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September 7, 2018

Advice No. 18-01-G Supplemental /UG-360 (Purchased Gas Cost Adjustment Filing)

Public Utility Commission of Oregon
Attn: Filing Center
201 High St SE
Suite 100
Salem, OR 97301

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 electronically the following listed tariff sheets applicable to its Oregon natural gas operations. 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, 2018. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 27, 2018, and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on November 1, 2018:

Oregon PUC Sheet No.	**Title of Sheet**	**Canceling Oregon PUC Sheet No.**
Supplemental Fourteenth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Thirteenth Revision Tariff Sheet 461
Supplemental Twelfth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Eleventh 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 gas costs for the forthcoming year (November 1, 2018 through October 1, 2019). 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	$0.20072	$0.20323	**$0.00251**
440	$0.20072	$0.20323	**$0.00251**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.18539	$0.16723	**($0.01816)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.38611	$0.37046	**($0.01565)**
440	$0.20072	$0.20323	**$0.00251**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is $0.20323 per therm, a slight increase of $0.00251 per therm from the present WACOG of $0.20072 per therm included in customer's rates. In January 2018 Avista filed an out-of-cycle PGA, reducing the commodity WACOG from $0.24036 per therm to $0.20072 per therm primarily due to continued low natural gas prices due to high natural gas production levels and an abundance of natural gas in storage. In doing so, we were able to pass back these lower prices to our customers during the winter heating season when it was needed most. Since that time, prices have continued to stay within the range estimated in that filing, resulting in only a slight increase in Commodity rate of $0.00251 per therm for the upcoming PGA year.

Avista has been hedging natural gas on both a periodic and discretionary basis throughout 2018-2019 for the forthcoming PGA year. Approximately 35% of estimated annual load requirements for the PGA year (November 2018 through October 2019) 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, 2018, the Company's executed hedge costs is $2.484 per dekatherm ($0.2484 per therm).

As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2018) 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 65% of estimated annual volumes and the annual weighted average price for these volumes is $1.639 per dekatherm ($0.1639 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[1] 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 $0.18539 per therm to $0.16723 per therm, for a proposed reduction of approximately $0.01816 per therm. This reduction is primarily due to costs related to our Canadian pipeline transportation contracts.[2]

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	($0.05278)	($0.08021)	**($0.02743)**
440	($0.05278)	($0.08021)	**($0.02743)**

[1] Alliance of Western Energy Consumers (AWEC) and Citizens' Utility Board (CUB) are invited to, and attend, each Quarterly meeting.

[2] In previous years, due to the U.S and Canadian currency being close to par, the Company kept Canadian contracts in Canadian dollars in PGA filings.

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.02580)	($0.01383)	**$0.01197**
440	$0.00000	$0.00000	**$0.00000**

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.07858)	($0.09404)	**($0.01546)**
440	($0.05278)	($0.08021)	**($0.02743)**

As noted in the Commodity section above, commodity costs remained fairly close with what was forecasted in the Company's out-of-cycle PGA filed in January 2018. However, by utilizing transportation capacity not needed to serve load, the Company was able to capture price variability between basins in the daily market which further reduced overall commodity costs for the benefit of our customers. This was the primary contributor to the increase in the commodity rebate from the present of $.05278 per therm to the proposed $0.09404.

For the demand portion of the amortization rate, the deferral balance as of June 30, 2018 is a rebate of approximately $1.1 million as compared to $2.1 million the previous year. This difference is primarily due to the changes in weather for the Pacific Northwest between 2016-2017 and 2017-2018. The winter of 2016-2017 was colder than normal which resulted in an over-amortized demand balance of $2.1 million (rebate). The winter of 2017-2018 was, on average, closer to normal which resulted in a smaller demand deferral of $1.1 million (rebate). This change is reflected in the previous demand amortization rebate rate of $0.2580 per therm vs. the proposed rebate rate of $0.1383

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 2017 was $160,211,060 and Total Prior Period Gas Cost Deferral True-up is a rebate of $8,210,020. The resulting annual average rate impact from the PGA amortization is (5.1%).[3]

Including the effect of the Company's other four amortization rates filed coincident with the initial July PGA filing (Natural Gas Decoupling Amortization Advice No. 18-02-G, Demand Side Management Amortization Advice No.18-03-G, Intervenor Funding Advice No. 18-04-G and

[3] Please see attachment C included in the Purchase Gas Adjustment workpapers.

Bank Payment Fee Free Amortization Advice No. 18-05-G[4]) the resulting annual average rate impact from the Company's qualifying amortization is (7.0%).

Other Information

The PGA filing reflects an overall annual revenue decrase of $2.7 million, or 2.9% effective November 1, 2018. 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, 2018, 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	91,122
Schedule 420	11,827
Schedule 424	88
Schedule 440	37
Schedule 444	3
Schedule 456	38

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	$ 59,705,765	$ 58,117,067	$ (1,588,698)	-2.7%	47	$ 54.89	$ 53.42	$ (1.47)	-2.7%
420	General	$ 27,419,349	$ 26,553,819	$ (865,530)	-3.2%	196	$ 193.17	$ 187.07	$ (6.10)	-3.2%
424	Large General	$ 2,118,852	$ 1,985,445	$ (133,407)	-6.3%	4,076	$ 2,013.98	$ 1,887.18	$ (126.80)	-6.3%
				$ -						
440	Interruptible	$ 1,314,232	$ 1,200,936	$ (113,296)	-8.6%	10,380	$ 3,000.55	$ 2,741.88	$ (258.67)	-8.6%
				$ -						
444	Seasonal	$ 130,784	$ 122,881	$ (7,903)	-6.0%	6,351	$ 3,269.62	$ 3,072.04	$ (197.58)	-6.0%

After combining the impact of this PGA filing with the four other regulatory filings which also have a November 1, 2018 effective date[5], a residential customer using an average of 47 therms a month could expect their bill to *decrease* by $4.56, or 8.3 percent, for a revised monthly bill of $50.33 effective November 1, 2018.

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[4] Per the requirements of UM1286 Order No. 14-238, the Company is to file concurrent with its annual Results of Operations filing a notice of "intent to request amortization effective November 1, for any non-gas cost deferral it intends to amortize coincident with the PGA, that requires an earnings test. The Company inadvertently failed to provide such notice in early 2018 in regards to the Bank Payment Fee Free amortization (Advice No. 18-05-G) which is filed coincident with the initial PGA filing in July 2018. The Bank Payment Fee Free deferral was authorized in UM 1759, Order No. 16-122 for future recovery of costs associated with the waiver of bank fees for Residential customers. After discussions with Staff, due to the immateriality of this filing (approximately $77,000 or 0.0478% of gross revenue), we were advised to proceed with the filing this year.

[5] On July 27, 2018 , Avista filed to update effective November 1, 2018 Schedule 475 Decoupling (Advice No. 18-02-G), Schedule 476 Intervenor Funding (Advice No. 18-04-G), Schedule 478 Demand Side Management (Advice No 18-03-G), Schedule 484 Bank Fee Free (Advice No. 18-05-G). The net effective of all filings (including PGA) is a revenue reduction of $7.8 million or 8.3%.

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, 2018 effective date:

Rate Schedule	Proposed Rate Change[6]
Schedule 410	(8.3)%
Schedule 420	(8.1)%
Schedule 424	(16.1)%
Schedule 440	(24.6)%
Schedule 444	(15.5)%
Schedule 456	0.7%
Total	(8.3)%

Included with the original filing (July 27, 2018) 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 2018. The Company has provided, via overnight mail, one electronic disc which contains confidential supporting workpapers and one electronic disc which contains non-confidential workpapers (which are not a part of the official filing).[7]

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

Sincerely,

Patrick D. Ehrbar
Director of Regulatory Affairs

[6] Includes filed rate changes to Schedules 461, 462, 475,476, 478, and 484.
[7] For convenience, each party to this proceeding has also been copied electronically on the filing, and mailed overnight compact discs for confidential and non-confidential workpapers.

November 1, 2018
As of September 7, 2018
(As filed – these are not approved rate changes)

1	Company	Avista	
2	Docket Numbers	UG-360	
3	Advice No.	18-01-G Supplemental	
4	Principal Analysts	Brian Fjeldheim	
5	Current Customer Charge - Residential ($)	$10.00	
6	Average Monthly Therm Use (Residential)	47	
7	Current Energy Charge/Rate (dollars/therm)	Billing - $0.95504 Base - $0.58399	
8	PGA Base Gas Cost Change - Residential (dollars/therm)	$0.00251	Commodity Only – including revenue sensitive
9	Other Temporary Rate Increments - Residential (dollars/therm)	($0.01816) Demand ($0.01546) Amort	Demand, Amortization, including revenue sensitive
10	Permanent Base Rate Adjustment – Residential (dollars/therm)	$0.00	
11	Overall Change - Residential Rate (dollars/therm)	($0.03111)	Gas, Demand and Amortization
12	Proposed Tariff Rate - Residential (dollars/therm)	$0.85806	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	Average monthly bill change for typical residential customer ($/bill on an annual basis)	($4.56)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	Overall Change - Residential Revenue (%)	(8.3%)	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
15	Overall Change – Commercial & Industrial firm (%)	Commercial = (8.1%) Industrial = (16.1%)	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
16	WACOG (dollars/therm) – not revenue-sensitized	$0.19678	
	Comments – Other (continued)		

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES
ADVICE NO. 18-01-G Supplemental

Tariff Sheets

September 7, 2018

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 $0.37046 per therm in all blocks of these rate schedules. (R)

(b) The rate of gas Schedule 440 is to be increased by $0.20323 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	$0.20323	(I)
Without Gross Revenue Factor	$0.19678	(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	$0.16723	(R)
Without Gross Revenue Factor	$0.16192	(R)

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

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 18-01-G Supplemental

Tariff Sheets

September 7, 2018

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 461

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SCHEDULE 461 (continued)

PURCHASED GAS COST ADJUSTMENT PROVISION – OREGON

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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.

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With Gross Revenue Factor	$0.16723	(R)
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9. Forecasted Monthly Calendar Sales Volumes: Forecasted billed sales therms, adjusted for estimated unbilled therms, for Schedules 410, 420, 424, 440, and 444.