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IDAHO PUBLIC
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF AVISTA CORPORATION'S AMENDED APPLICATION FOR AN ORDER APPROVING A CHANGE IN RATES FOR PURCHASED GAS COSTS AND AMORTIZATION OF GAS-RELATED DEFERRAL BALANCES	)	**CASE NO. AVU-G-26-03** **COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission ("Commission"), by and through its attorney of record, Kelsea E. Ross, Deputy Attorney General, submits the following comments.

BACKGROUND

On July 31, 2026, Avista Corporation, doing business as Avista Utilities ("Company"), applied to the Commission requesting approval of proposed rates in its Purchased Gas Adjustment ("PGA") filing for natural gas service in Idaho ("Application"), effective November 1, 2026. Application at 1. On September 21, 2026, the Company filed an amended application correcting an input error in the Company's demand costs calculation ("Amended Application"). If the Amended Application is approved, an Idaho residential customer[1] that uses approximately 66

[1] The Company referred to the monthly bill for Idaho residential *and* small commercial customers using 66 therms per month. Amended Application at 4 (emphasis added). However, because the Company only referred to residential natural gas customers in the cover letter of its Amended Application, the Commission believed that the Company meant to only describe the monthly bill for Idaho **residential** customers using 66 therms per month. Order No. 37191 at 1.

therms per month would see a $1.90 decrease in their monthly bill (i.e., decrease from $58.56[2] to $56.66). Amended Application at 4.

The Company's rates include a base-rate component and a gas-related cost (PGA) component. The base-rate component is intended to cover the Company's fixed costs to serve its customers. For example, the Company's costs for equipment and facilities to provide service rarely change. The Company's PGA is a Commission-approved mechanism that adjusts rates up or down to reflect actual changes in the Company's costs to buy natural gas from suppliers (compared to the same cost assumptions embedded in rates), including changes in transportation, storage, and other related costs.

The PGA consists of two tariffs schedules—Schedule 150 and Schedule 155. Schedule 150 is forward looking and estimates the Company's weighted average cost of gas ("WACOG") for the upcoming PGA deferral period. Schedule 155 amortizes the prior year's deferral of actual gas costs compared to the amount collected through rates and collects or returns the difference as a rebate or surcharge.

The Company represented that if the Amended Application is approved as filed, the annual revenue of the Company will decrease by about $3.0 million or 3.6%. *Id.* at 1.

The Company represented that the annual PGA would: (1) pass through the changes in the estimated cost to purchase natural gas for November 2026 through October 2027; and (2) adjust the amortization rate(s) used to return or collect the deferred natural gas costs balance. *Id.* at 2–3.

The Company represented that the proposed WACOG rate (one component of Schedule 150) would be a decrease of $0.04529 per therm from the present WACOG of $0.21148 per therm. *Id.* at 3. The proposed WACOG is $0.16619 per therm. *Id*.

The Company stated it expects demand costs for residential customers to increase by approximately $0.00535. *Id.* at 4.

The Company stated the proposed amortization rate (Schedule 155) change for Schedule 101 and Schedule 111 customers would increase by $0.01113 per therm. *Id.* The Company also represented that the proposed Schedule 155 rate would be $0.05165 per therm. *Id.*

[2] The Commission believed that this monthly bill amount did not include the State of Idaho Usage Tax from the Company's Schedule 157 and thus may not accurately reflect an Idaho residential customer's monthly bill. Order No. 37191 at 1.

STAFF ANALYSIS

Staff examined the Company's Amended Application and accompanying workpapers and recommends that the Commission approve the Company's Amended Application to decrease natural gas revenues in Idaho by approximately $3.0 million, or about 3.6%. *Id.* Staff determined that the Company's proposed WACOG or variable commodity costs, and fixed demand costs included in the proposed Tariff Schedule 150 are reasonable, as are the Company's reported Lost and Unaccounted For ("LAUF") gas volumes. Staff verified that the Company's filing would not affect the Company's earnings and confirmed the proposed changes to Tariff Schedule 155 properly amortize the deferral balance from the prior year.

Schedule 150 – Forecasted PGA Rates

The Schedule 150 rates include forecasted costs for the gas commodity cost and forecasted demand cost needed to store and transport gas to the Company's city gates. Rates derived for each component are summed to determine the "Schedule 150 - Purchased Gas Cost Adjustment", and when adjusted using the Company's Revenue Gross Up Factor[3] of 1.004358, the resulting proposed rate is 0.271340 per therm. Staff's analyses for both components are included in the subsections below.

WACOG

The WACOG is the Company's forecasted cost of natural gas derived from historical average forward prices from basins that supplies the Company with gas, hedges that the Company has put in place over the past 3 years, and gas it has purchased and placed into underground storage to supply customers over the coming year. *Id.* at 3–4. The Company has also included Gas Research Institute funding and the Revenue Gross Up factor in its calculation. Amended Application Exhibit D (Confidential). In this case, the Company proposes a WACOG of $0.16619 per therm. *Id.* at 3. This is a decrease of approximately 21% from the current approved WACOG of $0.21148 per therm.

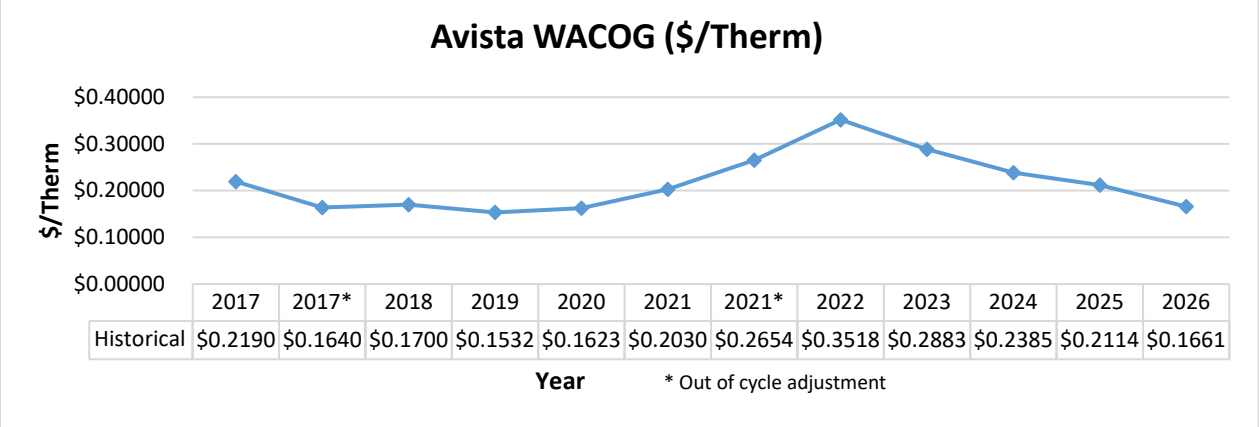
[3] The Company in it's Amended Application Exhibit D (Confidential) inadvertently labeled the Revenue Gross Up Factor as the Revenue Conversion Factor ("RCF"). Staff confirmed in conversations with the Company that the RCF label should have been identified as the Revenue Gross Up Factor throughout the exhibit. Staff determined the correct value for the Revenue Gross Up Factor was not affected by the mislabeling. For clarity, Staff refers to the Revenue Gross Up Factor throughout these comments.

The Company attributes the decrease in forecasted commodity prices to several factors. The regional temperatures for the 2025-2026 winter season were higher than forecasted, which reduced customer demand resulting in more gas stored and healthier supply. *Id.* Also, the Pacific Northwest's largest supply points, Sumas and AECO, have continued to trade at a discount to Henry Hub, with supply being plentiful to meet demand for the region. *Id.* The region has also benefited from pipeline flows which have been uninhibited for much of the typical maintenance season. *Id.*

Looking toward the 2026-2027 winter of, "national fundamentals look balanced as production has remained stable." *Id.* As expected, LNG offtake has increased, and Western storage remains modestly above the 5-year rolling average. *Id.* "With pipeline flows having been generally uninhibited," the Company states that "this region is on a healthy, well-supplied path towards the winter season ahead." *Id.* Therefore, Staff believes that the Company's proposed WACOG is justified and reasonable. Staff encourages the Company to update its WACOG if gas prices materially deviate.

Chart No. 1 below illustrates the changes in WACOG over time.

Chart No. 1: Ten-Year Historical WACOG



Demand Cost

The Company's demand costs included in Schedule 150 include pipeline transportation costs necessary to transport gas from the market to the Company's system and the fixed cost of natural gas storage. *Id.* at 4. The Company initially proposed a demand cost of 0.10975 per therm, which is an increase of $0.00995 per therm for residential customers as compared to the amount

currently authorized in last year's PGA. Application at 4; Order No. 36823. However, the Company inadvertently double counted a contract in its contract and trading system, which incorrectly increased demand costs by $1,366,289 (system) from November 2026 through October 2027. Response to Staff's Production Request No. 1. After correcting the double-counted entry, the Company filed an Amended Application and workpapers. In the Amended Application Exhibit D (Confidential), the estimated expense for Northwest Pipeline Corporation decreased by $1,366,289, resulting in a decreased demand cost increase of $0.00535 per therm and reducing the proposed Tariff Schedule 150 collection amount by approximately $474,000. Amended Application at 4; Amended Application Exhibit D (Confidential). The resulting proposed demand cost rate is 0.10515 per therm. Amended Application Exhibit D (Confidential). Staff believes this correction is justified and reasonable.

The Company justified the increased demand cost based on an updated Canadian exchange rate, an updated demand forecast, and a 50% increase in Northwest Pipeline Corporation's cost recovery mechanism that increased its rates from $0.02256 per million British Thermal Units ("MMBtu") to $0.03389 per MMBtu. Response to Staff's Production Request No. 1.

Schedule 155 – Amortization of the Deferral Account

Tariff Schedule 155 reflects the amortization of the Company's deferral account. The deferral consists of the difference between the actual price the Company paid for natural gas, storage, and transportation and the Schedule 150 rates established in the previous PGA. The Company's proposed amortization rate change for Schedules 101 and 111 is an increase in revenue of $0.01113 per therm. Amended Application at 4. The current rate for Schedules 101 and 111 is "$0.06278 per therm in the rebate direction[,]" and "the proposed rate is $0.05165 per therm in the rebate direction[,]" reflecting an increase in revenue of $0.01113 per therm. *Id.* at 4 (emphasis in original not included).

Included in the deferral activity are two items that benefit customers: (1) excess capacity releases totaling $3,688,848, discussed in the Capacity Release section below, and (2) benefits from the Deferred Exchange Contract totaling $3,784,319. Amended Application Exhibit D (Confidential). These amounts are included in the deferral activity shown in Table No. 1 below. The deferral also includes monthly interest charges on the deferred balances. Amended Application Exhibit D (Confidential)

The Company calculated the balance to be amortized as $5,209,940. *Id.* On a per therm basis, the net impact of the expiring amortization rebate and the proposed amortization rebate of $0.05165 per therm is an increase in revenue of $0.01113 per therm.

In the workpapers accompanying Amended Application Exhibit D (Confidential), the Company provided a reconciliation of Tariff Schedule 155 deferrals and amortization, as shown in Table No. 1 below:

Table No. 1: PGA Deferral and Amortization Reconciliation

Amortization Balance as of June 30, 2025	(2,264,683)
Amortization Activity	4,837,882
True-Up (Nov 1, 2025)	(5,820,542)
Interest on Unamortized Balance	(187,158)
Total Unamortized Balance	$ (3,434,501)
Current Year Deferral Activity	
Deferral Balance as of June 30, 2025	(4,351,701)
Transfer to Amortization Account (Nov 1, 2025)	5,820,720
Deferral of Demand Costs	5,009,757
Commodity Cost Deferral	(1,630,256)
Interest on Deferrals	(119,850)
Excess Capacity Releases	(3,688,848)
Deferred Exchange Contract (Idaho Portion)	(3,784,319)
Total Amortization Balance	$ (2,744,497)
Forecasted Amortization/Interest (Jul 1, 2026 – Oct 31, 2026)	969,058
Total Balance to be Amortized Through Rate Schedule 155	$ (5,209,940)

Market Fundamentals and Price Analysis

Throughout the previous thirty-six months, the Company "has been hedging natural gas on both a periodic and discretionary basis" for the upcoming PGA year. Amended Application at 3. "Approximately 34% of the annual load requirements for this year's PGA period (November 2026 through October 2027) have been hedged at a fixed price derived from" the Company's Procurement Plan. *Id.* Through June, the hedged volumes for the PGA period have been executed at a weighted average price of $2.61 per dekatherm, or $0.26065 per therm. *Id.*

"The Company used a 30-day historical average of AECO forward prices (ending June 30, 2026) to develop an estimated cost associated with index purchases." *Id.* at 4. "These index purchases represent approximately 46% of estimated annual load requirements for the coming year." *Id.* (emphasis in original not included). The annual weighted average price for these volumes is $1.87 per dekatherm, or $0.1874 per therm. *Id.* Last year, the annual weighted average price was $2.58 per dekatherm, or $0.2584 per therm. Case No. AVU-G-25-07Application at 4.

Staff also examined the forecasts of national and regional organizations to see how perceived market conditions might vary from the monthly Henry Hub Natural Gas futures and options on the New York Mercantile Exchange. Specifically, Staff reviewed the Energy Information Administration ("EIA") Short-Term Energy Natural Gas Outlook, which states:

> **Natural gas trade**
> We expect U.S. liquefied natural gas (LNG) exports in the third quarter of 2026 (3Q26) to average 16.5 billion cubic feet per day (Bcf/d), down 0.2 Bcf/d compared with last month's forecast. In July, international prices rose to levels last reached in early April, as LNG vessel traffic through the Strait of Hormuz slowed considerably after strikes on vessels resumed on July 7. Maintenance at Freeport LNG began on July 10 and is expected to be completed in late August, affecting 2.0 Bcf/d of nominal export capacity in the short-term. However, even with Freeport fully operational, exports would remain limited due to slow growth in additional export capacity despite U.S. price spreads to Europe and Asia remaining elevated due to ongoing disruptions.
> Maintenance at Freeport and other LNG export terminals have reduced feedgas demand on the Gulf Coast in June and July. Reduced demand has helped boost storage inventories in the South Central region to 5% above the five-year average (2021–2025) as of the week ending July 31, compared with inventories that were almost equal to the five-year average during the week ending May 29, according to our *Weekly Natural Gas Storage Report*….
>
> **Natural gas prices and storage**
> We expect the Henry Hub spot price to average $2.87 per million British thermal units (MMBtu), in 3Q26, down 50 cents compared with last month's forecast. Our lower price forecast reflects reduced LNG feedgas demand and record natural gas production, which we expect will leave natural gas inventories at their highest level heading into winter since 2016. We expect Henry Hub prices to rise gradually in the coming months but remain relatively low because inventories are well above the five-year average. Futures prices show a similar pattern, with contracts through September 2026 remaining below $3.00/MMBtu….
>
> In this forecast, we expect natural gas inventories to be a record 3,985 billion cubic feet (Bcf) at the end of October 2026, which is an increase of 19 Bcf compared with the July STEO and 5% above the five-year average. With high storage heading into

> winter, we expect the Henry Hub spot price will remain below $3.00/MMBtu until November and average $3.03/MMBtu over the remaining five months of the year, nearly 50 cents/MMBtu lower than last month's forecast. [4]

Based on Staff's review of the market fundamentals and trends, Staff believes that the Company's cost of its current hedges and estimated cost of forward-looking index purchases are reasonable.

Capacity Release

The Company buys the right to transport gas through several interstate pipelines, which enables the Company to purchase natural gas from a variety of supply basins, both in the U.S. and Canada, and transport that gas to its service territory. Whenever the Company has surplus capacity on the pipelines that serve its customers, the available capacity is released to other pipeline users, and the resulting revenue is included in the amortization calculations. The Company's total excess capacity release revenue for the current PGA period for Idaho was $3,688,848. Amended Application Exhibit D (Confidential).

Lost and Unaccounted for Gas

LAUF gas is the inevitable imbalance that exists at any given time between the measured gas coming into a utility distribution system and the measured gas going out of the same system.[5] Staff verified that the five-year average is 0.91%, and is appropriately utilized when calculating their monthly demand forecast. Amended Application Exhibit D (Confidential). Staff reviewed the Company's LAUF gas rate and compared it to previous years. The Company reported a LAUF gas rate of 1.09%, which is an improvement from the previous year's LAUF gas rate of 2.61%. *Id.* Staff examined the Company's supporting LAUF gas workpapers and reconciled the data to information reported to the Pipeline and Hazardous Materials Safety Administration.

[4] EIA, *Short-Term Energy Outlook*, 10-11 (2026) https://www.eia.gov/outlooks/steo/archives/aug26.pdf (last visited Oct. 9, 2026).
[5] American Gas Association, *Unaccounted for Natural Gas in the Utility System,* Lost and Unaccounted For Gas V 11 (last visited Sep. 1, 2026).

Reporting

Staff recommends the Company continues the quarterly submission of the WACOG report, the Gas Accounting Data Download ("GADD") report, and deferred costs report with a journal entry with the Commission as they have been. Additionally, Staff recommends that the Company continue to submit the deferral calculation workbook ("DCW") in Excel format with the Commission because the workbook summarizes the numbers in the GADD and ties them to the PGA workpaper. Staff recommends that the DCW workbook be filed with the last quarterly report before a PGA application.

The reports requested by Staff have provided Staff with an opportunity to improve efficiencies, decrease turnaround time of data requests, and decrease the number of Staff audit/production requests.

CUSTOMER NOTICE AND PRESS RELEASE

The Company's press release and customer notice[6] were included with its Application. Staff reviewed the documents and determined that both met the requirements of Rule 125 of the Commission's Rules of Procedure, IDAPA 31.01.01.125. The notice was included with billing statements mailed to customers from August 4 through September 1, 2026. For customers enrolled in paperless billing, the notice was e-mailed during the same period and included a link to the digital version of the notice.

The Commission set a public comment deadline of October 14, 2026, which Staff believes provides customers with a reasonable opportunity to file timely comments. As of October 14, 2026, no customer comments have been submitted to the Commission.

STAFF RECOMMENDATION

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

[6] The press release and customer notice addressed the following cases. **Electric**: AVU-E-26-05 Power Cost Adjustment (PCA), AVU-E-26-06 Fixed Cost Adjustment (FCA), and AVU-E-26-07 Bonneville Power Administration Residential Exchange (ResEx). **Natural Gas**: AVU-G-26-02 Fixed Cost Adjustment (FCA), AVU-G-26-05 Energy Efficiency, and AVU-G-26-03 Purchased Gas Cost (PGA).

1. approve the Company's proposed Tariff Schedule 155 as filed with its original Application, which includes an amortization rate of $0.05165 per therm in the rebate direction, with an effective date of November 1, 2026;
2. approve the Company's Amended Application and proposed Tariff Schedule 150 as filed, which includes a Weighted Average Gas Cost rate of $0.16619 per therm, with an effective date of November 1, 2026;
3. direct the Company to continue filing with the Commission WACOG reports, GADD reports, and deferred costs report with journal entries quarterly, as they have been, and the DCW workbook in Excel format with the last quarterly report before the next PGA filing; and,
4. consider any late-filed comments from customers.

Respectfully submitted this 14th day of October 2026.

Kelsea Ross

Kelsea E. Ross
Deputy Attorney General

Technical Staff: Vicki Stephens, Leena Gilman, Seungjae Lee, Curtis Thaden

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 14th DAY OF OCTOBER 2026, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF ,** IN CASE NO. AVU-G-26-03, BY E-MAILING A COPY THEREOF TO THE FOLLOWING:

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