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AVISTA Corp.

September 12, 2014

**Advice No. 14-04-G Supplemental/ UG-267 (Purchased Gas Cost Adjustment Filing)**

Public Utility Commission of Oregon
3930 Fairview Industrial Drive SE
Salem, OR 97302-1166

Attention: Filing Center

Pursuant to OAR 860-022-0070, ORS 757.210, ORS 757.259(5) and Order Nos. 08-504, 11-196 and 14-238 in Docket UM 1286, Avista Utilities hereby submits an original and 10 copies of the following listed tariff sheets applicable to its Oregon natural gas operations along with three (3) copies of supporting workpapers (which are not a part of the official filing). The Company requests that the following tariff sheets become effective on November 1, 2014:

| Oregon PUC Sheet No. | Title of Sheet | Canceling Oregon PUC Sheet No. |
|---|---|---|
| Supplemental Ninth Revision Tariff Sheet 461 | Purchased Gas Cost Adjustment Provision | Supplemental Eighth Revision Tariff Sheet 461 |
| Supplemental Seventh Revision Tariff Sheet 461A | Purchased Gas Cost Adjustment Provision | Supplemental Sixth Revision Tariff Sheet 461A |
| Supplemental Fourth Revision Tariff Sheet 462 | Gas Cost Rate Adjustment | Supplemental Third Revision Tariff Sheet 462 |

This filing is a Purchased Gas Cost Adjustment (PGA) to change rates within Avista Utilities' natural gas service schedules to reflect the projected cost of natural gas pursuant to tariff Schedule 461, "Purchased Gas Cost Adjustment Provision". Schedule 461 sets forth the estimated purchased natural gas costs for the forthcoming year (November 1, 2014 through October 1, 2015). The difference between the actual cost of natural gas purchased and the amount collected from customers (i.e., the amortization rate pertaining to the PGA balancing account) are passed through to customers through Schedule 462, "Gas Cost Rate Adjustment".

Tables 1 through 3 below summarize the changes in the 1) forward looking commodity costs included in Schedule 461, 2) the demand costs included in Schedule 461, and 3) the combined changes to Schedule 461 (both commodity and demand):

**Table 1 - Schedule 461 Commodity**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.39869 | $0.41155 | **$0.01286** |
| 440 | $0.39869 | $0.41155 | **$0.01286** |

**Table 2 - Schedule 461 Demand**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.21200 | $0.20914 | **-$0.00286** |
| 440 | $0.00000 | $0.00000 | **$0.00000** |

**Table 3 - Schedule 461 Commodity + Demand**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.61069 | $0.62069 | **$0.01000** |
| 440 | $0.39869 | $0.41155 | **$0.01286** |

## Commodity Costs (Schedule 461)

As shown in the Table 1 above, the estimated commodity cost (WACOG) change is an increase of 1.286 cents per therm. The proposed WACOG is 41.155 cents per therm compared to the present WACOG of 39.869 cents per therm included in rates. The winter of 2013-2014 was significantly colder than normal not only in the western United States but nationally. The colder than normal weather led to an increase in overall natural gas demand and a heavy reliance on natural gas storage reserves. Natural gas storage both nationally and in the west were drawn down well below their five year average balance. The cold weather and increased demand increased wholesale natural gas prices both in the winter as well as in the summer as more natural gas is required to replenish storage facilities. Storage may not be full by the coming winter, and this storage imbalance may persist through the coming winter. While prices are currently forecast to remain higher throughout the upcoming winter, natural gas prices in future winter periods are below the upcoming winter. As a result, the market prices indicate that the storage imbalance issue is temporary, and the long-term trend of lower priced gas should return.

Avista has been hedging natural gas on both a periodic and discretionary basis throughout 2014 for the forthcoming PGA year. Approximately 43% of estimated annual load requirements for the PGA year (November 2014 through October 2015) will be hedged at a fixed price, comprised of: 1) volumes hedged for a term of one year or less and 2) volumes from prior multi-year hedges. Through August 31, 2014, a majority of the planned hedge volumes for the PGA year have been executed at a weighted average price of $4.18 per dekatherm ($0.418 per therm).

The Company has approximately 920,000 dekatherms of underground storage capacity at Jackson Prairie available for its Oregon customers[1]. Total underground storage capacity represents approximately 11% of annual load requirements (19% of load requirements during the Dec.-Mar. withdrawal period). The projected storage costs as of August 31, 2014 for all storage volumes is $4.05 per dekatherm.

As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2014) historical average of forward prices weighted by supply basin to determine the estimated cost associated with index/spot volumes. These index/spot volumes represent approximately 46% of estimated annual volumes and the annual weighted average price for these volumes is $3.72 per dekatherm ($0.372 per therm).

The information contained in the Company's responses to "Natural Gas Portfolio Development Guidelines" describes the Company's Natural Gas Procurement Plan ("Procurement Plan"). The Company's Procurement Plan uses a diversified approach to procure natural gas for the upcoming year. While the Procurement Plan generally incorporates a structured approach for the hedging portion of the portfolio, the Company exercises flexibility and discretion in all areas of the plan based on changes in the wholesale market. The Company meets with the Commission Staff quarterly[2] to discuss the state of the wholesale market and the status of the Company's Procurement Plan, among other things. Should there be a deviation from the Procurement Plan due to a change in market dynamics etc., the Company documents and communicates any such changes with the Risk Management Committee and provides updates to Commission Staff.

**Demand Costs (Schedule 461)**

Demand costs reflect the cost of pipeline transportation to the Company's system, as well as fixed costs associated with natural gas storage. As shown in the Table 2 above, demand costs are expected to be relatively stable, with the Company proposing only a slight decrease of 0.286 cents per therm. No significant pipeline rate changes are anticipated for the upcoming PGA year. The primary reason for the decrease in the demand rate per therm is due to the cost of the fixed price contracts being spread over a slightly higher level of natural gas retail sales.

**Amortization of Deferral Accounts (Schedule 462)**

Tables 4 through 6 below summarize the changes in the commodity and demand amortization rates included in Schedule 462, and the combined change to Schedule 462 (both commodity and demand):

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[1] At the present time, Avista Utilities owns a total of 8,528,013 dekatherms (Dth) of capacity. This capacity comes with a withdrawal capability of 398,667 Dth per day (deliverability). Oregon's current share of that capacity is 823,337 Dth and 52,000 Dth of deliverability. Additionally, the Company has leased an additional 95,565 Dth of Capacity (2,623 Dth of deliverability) from Jackson Prairie for the benefit of Oregon customers. The combined leased and owned storage provides Oregon customers storage capacity of 918,902 Dth and deliverability of 54,623 Dth per day.

[2] The Northwest Industrial Gas Users (NWIGU) and Citizens' Utility Board (CUB) are invited to, and attend, each Quarterly meeting.

**Table 4 - Schedule 462 Commodity Amortization**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | -$0.00728 | $0.05099 | **$0.05827** |
| 440 | -$0.00728 | $0.05099 | **$0.05827** |

**Table 5 - Schedule 462 Demand Amortization**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | -$0.07737 | -$0.05226 | **$0.02511** |
| 440 | $0.00000 | $0.00000 | **$0.00000** |

**Table 6 - Schedule 462 Commodity + Demand Amortizations**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | -$0.08465 | -$0.00127 | **$0.08338** |
| 440 | -$0.00728 | $0.05099 | **$0.05827** |

As shown in the Table 4 above, the current Commodity Amortization amount approved in the Company's 2013 PGA is a refund rate of approximately 0.7 cents per therm. For reasons discussed earlier in this letter, actual wholesale natural gas prices were higher than the level approved in the Company's 2013 PGA. As a result, commodity costs exceeded collections from customers and created a surcharge deferral balance of approximately $4.1 million or 5.1 cents per therm.

As shown in Table 5 above, the current Demand Amortization is a refund rate of approximately 7.7 cents per therm, based on a deferral balance of approximately $6.5 million. The amortization balance currently being amortized was primarily the result of the expiration of a contracted demand rate with Gas Transmission Northwest (GTN) for the Medford Lateral. The actual demand balance included in the Company's filing is approximately $4.0 million. The new balance primarily is the result of the unamortized balance from the 2013 PGA, as the new cut-off date of June 30 is to be used for PGA amortizations starting with this filing.[3] In prior years, the Company would have used estimated amortization balances through September 30.

With the exception of Schedule 440, the overall net impact as it relates to the combined commodity and demand amortization rates included in Schedule 462 is an increase (i.e., a lower rebate rate) of approximately 8.4 cents per therm as shown in Table 6 above.

**<u>3% Test</u>**

Pursuant to ORS 757.259 and OAR 860-027-0300, the overall annual average rate impact of the amortizations authorized under the statutes may not exceed three percent of the natural gas utility's gross revenues for the preceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. As shown on Attachment A of the Company's PGA workpapers, total <u>gross</u> revenues for calendar year 2013 was $185,283,342. The total amortization revenue requested for the "Prior Period Gas Cost

[3] See Order No. 14-238 in Docket UM-1286.

Deferral" as shown in Attachment A is $98,921. The resulting annual average rate impact from the PGA amortization is 0.1% and falls within the requirements of the statute[4].

The combination of the "Prior Period Gas Cost Deferral" and the "Non-Gas Cost Amortization" related to the Company's Demand Side Management filing made on July 31, 2014, is a total amortization revenue request of $1,484,787. The resulting annual average rate impact from both amortizations is 0.8% and falls within the requirements of the statute[5].

## Other Information

This filing reflects an overall annual revenue *increase* of $7.73 million, or 8.3% effective November 1, 2014. After combining the impact of this PGA filing with the two other regulatory filings made on July 31, 2014 which also have a November 1, 2014 effective date[6], a residential customer using an average of 47 therms a month could expect their bill to *increase* by $4.36, or 7.8 percent, for a revised monthly bill of $60.33 effective November 1, 2014.

Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by the three filings, and the annual revenue before and after the impact of the proposed rate changes, are as follows:

| **Rate Schedule** | **Average Number of Customers** |
|---|---|
| Schedule 410 | 86,184 |
| Schedule 420 | 11,322 |
| Schedule 424 | 81 |
| Schedule 440 | 35 |
| Schedule 444 | 3 |

| Sch No | Description | Present Revenues | Proposed Revenues | Revenue Incr (Decr) | Percent Incr (Decr) | Use (Therms) | Present Monthly Cost | Proposed Monthly Cost | Change to Monthly Cost | % Change Monthly Cost |
|---|---|---|---|---|---|---|---|---|---|---|
| 410 | Residential | $ 58,136,705 | $ 62,698,352 | $ 4,561,647 | 7.8% | 47 | $ 55.97 | $ 60.33 | $ 4.36 | 7.8% |
| 420 | General | $ 25,982,745 | $ 28,436,643 | $ 2,453,899 | 9.4% | 193 | $ 190.85 | $ 208.88 | $ 18.03 | 9.4% |
| 424 | Large General | $ 3,053,131 | $ 3,463,155 | $ 410,025 | 13.4% | 4,289 | $ 2,985.01 | $ 3,385.51 | $ 400.50 | 13.4% |
| | | | | $ - | | | | | | |
| 440 | Interruptible | $ 1,990,047 | $ 2,268,868 | $ 278,821 | 14.0% | 6,101 | $ 3,097.36 | $ 3,531.32 | $ 433.96 | 14.0% |
| | | | | $ - | | | | | | |
| 444 | Seasonal | $ 181,228 | $ 204,863 | $ 23,635 | 13.0% | 5,558 | $ 3,979.82 | $ 4,498.81 | $ 518.99 | 13.0% |

Below is a table showing the net impact to the Company's customers, by rate schedule, inclusive of all of the filings made by the Company[7]:

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[4] Please see attachment C included in the Purchase Gas Adjustment workpapers.
[5] Id.
[6] On July 31, 2014, Avista filed to update effective November 1, 2014 Schedule 476 (Intervenor Funding Schedule - Advice No. 14-05-G), and Schedule 478 (DSM Cost Recovery - Advice No. 14-06-G).
[7] Id.

| Rate Schedule | Proposed Rate Change[8] |
|---|---|
| Schedule 410 | 7.8% |
| Schedule 420 | 9.3% |
| Schedule 424 | 13.2% |
| Schedule 440 | 14.2% |
| Schedule 444 | 12.9% |
| Schedule 456 | 1.1% |

Included with this filing is the information in response to the Natural Gas Portfolio Development Guidelines and the PGA Filing Guidelines, as approved by the Commission in Order No. 09-248 and as amended in Order No. 10-197, Order No. 11-196 and Order No. 14-238. The Company will issue a media release coincident with this filing and provide notice to customers via a newspaper advertisement following is supplemental filing.

Please direct any questions regarding this filing to Patrick Ehrbar at (509) 495-8620.

Sincerely,

David J. Meyer
Vice President and Chief Counselor for
Regulatory and Governmental Affairs

[8] Includes filed rate changes to Schedules 461, 462, 476, and 478.

# CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that I have this day served Avista Utilities', a division of Avista Corp, 2014 Purchase Gas Cost Adjustment upon the parties listed below by mailing a copy thereof, postage prepaid and by electronic mail or CD.

Bob Jenks
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I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 12th day of September, 2014.

Patrick Ehrbar
Manager, Rates & Tariffs

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

# AVISTA UTILITIES
ADVICE NO. 14-04-G Supplemental

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**Tariff Sheets**

September 12, 2014

# SCHEDULE 461

## PURCHASED GAS COST ADJUSTMENT PROVISION – OREGON

APPLICABILITY:

This schedule applies to all schedules for natural gas sales service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE:

The purpose of this provision is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

RATE:

(a) The rates of gas Schedules 410, 420, 424 and 444 are to be increased by $0.62069 per therm in all blocks of these rate schedules. (I)
(b) The rate of gas Schedule 440 is to be increased by $0.41155 per therm in all blocks of these rate schedules. (I)
(c) The rates of transportation Schedule 456 are to be increased by $0.0000 per therm in all blocks.

A. DEFINITIONS:

1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of gas associated with pipeline imbalances, plus propane costs, plus odorization charges, less Commodity Off-System Sales Revenues received during the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, less all transportation demand charges embedded in commodity costs.

2. Commodity Off-System Sales Revenues: Revenues received from the sale of natural gas to a party other than the Company's Oregon sales customers less costs associated with the sales transactions.

3. Variable Transportation Costs: Variable transportation costs, including pipeline volumetric charges and other variable costs related to volumes of commodity delivered to sales customers.

4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release Benefits, plus or minus actual pipeline refunds or surcharges.

5. Demand Costs: Fixed monthly pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity cost.

SCHEDULE 461 (continued)

PURCHASED GAS COST ADJUSTMENT PROVISION – OREGON

6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to Customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full pipeline rate, and 80% of the capacity release revenues in excess of full pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

7. Estimated Weighted Average Cost Of Gas (WACOG): The estimated WACOG is calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales.

a. "Forecasted Purchases" means November 1 – October 31 forecasted sales, plus a percentage for "Distribution System Unaccounted for Gas."
b. "Distribution System Unaccounted for Gas" means the 5-year average of actual unaccounted for gas, not to exceed 2%.
c. "Adjusted Contract Prices" means contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel-in-kind and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

The Estimated WACOG per therm is as follows:

| | | |
|---|---|---|
| With Gross Revenue Factor | $0.41155 | (I) |
| Without Gross Revenue Factor | $0.39962 | (I) |

8. Estimated Non-Commodity Cost per Therm: The estimated Non-Commodity Cost per therm shall be equal to estimated Demand Costs, less estimated Capacity Release Benefits, plus or minus estimated pipeline refunds or surcharges, divided by November 1 – October 31 forecasted sales.

The Estimated Non-Commodity Cost per therm is as follows:

| | | |
|---|---|---|
| With Gross Revenue Factor | $0.20914 | (D) |
| Without Gross Revenue Factor | $0.20308 | (D) |

9. Forecasted Monthly Calendar Sales Volumes: Forecasted billed sales therms, adjusted for estimated unbilled therms, for Schedules 410, 420, 424, 440, and 444.

# SCHEDULE 462

## GAS COST RATE ADJUSTMENT – OREGON

APPLICABILITY:

This schedule applies to all schedules for natural gas sales service within the entire territory served by the Company in the State of Oregon.

PURPOSE:

The purpose of this provision is to allow the Company to pass through the differences between the actual cost of gas purchased and transported for customer usage and the amount collected from customers. These differences are accumulated in a sub-account of Account 191 for later refund or surcharge to customers.

RATE:

(a) The rates of gas Schedules 410, 420, 424 and 444 are to be decreased by $0.00127 per therm. (I)

(b) The rate of gas Schedule 440 is to be increased by $0.05099 per therm. (C) (I)

AMORTIZATION OF ACCOUNT 191 SUB-ACCOUNT DEFERRALS:

The Account 191 sub-account deferred balances approved for surcharge or refund to customers shall include interest calculated on a monthly basis using the interest rate(s) approved by the Commission.

The surcharge or refund rate shall be adjusted annually as part of the annual Purchased Gas Adjustment (PGA) filing.

AMOUNT OF ADJUSTMENT:

The amount of adjustment to be made to customers' rates shall consist of the sum of the changes in the Embedded Commodity Cost and Non-Commodity Cost deferral accounts and the change in amortization rates of the Account 191 sub-accounts, as well as other gas cost related deferral accounts as the Commission may approve.

GENERAL RULES AND REGULATIONS:

This schedule is subject to the General Rules and Regulations contained in this tariff and to those prescribed by regulatory authorities. This schedule is an automatic adjustment clause (PGA) as described in ORS 757.210(1) and is subject to the customer notification requirements as described in OAR 860-022-0017.