JOHN R. HAMMOND, JR.
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0357
IDAHO BAR NO. 5470

Street Address for Express Mail:
11331 W CHINDEN BVLD, BLDG 8, SUITE 201-A
BOISE, ID 83714

Attorney for the Commission Staff

RECEIVED
2021 AUG 17 PM 2:43
IDAHO PUBLIC
UTILITIES COMMISSION

## BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

| | |
|---|---|
| **IN THE MATTER OF THE APPLICATION OF AVISTA UTILITIES FOR AN ORDER APPROVING A CHANGE IN RATES FOR PURCHASED GAS COSTS AND AMORTIZATION OF GAS-RELATED DEFERRAL BALANCES** | **CASE NO. AVU-G-21-04**<br><br>**COMMENTS OF THE COMMISSION STAFF** |

The Staff of the Idaho Public Utilities Commission submits the following comments regarding the above referenced case.

**BACKGROUND**

On July 2, 2021, Avista Corporation dba Avista Utilities ("Company") filed its annual Purchased Gas Cost Adjustment ("PGA") Application. The PGA is a Commission-approved mechanism that adjusts rates up or down to reflect changes in the Company's costs to buy natural gas from suppliers—including changes in transportation, storage, and other related costs. The Company defers these costs into its PGA account and then passes them on to customers through an increase or decrease in rates. The Company states its proposal will increase rates for an average residential or small commercial customer by $6.00 per month (12.1%). The Company requested that the new rates take effect September 1, 2021.

The Company is filing this Application earlier than the typical August-September timeframe to limit the bill impact to customers from the accumulated deferral and amortization surcharge balances that have increased due to rising natural gas costs in recent months since the Company's last filing. *Id.*

Concurrent with the PGA filing, the Company filed a Deferred Balances Credit Case No. AVU-G-21-03. That case, if approved, would return to customers deferred balances related to Natural Gas Deferred Depreciation Expense of $894,000, Accumulated Funds Used During Construction ("AFUDC") of $393,000, and Coronavirus Aid, Relief, and Economic Security ("CARES") Act benefits of $648,000.

**Overview of Proposed Rates**

In this PGA Application, the Company proposes to: (1) pass any change in the estimated cost of natural gas for the next 12 months to customers (Tariff Schedule 150); and (2) revise the amortization rates to refund or collect the balance of deferred gas costs (Tariff Schedule 155).

The Company's PGA proposal would *increase* the Company's annual revenue by approximately $9.0 million or about 13.5%. If approved, residential customers using an average of 63 therms per month would see rates *increase* by $4.56 or 9.2% per month. The Company's proposed changes to Schedules 150 and 155 and the Company's rates are further explained below.

The Company proposes to change its PGA per therm rates for its customer classes as follows:

**Table No. 1: Summary of Proposed PGA Rate Changes by Class**

| Service | Schedule No. | Commodity Change per Therm (a) | Demand Change per Therm (b) | Total Sch. 150 Change (c=a+b) | Amortization Change per Therm (d) | Total Rate Change per Therm (e=c+d) |
|---|---|---|---|---|---|---|
| General | 101 | $0.04022 | $0.00238 | $0.04260 | $0.05259 | $0.09519 |
| Lg. General | 111 | $0.04022 | $0.00238 | $0.04260 | $0.05259 | $0.09519 |
| Lg. General | 112 | $0.04022 | $0.00238 | $0.04260 | - | $0.04260 |
| Interruptible | 131 | $0.04022 | - | $0.04022 | - | $0.4022 |
| Transportation | 146 | - | - | - | - | - |

**STAFF ANALYSIS**

Staff reviewed the Company's PGA Application and accompanying workpapers and supports the Company's proposal to increase natural gas revenues in Idaho by approximately $9.04 million or 13.5%. Staff examined the Company's gas purchases for the year, its fixed price hedges, pipeline transportation and storage costs, and estimates of future commodity prices to assess the reasonableness of the proposed changes. Staff also reviewed the Company's jurisdictional allocation and the reasonableness of the Company's Lost and Unaccounted for Gas ("LAUF") volumes. Staff verified that the Company's filing will not change the Company's earnings. Staff also confirmed that the proposed changes to Schedules 150 and 155 accurately capture the Company's fixed (demand) and variable (commodity) costs given the coming year's forecasted gas purchases and properly amortizes the deferral balance from the prior year.

**Schedule 150 – Purchased Gas Cost Adjustment**

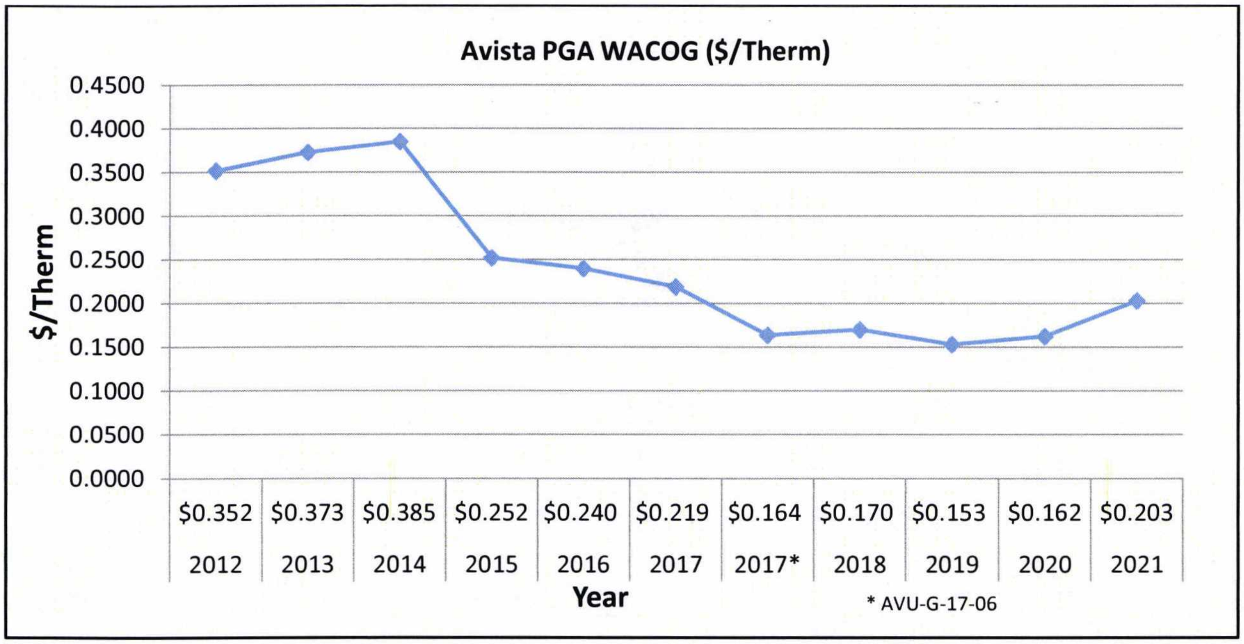
The Tariff Schedule 150 portion of the PGA consists of commodity costs and demand costs. The Company's commodity costs are the variable costs that the Company incurs to buy natural gas. The weighted average cost of gas ("WACOG") is an estimate of those costs. In this case, the Company estimates its commodity costs will increase by $0.04022 per therm, from the currently approved $0.16283 per therm to $0.20305 per therm.

The Company's demand costs are the costs for interstate transportation and underground storage. The demand portion of Schedule 150 also includes some benefits from the Deferred Exchange Contract that are credited back to customers. The Company proposes an overall demand rate of $0.00238 per therm. The proposed increase is primarily related to changes in exchange rates between Canadian and U.S. dollars, updated demand forecasts, and new Canadian Pipeline rates that went into effect June 1, 2021. *Id.*

*Weighted Average Cost of Gas ("WACOG")*

The WACOG includes fuel charges to move gas at the city gate, some variable transport costs, Gas Research Institute ("GRI") funding, and some benefits associated with the Deferred Exchange Contract. It does not include third party gas management fees. In this case, the Company proposes a WACOG of $0.20305 per therm. This is an increase of approximately 25% from the current approved WACOG of $0.16238 per therm. Staff encourages the Company to update its WACOG if gas prices materially deviate. Chart No. 1 shows the Company's historical WACOG.

**Chart No. 1: Historical WACOG**




**Schedule 155 – Amortization of the Deferral Account**

Tariff Schedule 155 reflects the amortization of the Company's deferral account. The Company's proposed amortization rate change for Schedule 101 and Schedule 111 is an *increase* in revenue (or expiration of the existing rebate and replacing it with a surcharge) of $0.05259 per therm. The current rate applicable to Schedule 101 and Schedule 111 is $0.03754 per therm in the *rebate* direction; the proposed rate is $0.01505 per therm in the *surcharge* direction.

The deferral consists of the difference in the price the Company paid for natural gas and the WACOG established in the previous PGA. The deferral also includes the monthly interest charges on the deferred balances. Included in the deferral activity are two items that benefit customers: excess capacity releases totaling $1,679,915 - discussed in detail in the Risk Management section below, and the benefits from the Deferred Exchange Contract totaling $1,089,713.

The Company has a Deferred Exchange Contract under which it receives natural gas during the summer and redelivers that natural gas in the winter. The Company charges a fixed per therm price for this service and flows all the benefits through Schedules 150 and 155. Customers received a benefit of $1,089,713 during the PGA year from the Deferred Exchange Contract, and these benefits, along with the excess capacity releases, are included in the deferral activity shown in Table No. 2 below.

In the past, the Company has included forecasted natural gas deferrals and amortization amounts until the time when the new rates are in effect. This year the Company did not include a forecast in its Application to mitigate a large rate increase. The Company also filed this Application with a shortened deferral period to mitigate the increasing deferral balance and to time the increase with the proposed rate decrease in Case No. AVU-G-21-01. Staff supports the Company's rate mitigation efforts to prevent rate shock to customers.

The Company calculated the balance for amortization as of May 31, 2021, to be $4,363,943. On a per therm basis, the net impact of the expiring amortization rebate and the new amortization surcharge is a change in the amortization rate of $0.05259.

In an effort to reduce the impact on customer bills, the Company is proposing to amortize the surcharge balance of approximately $4.4 million to be received from customers over a 38-month period, rather than the normal 12-month period. This will allow the Company to re-evaluate the amortization period during the next PGA filing and adjust the recovery period as appropriate. Staff believes that this is a reasonable approach to mitigating the increase in customer rates.

A reconciliation of the Schedule 155 deferral and amortization is shown in Table No. 2:

**Table No. 2: PGA Deferral and Amortization Reconciliation**

| | |
|---|---|
| **Amortization Balance as of October 31, 2020** | $ 747,614 |
| Amortization Activity | 2,711,448 |
| Interest on Unamortized Balance | 15,460 |
| Total Unamortized Balance | $ 3,474,522 |
| | |
| **Current Year Deferral Activity** | |
| Deferral Balance as of October 31, 2020 | $ - |
| Deferral of Demand Costs | 78,638 |
| Deferral of Commodity Price Differences | 3,579,622 |
| Interest on Deferrals | 789 |
| Excess Capacity Releases | (1,679,915) |
| Deferred Exchange Contract | (1,089,713) |
| Total Amortization Balance | $ 889,421 |
| | |
| Total Balance to be amortized via Rate Schedule 155 | $ 4,363,943 |

**Market Fundamentals & Price Analysis**

Because a large portion of the Company's annual throughput consists of market index purchases (approximately 60%), Staff routinely scrutinizes the Company's projected monthly cost of purchased gas. The Company continues to use a 30-day historical average of forward prices to forecast the volume-weighted average annual index price and forecasts a cost of $2.34 per dekatherm ($0.234 per therm), which is an increase of $0.57 per dekatherm ($0.057 per therm) over the 2020 PGA forecast of $1.77 per dekatherm ($0.177 per therm). Staff reviewed Futures prices at each of the three hubs where the Company purchases gas[1] and believes the Company's cost forecasts to be reasonable.

Staff also examined the forecasts of national and regional organizations to see how perceived market conditions might vary from the NYMEX/NGX Futures prices. Specifically, Staff reviewed the forecasts from the Energy Information Administration (EIA). [2] The EIA Short-Term Energy Natural Gas Outlook[3] states:

> In May, the natural gas spot price at Henry Hub averaged $2.91 per million British thermal units (MMBtu), which is up from the April average of $2.66/MMBtu. We expect the Henry Hub spot price will average $2.92/MMBtu in 3Q21 and $3.07/MMBtu for all of 2021, which is up from the 2020 average of $2.03/MMBtu. Higher natural gas prices this year primarily reflect two factors: growth in liquefied natural gas (LNG) exports and rising domestic natural gas consumption outside of the power sector. In 2022, we expect the Henry Hub price will average $2.93/MMBtu amid slowing growth in LNG exports and rising U.S. natural gas production.

Based on Staff's review of the market fundamentals and trends, the 2021-2022 forecasts are consistent, predicting relatively stable near-term gas prices. Staff believes that the Company's cost of its current hedges and estimated cost of forward-looking index purchases are reasonable.

**Risk Management**

The Company's uses a diversified approach to procure natural gas for the coming PGA year. The Company's Procurement Plan uses a structured approach to execute its hedges that includes a range of possible hedge windows with varying long-term and short-term trigger prices.

---

[1] The Company is supplied by three natural gas hubs (Rockies, Sumas, and AECO). Future settlement prices are reported daily as a price differential from the NYMEX Henry's Hub price.

[2] EIA website https://www.eia.gov/naturalgas/

[3]Source https://www.eia.gov/outlooks/steo/report/natgas.php 7/7/2021

However, its Procurement Plan also allows it to make discretionary decisions so it can adjust to changes in market conditions.

The Company modified its Natural Gas Procurement Plan in mid-2015 to change how the Company uses its portion of the Jackson Prairie storage facility. With the modified plan, storage can be used to capture the economic benefits of purchasing lower cost natural gas throughout the year and selling it later if not consumed by customers. For this year's PGA (September 2021 through May 31, 2022), the Company's hedges were executed at a weighted average price of $0.181 per therm, an increase of $0.01 per therm from the 2020 price of $0.171 per therm.

*Capacity Release*

The Company buys the right to transport gas through several interstate pipelines. This enables the Company to buy gas from a variety of supply basins, both in the U.S. and in Canada, and then transport that gas to its jurisdiction. As mentioned previously, whenever the Company has surplus capacity on the pipelines that serve its jurisdictions, surplus capacity is sold to other pipeline users at the highest price available. The Company's total excess capacity release revenue this year for Idaho was $1,679,915.

*Lost and Unaccounted for (LAUF)*[4] *Gas*

Staff reviewed the Company's LAUF gas rate and compared it to previous years. The Company reported a LAUF gas rate of 0.44%. Staff asked the Company to provide supporting LAUF workpapers, a reconciliation of LAUF numbers used in the PGA Report, and numbers reported to the Pipeline and Hazardous Material Safety Administration ("PHMSA"). The Company provided the following table showing a five-year view of LAUF gas PGA and PHMSA rates. Staff notes that the five-year average is 0.07%.

[4] The American Gas Association describes unaccounted for natural gas in the utility system is defined as follows: At a city gate, natural gas is transferred from an interstate or intrastate pipeline to a local natural gas utility. At that moment, some utilities measure the volume of gas using highly sophisticated technology that can quickly and precisely take into account a variety of factors, including temperature and pressure. The utility reports the volume of gas sold to customers as represented on their bills. The difference between the city-gate measurement and the volume of gas sold is treated as unaccounted-for gas by regulators, who build a form of reimbursement for this gas into the utility's rate structure.

**Table No. 3: LAUF Rates and Reconciliation**

| Year | Delivery | Revenue | Loss +/- | % Of Purchase | PGA Report | PHMSA[5] Report |
|---|---|---|---|---|---|---|
| 2017 | 147,097,624 | 146,490,005 | 607,619 | 0.41 | 0.41 | 0.41 |
| 2018 | 134,637,626 | 134,139,456 | 498,170 | 0.37 | 0.37 | 0.37 |
| 2019 | 143,375,963 | 141,549,516 | 1,826,447 | 1.27 | 1.27 | 1.29 |
| 2020 | 155,715,413 | 158,836,712 | (3,121,299) | (1.97) | (1.97) | (1.97) |
| 2021 | 156,717,867 | 156,036,168 | 681,699 | 0.44 | 0.44 | N/A |
| 5 Year Average | 147,508,899 | 147,410,371 | 98,527 | 0.07 | | |

**SUMMARY OF CUSTOMER IMPACT (Deferred Balance Credit and PGA)**

On July 2, 2021, the Company filed two Applications: (1) the annual PGA, Case No. AVU-G-21-04; and (2) Deferred Balance Credit, Case No. AVU-G-21-03. If the Commission approves both Applications, the net effect on natural gas revenue is an increase of approximately $7.1M or 10.6% as shown in Table No. 4.

**Table No. 4 – PGA and Deferred Balances Credit Summary**

| Adjustment | Revenue Impact $ | Revenue Impact % |
|---|---|---|
| PGA | $9.0M | 13.5% |
| Deferred Balances Credit | ($1.9M) | (2.9%) |
| **Net Effect** | **$7.1** | **10.6%** |

[5] PHMSA CALCULATION PART G – PERCENT OF UNACCOUNTED FOR GAS "Unaccounted for gas" is gas lost; that is, gas that the operator cannot account for as usage or through appropriate adjustment. Adjustments are appropriately made for such factors as variations in temperature, pressure, meter-reading cycles, or heat content; calculable losses from construction, purging, line breaks, etc., where specific data are available to allow reasonable calculation or estimate; or other similar factors. State the amount of unaccounted for gas as a percent of total consumption for the 12 months ending June 30 of the reporting year. [(Purchased gas + produced gas) minus (customer use + company use + appropriate adjustments)] divided by (customer use + company use + appropriate adjustments) times 100 equals percent unaccounted for.

## CUSTOMER COMMENTS, NOTICE, AND PRESS RELEASE

The Company's press release and customer notice were included with its Application. Each document addresses two cases: this case (AVU-G-21-04) and the Deferral Balances Credit Filing (AVU-G-21-03). Staff reviewed the documents and determined that both meet the requirements of Rule 125 of the Commission's Rules of Procedure, IDAPA 31.01.01.125.

The Commission set a comment deadline of August 17, 2021. Because customer notices were inserted into bills beginning July 8, 2021, through August 5, 2021, some customers in the last billing cycle may not have adequate time to submit comments before the deadline. Customers should have the opportunity to file comments and have those comments considered by the Commission. Staff recommends that the Commission accept late-filed comments from customers. As of August 16, 2021, the Commission had received four comments, which were all opposed to raising rates.

## STAFF RECOMMENDATIONS

After examining the Company's Application, natural gas purchases, and deferral activity for the year, Staff recommends the Commission:

1. Approve the Company's proposed Tariff Schedule 150, including the proposed WACOG of $0.20305 per therm and demand charge of $0.09243 per therm, for a total of $0.29548 per therm;
2. Approve the Company's proposed Tariff Schedule 155, with the proposed amortization rate of $0.01505 per therm;
3. Direct the Company to continue filing quarterly WACOG reports and monthly deferred cost reports with the Commission on an ongoing basis; and
4. Accept late-filed comments from customers.

Respectfully submitted this 17th day of August 2021.

John R. Hammond
Deputy Attorney General

Technical Staff: Kevin Keyt
Kathy Stockton
Travis Culbertson
Curtis Thaden

i:umisc:comments/avug21.4jhkkklstncct comments

# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 17th DAY OF AUGUST 2021, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. AVU-G-21-04, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

PATRICK EHRBAR
DIR OF REGULATORY AFFAIRS
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727
E-MAIL: patrick.ehrbar@avistacorp.com
avistadockets@avistacorp.com

DAVID J MEYER
VP & CHIEF COUNSEL
AVISTA CORPORATION
PO BOX 3727
SPOKANE WA 99220-3727
E-MAIL: david.meyer@avistacorp.com

SECRETARY