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September 10, 2021

**Advice No. 21-04-G Supplemental/UG-413 (Purchased Gas Cost Adjustment Filing)**

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

Attn: 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 electronically submits the following listed tariff sheets applicable to its natural gas operations (cover letter, as filed summary, tariff sheets, and newspaper ad draft).[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, 2021. Supplemental Tariff Sheets 461 and 461A reflect these updates. Tariff Sheet 462 (amortization) remains unchanged from the original filing dated July 30, 2021 and has not been included in this Supplemental filing.

The Company requests that the following tariff sheets become effective on November 1, 2021:

| **Oregon PUC Sheet No.** | **Title of Sheet** | **Canceling Oregon PUC Sheet No.** |
|---|---|---|
| Supplemental Seventeenth Revision Tariff Sheet 461 | Purchased Gas Cost Adjustment Provision | Supplemental Sixteenth Revision Tariff Sheet 461 |
| Supplemental Fifteenth Revision Tariff Sheet 461A | Purchased Gas Cost Adjustment Provision | Supplemental Fourteenth 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

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

purchased natural gas costs for the forthcoming year (November 1, 2021 through October 31, 2022). 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 | $0.20655 | $0.30132 | **$0.09477** |
| 440 | $0.20655 | $0.30132 | **$0.09477** |

**Table No. 2 - Schedule 461 Demand**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.15787 | $0.15616 | **($0.00171)** |
| 440 | $0.00000 | $0.00000 | **$0.00000** |

**Table No. 3 - Schedule 461 Commodity + Demand**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.36442 | $0.45748 | **$0.09306** |
| 440 | $0.20655 | $0.30132 | **$0.09477** |

**Commodity Costs (Schedule 461)**

As shown in the Table No. 1 above, the proposed weighted average cost of gas ("WACOG") is $0.30132 per therm, an increase of $0.09477 per therm from the present WACOG of $0.20655 per therm included in customer's rates. The cost of natural gas commodity remains relatively low in comparison to historical periods, however, wholesale natural gas prices in recent months as well as the forward prices have risen substantially compared to the level presently included in rates. The market factors attributing to the rise in prices is an overall increase in demand and lower supply. The main driver in demand has been record exports to Mexico, elevated liquified natural gas (LNG) exports, and increased use for power generation. On the supply side, production has been slow to ramp up to pre-pandemic levels, putting pressure on wholesale prices. In addition, storage levels are well below where they were at this time last year and the current forecasted end of season level is seen as significantly below last year's level.

Approximately 29% of estimated annual load requirements for the PGA year (November 2021 through October 2022) have been hedged at a fixed price in accordance with the Company's Procurement Plan. Through August 31, 2021, the Company's average executed hedge costs is $2.103 per dekatherm ($0.2103 per therm).

As required by Commission Order No. 14-238, the Company used a 60-day (ending August 31, 2021) 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 71% of estimated annual volumes and the annual weighted average price for these volumes is $3.171 per dekatherm ($0.3171 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 $0.15787 per therm to $0.15616 per therm, for a proposed reduction of approximately $0.00171 per therm. This change is related to a variety of factors including Canadian exchange rate, updated demand forecast, and new rates for Canadian pipelines effective June 1, 2021.

**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 | ($0.02026) | ($0.01610) | **$0.00416** |
| 440 | ($0.02026) | ($0.01610) | **$0.00416** |

**Table No. 5 - Schedule 462 Demand Amortization**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | $0.00477 | $0.01039 | **$0.00562** |
| 440 | $0.00000 | $0.00000 | **$0.00000** |

**Table No. 6 - Schedule 462 Commodity + Demand Amortizations**

| Rate Schedule | Present | Proposed | Change |
|---|---|---|---|
| 410, 420, 424, 444 | ($0.01549) | ($0.00571) | **$0.00978** |
| 440 | ($0.02026) | ($0.01610) | **$0.00416** |

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

Related to the Commodity portion of the amortization rate, except for the spike in prices that resulted from the Artic freeze in the Southwest in February, the winter of 2020-2021 prices remained stable. However, as noted in the Commodity Costs (Schedule 461) section above, natural gas commodity prices have been on an upward trajectory during the second quarter of 2021. A combination of these factors has resulted in a lower rebate amortization rate of $0.01610 per therm, relative 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. A combination of these factors has resulted in a surcharge amortization rate of $0.01039 per therm.

Combining the commodity and demand amortization balances results in an overall increase 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 2020 was $138,266,166 and Total Prior Period Gas Cost Deferral True-up is a rebate of $747,999. The resulting annual average rate impact from the PGA amortization is (0.54%).[2]

Including the effect of the Company's other four amortization rates filed coincident with the initial July PGA filing (Intervenor Funding Advice No. 21-03-G, Natural Gas Decoupling Amortization Advice No. 21-05-G, Demand Side Management Amortization Advice No.21-07-G, and Regulatory Fees Amortization Advice No. 21-06-G) the resulting annual average rate impact from the Company's qualifying amortization is (0.5%).

**Other Information**

The PGA filing reflects an overall annual revenue increase of approximately $10.5 million, or 9.6% effective November 1, 2021. 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, 2021, 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 | 93,820 |
| Schedule 420 | 11,949 |
| Schedule 424 | 90 |
| Schedule 440 | 38 |
| Schedule 444 | 3 |

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

| 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 | $ 69,254,524 | $ 74,783,182 | $ 5,528,658 | 8.0% | 48 | $ 61.78 | $ 66.72 | $ 4.94 | 8.0% |
| 420 | General | $ 30,885,552 | $ 33,865,926 | $ 2,980,374 | 9.6% | 202 | $ 215.29 | $ 236.06 | $ 20.77 | 9.6% |
| 424 | Large General | $ 2,076,450 | $ 2,518,566 | $ 442,116 | 21.3% | 4,003 | $ 1,933.45 | $ 2,345.12 | $ 411.67 | 21.3% |
| | | | | $ - | | | | | | |
| 440 | Interruptible | $ 4,169,305 | $ 5,706,420 | $ 1,537,115 | 36.9% | 34,223 | $ 9,183.40 | $ 12,644.08 | $ 3,460.68 | 37.7% |
| | | | | $ - | | | | | | |
| 444 | Seasonal | $ 109,100 | $ 131,353 | $ 22,253 | 20.4% | 6,557 | $ 3,305.91 | $ 3,980.23 | $ 674.32 | 20.4% |

After combining the impact of this PGA filing with the four other regulatory filings, which also have a November 1, 2021 effective date[3], a residential customer using an average of 48 therms a month could expect their bill to *increase* by $5.19, or 8.4 percent, for a revised monthly bill of $66.97 effective November 1, 2021.

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, 2021 effective date:

| **Rate Schedule** | **Proposed Rate Change[4]** |
|---|---|
| Schedule 410 | 8.4% |
| Schedule 420 | 12.9% |
| Schedule 424 | 28.5% |
| Schedule 440 | 49.3% |
| Schedule 444 | 27.3% |
| Schedule 456 | (1.2)% |
| Total | 11.3% |

Included with the original filing (July 30, 2021) 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. The Company had previously provided notice to customers via newspaper advertisement after the Company's initial filing in July 2021.

Please direct any questions regarding this filing to Marcus Garbarino at (509) 495-2567.

Sincerely,

*/S/Patrick D. Ehrbar*

Patrick D. Ehrbar
Director of Regulatory Affairs

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[3] On July 30, 2021, Avista filed to update effective November 1, 2021 Schedules 461 Purchased Gas Cost Adjustment and 462 Gas Cost Rate Adjustment (Advice No. 21-04-G), Schedule 476 Intervenor Funding (Advice No. 21-03-G), Schedule 475 Decoupling (Advice No. 21-05-G), Schedule 478 Demand Side Management (Advice No. 21-07-G), and Schedule 482 Regulatory Fee Amortization (Advice No. 21-06-G). The net effect of all filings is a revenue increase of approximately $12.4 million or 11.3%.

[4] Includes filed rate changes to Schedules 461, 462, 475, 476, 478, and 482.

# 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 $0.45748 per therm in all blocks of these rate schedules. (I)
(b) The rate of gas Schedule 440 is to be increased by $0.30132 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 | $0.30132 | (I) |
| Without Gross Revenue Factor | $0.29216 | (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 | $0.15616 | (R) |
| Without Gross Revenue Factor | $0.15142 | (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 $0.00571 per therm. (I)

(b) The rate of gas Schedule 440 is to be decreased by $0.01610 per therm. (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.