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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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

FOR AVISTA CORPORATION

(NATURAL GAS)

I. INTRODUCTION

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

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

Q. Would you briefly describe your responsibilities?

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

Q. Please describe your educational background and professional experience.

A. I am a 1999 graduate of Portland State University with a Bachelors degree in Business Administration, majoring in Accounting. In 2005 I graduated from Gonzaga University with a Masters degree in Business Administration. I joined the Company in March 2008 after spending eight years in both the public and private accounting sector. I started with Avista as a Natural Gas Accounting Analyst in the Company’s Resource

Accounting Department. In January 2009, I joined the State and Federal Regulation Department as a Regulatory Analyst. My primary responsibility was coordinating discovery for the Company's general rate case filings. In my current role as a Senior Regulatory Analyst, I am responsible for the Company's natural gas cost of service studies and revenue adjustments in all jurisdictions.

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

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

Q. Are you sponsoring any Exhibits in this case?

A. Yes. I am sponsoring Exhibit 14, Schedule 1 which includes a narrative of the natural gas cost of service study process, and Schedule 2, the natural gas cost of service study summary results.

Q. Were these Exhibits prepared by you or under your direction?

A. Yes they were.

II. NATURAL GAS REVENUE NORMALIZATION

Q. Would you please describe the natural gas revenue adjustment included in Company witness Ms. Andrews' pro forma results of operations?

A. Yes. Similar to the electric revenue normalization adjustment, sponsored by Company witness Ms. Knox, the natural gas revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2014 test period, and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Purchase Gas Cost Adjustment Schedule 150, which reflects the costs related to purchasing and transporting natural gas approved in the Company's last PGA filing, 2) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for prior deferred natural gas costs approved in the Company's last PGA filing, and 3) Rebate of 2013 Natural Gas Earnings Test and DSM Deferrals Schedule 197.[1]

Q. Does the Revenue Normalization Adjustment contain a component reflecting normalized natural gas costs?

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

Q. Have you determined the impact of each of the components of this adjustment?

A. Yes. The net operating income impact for each of the components is as follows:

1. Re-pricing of base distribution revenue <u>decreased</u> net operating income by $270,000.
2. Re-pricing base distribution unbilled revenue <u>increased</u> net operating income by $307,000,
3. The weather adjustment at present base rates <u>increased</u> net operating come by $664,000.
4. The elimination of the 2014 earnings sharing (customer share), <u>increased</u> net operating income by $137,000

[1] Documentation related to this adjustment is detailed in my workpapers accompanying this case.

The total net amount of the natural gas revenue normalization adjustment is an increase to net operating income of $838,000, as shown in adjustment column 2.07, on page 7 of Ms. Andrews Exhibit No. 12, Schedule 2.

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

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

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

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

Q. What data did you use to determine "normal" heating degree days?

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year. The calculation includes the 30-year period from 1985 through 2014.

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

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation is consistent with the methodology presented in Case No. AVU-G-12-07.

Q. What was the impact of natural gas weather normalization on the twelve months ended December 2014 test year?

A. Weather was warmer than normal during the months of May, June, October, and December, which was partially offset by a cooler than normal February. The adjustment to normal required the addition of 340 heating degree-days from October through June.[2] The adjustment to sales volumes was an addition of 2,662,260 therms which is approximately 2.3% of total billed usage.

III. NATURAL GAS COST OF SERVICE

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

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. 14, Schedule 1 explains

[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.

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.

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

A. The cost of service study provided by the Company as Exhibit 14, Schedule 2 is based on the twelve months ended December 2014 test year pro forma results of operations presented by Ms. Andrews in Exhibit 12, Schedule 2.

Q. Would you please explain the natural gas cost of service study presented in Schedule 2?

A. Yes. Exhibit 14, Schedule 2 is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return and the ratio of each schedule’s return to the overall return are shown on lines 38 and 39. This summary is provided to Company witness Mr. Ehrbar for his consideration regarding rate spread and rate design. The results will be presented later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a summary identifying specific customer-related costs embedded in the study.

The Excel model used to calculate the natural gas cost of service and supporting schedules has been included in its entirety both electronically and hard copy in the natural gas workpapers accompanying this case.

Q. Does the Natural Gas Base Case cost of service study utilize the methodology from the Company's last natural gas case in Idaho?

A. Yes, with the exception of a change related to the allocation of common costs detailed below, the Base Case cost of service study was prepared using the methodology accepted by the Idaho Commission in Case No. AVU-G-04-01, and presented in AVU-G-08-01, AVU-G-09-01, AVU-G-10-01, AVU-G-11-01 and AVU-G-12-07.

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

A. Underground storage costs are allocated by normalized winter throughput. Natural gas main investment has been segregated into large and small mains. Large usage customers that take service from large mains do not receive an allocation of small mains. System facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by coincident peak demand and throughput, respectively. Meter installation and services investment is allocated by number of customers weighted by the relative current cost of those items. General plant is allocated based on the Company's blended 4-part factor allocator (4-factor). Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts are allocated based on the Company's 4-factor. A detailed description of the methodology is included in Exhibit 14, Schedule 1.

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

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

A. The Company is proposing to allocate both general plant and other A&G expenses, which are functionalized as common costs, based on the Company's blended 4-part factor allocator ("4-factor"). This allocation factor is used on all common plant and other A&G expenses and is the cost of service equivalent of the

4-factor allocator used in the Company's results of operations reporting. The 4-factor has historically been utilized by the Company to allocate common operating costs and plant between states (Washington, Idaho, and Oregon) and among services (electric and natural gas) for purposes of determining results of operations.

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

A. In prior cases, the "other" A&G amounts received a combined allocation that was one-half based on O&M expenses and one-half based on throughput.

The Company has prepared a cost of service study based on the methodology utilized in prior cases for comparison purposes. The Excel model used to calculate the cost of service under the prior method has been included in its entirety electronically.

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

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

- Direct O&M excluding resource costs and labor
- Direct O&M labor
- Number of customers
- Net direct plant

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

A. There are two primary benefits of using the 4-factor to allocate general plant and other A&G expenses. First, it provides consistency and balance between the way common costs are allocated for purposes of results of operations and the cost of service study used in general rate cases. Second, it provides consistency with how common costs are allocated in the Company's electric cost of service study sponsored by Company witness Ms. Knox.

IV. 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 we believe provides a fair representation of the costs to serve each customer group. The study indicates that the General Service Schedule 101 (serving most residential customers) is providing less than the overall rate of return (unity), and Large General, Interruptible, and Transportation service schedules (111/112, 131/132 and 146) are providing more than unity. The following Table No. 1 shows the rate of return and the relative return ratio at present rates for each rate schedule:

Table No.1:

Base Case Results

Customer Class	Rate of Return	Return Ratio
General Service Schedule 101	5.42%	0.89
Large General Service Schedule 111/112	8.99%	1.48
Interruptible Service Schedule 131/132	6.70%	1.10
Transportation Schedule 146	7.72%	1.27
Total Idaho Natural Gas System	6.07%	1.00

The summary results of this study were provided to Mr. Ehrbar for consideration in the development of the proposed rates.

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

A. Yes.