 Purchased Gas Cost Adjustment that were rebated to customers between October 1, 2013 and December 31, 2014.

[13] In Case No. AVU-E-12-08/AVU-G-12-07, the settlement stipulation approved by the Commission contained an earnings test. Under the settlement, the Company agreed to an after-the-fact earnings test, where it would share with customers one-half of any earnings in excess of the 9.8% ROE for each of the years 2013 and 2014.

[14] Consistent with the provisions of Schedule 197, any over or under amortization of the $0.2 million would be trued up in a future PGA filed by the Company.

rate will be set at $0.00000 per therm, resulting in a $0.2 million increase for customers.

Q. What is the overall revenue effect when you combine the general rate request and the effect of the new and expiring rebates?

A. All together, the net effect of the 2016 base rate increase coupled with the net effect of new and expiring tariffs is a billing rate increase of 5.8%. Provided below is a table showing the effect of the Company's proposed natural gas increase by rate schedule, including the effects of the new and expiring rebate:

Table No. 6 - Proposed % Natural Gas Increase by Schedule - 2016

Rate Schedule	**Increase in Margin Rates**	**Increase in Billing Rates**	**Billing Increase Net of New & Expiring Rebate**
General Service Schedule 101	9.8%	5.3%	6.5%
Large General Service Schedules 111/112	4.8%	1.9%	3.5%
Interrupt. Sales Service Schedules 131/132	9.6%	3.4%	5.5%
Transportation Service Schedule 146*	6.6%	6.6%	4.5%
Overall	**8.8%**	**4.5%**	**5.8%**

** excludes commodity and interstate pipeline transportation costs*

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

A. No. The proposed billing percentage increase for Transportation Schedule 146 is not comparable to the proposed increases for the other (sales) service schedules, as Schedule 146 revenue does not include an amount for the cost of natural gas or upstream pipeline transportation. Transportation customers acquire their own natural gas and pipeline transportation. Including an estimate of 45.0 cents per therm for the cost of natural gas and pipeline transportation, the proposed increase to Schedule 146 rates represents an average increase of 1.0% (2016) and 1.2% (2017) in those customers' total natural gas bill.

Q. What information did the Company use to develop the proposed spread of the overall 2016 increase to the various rate schedules?

A. The Company used the results of the cost of service study (sponsored by Company witness Mr. Miller) as a guide to spread the natural gas general increase. The spread of the proposed increase generally results in the rates of return for the various service schedules moving approximately one-quarter closer to the overall rate of return (unity). The relative rates of return before and after application of the proposed 2016 increase by schedule are as follows:

Table 7 - Present & Proposed Relative Rates of Return

Rate Schedule	Present Relative ROR	Proposed Relative ROR
General Service Schedule 101	0.89	0.93
Large General Service Schedules 111/112	1.48	1.32
Interruptible Sales Service Schedules 131/132	1.10	1.07
Transportation Service Schedule 146	1.27	1.18
Overall	**1.00**	**1.00**

Page 2 of Exhibit No. 15, Schedule 6 shows this information in more detail.

Q. For 2017, what is the proposed natural gas revenue increase, and how is the Company proposing to spread the increases by rate schedule?

A. For 2017, the proposed base revenue increase is $1,665,000, or 4.2% in base margin revenue (on a billed revenue basis, the increase is 2.2%). Including the expiration of the proposed $0.2 million rebate that would expire December 31, 2016, the net increase in billing rates in 2017 would be 2.5%.

The Company used a pro-rata allocation of the Company's 2016 natural gas rate spread percentages for purposes of spreading the proposed 2017 natural gas revenue increase to its natural gas service schedules. Below is a table showing the effect of the Company's 2017 proposed natural gas increase by rate schedule, including the effects of the expiring rebate:

Table No. 8 - Proposed % Natural Gas Increase by Schedule - 2017

Rate Schedule	Increase in Margin Rates	Increase in Billing Rates	Billing Increase Net of Expiring Rebate
General Service Schedule 101	4.6%	2.6%	2.9%
Large General Service Schedules 111/112	2.4%	0.9%	1.3%
Interrupt. Sales Service Schedules 131/132	4.1%	1.5%	2.0%
Transportation Service Schedule 146*	3.3%	3.4%	5.4%
Overall	**4.2%**	**2.2%**	**2.5%**

** excludes commodity and interstate pipeline transportation costs*

This information is also shown on page 1 of Exhibit No. 15, Schedule 6.

Proposed Rate Design

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

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

Large General Service Schedule 111 has a four-tier declining-block rate structure and is generally for customers who consistently use over 200 therms/month, such as schools, restaurants, and office buildings. The 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, 1001-10,000 therms/month and usage over 10,000 therms/month.

Interruptible Sales Service Schedule 131 contains a single rate per therm for all natural gas usage. The schedule also has an annual minimum (deficiency) charge based on a usage requirement of 250,000 therms per year. The lone customer served on this schedule is a hospital which has standby facilities with an alternate fuel, as required by tariff.

Transportation Service Schedule 146 contains a $225 per month customer charge and contains a single rate per therm for all natural gas usage. The schedule also has an annual minimum (deficiency) charge based on a usage requirement of 250,000 therms per year.

Q. Where in your Exhibit No. 15 do you show the present and proposed rates for the Company's natural gas service schedules?

A. Pages 3 and 4 of Schedule 6 shows the present and proposed rates under each of the rate schedules, including all present rate adjustments (adders) for the 2016 and 2017 rate changes. Column (e) on those pages show the proposed changes to the rates contained in each of the schedules.

Q. How does the Company propose to spread Schedule 101's proposed <u>2016</u> general revenue increase of $2,860,000

to the rates within that schedule?

A. The Company proposes to increase the monthly customer charge from $4.25 per month to $8.00 per month. As a result of the proposed increase in the basic charge, the volumetric energy rate would decrease by 0.981 cents per therm. This is shown in column (e), page 3, Schedule 6 of Exhibit No. 15.

Q. Why is the Company proposing to increase the monthly customer charge from $4.25 to $8.00 per month?

A. Like the electric business, a substantial portion of the Company's costs are fixed and do not vary with the amount of energy used by customers. As reflected in this filing, the fixed costs of operating and maintaining our natural gas system are increasing. The Company believes it is important that rates better reflect these increasing costs to serve customers. Later in Section IV. of my testimony I will provide greater detail as to why the Company believes the monthly customer charge should increase to $8.00 per month.

Q. How does the Company propose to spread Schedule 101’s proposed <u>2017</u> general revenue increase of $1,486,000 to the rates within that schedule?

A. The Company proposes to keep the monthly customer charge at $8.00 per month. The revenue increase for the schedule would be recovered through a 6.0% increase in the volumetric energy rate. This is shown in column (e), page 4, Schedule 6 of Exhibit No. 15.

Q. For 2016, what is the proposed monthly increase for a residential natural gas customer with average usage?

A. The increase for a residential customer using an average of 61 therms of natural gas per month would be $3.90 per month, or 6.6%, inclusive of the general rate increase as well as the net effect of the Schedule 197 rebate. A bill for 61 therms per month would increase from the present level of $59.22 to a proposed level of $63.12.

Q. For 2017, what is the proposed monthly increase for a residential natural gas customer with average usage?

A. The increase for a residential customer using an average of 61 therms of natural gas per month would be $1.79 per month, or 2.8%, inclusive of the general rate increase as well as the expiration of the Schedule 197 rebate, resulting in an overall bill of $64.91, including all rate adjustments.

Q. Would you please explain the proposed changes in the rates for Large General Service Schedules 111?

A. Yes. The present rates for Schedules 101 and 111 provide guidance for customer placement: customers who generally use less than 200 therms/month should be placed on

Schedule 101, customers who consistently use over 200 therms per month should be placed on Schedule 111. Not only do the rates provide guidance for customer schedule placement, they provide a reasonable classification of customers for analyzing the costs of providing service.

The proposed <u>2016</u> increase to the minimum charge for Schedule 111 (for 200 therms or less) of $1.79 per month is a function of the basic charge increase under Schedule 101 as well as the change in the Schedule 101 variable rate. This methodology maintains the present relationship between the schedules, and will minimize customer shifting. The remaining revenue requirement for the schedule is proposed to be recovered through a uniform percentage increase of approximately 5.7% to blocks 2, 3 and 4.

The proposed <u>2017</u> increase to the Schedule 111 minimum charge for Schedule 111 (for 200 therms or less) is $5.33 per month. The remaining revenue requirement for the schedule is proposed to be recovered through a uniform percentage increase of approximately 1.4% to blocks 2, 3 and 4.

Q. How is the Company proposing to spread the proposed <u>2016</u> increase of $6,000 to the rates under Interruptible Schedule 131?

A. The Company proposes to increase the usage charge under the schedule by 1.956 cents per therm.

Q. How is the Company proposing to spread the proposed <u>2017</u> increase of $3,000 to the rates under Interruptible Schedule 131?

A. The Company proposes to increase the usage charge under the schedule by 0.909 cents per therm.

Q. How is the Company proposing to spread the proposed <u>2016</u> increase of $23,000 to the rates under Transportation Schedule 146?

A. The Company is proposing to increase monthly Basic Charge from $225 per month to $400 per month. The remaining revenue requirement would be recovered through an increase of 0.448 cents to the per-therm rate.

Q. How is the Company proposing to spread the proposed <u>2017</u> increase of $12,000 to the rates under Transportation Schedule 146?

A. The Company is proposing to increase the per therm charge under the schedule by 0.445 cents per therm.

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

A. No, it is not.

IV. BASIC CHARGE FOR SCHEDULES 1 & 101

Q. Why is the Company proposing to increase the <u>electric</u> monthly customer charge for Schedule 1 from $5.25 to $8.50 per month?

A. A significant portion of the Company's costs are fixed and do not vary with customer usage. These costs include distribution plant and operating costs to provide reliable service to customers. Upon evaluation of the <u>total customer allocated costs</u> for Schedule 1, as shown in Schedule 3 of Ms. Knox's Exhibit No. 13, page 4, line 26, those costs are <u>$17.82</u> per customer per month. Factoring in <u>distribution demand costs</u> per customer per month of <u>$23.58</u>, as shown in Schedule 3 of Exhibit No. 13, page 4, line 28, the total customer and distribution demand monthly cost per customer is <u>$41.40</u> These are essentially the fixed distribution costs for providing service to customers. Given the large disparity between the level of customer and demand costs and the present level of the basic charge, the Company believes that it is appropriate to recover a more reasonable level of these fixed customer costs through the basic charge.

Q. Why is the Company proposing an increase in the basic charge for Schedule 1 of $3.25 per month in this filing?

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

Publicly-owned electric utilities have been charging higher monthly customer charges for years in order to more accurately reflect (and recover) the fixed costs of providing service. For example, Avista’s nearest neighbor in North Idaho, Kootenai Electric Cooperative, has a residential monthly basic charge of $19.50, and a minimum charge of $25.00 per month. Avista’s nearest neighbor in Eastern Washington, Inland Power and Light, has a residential monthly basic charge of $19.23 per month.

Q. Turning now to <u>natural gas</u>, why is the Company proposing to increase the Schedule 101 monthly customer charge from $4.25 to $8.00 per month?

A. Schedule 101 total customer allocated costs, as shown in Schedule No. 2 of Mr. Miller's Exhibit No. 14, page 4, line 25, is $21.57 per customer per month. $11.60 of the $21.57 noted above is related to the cost of the meter and service, billing, and providing customer service, as shown in Schedule No. 2 in Exhibit No. 14, page 4, line 23. The Company believes that the requested increase in the basic charge provides for rates that are more cost-based.

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

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

- It results in almost all customers paying more "per-customer" related costs in the winter, even though their customer costs are not higher in the winter.

- It results in the amount of customer costs a customer pays being unpredictable, even though customer costs are actually very predictable.
- A portion of fixed costs of providing service to low usage customers is actually recovered from other higher usage customers served under the same schedule.

Ideally, to properly match revenues with the cost of service, the fixed costs of providing service would be recovered through a fixed monthly charge, paid by each customer irrespective of actual usage. The rationale for that type of rate design is that a utility's facilities and support functions are made available to its customers irrespective of how much energy they use.

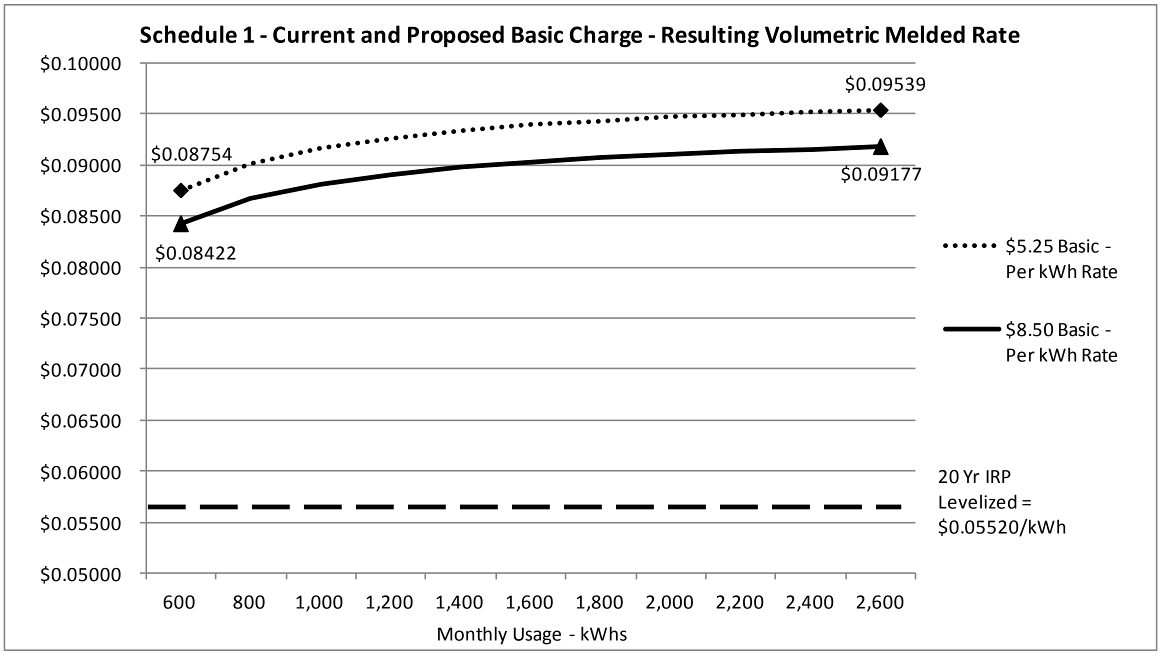
In summary, setting the basic charge at a rate substantially less than an amount that covers annual customer costs can result in rates that do not reflect the cost to serve, and monthly bills that are unnecessarily volatile.

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

A. No. Conservation of electricity and natural gas is important for customers and for the Company, and one might argue that a lower basic charge results in higher commodity charges and a stronger price signal related to volume usage. However, sending a price signal to customers through a residential rate design that contains a two-tier increasing block rate for electric (natural gas has two volumetric tiers) was developed for just such a reason. The more electricity that is used, the higher the rate, and therefore the higher the overall customer bill. The volumetric pricing components will still send a very clear price signal to conserve, even with the Company's proposed basic charge increase.

The Company's Integrated Resource Plans provide a perspective of the incremental cost of electricity and natural gas on a forward looking basis, as compared to retail rates. Illustration No. 2 below shows the average or melded Schedule 1 volumetric rate per kWh, at varying usage levels, and with the current $5.25 basic charge (and the rate increase applied to the two energy blocks) and the proposed basic charge of $8.50.

Illustration No. 2



The dotted line at the top of the graph shows the melded volumetric rate per kWh with the present $5.25 per month basic charge. The second solid line shows the melded volumetric rate per kWh with a $8.50 basic charge. At the bottom of the graph is a dashed line which shows the levelized 20-year avoided cost from the Company’s 2013 electric Integrated Resource Plan ($0.05520 per kWh). By adjusting the basic charge from its current $5.25 per month level to $8.50 per month, the resulting melded volumetric rate, remains well above the 20-year levelized avoided cost. With a basic charge of $8.50 per month, customers will continue to pay a volumetric rate, regardless of usage, that exceeds the Company’s avoided cost and, therefore, sends a very clear price signal.

For natural gas, the Company included several forecasts in its 2014 Integrated Resource Plan which all showed forecast natural gas prices at Henry Hub over the next 20 years being lower than Avista’s retail rate, which means that a clear price signal is also being provided on the natural gas side of the business.[15]

Q. Does the fact that that Avista is requesting Fixed Cost Adjustment mechanisms change the Company’s view of the appropriate level of the basic charge?

A. No. The proposed Fixed Cost Adjustment mechanisms are important mechanisms which would allow the Company to recover, on a per customer basis, the fixed costs of providing service to customers which are not otherwise recovered in the basic charge. A Fixed Cost Adjustment mechanism, however, does not fix the problem of intra-schedule cross subsidization. As long as a portion of the Company’s fixed costs are recovered in volumetric rates, ultimately some customers in a rate schedule are being subsidized by other customers. The Company believes that progress needs to be made in reducing the amount of intra-

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[15] See. Exhibit No. 7, Schedule 1, p. 6.

schedule subsidization, and the proposed basic charges help to do just that.

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

A. Yes. The Company completed an analysis demonstrating the effect of the increased basic charge on low, average, and high use electric and natural gas customers. The comparison shows the difference in a customer's bill (base rates only) if the Company had proposed to keep the basic charge unchanged versus the proposed increase. Table No. 9 below details the results of that analysis for residential electric customers on Schedule 1:

Table No. 9 – Electric Results

Avista - Bill Impacts for Low, Medium and High Use Customers (Sch 1)

Monthly Bill Impact	Current $5.25 Basic Charge	Proposed $8.50 Basic Charge	Difference	Percent. Difference
600 kWh/mo Customer	$58.54	$59.80	$1.26	**2.1%**
929 kWh/mo Customer	$89.93	$89.97	$0.04	**0.0%**
1600 kWh/mo Customer	$155.52	$153.07	-$2.45	**-1.6%**

Table No. 10 below details the analysis for <u>natural gas</u> customers on Schedule 101:

<u>Table No. 10 – Natural Gas Results</u>

<u>Avista - Bill Impacts for Low, Medium and High Use Customers (Sch 101)</u>				
Monthly Bill Impact	Current $4.25 Basic Charge	Proposed $8.00 Basic Charge	Difference	Percent. Difference
46 therms/mo Customer	$48.63	$49.56	$0.94	**1.9%**
61 therms/mo Customer	$63.38	$63.39	$0.00	**0.0%**
100 therms/mo Customer	$100.72	$98.35	-$2.36	**-2.3%**

The impact of the Company's proposed change to the basic charge varies based on monthly consumption. For an electric customer who uses <u>less</u> than the average 929 kWhs per month, and/or a natural gas customers who uses <u>less</u> than 61 therms per month, the percentage impact will be slightly higher than for those customers who use <u>more</u> than the average. That makes sense in that, with fixed costs being recovered in variable energy rates, <u>customers with higher use are subsidizing lower use customers</u>. We believe movement toward matching customer payment of fixed costs with the fixed costs to serve customers, together with removing part of the inequity among customers on the amount of fixed costs paid, is appropriate.

Table No. 11 below shows a comparison of monthly bills for an electric customer with average usage for a 12-month period. It shows the difference in the monthly bills with the basic charge as compared to the Company’s proposed $8.50 Schedule 1 basic charge. The table illustrates the reduction in 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 essentially no change in overall annual payment.

Table No. 11 - Monthly Bills for a Residential Schedule 1 Electric Customer using an Average of 929 kWhs per Month

Monthly Bills of an Electric Customer

Month	**kWh's**	**$5.25 Basic Charge**	**$8.50 Basic Charge**	**Higher / Lower Bill**
January	1,284	$126.28	$125.00	($1.28)
February	1,066	$104.69	$104.22	($0.47)
March	1,076	$105.68	$105.17	($0.51)
April	859	$84.19	$84.49	$0.30
May	789	$77.26	$77.82	$0.56
June	700	$68.45	$69.33	$0.89
July	782	$76.57	$77.15	$0.58
August	791	$77.46	$78.01	$0.55
September	545	$53.66	$55.10	$1.44
October	788	$77.16	$77.72	$0.56
November	1,068	$104.89	$104.41	($0.48)
December	1,395	$137.27	$135.58	($1.69)
Total Annual	**11,143**	**$1,093.54**	**$1,093.99**	**$0.45**
Total % Bill Change				**0.0%**

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

Table No. 12 – Monthly Bills for a Schedule 101 Natural Gas Customer using an Average of 61 therms per Month

Monthly Bills of an Average Natural Gas Customer				
Month	**Therms**	**Current $4.25 Basic Charge**	**Proposed $8.00 Basic Charge**	**Higher / Lower Bill**
January	118	$118.08	$114.62	($3.47)
February	103	$103.61	$101.06	($2.55)
March	90	$91.07	$89.32	($1.75)
April	52	$54.41	$54.98	$0.57
May	34	$37.05	$38.72	$1.67
June	21	$24.51	$26.97	$2.47
July	13	$16.79	$19.75	$2.96
August	13	$16.79	$19.75	$2.96
September	16	$19.68	$22.46	$2.77
October	50	$52.48	$53.18	$0.69
November	99	$99.75	$97.45	($2.30)
December	126	$125.80	$121.84	($3.95)
Total Annual	**735.0**	**$760.04**	**$760.09**	**$0.05**
Total % Bill Change				**0.0%**

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 lower user of electricity. As explained below, the available data that we have suggests that just the opposite is true, which means the increased basic charge would generally be beneficial to limited income customers.

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 natural gas is available, but conversion is not affordable. These limited income customers, with electric space and water heat, can have electric usage in the tail-block (above 600 kWhs) during the winter months.

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

A. Yes. The Company recently conducted an analysis which shows that limited income customers, on average, do use more electricity than other residential customers. For the analysis, the Company looked at those limited income customers who received a LIHEAP grant during the January – December 2014 time period, and compared their annual usage to the usage of all of the other residential customers.[16] The results of the analysis are shown in the Table 13 below:

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[16] 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 January 1, 2014 through December 31, 2014. Any accounts opened for a partial year were excluded. The Company acknowledges that the limited income population used for this analysis is not comprehensive. However, because the Company does not track customer incomes, it is based on the best information available.

Table No. 13

Idaho Residential Electric Usage Analysis (Billed Usage - Not Weather Corrected)
Year: Calendar 2014

	Sample Size	Average Annual kWh Usage	Average Monthly kWh Usage
Electric Only Customers - Limited Income (LIHEAP)	2,615	13,160	1,097
Electric Only Customers - All Other Residential Customers	34,641	12,800	1,067
Difference		**360**	**30**
Dual Fuel Customers - Limited Income (LIHEAP)	1,727	9,828	819
Dual Fuel Customers - All Other Residential Customers	44,235	10,507	876
Difference		**-679**	**-57**
Total Limited Income (LIHEAP)	4,342	11,835	986
Total All Other Residential Customers	78,876	11,514	960
Difference		**321**	**27**

The analysis shows that limited income customers who only have electric service use 360 kWhs more per year than the "All Other Residential Customers" population. For the combined limited income population, the analysis shows that they used 321 kWhs more in 2014 than "Total All Other Residential Customers" population.

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.

V. ELECTRIC AND NATURAL GAS FIXED COST ADJUSTMENT MECHANISMS

Q. Is the Company requesting approval of electric and natural gas fixed cost adjustment mechanisms in this general rate case?

A. Yes, the Company is requesting both an electric and natural gas Fixed Cost Adjustment Mechanism ("FCA") in this case. The Company believes, for reasons stated below, that the FCA would provide benefits to both customers and the Company, and therefore is in the public interest and should be approved.[17]

Q. Do you believe that the electric and natural gas FCA proposed by the Company is consistent with what the Commission generally has been supportive of in the past?

A. Yes. The proposed mechanism is in keeping with the Commission's previous orders related to Idaho Power's Fixed Cost Adjustment mechanism. In Order No. 33295 issued on May 6, 2015, in Case No. IPC-E-14-17, the Commission approved a settlement stipulation filed by certain parties that modified Idaho Power's Fixed Cost Adjustment mechanism. The mechanisms requested by Avista in this case removes the relationship between kilowatt-hour and therm sales and revenues, mitigates the disincentive to promote energy

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[17] The Company is proposing that the FCA go into effect on the first day of the calendar month that is on, or subsequent to, the effective date of new retail rates from this case.

efficiency, and improves fixed cost recovery, similar to Idaho Power's mechanism.

Q. Before describing the mechanism, would you please provide further details on how the mechanism provides benefits the Company and its customers?

A. Yes. To the extent use-per-customer declines between general rate cases, the FCA would provide recovery of the fixed costs of providing service to its customers. These are the same fixed costs, on a revenue-per-customer basis, that the Commission approves for recovery in a general rate case. The mechanism would also ensure that, to the extent there is customer growth in the rate year and beyond, the revenues from those new customers would be available to offset the growth in utility costs following the test year.

Customers benefit from the proposed mechanism. By separating sales from revenues, the disincentive to promote conservation would be removed, as would any incentive for the utility to increase throughput. Customers benefit if the overall actual sales revenue collected by the Company on a per-customer basis is greater than that approved by the Commission. For example, if a winter is colder than normal, leading to loads that are higher than normal, the Company would rebate to customers all of the revenue collected above the allowed level. And on the other hand, should sales be lower due to warmer than normal winter weather, the associated reduction in revenues would be deferred for later recovery from customers.

The revenue provided to Avista through a FCA would <u>not</u> represent additional revenue to the Company over and above what is needed to recover its costs; it represents <u>restoration</u> of revenues that the Commission has already determined should be provided to the utility from the last rate case, on a per customer basis. Furthermore, customers can expect to see rebates as well as surcharges over time with the FCAs.

Q. Is weather normalized as a part of the proposed mechanism?

A. No, the proposed electric and natural gas FCA mechanisms do not have a weather normalization adjustment. The Company has a certain level of fixed costs that are recovered in its variable energy rates. If weather were to be normalized as part of the mechanism, the mechanisms would not provide the same level of fixed cost recovery as determined in the last general rate case. With the Company’s proposed FCA, should sales be higher due to colder than normal winter weather, those additional revenues would be deferred and returned to customers. And on the other hand, should sales be lower due to warmer than normal winter weather, the associated reduction in revenues would be deferred for later recovery from customers.

Q. Does the Company have a FCA in its other jurisdictions?

A. Yes. Effective January 1, 2015, Avista has an electric and natural gas adjustment mechanism that, with the exception of the name, is materially the same as the proposed FCA in this case. Further, on May 2, 2015 Avista filed a general rate case in the State of Oregon (Docket No. UG-288), and requested a similar adjustment mechanism as well.

ELEMENTS OF THE ELECTRIC AND NATURAL GAS FIXED COST ADJUSTMENT MECHANISMS

Q. Would you please provide a summary of how the proposed electric and natural gas FCA would function?

A. Yes. As I will explain in more detail below, the Company is proposing a Revenue-Per-Customer FCA for its Idaho electric and natural gas operations. The proposed FCA compares the actual revenues to the allowed revenues determined on a per customer basis, with any differences deferred for later rebate or surcharge. In addition, the Company is proposing to group customers into two Rate Groups

– Residential and Non-Residential. More discussion on the two Rate Groups will follow later in my testimony.

Q. Please provide information related to when the Company would file for a rate adjustment under the proposed FCA.

A. On or before September 1, the Company would file a proposed rate adjustment surcharge or rebate based on the amount of deferred revenue recorded for the prior January through December time period. The rate adjustment would be calculated separately for each Rate Group.

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

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

Interest would be accrued on the unamortized balance in the FCA balancing accounts at the quarterly rate published by the Federal Energy Regulatory Commission ("FERC").[18]

Q. For the <u>Electric</u> FCA, would you please describe how the Fixed Cost Adjustment Revenue is determined?

A. Yes. Provided on Page 1 of Exhibit No. 15, Schedule 7 is information that calculates the Fixed Cost Adjustment Revenue.[19] This is the revenue that the Company collects in its variable energy and demand charges to cover the fixed costs of providing service to customers. It excludes revenues associated with power supply, and revenues that are collected in fixed basic, demand and minimum charges.

The steps to calculate the base FCA-related revenue are as follows:

- Step 1 – <u>Determine Total Rate Revenue</u> - Lines 1 through 3 on Page 1 of Exhibit No. 15, Schedule 7 shows the

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[18] 18 CFR 35.19a.

[19] If the Commission approves the FCA, the Company would file conforming Exhibit No. 15, Schedules 7 & 8 reflecting the final approved revenue and rates for both January 1, 2016 and January 1, 2017.

Total Normalized Test Year Revenue from the test period ($245.0 million) and adds to that total the Proposed Revenue Increase ($13.2 million). The resulting calculation is the Total Rate Revenue that the Company has requested in this case ($258.2 million) effective January 1, 2016.

- Step 2 – <u>Remove Variable Power Supply Revenue</u> – The Normalized kWhs by rate schedule for the test year are detailed on Line 4. On Line 5, those kWhs are multiplied by the proposed Load Change Adjustment Rate of $0.02513 to determine the total Variable Power Supply Revenue.[20] Lines 12-14 show the calculation of the Load Change Adjustment Rate grossed up for revenue-related expenses.

- Step 3 – <u>Remove Fixed Charge Revenues</u> – Because the proposed FCA only tracks revenue that varies with customer usage, the revenue from Fixed Charges must be removed. Line 8 shows the number of Customer Bills in the test period, and Line 9 shows the proposed basic and fixed demand charges in this case. Line 10 is the

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[20] See Exhibit No. 13, Schedule No. 1 for the Load Change Adjustment Rate of $0.02399/kWh. As shown on page 1 of Exhibit No. 15, Schedule 7, the Load Change Adjustment Rate has been grossed up for revenue-related expenses to $0.02513/kWh.

total Fixed Charge Revenue which is calculated by taking the number of customer bills and multiplying those by the associated Basic Charges, by rate schedule.

- Step 4 – Determine Fixed Cost Adjustment Revenue – The final step to calculate the allowed or base Fixed Cost Adjustment Revenue, as shown on Line 11, is to subtract the Fixed Charge Revenue (Line 10) from the subtotal on Line 7.

Steps 1 through 4 above subtract from the Total Rate Revenue the revenues associated with Variable Power Supply and Fixed Charges in order to develop the Allowed Fixed Cost Adjustment Revenue. The next step will be to determine the Allowed Fixed Cost Adjustment Revenue on a per-customer basis.

Q. Would you please describe how the Allowed Fixed Cost Adjustment Revenue per-Customer is determined?

A. Yes. Provided on Page 2 of Exhibit No. 15, Schedule 7 are the inputs and calculations to determine the Allowed Fixed Cost Adjustment Revenue per-Customer. Line 1 on Page 2 of Exhibit No. 15, Schedule 7 shows the Allowed Fixed Cost Adjustment Revenue, by Rate Group, that was calculated earlier. Note that the information on Page 2 now shows the revenues by Rate Group rather than by individual rate schedule. More discussion related to the Rate Groups will follow later in my testimony.

Line 2 shows the Test Year Customers, by Rate Group. Finally, Line 3 divides the Allowed Fixed Cost Adjustment Revenue by the Test Year number of Customers to determine the annual allowed Fixed Cost Adjustment Revenue per-Customer.

Page 3 of Exhibit No. 15, Schedule 7 calculates the monthly allowed Fixed Cost Adjustment Revenue per-Customer. To determine the monthly allowed Fixed Cost Adjustment Revenue per customer, which is required for the monthly deferral calculations discussed later in my testimony, the annual allowed Fixed Cost Adjustment Revenue per customer is shaped based on the monthly kWh usage from the test year, as shown on Page 3 of Exhibit No. 15, Schedule 7. For example, as shown on line 4, the Residential Group used 11.50% of its annual usage in January 2014 (131,9655 MWh / 1,147,395 MWh). The Company used the resulting monthly percentage of usage by month and multiplied that by the annual allowed Fixed Cost Adjustment Revenue per Customer to determine the 12 monthly values.

Q. Please describe how deferrals for the <u>Electric</u> FCA would be calculated?

A. In the rate year, the Company would compare the <u>Actual</u> revenue it receives with the <u>allowed</u> Fixed Cost Adjustment Revenue, and defer the difference between the two. Deferrals would be tracked separately for each Rate Group. A sample calculation, <u>provided for illustrative purposes</u>, is included on Page 4 of Exhibit No. 15, Schedule 7. Detailed below are the steps outlined on Page 4 to calculate the deferral. For purposes of describing the deferral calculation, I will only refer to the calculation of the deferral for the Residential Group; there is no difference in the calculations for the Non-Residential Group.

- Step 1 – <u>Determine Allowed Fixed Cost Adjustment Revenue</u> - The first step is to pull from the Company's billing system the actual number of customers each month. Line 1 on <u>Page 4 of Exhibit No. 15, Schedule 7</u> shows an illustrative Residential Group level of customers for the Rate Year of 2016. Line 2 shows the Allowed Monthly Fixed Cost Adjustment Revenue per-Customer for that group. Multiplying those values together results in an Allowed Fixed Cost Adjustment

Revenue for each month, shown on Line 3. The calculated values on Line 3 show, by month, the total amount of FCA revenue that the Company would be allowed.

- Step 2 – Determine Period "Actuals" - The next step is to pull from the Company's billing system the Actual Base Rate Revenue (Line 4 on Page 4 of Exhibit No. 15, Schedule 7), Actual Fixed Charge Revenue (Line 5) and Actual Usage (Line 6). These "actuals" would not be weather normalized.

- Step 3 – Calculation of Variable Power Supply Revenue – The next step in the deferral calculation multiplies the approved Load Change Adjustment Rate (Line 7 on Page 4 of Exhibit No. 15, Schedule 7)) by the Actual Usage (kWhs) shown on Line 6. The result is the level of revenues associated with variable power supply that will be deducted in Step 4.

- Step 4 – Calculation of Actual Fixed Cost Adjustment Revenue – Line 9 on Page 4 of Exhibit No. 15, Schedule 7 shows the calculation of the Actual Fixed Cost Adjustment Revenue. This calculation subtracts from

Actual Base Rate Revenue on Line 4 the Actual Basic Charge Revenue (Line 5) and the Variable Power Supply Revenue (Line 8). The calculated values on Line 9 show, by month, the total amount of FCA revenue that the Company actually received.

- Step 5 – <u>Deferral Calculation</u> – In order to determine if the Company over- or under-recovered its fixed costs, Actual Fixed Cost Adjustment Revenue (Line 9 on Page 4 of Exhibit No. 15, Schedule 7) is subtracted from allowed Fixed Cost Adjustment Revenue (Line 3). Line 10 shows the result. If the number is positive (surcharge direction), then the Company under-recovered its allowed revenue. If the number is negative, then the Company over-recovered its allowed revenue. The monthly deferrals are tracked on a monthly basis, and accrue interest at the FERC rate (as shown on Line 12).[21] Finally, Line 13 shows the Cumulative Deferral.[22]

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[21] Interest would be accrued on the balance in the fixed cost adjustment balancing accounts at the quarterly rate published by the Federal Energy Regulatory Commission ("FERC").

[22] 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, as shown on line 11. 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.

In summary, the calculations shown on Page 4 of Exhibit No. 15, Schedule 7 provide an example of how the Electric FCA would work. It shows the use of the Monthly allowed Fixed Cost Adjustment Revenue per-Customer and how that value is applied to the actual level of customers to determine the allowed Fixed Cost Adjustment Revenue. Further, the example shows how actual Basic Charge and variable power supply revenue are removed from actual revenues to determine the amount of revenues the Company actually received related to fixed costs. Finally, the example shows the monthly and cumulative deferral calculations, including the effect of interest.

Q. For the Natural Gas FCA, would you please describe how the Fixed Cost Adjustment Revenue is determined?

A. Yes, and it is very similar to the calculation for the Electric FCA. Provided on Page 1 of Exhibit 15, Schedule 8 is information that calculates the Fixed Cost Adjustment Revenue. This is the revenue that the Company collects in its variable energy charges to cover the fixed costs of providing service to customers. It excludes revenues associated with the natural gas commodity and interstate pipeline transportation, and revenues that are collected in basic and minimum charges.

- Step 1 – <u>Determine Total Delivery Revenue</u> - Lines 1 through 3 on Page 1 of Exhibit 15, Schedule 8 shows the Total Normalized Test Year Revenue ($36.1 million) and adds to that total the Proposed Revenue Increase ($3.2 million). The resulting calculation is the proposed Total Delivery Revenue that the Company has requested in this case ($39.4 million).
- Step 2 – <u>Remove Fixed Charge Revenue</u> – Included in the Total Delivery Revenue on Line 3 are revenues that are recovered from customers in fixed monthly basic Charges. Because the proposed FCA only tracks revenue that varies with customer usage, the revenue from Fixed Charges must be removed. Line 4 shows the number of Customer Bills in the test year, and Line 5 shows the Proposed Fixed Charges in this case.[23] Line 6 is the total Fixed Charge Revenue which is calculated by taking the number of customer bills and multiplying those by the associated Fixed Charges, by rate schedule.
- Step 3 – <u>Determine Fixed Cost Adjustment Revenue</u> – The final step to calculate the <u>Allowed</u> Fixed Cost Adjustment Revenue, as shown on Line 7, is to subtract

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[23] If the Commission approves basic charges that are different than what the Company proposed, the basic charges included in Exhibit 15, Schedule 8 p. 1, ln. 5 would need to be updated.

the Fixed Charge Revenue (Line 6) from the Total Delivery Revenue (Line 3).

Steps 1 through 3 above subtract from the Total Delivery Revenue the revenues associated with the Fixed Charges to develop the Fixed Cost Adjustment Revenue. The next step will be to determine the allowed Fixed Cost Adjustment Revenue on a <u>per-customer</u> basis.

Q. Would you please describe how the Allowed Fixed Cost Adjustment Revenue <u>per-Customer</u> is determined?

A. Yes. Provided on Page 2 of Exhibit 15, Schedule 8 are the inputs and calculations to determine the Allowed Fixed Cost Adjustment Revenue per-Customer. Line 1 on Page 2 of Exhibit 15, Schedule 8 shows the Fixed Cost Adjustment Revenue, by Rate Group, that was calculated earlier. Note that the information on Page 2 now shows the revenues by Rate Group rather than by individual rate schedule. More discussion related to the Rate Groups will follow later in my testimony.

Line 2 shows the Test Year Number of Customers, by Rate Group. Finally, Line 3 divides the Fixed Cost Adjustment Revenue by the Test Year Number of Customers to determine the <u>annual</u> Fixed Cost Adjustment Revenue per-Customer.

Page 3 of Exhibit 15, Schedule 8 calculates the <u>monthly</u> Fixed Cost Adjustment Revenue per-Customer. To determine the monthly Fixed Cost Adjustment Revenue per-Customer, which is required for the monthly deferral calculations discussed later in my testimony, the annual Fixed Cost Adjustment Revenue per-Customer is shaped based on the monthly therm usage from the test year as shown on Page 3 of Exhibit 15, Schedule 8. For example, the Residential Group used to use 15.95% of its annual usage in January 2014 (8,886,364 therms / 55,714,011 annual therms) as shown on line 5. The Company used the resulting monthly percentage of usage by month and multiplied that by the annual allowed Fixed Cost Adjustment Revenue per Customer to determine the 12 monthly values shown by Rate Group on lines 14 and 18.

Q. Please describe how deferrals for the Fixed Cost Adjustment Mechanism would be calculated.

A. In the rate year, the Company would compare the Actual revenue it receives with the allowed Fixed Cost Adjustment Revenue, and defer the difference between the two. Deferrals would be tracked separately for each Rate Group. A sample calculation, provided for illustrative purposes, is included on Page 4 of Exhibit 15, Schedule 8. Detailed below are the steps outlined on Page 4 to calculate the deferral.

For purposes of describing the deferral calculation, I will only refer to the calculation of the deferral for the

Residential Group; there is no difference in the calculations for the Non-Residential Group.

- Step 1 – Determine Allowed Fixed Cost Adjustment Revenue – The first step is to pull from the Company's billing system the actual number of customers each month. Line 1 on Page 4 of Exhibit 15, Schedule 8 shows an illustrative Residential Group level of customers for the Rate Year of 2016. Line 2 shows the allowed Monthly Fixed Cost Adjustment Revenue per-Customer for that group. Multiplying those values together results in an allowed Fixed Cost Adjustment Revenue for each month, shown on Line 3. The calculated values on Line 3 show, by month, the total amount of revenue that the Company would be allowed.

- Step 2 – Determine Period "Actuals" – The next step is to pull from the Company's billing system the Actual Monthly Delivery Revenue, which excludes the cost of natural gas (Line 5 on Page 4 of Exhibit 15, Schedule 8). These "actuals" would not be weather normalized.

- Step 3 – Calculation of Actual FCA Revenue – Line 7 on Page 4 of Exhibit 15, Schedule 8 shows the calculation of the Actual Fixed Cost Adjustment Revenue. This calculation subtracts from Actual Monthly Delivery Revenue on Line 5 the Actual Fixed Charge Revenue (Line 6). The calculated values on Line 7 show, by month, the Actual Fixed Cost Adjustment Revenue (e.g., the actual fixed costs recovered in volumetric rates).

- Step 4 – Deferral Calculation – In order to determine if the Company over- or under-recovered its fixed costs, Actual Fixed Cost Adjustment Revenue (Line 7 on Page 4 of Exhibit 15, Schedule 8) is subtracted from Allowed Fixed Cost Adjustment Revenue (Line 3). Line 7 shows the calculation. If the number is positive (surcharge direction), then the Company under-recovered its allowed revenue. If the number is negative, then the Company over-recovered its allowed revenue. The monthly deferrals are tracked on a monthly basis, and accrue interest at the FERC rate (as shown on Line 12). Finally, Line 9 shows the Cumulative Deferral.

In summary, the calculations shown on Page 4 of Exhibit 15, Schedule 8 provide an example of how the Natural Gas FCA would work. It shows the use of the Allowed Monthly Fixed Cost Adjustment Revenue per-Customer and how that value is applied to the actual level of customers to determine the

Allowed Fixed Cost Adjustment Revenue opportunity. Further the example shows how actual revenue from Fixed Charges are removed from actual delivery revenue to determine the Actual Fixed Cost Adjustment Revenue. Finally, the example shows the monthly and cumulative deferral calculations, including the effect of interest.

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

A. Avista has combined customers into Rate Groups. For the Electric FCA, customers would be included in one of two Rate Groups:

1. Residential – Schedule 1
2. Commercial – Schedules 11, 12, 21, 22, 31, and 32

First, the Company believes that Schedule 1 is a homogenous group, unlike all of the other rate schedules, and therefore should be individually tracked in the FCA. For the "Commercial" rate schedules, the Company believes that keeping these non-residential customers 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.

Street and Area Lighting customers served on Schedules 41-49 were excluded because the fixed costs to serve them are recovered in their flat monthly rates, and therefore fixed cost recovery is not dependent upon customer usage. Extra Large General Service Schedule 25 and Extra Large General Service to Clearwater Paper Schedule 25P were excluded from the mechanism primarily because these customers tend to be higher load factor customers. With a higher load factor, the Company believes that the recovery of fixed costs from these customers is less volatile versus the other schedules, and as such inclusion in the FCA at this time is not necessary.

For the Natural Gas FCA, customers would be included in one of two Rate Groups:

1. Residential – Schedule 101
2. Commercial – Schedules 111, 112, 131, and 132

For similar reasons that were provided for the residential and commercial electric grouping, the Company believes that the two proposed rate groups are appropriate. Schedule 146 transportation customers were not included in the design of the FCA because, like Schedule 25 customers, they tend to have less volatile usage (higher load factor).

As such, the Company believes that the fixed costs recovered in these customer's variable rates tend to be more stable, and therefore do not need to be included in the mechanism.

Q. Would you describe the accounting for the proposed electric and natural gas FCA?

A. Yes. The Company would record the deferral in account 186 – Miscellaneous Deferred Debits. The amount approved for recovery or rebate would then be transferred into a Regulatory Asset or Regulatory Liability account for amortization. On the income statement, the Company would record both the deferred revenue and the amortization of the deferred revenue through Account 456 –Other Electric Revenue, or Account 495 – Other Gas Revenue, in separate sub-accounts. The Company would file quarterly reports with the Commission showing pertinent information regarding the status of the current deferral. This report would include a spreadsheet showing the monthly revenue deferral calculation for each month of the deferral period (January - December), as well as the current and historical monthly balance in the deferral account.

Q. Has the Company prepared electric and natural gas tariffs that would administer the FCA?

A. Yes, included in Exhibit 15, Schedule 2 (electric) and Schedule 5 (natural gas) are new tariff Schedules 75 (electric) and 175 (natural gas). These tariffs outline the mechanics of the FCA and would serve as the rate adjustment tariff.

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

A. Yes, it does.