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September 15, 2017

Advice No. 17-02-G Supplemental /UG-339 (Purchased Gas Cost Adjustment Filing)

Public Utility Commission of Oregon
201 High St SE
Suite 100
Salem, OR 97301

Attention: Filing Center

Pursuant to OAR 860-022-0070, ORS 757.210 and Order Nos. 08-504, 11-196 and 14-238 in Docket No. UM 1286, Avista Utilities hereby submits for electronic filing the following listed tariff sheets applicable to its Oregon natural gas operations along with three (3) copies of confidential supporting workpapers (which are not a part of the official filing).[1] In accordance with guidance provided in Docket No. UM 1286 the Company has updated commodity costs to reflect index purchases based on 60 day basin-weighted average prices and executed hedges as of August 31, 2017. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 28, 2017, and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on November 1, 2017:

Oregon PUC Sheet No.	**Title of Sheet**	**Canceling Oregon PUC Sheet No.**
Supplemental Twelfth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Eleventh Revision Tariff Sheet 461
Supplemental Tenth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Ninth Revision Tariff Sheet 461A

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

[1] The Company has enclosed a disk which contains confidential workpapers.

gas costs for the forthcoming year (November 1, 2017 through October 1, 2018). 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".

Table Nos. 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 No. 1 - Schedule 461 Commodity

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.24529	$0.24036	**($0.00493)**
440	$0.24529	$0.24036	**($0.00493)**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.19759	$0.18539	**($0.01220)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.44288	$0.42575	**($0.01713)**
440	$0.24529	$0.24036	**($0.00493)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is 24.036 cents per therm, a decrease of 0.493 cents per therm from the present WACOG of 24.529 cents per therm included in customer's rates. The Commodity WACOG is a slight reduction due to the continued high natural gas production levels and an abundance of natural gas in storage.

Avista has been hedging natural gas on both a periodic and discretionary basis throughout 2016-2017 for the forthcoming PGA year. Approximately 34% of estimated annual load requirements for the PGA year (November 2017 through October 2018) has been 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, 2017, the Company's executed hedge costs is $2.626 per dekatherm ($0.2626 per therm). As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2017) 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 66% of estimated annual volumes and the annual weighted average price for these volumes is $2.109 per dekatherm ($0.2109 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 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 material changes in market dynamics etc., the Company documents and communicates any such changes with the Company's 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 No. 2 above, demand costs are expected to decrease from $0.19759 per therm to $0.18539, for a proposed reduction of approximately $0.01220 per therm. This reduction is primarily due to new transportation rates for Williams Northwest Pipeline effective both on January 1, 2018 and October 1, 2018.[3]

Amortization of Deferral Accounts (Schedule 462)

Table Nos. 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):

Table No. 4 - Schedule 462 Commodity Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.08273)	($0.05278)	**$0.02995**
440	($0.08273)	($0.05278)	**$0.02995**

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.01251	($0.02580)	**($0.03831)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.07022)	($0.07858)	**($0.00836)**
440	($0.08273)	($0.05278)	**$0.02995**

For the Commodity portion of the amortization rate, actual wholesale natural gas prices were lower than the level approved in the Company's 2016 PGA.[4] Reduced commodity rates, combined

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

[3] The Williams Northwest Pipeline Settlement agreement is pending approval before the Federal Energy Regulatory Commission (FERC).

[4] Per Order 13-11-G, Avista created an account (191715) that accrues, with interest, 90% of the additional revenues received from Collins Forest Products after comparing their prior Special Contract rates to the new transitional rates approved in the above referenced Order. As per the Order, the accrued balance ($31,583.07) is being returned to ratepayers through this PGA rate adjustment.

with optimization benefits, resulted in an excess of revenue collected from customers compared to the Company's costs. This created a rebate deferral balance of approximately $4.6 million (compared to $5.8 million in present rates). In addition, higher demand due to colder than normal weather, resulted in the commodity amortization balance to be almost fully amortized, with a small balance of $37,000 remaining. The combination of the current commodity deferrals and residual account balance resulted in an amortization rebate rate of $.05278 per therm compared to the present commodity rebate amortization rate of $0.08273, an increase of $0.02995.

For the demand portion of the amortization rate, the deferral balance as of June 30, 2017 is a rebate of approximately $2.2 million (compared to a surcharge of approximately $995,000 in present rates). The colder than normal weather for the Pacific Northwest increased demand, resulting in an over-collection of demand.

Combining the commodity and demand amortization balances results in an overall reduction in the amortization rates included in Schedule 462 as shown in Table No. 6 above.

3% Test

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 proceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. As shown on Attachment C of the Company's PGA workpapers, total gross revenue for calendar year 2016 was $156,148,758 and Total Prior Period Gas Cost Deferral True-up is a rebate of $6,762,827. The resulting annual average rate impact from the PGA amortization is (4.3%).[5] Including the effect of the Company's Natural Gas Decoupling Amortization (Advice No.17-05-G), the resulting annual average rate impact from the Company's qualifying amortization is (2.9%).[6]

Other Information

The PGA filing reflects an overall annual revenue decrease of $2.0 million, or 2.1% effective November 1, 2017. Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by the four filings with an effective date of November 1, 2017, 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	89,839
Schedule 420	11,779
Schedule 424	86
Schedule 440	35
Schedule 444	4
Schedule 456	38

[5] Please see attachment C included in the Purchase Gas Adjustment workpapers.
[6] The effects of the Company's Intervenor Funding rate adjustment (Advice No. 17-03-G) is excluded from the 3% test.

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	$ 60,479,089	$ 59,189,710	$ (1,289,379)	-2.1%	47	$ 56.10	$ 55.10	$ (1.00)	-1.8%
420	General	$ 27,258,404	$ 26,548,334	$ (710,070)	-2.6%	197	$ 192.78	$ 187.75	$ (5.03)	-2.6%
424	Large General	$ 2,419,566	$ 2,308,179	$ (111,387)	-4.6%	4,240	$ 2,347.66	$ 2,239.58	$ (108.08)	-4.6%
				$ -						
440	Interruptible	$ 1,259,259	$ 1,371,630	$ 112,371	8.9%	10,592	$ 2,969.70	$ 3,234.70	$ 265.00	8.9%
				$ -						
444	Seasonal	$ 139,285	$ 133,110	$ (6,175)	-4.4%	5,155	$ 2,963.52	$ 2,832.12	$ (131.40)	-4.4%

After combining the impact of this PGA filing with the three other regulatory filings which also have a November 1, 2017 effective date[7], a residential customer using an average of 47 therms a month could expect their bill to *decrease* by $1.00, or 1.8 percent, for a revised monthly bill of $55.10 effective November 1, 2017.

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 that have a November 1, 2017 effective date:

Rate Schedule	Proposed Rate Change[8]
Schedule 410	(1.8)%
Schedule 420	(2.1)%
Schedule 424	(3.7)%
Schedule 440	17.2%
Schedule 444	(3.6)%
Schedule 456	(1.2)%

Included with the original filing (July 28, 2017) 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 provide notice to customers via newspaper advertisement with this updated PGA filing. A media release was released coincident with the Company's initial filing in July 2017.

Please direct any questions regarding this filing to Annette Brandon at (509) 495-4324.

Sincerely,

Patrick D. Ehrbar
Senior Manager, Rates and Tariffs

[7] On July 28, 2017, Avista filed to update effective November 1, 2017 Schedule 476 (Intervenor Funding Schedule - Advice No. 17-03-G), Schedule 477/478/479 (DSM/Residual Account/SB408, Advice No. 17-04-G), and Decoupling Mechanism – Natural Gas (Advice No. 17-05-G). The net effect of all filings is a revenue reduction of $1.1 million or 1.1%.

[8] Includes filed rate changes to Schedules 461, 462, 475,476, 477, 478, and 479.

November 1, 2017
As of August 31, 2017
(As filed – these are not approved rate changes)

1	**Company**	**Avista**	
2	**Docket Numbers**	UG-339	
3	**Advice No.**	17-02-G Supplemental	
4	**Principal Analysts**	Lisa Gorsuch	
5	**Current Customer Charge - Residential ($)**	$9.00	
6	**Average Monthly Therm Use (Residential)**	47	
7	**Current Energy Charge/Rate (dollars/therm)**	Billing - $1.00381 Base - $0.58062	
8	**PGA Base Gas Cost Change - Residential (dollars/therm)**	($0.00493)	Commodity Only – including revenue sensitive
9	**Other Temporary Rate Increments - Residential (dollars/therm)**	($0.01220) Demand ($0.00836) Amort	Demand, Amortization, including revenue sensitive
10	**Permanent Base Rate Adjustment – Residential (dollars/therm)**	$0.00	
11	**Overall Change - Residential Rate (dollars/therm)**	($0.02549)	Gas, Demand and Amortization
12	**Proposed Tariff Rate - Residential (dollars/therm)**	$0.98225	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	**Average monthly bill change for typical residential customer ($/bill on an annual basis)**	($1.0)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	**Overall Change - Residential Revenue (%)**	(2.1%)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
15	**Overall Change – Commercial & Industrial firm (%)**	Commercial = (2.3%) Industrial = (3.8%)	Including all filings (Gas and Non-gas) – See Attachment D
16	**WACOG (dollars/therm) – not revenue-sensitized**	$0.23273	
	Comments – Other (continued)		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 17-02-G Supplemental

Tariff Sheets

September 15, 2017

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 $0.42575 per therm in all blocks of these rate schedules. (R)
(b) The rate of gas Schedule 440 is to be increased by $0.24036 per therm in all blocks of these rate schedules. (R)
(c) The rates of transportation Schedule 456 are to be increased by $0.0000 per therm in all blocks.

A. DEFINITIONS:

1. <u>Actual Commodity Cost:</u> 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. <u>Commodity Off-System Sales Revenues</u>: 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. <u>Variable Transportation Costs</u>: Variable transportation costs, including pipeline volumetric charges and other variable costs related to volumes of commodity delivered to sales customers.

4. <u>Actual Non-Commodity Cost</u>: 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. <u>Demand Costs:</u> 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	$0.24036	(R)
Without Gross Revenue Factor	$0.23273	(R)

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	$0.18539	(R)
Without Gross Revenue Factor	$0.17951	(R)

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