Avista Corp.
1411 East Mission P.O. Box 3727
Spokane, Washington 99220-0500
Telephone 509-489-0500
Toll Free 800-727-9170

September 11, 2019

Advice No. 19-04-G Supplemental /UG-368 (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 as of August 31, 2019. No additional hedges have been executed since our original filing dated July 31, 2019. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 31, 2019, and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on November 1, 2019:

Oregon PUC Sheet No.	**Title of Sheet**	**Canceling Oregon PUC Sheet No.**
Supplemental Fifteenth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Fourteenth Revision Tariff Sheet 461
Supplemental Thirteenth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Twelfth 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, 2019 through October 1, 2020). 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	$0.20323	$0.16806	**($0.03517)**
440	$0.20323	$0.16806	**($0.03517)**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.16723	$0.16237	**($0.00486)**
440	$0.00000	$0.00000	**$0.00000**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$0.37046	$0.33043	**($0.04003)**
440	$0.20323	$0.16806	**($0.03517)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is $0.16806 per therm, a decrease of $0.03517 per therm from the present WACOG of $0.20323 per therm included in customer's rates. The reduction in commodity WACOG is primarily attributed to lower index prices for the upcoming natural gas year as a result of continued high production and an abundance of natural gas in storage. In addition, several previous longer-term transactions, which were executed at higher prices, rolled off and were replaced with lower priced deals.

Approximately 43% of estimated annual load requirements for the PGA year (November 2019 through October 2020) has been hedged at a fixed price, comprised of: 1) volumes hedged for a term of 36 months or less, 2) volumes from prior multi-year hedges, and 3) volumes hedged related to risk responsive hedging. Through June 30, 2019, the Company's executed hedge costs is $1.737 per dekatherm ($0.1737 per therm).

As required by Commission Order 14-238, the Company used a 60-day (ending August 31, 2019) 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 57% of estimated annual volumes and the annual weighted average price for these volumes is $1.513 per dekatherm ($0.1513 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 slightly from $0.16723 per therm to $0.16237 per therm, for a proposed reduction of approximately $0.00486 per therm. This reduction is primarily due to a reduction in costs on Gas Transmission Northwest (GTN) related to federal tax reform.

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	($0.08021)	($0.01004)	**$0.07017**
440	($0.08021)	($0.01004)	**$0.07017**

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.01383)	$0.00009	**$0.01392**
440	$0.00000	$0.00000	**$0.00000**

Table No. 6 - Schedule 462 Commodity + Demand Amortizations

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	($0.09404)	($0.00995)	**$0.08409**
440	($0.08021)	($0.01004)	**$0.07017**

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

For the Commodity portion of the amortization rate, regionally, actual wholesale natural gas prices exhibited extreme volatility and higher prices after the Enbridge-owned West Coast Pipeline ("Enbridge") experienced a rupture in October 2018. The pipeline has since been repaired, but has been operating at reduced capacity especially throughout the 2018-2019 winter. The capacity shortage on Enbridge severely affected the natural gas supply in the Pacific Northwest during the winter months, driving prices and volatility higher. This relatively mild winter regionally turned very cold in February 2019. The arrival of cold weather, coupled with the loss of one of the compressors at the Jackson Prairie storage facility for a three-week period, further exacerbated the capacity shortage, increasing regional spot natural gas prices, including record high prices at the Sumas hub. A combination of these factors resulted in higher index prices for most of the winter versus the embedded WACOG for the 2018-2019 PGA year, contributing to an amortization rate of ($0.01004). In contrast, during the 2017-2018 PGA year, the Company was able to secure commodity at a total expense much lower than what was embedded in customer rates, resulting in a rebate amortization rate of approximately $0.08021 per therm.

The previous demand rebate rate of ($0.1383) was based on a rebate balance of approximately $1.1 million as of June 30, 2018. This balance was primarily a result of a difference related to the pricing of our Canadian Firm Demand Contracts. In the 2017-2018 PGA filing, these contracts were valued in Canadian dollars, whereas actuals were recorded in US Dollars, resulting in a rebate deferral for customers. However, in the 2018-2019 PGA year given the par value of the Canadian Dollar has remained fairly consistent, the Company valued these contracts in US Dollars in order to better match actual expenses. This resulted in a net demand deferral very close to what was forecast, with only a slight surcharge balance of $9,000, or $0.00009.

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 2018 was $145,242,892 and Total Prior Period Gas Cost Deferral True-up is a rebate of $917,662. The resulting annual average rate impact from the PGA amortization is (0.6%).[2]

Including the effect of the Company's other four amortization rates filed coincident with the initial July PGA filing (Intervenor Funding Advice No. 19-03-G, Natural Gas Decoupling Amortization Advice No. 19-05-G, Demand Side Management Amortization Advice No.19-06-G, and Bank Payment Fee Free Amortization Advice No. 19-07-G) the resulting annual average rate impact from the Company's qualifying amortization is 0.3%.

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

Other Information

The PGA filing reflects an overall annual revenue increase of approximately $4.0 million, or 4.7% effective November 1, 2019. 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, 2019, 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	92,202
Schedule 420	11,877
Schedule 424	91
Schedule 440	41
Schedule 444	4
Schedule 456	33

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	$ 53,596,121	$ 55,857,959	$ 2,261,838	4.2%	46	$ 48.11	$ 50.14	$ 2.03	4.2%
420	General	$ 24,771,096	$ 26,005,429	$ 1,234,333	5.0%	197	$ 174.15	$ 182.83	$ 8.68	5.0%
424	Large General	$ 1,798,192	$ 1,990,882	$ 192,690	10.7%	3,990	$ 1,640.57	$ 1,816.37	$ 175.80	10.7%
				$ -						
440	Interruptible	$ 1,748,440	$ 2,038,259	$ 289,819	16.6%	17,038	$ 3,597.57	$ 4,193.90	$ 596.33	16.6%
				$ -						
444	Seasonal	$ 91,583	$ 100,946	$ 9,363	10.2%	4,087	$ 1,761.21	$ 1,941.28	$ 180.07	10.2%

After combining the impact of this PGA filing with the four other regulatory filings, which also have a November 1, 2019 effective date[3], a residential customer using an average of 46 therms a month could expect their bill to *increase* by $5.16, or 10.7 percent, for a revised monthly bill of $53.27 effective November 1, 2019.

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, 2019 effective date:

[3] On July 31, 2019, Avista filed to update effective November 1, 2019 Schedule 476 Intervenor Funding (Advice No. 19-03-G), Schedule 475 Decoupling (Advice No. 19-05-G), Schedule 478 Demand Side Management (Advice No. 19-06-G), and Schedule 484 Bank Fee Free (Advice No. 19-07-G). The net effect of all filings (including PGA) is a revenue increase of approximately $8.5 million or 10.0%.

Rate Schedule	Proposed Rate Change[4]
Schedule 410	10.7%
Schedule 420	7.6%
Schedule 424	16.4%
Schedule 440	27.3%
Schedule 444	15.7%
Schedule 456	1.8%
Total	10.0%

Included with the original filing (July 31, 2019) 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 2019. The Company has provided, via overnight mail, one electronic disc which contains confidential supporting workpapers.[5]

Please direct any questions regarding this filing to Annette Brandon at (509) 495-4324 or Kaylene Schultz at (509) 495-2482.

Sincerely,

Patrick D. Ehrbar
Director of Regulatory Affairs

Enc.

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

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

AVISTA UTILITIES

ADVICE NO. 19-04-G Supplemental

Tariff Sheets

September 11, 2019

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 $0.33043 per therm in all blocks of these rate schedules. (R)
(b) The rate of gas Schedule 440 is to be increased by $0.16806 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.

Patrick D. Ehrbar

AVISTA CORPORATION
dba Avista Utilities

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	$0.16806	(R)
Without Gross Revenue Factor	$0.16273	(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	$0.16237	(R)
Without Gross Revenue Factor	$0.15722	(R)

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

Patrick D. Ehrbar