

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UG-15 _____

DIRECT TESTIMONY OF

JOSEPH D. MILLER

REPRESENTING AVISTA CORPORATION

1 **I. INTRODUCTION**

2 **Q. Please state your name, business address and present position with**
3 **Avista Corporation.**

4 A. My name is Joseph D. Miller. My business address is 1411 East Mission
5 Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State
6 and Federal Regulation Department.

7 **Q. Would you briefly describe your responsibilities?**

8 A. Yes. I am responsible for preparing and maintaining the regulatory natural
9 gas cost of service models for the Company. I also provide support in the preparation of
10 revenue analysis, rate spread and rate design, and miscellaneous other duties as required.

11 **Q. Please describe your educational background and professional**
12 **experience.**

13 A. I am a 1999 graduate of Portland State University with a Bachelors degree in
14 Business Administration, majoring in Accounting. In 2005 I graduated from Gonzaga
15 University with a Masters degree in Business Administration. I joined the Company in
16 March 2008 after spending eight years in both the public and private accounting sector. I
17 started with Avista as a Natural Gas Accounting Analyst in the Company's Resource
18 Accounting Department. In January 2009, I joined the State and Federal Regulation
19 Department as a Regulatory Analyst. My primary responsibility was coordinating discovery
20 for the Company's general rate case filings. In 2010, I was promoted to a Senior Regulatory
21 Analyst, where my primary responsibilities have been the preparation of the Company's
22 natural gas cost of service studies and revenue adjustments in all jurisdictions.

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

2 A. My testimony and exhibits will cover the Company’s natural gas revenue
 3 normalization adjustments and cost of service study performed for this proceeding. A table
 4 of contents for my testimony is as follows:

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12

13 **Q. Are you sponsoring any exhibits in this case?**

14 A. Yes. I am sponsoring Exhibit No. ____ (JDM-2) which includes a narrative of
 15 the natural gas cost of service study process, and Exhibit No. ____ (JDM-3), the natural gas
 16 cost of service study summary results.

17 **Q. Were these exhibits prepared by you or under your direction?**

18 A. Yes they were.

1 **II. NATURAL GAS REVENUE NORMALIZATION**

2 **Q. Would you please describe the natural gas revenue normalization**
3 **adjustment included in Company witness Ms. Andrews Attrition Study?**

4 A. Yes. Similar to the electric revenue normalization adjustment, sponsored by
5 Company witness Ms. Knox, there are three separate adjustments that normalize revenue as
6 part of the natural gas Attrition Study:

7 1 – The Commission Basis Results of Operations in Column [A] of Exhibit
8 No.__(EMA-3), page 4, includes a Commission Basis weather normalization adjustment.
9 Revenues and natural gas costs for this adjustment are based on rates that were in effect
10 during the October 2013 through September 2014 test period.

11 2 – In addition to the weather normalization adjustment, the Commission Basis
12 Results of Operations in Column [A] of Exhibit No.__(EMA-3), page 4, also includes an
13 Eliminate Adder Schedule adjustment which removes the impact of the adder schedule
14 revenues and related expenses during the October 2013 through September 2014 test period.

15 3 – The Pro Forma Revenue Normalization Adjustment in column [C] of Exhibit
16 No.__(EMA-4), page 4, adjusts October 2013 through September 2014 test period
17 customers and usage for any known and measurable (pro forma) changes. In addition, the
18 adjustment re-prices billed, unbilled, and weather adjusted usage and natural gas costs at the
19 base tariff rates approved for 2015, as if the January 1, 2015 revenue increase were effective
20 for the full 12-months of the test year.

1 **Q. Please begin with the first revenue normalizing adjustment in the**
2 **Attrition Study. What is the Commission Basis weather normalization adjustment?**

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

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

8 A. Yes. The natural gas weather normalization adjustment is developed from a
9 regression analysis of ten years of billed usage per customer and billing period heating
10 degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-
11 heating-degree day) are applied to monthly test period customers and the difference between
12 normal heating degree-days and monthly test period observed heating degree-days. This
13 calculation produces the change in therm usage required to adjust existing loads to the
14 amount expected if weather had been normal.

15 **Q. In the discussion of electric weather normalization sponsored by Ms.**
16 **Knox, she indicated that the adjustment utilized sensitivity factors from the ten year**
17 **period January 2004 through December 2013. Is this true for natural gas as well?**

18 A. Yes, the natural gas weather adjustment utilized updated weather sensitivity
19 factors for the same ten-year period.

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

21 A. Normal heating degree-days are based on a rolling 30-year average of heating
22 degree-days reported for each month by the National Weather Service for the Spokane
23 Airport weather station. Each year the normal values are adjusted to capture the most recent

1 year with the oldest year dropping off, thereby reflecting the most recent information
2 available at the end of each calendar year. The calculation includes the 30-year period from
3 1985 through 2014.

4 **Q. Is this proposed weather adjustment methodology consistent with the**
5 **methodology utilized in the Company's last general rate case in Washington?**

6 A. Yes. The process for determining the weather sensitivity factors and the
7 monthly adjustment calculation are consistent with the methodology presented in Docket
8 No. UG-140189. This methodology has been used in every case since it was introduced in
9 Docket No. UG-070805.

10 **Q. What was the impact of natural gas weather normalization on the twelve**
11 **months ended September 2014 test year?**

12 A. Weather was colder than normal for the fourth quarter of 2013 and February
13 of 2014. This was partially offset by warmer than normal weather for the months of January,
14 April, May and June of 2014. The adjustment to normal required the reduction of 107
15 heating degree-days from October through December and January through June.¹ The
16 adjustment to sales volumes was a reduction of 2,761,469 therms which is approximately
17 1.1 percent of billed usage.

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

20 A. The Commission Basis weather normalization adjustment decreased total gas
21 revenue by \$2,140,000, and, after an offsetting reduction to purchased gas expense, revenue
22 related expenses and taxes, produced a decrease to net operating income of \$497,000.

¹ 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.

1 **Q. Moving on to the second revenue normalizing adjustment in the**
2 **Attrition Study. What is the purpose of the Eliminate Adder Schedule adjustment?**

3 A. The Eliminate Adder Schedule adjustment removes both the revenues and
4 expenses associated with all adder schedule rates, except current gas costs, since these items
5 are recovered/rebated by separate tariffs and therefore are not part of base rates. The items
6 eliminated include: Schedule 191 Demand Side Management Rate Adjustment, Schedule
7 192 Low Income Rate Assistance Program Rate Adjustment, Schedule 155 Gas Rate
8 Adjustment amortization surcharge or rebate, and Schedule 159 Natural Gas Decoupling
9 Rate Adjustment. This adjustment also identifies and consolidates all of the purchased gas
10 cost related accounts into the “City Gate Purchases” line item in order to simplify the Pro
11 Forma Revenue Normalization adjustment described below.

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

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

17 **Q. Please describe the third revenue normalizing adjustment in the**
18 **Attrition Study. What is the purpose of the Pro Forma Revenue Normalization**
19 **adjustment?**

20 A. The purpose of the “Pro Forma Revenue Normalization” adjustment is to
21 restate revenue and natural gas costs on a forward-looking basis. This is accomplished by
22 re-pricing test year normalized billing determinants (including unbilled and weather
23 adjustments, as well as any known and measurable changes to the test year loads and

1 customers) to reflect revenues and gas costs for the October 2013 through September 2014
2 test period, as if the revenue increase effective January 1, 2015 had been in effect for the full
3 twelve months of the test period. This includes the effects of the January 1, 2015 rate
4 increase approved in Docket No. UG-140189.

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

7 A. Yes. Purchased natural gas costs are normalized using the natural gas costs
8 approved by the Commission in Docket No. UG-143328 (the Company's 2014 PGA filing),
9 as set forth under Schedule 150. These natural gas costs, effective November 1, 2014, are
10 applied to the pro forma retail sales volumes so that there is a matching of revenues and
11 natural gas costs.

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

14 A. The Pro Forma Revenue Normalization adjustment increases operating
15 income before federal income taxes by \$8,524,000, which after income taxes increases
16 Washington net operating income \$5,541,000, as shown in column [C] on pages 4 and 5 of
17 Exhibit No. ____ (EMA-3).

18 **Q. Are the same normalized restated revenues and natural gas costs**
19 **included in Company witness Ms. Smith's Pro Forma Cross Check Study shown as**
20 **Exhibit No. ____ (JSS-3)?**

21 A. Yes, the Weather Normalization adjustment is shown as adjustment 2.10 and
22 the Eliminate Adder Schedule adjustment is shown as adjustment 2.11 on page 7 of Exhibit

1 No.____ (JSS-3). The Pro Forma Revenue Normalization adjustment is shown as adjustment
2 3.06 on page 8 of Exhibit No.____ (JSS-3).

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III. NATURAL GAS COST OF SERVICE

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**Q. Please identify the natural gas cost studies presented to this Commission
in the last five years as required by WAC 480-07-510 (6).**

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A. Natural gas cost of service studies were filed with this Commission in Docket
No. UG-140189, No. UG-120437, No. UG-110877, No. UG-100468, and No. UG-090135.

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

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A. A natural gas cost of service study is an engineering-economic study which
separates the revenue, expenses, and rate base associated with providing natural gas service
to designated groups of customers. The groups are made up of customers with similar usage
characteristics and facility requirements. Costs are assigned in relation to each group's test
year load and facilities requirements, resulting in an evaluation of the cost of the service
provided to each group. The rate of return by customer group indicates whether the revenue
provided by the customers in each group recovers the cost to serve those customers. The
study results are used as a guide in determining the appropriate rate spread among the
groups of customers. Exhibit No.____ (JDM-2) explains the basic concepts involved in
performing a natural gas cost of service study. It also details the specific methodology and
assumptions utilized in the Company's Base Case cost of service study.

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

3 A. The cost of service study provided by the Company as Exhibit No. ____ (JDM-
4 3) is based on the twelve months ended September 2014 test year Pro Forma Cross Check
5 Study presented by Ms. Smith in Exhibit No. ____ (JSS-3). The Pro Forma Cross Check
6 Study analysis was used for the cost of service study to provide results at the comprehensive
7 level of detail required by the cost of service model. The Pro Forma Cross Check Study
8 includes an adjustment that brings total expenses and rate base into agreement with the
9 Attrition Study, therefore it provides the appropriate detailed cost basis for the cost of
10 service study in this case.

11 **Q. Would you please explain the cost of service study presented in Exhibit**
12 **No. ____ (JDM-3)?**

13 A. Yes. Exhibit No. ____ (JDM-3) is composed of a series of summaries of the
14 cost of service study results. Page 1 shows the results of the study by FERC account
15 category. The rate of return and the ratio of each schedule's return to the overall return are
16 shown on lines 38 and 39. This summary is provided to Company witness Mr. Ehrbar for
17 his consideration regarding rate spread and rate design. The results will be presented later in
18 my testimony. Additional summaries show the costs organized by functional category (page
19 2) and classification (page 3), including margin and unit cost analysis at current and
20 proposed rates. Finally, page 4 is a summary identifying specific customer related costs
21 embedded in the study.

1 The Excel model used to calculate the base case cost of service and supporting
2 schedules have been included in its entirety both electronically and hard copy in the
3 workpapers accompanying this case.

4 **Q. With the exception of the two changes that will be discussed later in your**
5 **testimony, does the Natural Gas Base Case cost of service study utilize the methodology**
6 **from the Company's last natural gas case in Washington?**

7 A. Yes, with the exception of the changes related to distribution main plant and
8 common costs detailed below, the Base Case cost of service study was prepared using the
9 same methodology applied to the study presented in Docket No. UG-140189.

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

11 A. Allocations of natural gas costs reflect the current purchased natural gas
12 tracker methodology. Underground storage costs are segregated proportionately into
13 commodity storage benefits for sales customers and load balancing benefits for all
14 customers. Natural gas main investment is allocated by coincident peak demand and
15 throughput, respectively. The throughput portion of the main investment allocation has been
16 segregated into small, medium and large mains, with large usage customers (Schedules
17 131/132 & 146) receiving zero allocation of small mains and a 33% of allocation of medium
18 mains. Other system facilities that serve all customers are classified by the peak and
19 average ratio that reflects the system load factor, then allocated by coincident peak demand
20 and throughput, respectively. Meter installation and services investment is allocated by
21 number of customers weighted by the relative current cost of those items. General plant is
22 allocated based on the Company's blended 4-part factor allocator (4-factor). Administrative
23 & general expenses are segregated into labor-related, plant-related, revenue-related, and

1 “other”. The costs are then allocated by factors associated with labor, plant in service, or
2 revenue, respectively. The “other” A&G amounts are allocated based on the Company’s 4-
3 factor. A detailed description of the methodology is included in Exhibit No. ____ (JDM-2).

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5

Distribution Main Cost Allocation

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**Q. Why is the Company proposing a change to the allocation of distribution
7 mains?**

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A. There have been varying points of view as to the proper allocation of
9 distribution mains as illustrated in the testimony sponsored by several parties in the
10 Company’s prior two general rate cases (UG-140189 & UG-120437). The Company has
11 modified its approach in an attempt to produce an allocation method that we believe 1) is
12 consistent with cost of service principles, 2) acknowledges past Commission decisions, 3) is
13 consistent with Avista’s distribution system, and 4) is both fair and balanced to all customer
14 classes.

15

**Q. Please summarize the Company’s prior distribution main allocation
16 methodology?**

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A. The allocation the Company used in its prior general rate case filings
18 separated distribution main investment into both small (less than 4 inches) and large (4
19 inches and greater) main. The Company then applied the peak and average ratio to separate
20 these costs into demand and commodity related costs. Demand (capacity) related costs were
21 allocated to rate schedules on the basis of each schedule’s contribution to system peak
22 demand. Commodity (energy) related costs were allocated based on each rate schedule’s
23 share of commodity consumption. Large usage customers that took service from large

1 mains did not receive an allocation of small mains. However, large usage customers that
2 took service from small mains had their associated throughput and coincident peak demand
3 assigned to the small main allocation factors. In addition, the Company individually
4 analyzed all large interruptible and transportation customers (Schedules 131/132 and 146) to
5 determine what size of pipe each customer directly took service from and any portion of
6 pipe that was directly assignable to a particular customer.

7 **Q. Please briefly summarize the distribution main allocation methodology**
8 **the Company is proposing in this proceeding?**

9 A. The Company is continuing to apply the peak and average ratio to classify
10 distribution main investment into both demand and commodity related costs. The portion of
11 main investment classified as demand related is allocated to all rate schedules on the basis of
12 each schedule's contribution to system peak demand. The demand related allocation does
13 not attempt to separate distribution main based on pipe size, as was done under the
14 Company's prior methodology.

15 The portion of distribution main investment classified as commodity related has been
16 separated main into three groups (small, medium & large) instead of two. Large main (4
17 inches and greater) is allocated to all rate schedules based on annual weather normalized
18 throughput. Small main (less than 2 inches) is allocated to all rate schedules with the
19 exception of Schedules 131/132 & 146 based on weather normalized throughput. Medium
20 main (2 and 3 inches) is allocated 33 percent to all rate schedules and 67 percent to all rate
21 schedules except Schedules 131/132 & 146 based on weather normalized throughput.

22 The proposed distribution main allocation methodology is discussed in greater detail
23 later in my testimony.

1 **Q. Please summarize the major concern that the Company is addressing by**
2 **changing its distribution main allocation?**

3 Under the prior approach, any large customer who was connected to large main did
4 not receive any allocation of small main. By excluding these customers from the small main
5 allocation altogether, the prior methodology ignored any benefits that large customers
6 receive from being connected to a broader distribution system which is heavily dependent on
7 small main.

8 **Q. Please describe the benefit all customers receive from being connected to**
9 **Avista's natural gas distribution main.**

10 A. Avista's natural gas distribution system is a network of pipes that includes
11 parallel and interconnected lines from which different pipes are used to move gas from one
12 point to another. The Company generally chooses to use 2 inch diameter pipes to serve
13 smaller customers and 4 or 6 inch diameter pipes to serve larger customers. However, all
14 sizes of pipe create capacity on the system. If there were less 2 inch diameter pipe, there
15 would need to be larger-sized pipe on the system, or less capacity would be available to
16 serve all customers, both large and small. The existence of smaller pipe makes capacity
17 available for everyone.

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

20 A. The investment in distribution main is classified as a demand-related cost,
21 however it is not allocated solely on peak demand. Following a long-standing practice, the
22 Company continues to use the peak and average method for allocating this portion of its
23 demand-related costs. This method allocates demand costs based on a combination of peak

1 demand and average demand. Average demand is essentially another term for average
2 throughput.

3 The Company used the system load factor to determine how much of the demand-
4 related costs would be allocated based on average demand and how much would be
5 allocated based on peak demand. A system load factor was calculated based on weather-
6 normalized throughput and peak demand. The load factor is the ratio of average load to
7 peak load, and when multiplied by the plant investment, provides an estimate of the costs
8 that can be attributed to average use rather than peak use.

9 The resulting load factor was used to divide the demand-related costs into peak
10 demand and average demand for purposes of allocating the costs to the rate schedules, with
11 the demand-related costs being allocated 39.8 percent on average demand and 60.2 percent
12 on peak demand. The load factor provides a reasonable basis for determining what portion
13 of the costs should be allocated based on average demand.

14 This peak and average approach to allocation of demand costs reflects a balance
15 between the way the system is designed (to meet peak demand) and the way it is utilized on
16 an annual basis (throughput based on gas usage that occurs during all conditions, not only
17 peak conditions).

18 **Q. Please describe how the peak and average method of cost allocation was**
19 **used to allocate the cost of distribution mains to the rate schedules.**

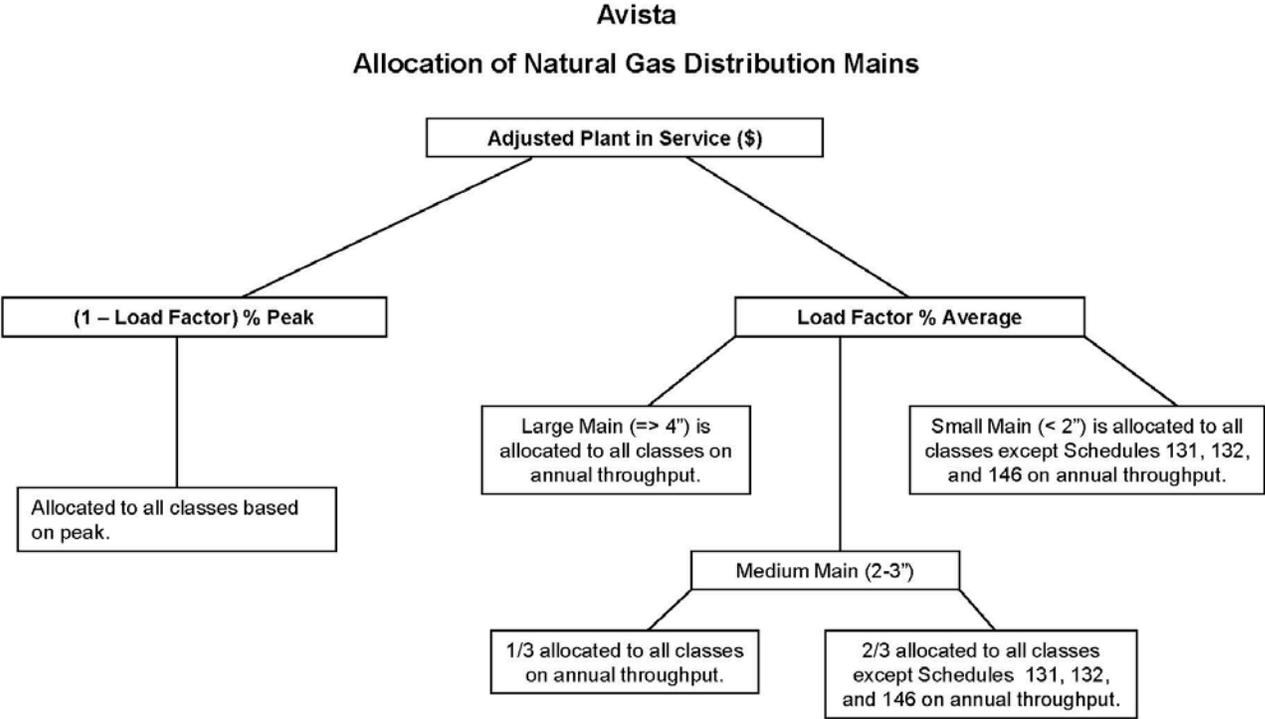
20 A. Illustration No. 1 provides a flow diagram of the steps referenced below.

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1 **Illustration No. 1:**



16 demand using the system load factor described above. This resulted in \$66.6 million (39.8
 17 percent) of plant allocated based on average demand and \$100.8 million (60.2 percent)
 18 allocated based on peak demand.

19 Second, the \$100.8 million, or 60.2 percent, to be allocated based on peak demand
 20 was allocated to all rate schedules based on their estimated contributions to the peak
 21 demand.

22 Third, the \$66.6 million, or 39.8 percent, to be allocated based on average demand
 23 was split into three groups: 1) large main (greater than or equal to four inches in diameter),

1 2) medium main (two and three inches in diameter), and 3) small main (less than two inches
2 in diameter). Large main is allocated to all rate schedules based on annual weather
3 normalized throughput. Small main is allocated to all rate schedules with the exception of
4 Schedules 131/132 & 146 based on weather normalized throughput. Medium main is
5 allocated 33 percent to all rate schedules and 67 percent to all rate schedules except
6 Schedules 131/132 & 146 based on weather normalized throughput.

7 **Q. Why were small mains (less than two inches) not allocated to all rate**
8 **schedules?**

9 A. The smallest mains are generally located in isolated parts of the Company's
10 distribution system and are unlikely to provide benefits to the large customer loads served
11 on Schedules 131/132 and 146.

12 **Q. For medium mains (two & three inches), why were they split into two**
13 **groups?**

14 A. Historically, there have been two opposing points of view regarding the
15 allocation of mains. One view is founded on a belief that customers only benefit from pipe
16 through which gas molecules flow, or might flow, to reach their locations, and thus should
17 only be allocated a share of the cost of those specific pipe sizes. The other view would
18 argue that the gas distribution network provides an integrated system which benefits all
19 customers, regardless of the customer's location on the system and regardless of which
20 specific diameter of pipe they are served from. The Company believes that larger customers
21 do benefit, at some level, from the medium main on the gas distribution network. While
22 they may not benefit from all of the medium main, we believe it is not reasonable to assert
23 that medium main provides no benefit to large customers. Therefore, medium main has

1 been allocated 33 percent to all rate schedules, and 67 percent to all rate schedules except
2 Schedules 131/132 & 146, based on weather normalized throughput.

3 **Q. Why did the Company choose the one-third, two-thirds split, with one-**
4 **third of medium main being allocated to all rate schedules and two-thirds to all rate**
5 **schedules except 131/132 & 146?**

6 A. The Company considered the historical treatment of Schedule 131/132 and
7 146 customers and the benefits they have received associated with being part of the entire
8 gas distribution system. Historically, Schedule's 131/132 & 146 customers had some
9 assignment of costs related to small and medium main, but that assignment was minimal.
10 A one-third allocation for Schedule 131/132 & 146 customers provides a meaningful
11 allocation of medium main, and is consistent with the allocation both Puget Sound Energy²
12 and Commission Staff³ have proposed in recent proceedings.

13 **Q. Please summarize the benefits of the Company's proposed approach to**
14 **allocating distribution mains.**

15 A. There are four benefits to the Company's approach. First, this method
16 recognizes that all customers benefit from the gas distribution system of medium to large
17 mains as a whole, and not solely from the actual main through which gas flows to reach the
18 individual customer. Second, by exempting certain large rate schedules from the cost of the
19 smallest diameter mains (less than two inches), this approach acknowledges that the smallest
20 main is unlikely to benefit large Schedule 131/132 & 146 customers. Third, the Company's
21 approach recognizes that the benefits of medium diameter mains to large interruptible and
22 transportation customers are less than the benefits medium diameter mains provide to other

² Dockets UG-090705, UG-101644, and UG-111049, see Direct Testimony of Janet K. Phelps

³ Dockets UG-120437 and UG-140189, see Direct Testimony of Christopher T. Mickelson

1 customers, however the benefits, and therefore assigned cost, should be higher than
2 traditionally assigned. Finally, the Company's new methodology is relatively transparent
3 and easy to understand.

4 **Q. Has the Company's approach to the allocation of distribution mains
5 been proposed by other parties in previous general rate case filings?**

6 A. Yes. A similar approach for allocating distribution mains was proposed by
7 Commission Staff in the Company's prior two general rate cases (UG-140189 and UG-
8 120437). In addition, Puget Sound Energy (UG-111049, UG-101644, and UG-090705) has
9 also proposed a similar methodology in several of its most recent general rate case filings.

10

11 **General Plant Costs and Other A&G Expenses (Common Costs)**

12 **Q. What change is the Company proposing related to the allocation of
13 general plant costs and other A&G expenses (common costs)?**

14 A. The Company is proposing to allocate both general plant and other A&G
15 expenses, which are functionalized as common costs, based on the Company's blended 4-
16 part factor allocator (4-factor). This allocation factor is used on all common plant and other
17 A&G expenses and is the cost of service equivalent of the 4-factor allocator used in the
18 Company's results of operations reporting. The 4-factor has historically been utilized by the
19 Company to allocate common operating costs and plant between states (Washington, Idaho,
20 and Oregon) and among services (electric and natural gas) for purposes of the Company's
21 Commission Basis results of operations.

22 **Q. How were the allocation of general plant costs and other A&G expenses
23 (common costs) done in prior rate cases?**

1 A. In prior cases, the “other” A&G amounts received a combined allocation that
2 was one-half based on O&M expenses and one-half based on throughput. This allocation
3 replicated the methodology established in Docket No. UG-940814 for Washington Natural
4 (now Puget Sound Energy).

5 **Q. Please describe the components of the 4-factor?**

6 A. The 4-factor is comprised of the following four equally weighted
7 components:

- 8 • Direct O&M excluding resource costs and labor
- 9 • Direct O&M labor
- 10 • Number of customers
- 11 • Net direct plant

12 **Q. Please describe the benefits of the 4-factor allocator?**

13 A. There are two primary benefits of the 4-factor. First, it reflects a variety of
14 relationships that are consistent with the specific costs and plant items which are recognized
15 as serving multiple functions. Second, it provides consistency and balance between the way
16 common costs are allocated for purposes of Commission Basis results of operations and the
17 cost of service study used in general rate cases.

18 **Q. Has the 4-factor allocation been proposed by other parties in the**
19 **Company’s previous general rate case filings?**

20 A. Yes. Commission Staff proposed this same allocation methodology in
21 Avista’s prior general rate case (UG-140189).

22

V. RESULTS

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

A. The Base Case cost of service study presented in this filing is a fair representation of the costs to serve each customer group. The study indicates that the General Service Schedule 101 (serves most residential customers) and Transportation Schedule (146) are providing less than the overall rate of return (unity), and Large General, High Load Factor Large General, and Interruptible service schedules (111/112, 121/122 and 131/132) are providing more than unity. The following table shows the rate of return and the relative return ratio at present rates for each rate schedule:

Table No.1:

Base Case Results

<u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>
General Service Schedule 101	4.01%	0.83
Large General Service Schedules 111/112	8.89%	1.83
Large General Service – High Annual Load Factor Schedules 121/122	9.23%	1.90
Interruptible Service Schedules 131/132	7.48%	1.54
Transportation Service Schedules 146	<u>4.01%</u>	<u>0.83</u>
Total Washington Natural Gas System	<u>4.85%</u>	<u>1.00</u>

Q. Have you prepared an analysis showing the results of the cost of service study using the cost of service methodology utilized in prior cases?

A. Yes, the Company has prepared a cost of service study based on the methodology utilized in prior cases which replicates the methodology established in Docket No. UG-940814 for Washington Natural (now Puget Sound Energy).

1 The Excel model used to calculate the cost of service under the prior method has
 2 been included in its entirety electronically.

3 **Q. What are the results of the Company’s natural gas cost of service study**
 4 **under the prior method?**

5 A. Similar to the Base Case cost of service study, the prior method cost of
 6 service study indicates that the General Service Schedule 101 (serves most residential
 7 customers) and Transportation Schedule (146) are providing less than the overall rate of
 8 return (unity), and Large General, High Load Factor Large General, and Interruptible service
 9 schedules (111/112, 121/122 and 131/132) are providing more than unity.

10 The following table shows the rate of return and the relative return ratio at present
 11 rates for each rate schedule under the Company's prior cost of service methodologies for
 12 distribution main, general plant and other A&G expenses:

13 **Table No.2:**

14 **Prior Methodology Results**

<u>Customer Class</u>	<u>Rate of Return</u>	<u>Return Ratio</u>
General Service Schedule 101	4.55%	0.94
Large General Service Schedules 111/112	6.54%	1.35
Large General Service – High Annual Load Factor Schedules 121/122	6.28%	1.29
Interruptible Service Schedules 131/132	7.62%	1.57
Transportation Service Schedules 146	<u>2.49%</u>	<u>0.51</u>
Total Washington Natural Gas System	<u>4.85%</u>	<u>1.00</u>

20

21 The summary results of both studies were provided to Mr. Ehrbar for consideration
 22 in the development of the proposed rates.

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

2 A. Yes.