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July 31, 2023

Advice No. 23-02-G/UG-467 (Purchased Gas Cost Adjustment Filing)

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

Attn: Filing Center

Pursuant to Order Nos. 08-504, 11-196 and 14-238 in Docket No. UM 1286, Avista Utilities hereby electronically submits its 2023 Purchased Gas Cost Adjustment (cover letter, as filed summary, tariff sheets, and newspaper advertisement draft).[1] The Company requests that the following tariff sheets become effective on November 1, 2023:

Oregon PUC Sheet No.	Title of Sheet	Canceling Oregon PUC Sheet No.
Nineteenth Revision Tariff Sheet 461	Purchased Gas Cost Adjustment Provision	Supplemental Eighteenth Revision Tariff Sheet 461
Seventeenth Revision Tariff Sheet 461A	Purchased Gas Cost Adjustment Provision	Supplemental Sixteenth Revision Tariff Sheet 461A
Fourteenth Revision Tariff Sheet 462	Gas Cost Rate Adjustment	Supplemental Thirteenth 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, 2023 through October 31, 2024). The difference between the actual cost of natural gas purchased and the amount collected

[1] The Company has also emailed confidential workpapers and non-confidential workpapers to "puc.workpapers@state.or.us".

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	$ 0.44416	$ 0.32984	**$ (0.11432)**
440	$ 0.44416	$ 0.32984	**$ (0.11432)**

Table No. 2 - Schedule 461 Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$ 0.16082	$ 0.15702	**$ (0.00380)**
440	$ -	$ -	**$ -**

Table No. 3 - Schedule 461 Commodity + Demand

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$ 0.60498	$ 0.48686	**$ (0.11812)**
440	$ 0.44416	$ 0.32984	**$ (0.11432)**

Commodity Costs (Schedule 461)

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is $0.32984 per therm, a decrease of $0.11432 per therm from the present WACOG of $0.44416 per therm included in customer's rates. The natural gas market in the western US experienced a period of extreme pricing volatility this winter due to a confluence of fundamental factors in the region. Prolonged colder than average temperatures region wide, combined with below average hydro generation led to a market where gas fired electric generators and LDC's were competeing for a limited supply of natural gas.

Generally speaking, the electric interconnection between the Pacific Northwest and California played a key role in the price volatility in the region. California has in recent years relied on imports of power from the northwest to balance its system in the winter. Lower than average precipitation during the fall reduced hydro output in the northwest this year which forced Mid-C power prices high enough to disincentivize power exports to California. California's only option to cover the missing imports was to increase gas fired generation which put additional pressure on the natural gas market. These conditions persisted for most of the winter and forced both generators and LDC's to rely on storage withdrawals more than usual. Storage balances throughout the region were drawn down earlier than normal which put even more upward pressure on the market. Prices at most west coast trading hubs were consistently 5 to 10 times higher than they have been for the past several years. The exception was the AECO hub in western Canada which was not affected by the supply constraints experienced south of the border.

But even with these elevated prices, Oregon customers were somewhat insulated as they have supply from the AECO basin that can either be used for demand or optimized and sold at Malin. Jackson Prairie storage also played a role in keeping Oregon customers costs lower. This resulted in forward prices for the upcoming PGA year less than what they were for the 2022-23 PGA year.

Approximately 50% of estimated annual load requirements for the PGA year (November 2023 through October 2024) have been hedged at a fixed price in accordance with the Company's Procurement Plan (as further discussed in the Company's Natural Gas Portfolio Development Guidelines. Through June 30, 2023, the Company's average executed hedge costs is $3.71 per dekatherm ($0.37099 per therm).

The Company has approximately 920,000 dekatherms of underground storage capacity at Jackson Prairie available for its Oregon customers. Total underground storage capacity represents approximately 10% of annual load requirements (13.6% of load requirements during the Nov.-Mar. withdrawal period). As of June 30, 2023, the current storage balance is approximately 781,795 dekatherms and costs for all storage volumes is $2.18 per dekatherm ($0.28137 per therm). The Company will inject additional volumes into storage throughout the Summer which will be included in the Company's PGA update filing in September.

As required by Commission Order No. 14-238, the Company used a 60-day (ending June 30, 2023) 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 40% of estimated annual volumes and the annual weighted average price for these volumes is $3.14 per dekatherm ($0.31440 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 $0.16082 per therm to $0.15702 per therm, for a proposed decrease of approximately $0.00380 per therm. This change is related to a variety of factors

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

including Canadian exchange rate, updated demand forecast, and pipelines in effective for the PGA year.

Amortization of Deferral Accounts (Schedule 462)

Table Nos. 4 through 6 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	$ 0.04133	$ (0.03504)	**$ (0.07637)**
440	$ 0.04133	$ (0.03504)	**$ (0.07637)**

Table No. 5 - Schedule 462 Demand Amortization

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$ 0.01100	$ (0.01985)	**$ (0.03085)**
440	$ -	$ -	**$ -**

able No. 6 - Schedule 462 Commodity + Demand Amortizatio

Rate Schedule	Present	Proposed	Change
410, 420, 424, 444	$ 0.05233	$ (0.05489)	**$ (0.10722)**
440	$ 0.04133	$ (0.03504)	**$ (0.07637)**

Related to the Commodity portion of the amortization rate, net commodity costs for the current PGA year to date, November 2022 – June 2023, were in line with the commodity WACOG included in Schedule 461. However, net commodity costs were significantly lower for the period of July 2023 – October 2023 resulting in a net rebate balance and a rebate amortization rate of $0.03504 per therm, a decrease of $0.07637 compared to the present rate in effect.

As previously discussed in the Demand Costs (Schedule 461) section above, demand costs are impacted by a variety of factors including the Canadian exchange rate, demand volumes, and changes in pipeline rates. Additionally in the current PGA year, as a result of Northwest Pipeline's most recent General Rate Case the Company received a refund of approximately $1.6 million attributable to Oregon customers that was recorded, in its entirety, as an offset to current year demand costs. A combination of these factors has resulted in a rebate amortization rate of $0.01985 per therm.

Combining the commodity and demand amortization balances results in an overall decrease 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. Total gross revenue for calendar year 2022 was $177,907,223 and total Prior Period Gas Cost Deferral True-up amortizations is a rebate of $5,327,429. The resulting annual average rate impact from the PGA amortization is (2.99)%.[2] Including the effect of the Company's other amortization rates filed coincident with the initial July PGA filing, the resulting annual average rate impact from the Company's qualifying amortization is (2.55)%. Please see Attachment C of the Company's PGA workpapers for a detailed calculation, and applicable amortization schedules, for the 3% test.

Other Information

The PGA filing reflects an overall annual revenue decrease of approximately $22.5 million, or 15.5% effective November 1, 2023. Pursuant to OAR 860-022-0025 and OAR 860-022-0030, the total number of customers affected by this filing, the annual revenue before and after the impact of the proposed rate changes, and the average monthly use and resulting bills under existing and proposed rates are as follows:

Rate Schedule	**Average Number of Customers**
Schedule 410	95,451
Schedule 420	12,013
Schedule 424	100
Schedule 440	42
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	$ 88,443,720	$ 76,274,265	$ (12,169,455)	-13.8%	47	$ 77.01	$ 66.41	$ (10.60)	-13.8%
420	General	$ 41,724,939	$ 35,144,434	$ (6,580,505)	-15.8%	203	$ 290.01	$ 244.27	$ (45.74)	-15.8%
424	Large General	$ 3,919,829	$ 2,887,954	$ (1,031,875)	-26.3%	3,822	$ 3,271.67	$ 2,410.42	$ (861.25)	-26.3%
440	Interruptible	$ 8,892,374	$ 6,184,464	$ (2,707,910)	-30.5%	28,009	$ 17,464.17	$ 12,198.14	$ (5,266.03)	-30.2%
444	Seasonal	$ 175,406	$ 130,089	$ (45,317)	-25.8%	6,285	$ 5,481.84	$ 4,065.58	$ (1,416.26)	-25.8%

After combining the impact of this filing with the other regulatory filings and the expiration of adder Schedule 467 (COVID Deferred Costs), which also have a November 1, 2023 effective date[3], a residential customer using an average of 47 therms a month could expect their bill to decrease by $11.25, or 14.6 percent, for a revised monthly bill of $65.76 effective November 1, 2023.

The following table shows 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, 2023 effective date:

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

[3] On July 31, 2023, Avista filed to update effective November 1, 2023 Schedules 461 Purchased Gas Cost Adjustment and 462 Gas Cost Rate Adjustment (Advice No. 23-02-G), Schedule 475 Decoupling (Advice No. 23-03-G), Schedule 476 Intervenor Funding (Advice No. 23-04-G), Schedule 482 Regulatory Fee Amortization (Advice No. 23-05-G), and Schedule 493 LIRAP (Advice No. 23-06-G). Additionally, Schedule 467 COVID Deferred Costs will expire effective November 1, 2023. The net effect of all filings, and the expiration of Schedule 467, is a revenue decrease of approximately $24 million or 16.5%.

Rate Schedule	Proposed Rate Change[4]
Schedule 410	(14.6)%
Schedule 420	(16.2)%
Schedule 424	(29.8)%
Schedule 440	(35.4)%
Schedule 444	(29.1)%
Schedule 456	0.7%
Total	(16.5)%

Included with the original 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 provide notice to customers via newspaper advertisement.

Please direct any questions regarding this filing to Marcus Garbarino at (509) 495-2567 or marcus.garbarino@avistacorp.com.

Sincerely,

/s/ Joe Miller

Joe Miller
Senior Manager of Rates and Tariffs, Regulatory Affairs
Enclosures

[4] Includes filed rate changes to Schedules 461, 462, 475, 476, 482, and 493.

November 1, 2023
As of July 31, 2023
(As filed – these are not approved rate changes)

1	**Company**	**Avista**	
2	**Docket Numbers**	UG-467	
3	**Advice No.**	23-02-G	
4	**Principal Analysts**	Anna Kim	
5	**Current Customer Charge - Residential ($)**	$10.50	
6	**Average Monthly Therm Use (Residential)**	47	
7	**Current Energy Charge/Rate (dollars/therm)**	Billing - $1.41500 Base - $0.69549	
8	**PGA Base Gas Cost Change - Residential (dollars/therm)**	$(0.11432)	Commodity Only – including revenue sensitive
9	**Other Temporary Rate Increments - Residential (dollars/therm)**	$(0.00380) Demand $(0.10722) Amort	Demand, Amortization, including revenue sensitive
10	**Permanent Base Rate Adjustment – Residential (dollars/therm)**	$0.00	
11	**Overall Change - Residential Rate (dollars/therm)**	$(0.22534)	Gas, Demand and Amortization
12	**Proposed Tariff Rate - Residential (dollars/therm)**	$1.17583	Including all filings (Gas and Non-gas) – See Attachment B in workpapers
13	**Average monthly bill change for typical residential customer ($/bill on an annual basis)**	$(11.25)	Including all filings (Gas and Non-gas) – See Attachment D in workpapers
14	**Overall Change - Residential Revenue (%)**	(14.6)%	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
15	**Overall Change – Commercial & Industrial firm (%)**	Commercial = (16.2)% Industrial = (29.8)%	Including all filings (Gas and Non-gas) – See ”Change in Annual Revenues” workpapers
16	**WACOG (dollars/therm) – not revenue-sensitized**	$0.32058	
	Comments – Other (continued)		

AVISTA CORPORATION
dba Avista Utilities

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 $0.48686 per therm in all blocks of these rate schedules. (R)
(b) The rate of gas Schedule 440 is to be increased by $0.32984 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. 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.

Patrick D. Ehrbar

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	$0.32984	(R)
Without Gross Revenue Factor	$0.32058	(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	$0.15702	(R)
Without Gross Revenue Factor	$0.15261	(R)

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

AVISTA CORPORATION
dba Avista Utilities

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 $0.05489 per therm. (R)

(b) The rate of gas Schedule 440 is to be decreased by $0.03504 per therm. (R)

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.

DRAFT

Recently, Avista requested a change in natural gas rates for our Oregon customers. We know you care about your energy costs, so we think it's important to share this news with you.

On July 31, 2023, Avista made five annual rate adjustment filings with the Public Utility Commission of Oregon (PUC) that if approved, are designed to decrease overall natural gas revenue by approximately $24.0 million or 16.5% effective Nov. 1, 2023. These filings have no impact on Avista's earnings.

The first rate adjustment is related to Avista's decoupling mechanism. Decoupling is designed to break the link between a utility's revenues and customers' energy usage. Generally, Avista's natural gas revenues are adjusted each month based on the number of customers rather than therms sales. The difference between revenues based on therm sales and revenues based on the number of customers is surcharged or rebated to customers beginning in the following year. If approved, Avista's request is designed to decrease overall natural gas revenue by approximately $3.3 million or 2.4%. This rate adjustment is driven primarily by a higher level of customer usage in 2022.

The second rate adjustment is the annual Purchased Gas Cost Adjustment (PGA) filing. PGAs are filed each year to balance the actual cost of wholesale natural gas purchased by Avista to serve customers with the amount included in rates. This includes the natural gas commodity cost as well as the cost to transport natural gas on interstate pipelines to Avista's local distribution system. If approved, Avista's natural gas revenues would decrease by approximately $22.5 million or 15.5%. This rate adjustment is driven primarily by wholesale natural gas prices, which are lower than the level presently included in rates. Avista does not profit on the actual natural gas commodity or the costs to transport natural gas to Avista's service territory.

The third rate adjustment is related to Avista's Low Income Rate Assistance Program (LIRAP), which provides bill assistance to income eligible customers with a household income less than or equal to 60% of the State Median Income (SMI). With the recent introduction of an income-based bill discount, as well as offerings intended to help customers manage their past due balances, or arrearages, the reach of LIRAP has expanded to serve more customers than ever before, requiring a significantly larger budget, which has caused the need for this rate increase. The overall rate increase to natural gas customers is approximately $2.7 million, or an overall increase of approximately 1.7%.

The remaining two miscellaneous adjustments relate to recovering costs associated with intervenor funding and regulatory fees. The combination of those two filings is an increase in overall natural gas revenue of approximately $29 thousand or 0.02% effective Nov. 1, 2023.

The bottom line
If all five requests are approved, and you are an Avista natural gas customer using an average of 47 therms per month, you could expect your bill to decrease by $11.25, or 14.6% for a revised monthly bill of $65.76 beginning Nov. 1, 2023. All other customer groups receiving firm natural gas service from Avista would also see decreases.

For more information
Copies of our filings are available at www.myavista.com/rates or you can call us at 1-800-227-9187.

This announcement is to provide you with general information about Avista's rate request and its effect on customers. The calculations and statements in this announcement are not binding on the PUC. For more information about the filing or for information about the time and place of any hearing, contact the PUC at:

Public Utility Commission of Oregon
201 High Street SE, Ste. 100
Salem, OR 97301
(800) 522-2404, www.puc.state.or.us

DRAFT

This notice contains forward-looking statements regarding the Company's current expectations. Forward-looking statements are all statements other than historical facts. Such statements speak only as of the date of the notice and are subject to a variety of risks and uncertainties, many of which are beyond the Company's control, which could cause actual results to differ materially from the expectations. These risks and uncertainties include, in addition to those discussed herein, all the factors discussed in the Company's Annual Report on Form 10-K for the year ended Dec. 31, 2022 and the Quarterly Report on Form 10-Q for the quarter ended June 30, 2023.