

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-20_____

DIRECT TESTIMONY OF

JOEL C. ANDERSON

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

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

A. My name is Joel C. Anderson. My business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Regulatory Analyst in the Regulatory Affairs Department.

Q. Would you briefly describe your educational background and professional experience?

A. I am a 2005 graduate of Eastern Washington University with a Bachelor's degree in Business Administration, majoring in Finance. In 2012, I became a Certified Public Accountant in the State of Washington. I joined the Company in January 2013, after spending seven years working in various accounting positions in the banking industry. I started with Avista as an Internal Auditor. In January 2016, I joined the Regulatory Affairs Department as a Regulatory Analyst. In my current role as a Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies in all jurisdictions, among other things.

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

My testimony presents the natural gas cost of service study and revenue normalization adjustment prepared for this filing. The results of this study were provided to Company witness Mr. Miller and were used to inform the spread of the proposed increase by service schedule. Company witness Knox will testify regarding the electric cost of service study and the electric revenue normalization adjustment. A table of contents for my testimony is as follows:

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15 **Q. Are you sponsoring any exhibits that accompany your testimony?**

16 A. Yes. I am sponsoring Exh. JCA-2 related to the natural gas cost of service study.

17 This exhibit was prepared by me and consists of summaries of information derived from the
 18 Cost of Service Study. I am also sponsoring Exh. JCA-3 related to AMI costs and benefits
 19 components of the natural gas cost of service study.

20

21 **II. SUMMARY**

22 **Q. Please briefly summarize your testimony related to the natural gas cost of**
 23 **service study.**

24 A. I believe the Base Case cost of service study presented in this case is a fair
 25 representation of the costs to serve each customer group. The cost of service study indicates
 26 that General Service Schedules 101/102 (serving mostly residential customers) and
 27 Transportation Schedule 146 are under parity as the classes provide less than the overall rate of
 28 return under present rates. The other classes, Large General and Interruptible Schedules

1 (111/112/116, 131/132) are over parity as they provide more than the overall rate of return at
 2 present rates. Table No. 1 shows the rate of return and the relationship of the customer class
 3 return to the overall return (relative return ratio) at present rates for each rate schedule as well
 4 as the revenue-to-cost parity ratio at present rates for each rate schedule:

5 **Table No. 1 – Relative Rates of Return at Present Rates and Parity Ratio**

6 <u>Rate Schedule</u>	<u>Rate of Return</u>	<u>Return Ratio</u>	<u>Parity Ratio</u>
7 General Service Schedule 101/102	3.42%	0.66	0.91
8 Large General Service Schedules 111/112	15.29%	2.96	1.70
9 Interruptible Sales Service Schedule 132	11.02%	2.14	1.40
10 Transportation Service Schedule 146	<u>4.42%</u>	<u>0.86</u>	<u>0.91</u>
11 Total Washington Natural Gas System	5.16%	1.00	1.00

12
 13 **III. NATURAL GAS REVENUE NORMALIZATION**

14 **Q. Would you please describe the natural gas revenue normalization**
 15 **adjustment included in Company witness Ms. Andrews's Natural Gas Pro Forma Study?**

16 A. Similar to the electric revenue normalization adjustment, sponsored by Ms.
 17 Knox, there are three separate adjustments that normalize revenue as part of the natural gas
 18 revenue normalization adjustment:

19 **1. Weather Normalization and Gas Cost Adjustment:** Column 2.10 of Ms. Andrews'
 20 Exh. EMA-3, page 6 is a Commission Basis weather normalization restating adjustment.
 21 Revenues for this adjustment are based on rates that were in effect during the January 2019
 22 through December 2019 test period, and therm sales and revenues have been adjusted to reflect
 23 normal weather conditions. The weather-related revenues associated with the Company's
 24 natural gas Decoupling Mechanism are removed in this adjustment, as therm sales and revenues
 25 have been normalized to reflect normal weather conditions.

1 **2. Eliminate Adder Schedules:** In addition to the weather normalization adjustment,
2 Ms. Andrews' study also includes an Eliminate Adder Schedules restating adjustment in
3 column 2.11 of Exh. EMA-3, page 6, which removes the impact of adder schedule revenues
4 and related expenses during the January 2019 through December 2019 test period.

5 **3. Pro Forma Revenue Normalization:** The Pro Forma Revenue Normalization
6 Adjustment in column 3.01 of Exh. EMA-3, page 8, adjusts January 2019 through December
7 2019 test period customers and usage for any known and measurable (pro forma) changes. In
8 addition, the adjustment re-prices billed, unbilled, and weather adjusted usage at the base tariff
9 rates approved for 2020, as if the April 1, 2020 base tariff rates were effective for the full 12
10 months of the year.¹

11 **Weather Normalization:**

12 **Q. Beginning with the first revenue normalizing adjustment, what is the**
13 **Commission Basis weather normalization adjustment?**

14 A. Weather normalization is a required element of Commission Basis reporting
15 pursuant to WAC 480-90-257. The intent of this adjustment is for Commission Basis adjusted
16 revenues and natural gas costs to reflect operations under normal temperature conditions during
17 the reporting period.

18 **Q. Would you please briefly discuss natural gas weather normalization?**

19 A. Yes. As in past cases, the natural gas weather normalization adjustment is
20 developed from a regression analysis of 10 years of billed usage per customer and billing period
21 heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-
22 per-heating-degree day) are multiplied by the monthly test period number of customers, which

¹ Docket No. UG-190335

1 is then multiplied by the difference between normal and actual heating degree-days. This
2 calculation produces the change in therm usage required to adjust existing loads to the amount
3 expected if weather had been normal.

4 **Q. In the discussion of electric weather normalization sponsored by Ms. Knox,**
5 **she indicated that the adjustment utilized sensitivity factors from the 10-year period**
6 **January 2009 through December 2018. Is this true for natural gas as well?**

7 A. Yes, the natural gas weather adjustment utilized updated weather sensitivity
8 factors for the same 10-year period.

9 **Q. What data did you use to determine “normal” heating degree days?**

10 A. Normal heating degree-days are based on a rolling 30-year average of heating
11 degree-days reported for each month by the National Weather Service for the Spokane
12 International Airport weather station. Each year the normal values are adjusted to capture the
13 most recent year with the oldest year dropping off, thereby reflecting the most recent
14 information available at the end of each calendar year. The calculation includes the 30-year
15 period from 1990 through 2019.

16 **Q. Is this proposed weather adjustment methodology consistent with the**
17 **methodology utilized in the Company’s last general rate case in Washington?**

18 A. Yes. The process for determining the weather sensitivity factors and the
19 monthly adjustment calculation is consistent with the methodology presented in Docket UG-
20 190335. This methodology has been used in every case since it was introduced in Docket UG-
21 070805.

22 **Q. What was the impact of natural gas weather normalization on the 12-**
23 **months ended December 2019 test year?**

1 A. Weather was colder than normal during the January 2019 through December
2 2019 period. The adjustment to normal required a decrease of 229 heating degree-days from
3 January through June and October through December.² The adjustment to sales volumes was
4 a decrease of 5,787,854 therms which is approximately 3.8 percent of billed usage.

5 **Q. What was the impact of this adjustment on Commission Basis results of**
6 **operations?**

7 A. The Commission Basis weather normalization adjustment decreased total
8 natural gas revenue by \$3,931,000, which after the offsetting increase to purchased gas expense
9 of \$1,658,000, resulted in a decrease to distribution margin of \$2,273,000. The combined effect
10 of netting the decrease to distribution margin against the decoupling revenue offset of
11 \$2,095,000, resulted in a net margin weather adjustment of \$(178,000).³ After an offsetting
12 increase for revenue related expenses and taxes, the weather normalization adjustment produced
13 a decrease to net operating income of \$6,000, as shown below:

14 **Table No. 2: - Summarize Weather Normalization Adjustment**

15			
16	General Business Revenue (Sales)	\$	(3,931,000)
17	Other Revenue (Decoupling Deferred)	\$	<u>2,095,000</u>
18	Total Revenue (Net Adjustment)	\$	(1,836,000)
19	Less: Purchased Gas Expense	\$	<u>1,658,000</u>
20	Distribution Margin Weather Adjustment	\$	(178,000)
21	Less: Revenue Related Expenses	\$	171,000
22	Less: Federal Income Tax	\$	<u>1,000</u>
23	Net Operating Income	\$	(6,000)
24			

25

² Heating degree days that occur during July through September do not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

³ The Decoupling Mechanism went into effect January 1, 2015.

1 **Eliminate Adder Schedules:**

2 **Q. Moving on to the second revenue normalizing adjustment, what is the**
3 **purpose of the Eliminate Adder Schedule adjustment?**

4 A. The Eliminate Adder Schedule adjustment removes both the revenues and
5 expenses associated with all adder schedule rates, except current natural gas costs (Purchased
6 Gas Cost Adjustment Schedule 150), since these items are recovered/rebated by separate tariffs
7 and, therefore, are not part of base rates. The items eliminated include: Schedule 174
8 Temporary Tax Rebate Rate Adjustment, Schedule 175 Decoupling Mechanism Rate
9 Adjustment, Schedule 189 Fixed-Income Senior & Disabled Residential Service Discount Rate
10 Adjustment, Schedule 191 Demand Side Management Rate Adjustment, Schedule 192 Low
11 Income Rate Assistance Program Rate Adjustment, and Schedule 155 Gas Rate Adjustment
12 amortization surcharge or rebate. This adjustment also identifies and consolidates all the
13 purchased gas cost related accounts into the “City Gate Purchases” line item in order to simplify
14 the Pro Forma Revenue Normalization adjustment described below.

15 **Q. What was the impact of the Eliminate Adder Schedule adjustment on**
16 **Commission Basis results of operations?**

17 A. The Commission Basis Eliminate Adder Schedule adjustment results in an equal
18 and offsetting reduction to both revenue and expense and has no impact on net income.

19 **Pro Forma Revenue Normalization:**

20 **Q. Please describe the third revenue normalizing adjustment, the Pro Forma**
21 **Revenue Normalization adjustment.**

22 A. The purpose of the “Pro Forma Revenue Normalization” adjustment is to restate
23 distribution revenue on a forward-looking basis and to remove natural gas costs. This is

1 accomplished by re-pricing test year normalized billing determinants (including unbilled and
 2 weather adjustments, as well as any known and measurable changes to the test year loads and
 3 customers) to reflect revenues for the January 2019 through December 2019 test period.

4 **Q. Does the Pro Forma Revenue Normalization Adjustment contain a**
 5 **component reflecting normalized natural gas costs?**

6 A. No, natural gas commodity costs previously shown as an equal and offsetting
 7 amount in both revenue and expense, have been removed from the Company's filing.

8 **Q. What is the impact of the Pro Forma Revenue Normalization adjustment?**

9 A. The Pro Forma Revenue Normalization adjustment increases operating income
 10 before federal income taxes by \$6,011,000. The combined effect of the decrease to revenue
 11 from rates with the elimination of both the 2019 restated decoupling deferred revenue
 12 \$1,188,000 and the 2019 provision for refund from tax reform (-\$325,000), resulted in a total
 13 pro forma revenue adjustment increase of \$8,551,000. After an offset for revenue-related
 14 expenses and taxes, Washington net operating income increased \$8,187,000, as shown below,
 15 and in column 3.01 on page 8 of Exh. EMA-3.

16 **Table No. 3 – Summarize Revenue Normalization Adjustment**

17	General Business Revenue	\$	(41,734,000)
18	Other Revenue (Eliminate Decoupling Deferred)	\$	(1,188,000)
19	Other Revenue (Eliminate Provision for Refund)	\$	<u>325,000</u>
20	Total Revenue (Net Adjustment)	\$	(42,597,000)
21	Eliminate Purchased Gas Expense	\$	<u>51,148,000</u>
22	Distribution Margin Adjustment	\$	8,551,000
23	Revenue Related Expenses	\$	1,812,000
24	Federal Income Tax	\$	<u>(2,176,000)</u>
25	Net Operating Income	\$	8,187,000

26

1 **IV. NATURAL GAS COST OF SERVICE**

2 **Q. Please describe the natural gas cost of service study and its purpose.**

3 A. A natural gas cost of service study is an engineering-economic study which
4 separates the revenue, expenses, and rate base associated with providing natural gas service to
5 designated groups of customers. The groups are made up of customers with similar usage
6 characteristics and facility requirements. Costs are assigned in relation to each group's test year
7 load and facilities requirements, resulting in an evaluation of the cost of the service provided to
8 each group. The rate of return by customer group indicates whether the revenue provided by
9 the customers in each group recovers the cost to serve those customers. The study results are
10 used as a guide in determining the appropriate rate spread among the groups of customers.

11 **Q. What is the basis for the natural gas cost of service study provided in this**
12 **case?**

13 A. The cost of service study provided by the Company as Exh. JCA-2 is based on
14 the 12-months ended December 2019 test year pro forma results of operations presented by Ms.
15 Andrews in Exh. EMA-3.

16 **Q. Please explain the basic concepts involved in performing a natural gas cost**
17 **of service study?**

18 A. There are three basic steps involved in a cost of service study: functionalization,
19 classification, and allocation. First, the expenses and rate base associated with the natural gas
20 system under study are assigned to functional categories. The FERC uniform system of
21 accounts provides the basic segregation into production, underground storage, and distribution.
22 Traditionally, customer accounting, customer information, and sales expenses are included in
23 the distribution function and administrative and general expenses and general plant rate base

1 are allocated to all functions. In this study I have created a separate functional category for
2 common costs. Administrative and general costs that cannot be directly assigned to the other
3 functions have been placed in this category.

4 Second, the expenses and rate base items are classified into three primary cost
5 components: demand, commodity or customer-related. Demand-related (capacity) costs are
6 allocated to rate schedules based on design day peak demand. Commodity-related (energy)
7 costs are allocated based on each rate schedule's share of commodity consumption. Customer-
8 related items are allocated to rate schedules based on the number of customers within each
9 schedule. The number of customers may be weighted by appropriate factors such as relative
10 cost of metering equipment. In addition to these three cost components, any revenue-related
11 expenses is allocated based on the proportion of revenues by rate schedule. The final step is
12 allocation of the costs to the various rate schedules utilizing the allocation factors selected for
13 each specific cost item. These factors are derived from usage and customer information
14 associated with the test period results of operation.

15 **Cost of Service Rulemaking**

16 **Q. Are Cost of Service studies a required component of general rate case**
17 **filings?**

18 A. Yes. WAC 480-07-510(6) which discusses cost studies in general rate
19 proceeding filings was recently amended by General Order R-599 on July 7, 2020 to state that
20 a company's initial general rate case filing must include a cost of service study that complies
21 with the new chapter WAC 480-85.

22 **Q. Was Avista a party to the generic cost of service collaborative that**
23 **culminated in Docket Nos. UE-170002 and UG-170003 rulemaking and General Order R-**

1 **599?**

2 A. Yes. Commission Staff initiated the generic cost of service collaborative in 2017
3 in response to the Final Order in Avista's 2016 general rate proceeding (Dockets UE-160228
4 and UG-160229). Avista participated in Staff's information gathering efforts and multiple
5 workshops over three years as the collaborative evolved into the UE-170002 and UG-170003
6 rulemaking proceedings.

7 **Q. What was the intended purpose of the collaborative and rulemaking?**

8 A. The stated purpose of establishing the collaborative was to "provide an
9 opportunity to establish greater clarity and some degree of uniformity in cost of service studies
10 going forward".⁴ The intention was refined and evolved over the course of the collaborative
11 into the purpose stated as WAC 480-85-010:

12 (1) The purpose of these rules is to establish minimum filing requirements for
13 any cost of service study filed with the commission. These rules are designed
14 to streamline, improve, and promote efficiency in analyzing rate cases, clarity
15 of presentation, and ease of understanding. The minimum filing requirements
16 will allow for comparisons of cost of service studies.

17 **Q. Have the rules set forth in WAC 480-85 accomplished these goals?**

18 A. Yes, I believe they have. The Commission-provided presentation templates that
19 establish a consistent framework for comparison among studies and provide clarity around the
20 level of detail desired for exhibits. The methodology requirements streamline analysis by
21 promoting consistent functionalization, classification, and allocation expectations. Staff should
22 be commended for three years of hard work attempting to establish consensus among all the
23 interested parties.

24

⁴ Dockets UE-160228 and UG-160229 (consolidated), Final Order 06, pages 57-58.

1 **Study Inputs – Load Study**

2 **Q. Has the Company complied with all requirements of WAC 480-85?**

3 A. Other than a conflict with section 050, the Company believes the natural gas cost
4 of service study presented in this filing meets all the requirements set forth in WAC 480-85.
5 With that said, the requirements of WAC 480-85 have required extensive modifications to the
6 cost of service model in order to meet both the presentation requirements and new data
7 requirements associated with the allocation methods within section 060. The Company has
8 interpreted the new requirements to the best of our ability and used the best available sources
9 of information to us at the time of filing when preparing the cost of service study.

10 **Q. What is the issue with WAC 480-85-050?**

11 A. WAC 480-85-050(1) requires usage data for the study to come from the best
12 available source, preferably advanced metering technology. The Company is presently in the
13 process of implementing AMI for its Washington customers. The implementation was just
14 beginning during the 2019 test year, therefore consistent daily data representative of all
15 customers during the test year is not available. Therefore, the Company falls under sub-section
16 (d) requiring the use of a load study.

17 **Q. Was a Load study provided in conjunction with this Cost of Service Study?**

18 A. No. Consistent with the comments Avista provided on March 27, 2020 in
19 Dockets UE-170002 and UG-170003 the Company is presently in the process of completing
20 implementation of AMI for its Washington customers, as discussed by Company witnesses Ms.
21 Rosentrater and Mr. DiLuciano. Avista's first natural gas load study will be conducted after
22 the full implementation of AMI. The Company does not believe that conducting an expensive
23 new load study prior to the completion of its AMI meters project, likely by a third-party entity,

1 would be a prudent use of resources for customers to incur given the imminent availability of
2 the AMI data. The Company asked for flexibility in this type of situation as the Company
3 completes its transition to full deployment of AMI meters during the pendency of the cost of
4 service rulemakings. As shown on page 1 of Appendix A to the adoption Order Commission
5 Staff stated that it “understands the concerns of stakeholders about implementation and will ask
6 that the Commission take it into consideration.” The Company is filing a petition for limited
7 exemption from WAC 480-85-050(1) concurrent with this filing from the requirement that rate
8 schedule usage must come from AMI (not fully implemented) or a load study (does not exist)
9 for purposes of the natural gas cost of service study.

10 **Q. Do you believe that if the Company would have conducted a new load study**
11 **with daily usage for all rate schedules it would have a material impact on the results of**
12 **the cost of service study in this proceeding?**

13 A. No. While it is reasonable to assume that a load study with daily usage by rate
14 schedule would help the shaping of daily demand estimates used in developing the design day
15 peak allocation factors, the Company does not believe this would have a material effect on the
16 directional accuracy of the study results given that the majority of rate schedules are
17 significantly above or below rate parity.

18 **Methodology**

19 **Q. Does the Natural Gas Base Case cost of service study utilize the same**
20 **methodology from the Company’s last natural gas case in Washington?**

21 A. No, the Base Case cost of service study was prepared using the methodology
22 outlined in WAC 480-85-060 resulting from the new cost of service rules approved in July
23 2020. This methodology differs from the cost studies the Company has provided in previous

1 natural gas general rate cases.

2 **Q. Please explain the cost of service study presented in Exh. JCA-2?**

3 A. Exh. JCA-2 presents the results of the cost of service study in the form of the
4 natural gas cost of service template available from the commission in compliance with WAC
5 480-85-040(1). Electronically the template consists of five workbook tabs that are presented
6 as separate sections in this exhibit. Section A is the Revenue Requirement Cross-reference
7 which shows Ms. Andrews revenue requirement development (Exh. EMA-2) expressed at the
8 FERC Account level to facilitate assignment of costs to customer rate classes in the study.
9 Section B presents the FERC Account level cost of service results for all customer rate classes.
10 Section C shows the allocation factors used to assign each type of cost to the customer rate
11 classes. Section D is a summary of the revenue requirement adjustments shown in Section A.
12 Finally, Section E is a high-level summary of the cost of service results showing the Parity ratio
13 at present rates and Revenue-to-Cost ratio at proposed rates.

14 The Excel model used to calculate the base case cost of service and supporting schedules
15 have been included in its entirety electronically and hard copy in the workpapers accompanying
16 this case. While there are macros to facilitate printing certain workpapers, no macros are
17 integral to the cost of service model calculations.

18 **Q. What are the key elements that define the cost of service methodology?**

19 A. Consistent with the allocation methodologies defined within WAC 480-85-060
20 underground storage costs classified as balancing are allocated to all customers based on winter
21 sales. All remaining costs are allocated to sales customers based on average winter sales that
22 exceed average summer sales. Natural gas main investment is allocated based on design day
23 peak demand and annual throughput, respectively. Other system facilities that serve all

1 customers are classified by the peak and average ratio that reflects the system load factor, then
2 allocated by design day peak demand and throughput, respectively. Meter installation and
3 services investment is allocated by number of customers weighted by the relative installed cost
4 of those items. General plant not specifically defined within rule is allocated based on the
5 Company's blended four-part factor allocator (four-factor). Administrative & general expenses
6 are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then
7 allocated by factors associated with labor, plant in service, or revenue, respectively. The
8 "other" A&G amounts are allocated based on the Company's four-factor.

9 **Q. Please describe how investment in distribution mains is classified and**
10 **allocated under the Company's proposed main allocation.**

11 A. The investment in distribution main is classified as a demand-related cost,
12 however, it is not allocated solely on peak demand. In accordance with WAC 480-85-060 the
13 Company uses the system load factor for allocating this portion of its demand-related costs.
14 This method allocates demand-related costs based on a combination of design day peak demand
15 and average demand. Average demand is essentially another term for average throughput.

16 The Company used the system load factor to determine how much of the demand-related
17 costs would be allocated based on annual throughput and how much would be allocated based
18 on design day peak demand⁵. A system load factor was calculated based on weather-normalized
19 throughput and design day peak demand. The load factor is the ratio of average load to peak
20 load, and when multiplied by the plant investment, provides an estimate of the costs that can be
21 attributed to average use rather than peak use.

22 The resulting load factor was used to divide the demand-related costs into peak demand

⁵ Peak demand is defined as the hypothetical design day demand.

1 and average demand for purposes of allocating the costs to the rate schedules, with the demand-
2 related costs being allocated 35.2 percent on average demand and 64.8 percent on peak demand.
3 The load factor provides a reasonable basis for determining what portion of the costs should be
4 allocated based on average demand.

5 **Q. Please describe how Customer Relations Distribution Costs are Classified?**

6 A. Customer service, customer information and sales expenses are the core of the
7 customer relations functional unit which is included with the distribution cost category. For the
8 most part these costs are classified as customer-related. The only exception is uncollectible
9 accounts expense, which is considered separately as a revenue conversion item.

10 **Q. How has the Company allocated the general plant costs, Intangible Plant**
11 **Costs and other A&G expenses (common costs)?**

12 A. Property insurance and taxes are functionalized and allocated based on plant in
13 service. Pensions and employee insurance expenses are allocated based on salary and wages.
14 FERC fees are identified and allocated based on energy consumption. Revenue based fees,
15 uncollectible accounts expenses, and excise taxes are allocated by relative share of total
16 revenue. The remainder of general plant, intangible plant and other A&G expenses are
17 considered common costs and are allocated based on the Company's four-factor. This
18 allocation factor is the cost of service equivalent of the four-factor allocator used in the
19 Company's results of operations reporting. The four-factor has historically been utilized by the
20 Company to allocate common operating costs and plant between states (Washington, Idaho,
21 and Oregon) and among services (electric and natural gas) for purposes of the Company's
22 Commission Basis results of operations.

23 **Q. Please describe the components of the four-factor.**

1 A. The four-factor is comprised of the following four equally weighted
2 components:

- 3 • Direct O&M excluding resource costs and labor
- 4 • Direct O&M labor
- 5 • Number of customers
- 6 • Net direct plant

7
8 **Q. Please describe the benefits of the four-factor allocator.**

9 A. There are two primary benefits of the four-factor. First, it reflects a variety of
10 relationships that are consistent with the specific costs and plant items which are recognized as
11 serving multiple functions. Second, it provides consistency and balance between the way
12 common costs are allocated for purposes of Commission Basis results of operations and the
13 cost of service study used in general rate cases.

14 **Q. Did the Company prepare an analysis of Intangible Plant balances while**
15 **preparing this Cost of Service Study?**

16 A. Yes. Account 303.120 software costs are associated with the meter data
17 management system (MDM) and advanced metering infrastructure (AMI) project. An analysis
18 of Account 303.100 computer software by project is included in the Company workpapers. No
19 additional functionalization resulted from the project level analysis. Common intangible plant
20 costs have been allocated based on tangible plant. This treatment of intangible plant costs is
21 consistent with the Company's past natural gas cost of service studies.

22 **Results**

23 **Q. What are the results of the Company's natural gas cost of service study?**

24 A. The cost of service study indicates that General Service Schedules 101/102
25 (serving mostly residential customers) and Transportation Schedule 146 is providing less than

1 the overall rate of return (unity), and Large General and Interruptible Schedules (111/112/116,
 2 131/132) are providing more than unity. The following table shows the rate of return, the
 3 relative return ratio and the parity ratio at present rates for each rate schedule.

4 **Table No. 4 - Base Case Results**

5	<u>Rate Schedule</u>	<u>Rate of Return</u>	<u>Return Ratio</u>	<u>Parity Ratio</u>
6	General Service Schedule 101/102	3.42%	0.66	0.91
7	Large General Service Schedules 111/112	15.29%	2.96	1.70
8	Interruptible Sales Service Schedule 132	11.02%	2.14	1.40
9	Transportation Service Schedule 146	<u>4.42%</u>	<u>0.86</u>	<u>0.91</u>
10	Total Washington Natural Gas System	<u>5.34%</u>	<u>1.00</u>	<u>1.00</u>

11

12 The summary results of the study were used for consideration in the development of the
 13 proposed rates.

14

15 **V. AMI COSTS AND BENEFITS BY RATE CLASS**

16 **Q. Please describe the context for the AMI cost and benefit analysis within**
 17 **your testimony and exhibits?**

18 A. As a part of Avista's Deferred Accounting Petition approved by the Commission
 19 in Dockets UE-170327 and UG-170328, in Attachment A to the Amended Petition Avista
 20 agreed to provide "a detailed analysis of AMI system costs and benefits relative to each
 21 customer rate class" as a part of its AMI Report, sponsored by Mr. DiLuciano. Given the
 22 proximity of the filing of the report, and this general rate case, Avista believed that such an
 23 analysis made more sense to the Commission and the Parties to review as an adjunct to our Cost
 24 of Service studies.

1 **Q. Have you prepared a detailed analysis of AMI system costs and benefits**
2 **relative to each customer rate class?**

3 A. Yes, I have. Exh. JCA-3 presents a summary of the rate year AMI and MDM
4 cost components embedded in the natural gas cost of service study followed by an estimate of
5 the Washington electric share of total rate year cost reductions identified in the AMI Report.
6 In this analysis, the rate class assignment of costs come directly from the cost of service model.
7 The quantifiable benefits, which represent reductions to potential costs, are measured by their
8 absence from the rate year revenue requirement. The Washington natural gas share of these
9 cost reductions have been treated like common administrative and general costs to estimate
10 their impact by rate class.

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

12 A. Yes it does.