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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION DBA AVISTA UTILITIES FOR AUTHORITY TO CHANGE ITS NATURAL GAS RATES AND CHARGES (2009 PURCHASED GAS COST ADJUSTMENT).	**CASE NO. AVU-G-09-05** **COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, by and through its Attorney of record, Kristine A. Sasser, Deputy Attorney General, in response to the Notice of Application and Notice of Modified Procedure (Order No. 30912) submits the following comments.

BACKGROUND

On September 15, 2009, Avista Corporation dba Avista Utilities (Avista; Company) filed its annual Purchased Gas Cost Adjustment (PGA) Application requesting authority to decrease its annualized revenues by approximately $14.7 million. Application at 1. The PGA mechanism is used to adjust rates to reflect annual changes in Avista's costs for the purchase of natural gas from suppliers – including transportation, storage, and other related costs. Avista's earnings will not be decreased as a result of the proposed changes in prices and revenues. The Company requests that its Application be processed by Modified Procedure and that its rates become effective on November 1, 2009.

The Company states that if the proposed changes are approved its annual revenue will decrease by approximately $14.7 million or 17.8%. The average residential or small commercial customer using 66 therms per month will see a decrease of $12.74 per month.

The Company states that it purchases natural gas for customer usage and then transports this gas over various pipelines for delivery to customers. The Company defers the effect of timing differences due to implementation of rate changes and differences between the Company's actual Weighted Average Cost of Gas (WACOG) purchased and the WACOG embedded in rates. The Company states that it also defers the revenue received from the release of its storage capacity as well as various pipeline refunds or charges and miscellaneous revenue received from gas-related transactions.

Avista proposes decreasing the WACOG from the currently approved $0.75984 per therm to $0.49093 per therm. The Application asserts that wholesale gas prices have fallen dramatically since July 2008 and the Company has been hedging gas on a periodic basis throughout 2009 for the coming PGA year. The Company states that approximately 64% of its estimated annual load requirements for the PGA year will be hedged at a fixed price comprised of: (1) 42% of volumes hedged for a term of one year or less; (2) 10% of prior multi-year hedges; and (3) 12% from underground storage. The Company states that through August 2009, most of the planned hedge volumes for the PGA year have been executed at a weighted average price of $0.582 per therm.

The demand costs included in the Company's Application primarily represent the costs of pipeline transportation to the Company's system. Avista's proposal includes essentially no change in the demand cost included in rates. Application at 4.

The Company is also proposing a change in the present amortization rate that is used to refund or surcharge customers the difference between actual gas costs and projected gas costs from the last PGA filing through the past year. The present amortization rate for firm sales customers is a $0.1580 per therm refund. Avista is proposing a $0.0760 per therm <u>increase</u> in the amortization rate for firm sales customers. In order to mitigate a potential 2010 PGA increase, the Company proposes to refund the deferral balance over a two-year period, rather than one. Application at 4.

Avista asserts that it has notified customers of its proposed decrease in rates by posting a notice at each of the Company's district offices in Idaho, by means of a press release distributed to various informational agencies, and by separate notice to each of its Idaho gas customers via a bill insert. The Company requests that this matter be handled under Modified Procedure pursuant to Rules 201-210 of the Commission's Rules of Procedure.

STAFF ANALYSIS

Staff has reviewed the Company's Application to determine whether its adjustments to Schedule 150 reasonably capture its fixed (demand) and variable (commodity) costs. More specifically, Staff has reviewed the Company's pipeline transportation and storage costs, fixed price hedges, estimates of future commodity prices, and its risk management policies. In addition, Staff has reviewed the Application to determine whether the Company's Schedule 155 proposed two-year amortization rate appropriately passes back the deferral account credit balance to customers. When combined, Schedules 150 and 155 make up the PGA. Each component will be discussed in greater detail below.

Schedule 150 – Purchased Gas Cost Adjustment

The Schedule 150 portion of the PGA is comprised of two parts: the commodity costs (WACOG) and the demand costs. The WACOG is the Company's forward-looking price of purchased gas and storage gas embedded in base rates. This also includes the benefit of some off system transactions such as the Terasen Reservation Credit. The demand costs represent the cost of pipeline transportation to the Company's distribution system. As stated in the Application, "there is essentially no change in the demand costs included in rates." In this Application the proposed WACOG is $0.49093 per therm compared to the present $0.75984 per therm WACOG settled in the last rate case as part of Order No. 30856. The PGA rate reductions in this proposal and throughout the past year have been because of decreases in the overall WACOG. More specifically, this proposal drops the WACOG by approximately 35% and drops Schedule 101 revenue by approximately $15.1 million.

Weighted Average Cost of Gas (WACOG)

Throughout the last year there have been substantial declines in the wholesale cost of natural gas, which have allowed Avista to purchase gas for the coming year at favorable rates. Aside from this spring's settled rate case, this request reflects the third decrease within the Company's past four PGA filings, and makes the Company's proposal the lowest rate since the 2003 filing. The table below illustrates the changes in the natural gas market over the past eight years and the volatility experienced over the same period.

Year Tariff Was Established	Approved Weighted Avg. Cost of Gas $/Therm	% Change From Previous Year	Resulting Total General Service Schedule 101 Tariff, $/Therm	% Change From Previous Year
2002	0.34572	Base Year	0.75722	Base Year
2003	0.44989	30.13%	0.77716	2.63%
2004	0.55739	23.89%	0.95315	22.64%
2005	0.76786	37.76%	1.18692	24.53%
2006	0.76085	-0.91%	1.16175	-2.12%
2007	0.75544	-0.71%	1.1056	-4.83%
2008	0.78646	4.11%	1.15103	4.11%
2009*	0.75984	-3.38%	1.07507	-6.60%
2009 (Company Proposed)	0.49093	-35.39%	0.88199	-17.96%

*The WACOG change was part of the AVU-G-09-01 settlement intended to offset the impact of the residential base rate increase approved in Order No. 30856.

In addition to the national economic impact on weather adjusted demand, a number of factors have contributed to excess supplies throughout the past year. Several influencing factors contributing to this supply include: (1) the cooler summer reduced the need for natural gas fired electric generation; (2) the discovery of an abundance of North American shale reserves; (3) the spread of global recession led to higher than normal supplies of Liquid Natural Gas (LNG); (4) the volume of natural gas in storage exceeded historical averages and continued to increase through the injection season; and (5) the surge in drilling rigs brought on by last summer's high prices.

In order to estimate natural gas prices for the following year the Company used a 30-day historical NYMEX average of forward prices (ending August 31) by supply basin to develop an estimated cost associated with index/spot purchases. The estimated monthly volumes to be purchased by basin are multiplied by the 30-day average price for the corresponding month and basin. The Company has already hedged 64% of its estimated annual load requirements at a fixed price of $0.582 per therm. The index spot volumes, using Company estimated future prices, represents approximately 36% of the estimated annual load requirements in the coming year. It has estimated the weighted average price for these volumes to be $0.478 per therm. Upon review the Company's estimates for these volumes seem reasonable given NYMEX forward prices. However, Staff has estimated approximately a 24% average premium built into the 2010 NYMEX prices when compared to the estimates of third party forecasters. It is understandably difficult to estimate the risk margin built into forward prices in these dynamic times. Consequently, Staff encourages the Company to closely watch these as a number of determining factors develop throughout the year.

When evaluating the Company's estimates against data from the NYMEX Futures Index, Energy Information Administration (EIA), and Wood Mackenzie, the Company seems to have estimated prices slightly higher than anticipated. The following factors support lower estimated prices through October 2010: (1) slight global economic improvements are only expected to increase consumption 0.5 percent in 2010 from a comparative decline of 2.6 percent in 2009; (2) compared to 2009, the 2010 expectation of lower coal prices is anticipated to lead to slight reductions in natural gas use by the electric power sector; (3) Gulf of Mexico production is expected to increase by 3.3 percent this year because of a lower anticipated incidence of hurricane activity and several deep water fields coming online; (4) Liquefied Natural Gas (LNG) imports are expected to increase by 240 bcf in 2010 as the U.S. becomes the most attractive import market; and (5) the EIA is forecasting fewer heating degree days than normal.

Given that the Company has hedged 64% of its estimated load requirements for the upcoming year at fixed prices, and it estimates the additional volumes to be purchased at $0.478 per therm, Staff recommends the Commission accept the Company's proposed $0.49093 WACOG. However, if spring and summer prices significantly deviate from the proposed rates, the Company should return to the Commission with a new filing.

Schedule 155 – Deferred Expenses

The Schedule 155 portion of the PGA is the amortization component of the Company's deferral account. When the Company pays more for gas than what is estimated in the preceding WACOG, a surcharge is issued to customers. However, if the Company pays less for gas than what is estimated in the preceding WACOG, a credit is issued to customers. Gas prices have continued to fall throughout the year compared to the WACOG anticipated in the Company's last filing, and as part of the adjustment in the last rate case settlement. By November 2009, the deferral balance is expected to leave customers with a refund of $12.3 million.

Typically the deferral balance is amortized over one year through a credit or surcharge. However, in this PGA filing the Company has proposed to refund the deferral balance over a two-year period. The Company believes that the substantial WACOG reduction in this filing presents a unique opportunity to mitigate future PGA increases through a two-year refund of the deferral balance. The inherent risk to customers of a two-year amortization centers around gas prices continuing to drop (or being less than the estimated WACOG), and therefore contributing to a larger deferral account credit owed to customers. Staff believes that the risk of higher gas cost for customers next year under a single year amortization is diminished by continued growth in the Schedule 155 deferral balance for refund since June 30, 2009. Staff also cites the potential for a lower WACOG than that included by the Company in this case.

Similar to the PGA, in 1993 the Commission instituted a "Power Cost Adjustment" (PCA) to ameliorate the adverse consequences of fluctuating power supply costs both to customers and the Company. Therefore, ratepayers receive a credit when power costs are lower than anticipated in the previous year, and a surcharge when power costs are higher than anticipated in the previous year. In two prior cases, IPC-E-01-07 and IPC-E-01-11, Idaho Power sought to recover a combined $227.4 million in power purchase costs over a one-year period.[1] Staff and intervening parties recommended a more flexible time period for administering the true-up of approximately $168.3 million. The Commission declined to adopt these recommendations and determined it was "reasonable and appropriate for the Company to recover these costs within the normal one year time frame." In Order No. 28852, the Commission reinforced its decision in Order No. 28722 by stating that it must "balance the needs of the Company to maintain its financial viability with customer concerns of fair rates and rate stability."

Based on prior Commission decisions and reasoning, Staff recommends in the present PGA filing that the Commission amortize the deferral credit balance to customers over one year. When a credit is due, business owners and families are entitled to maintain financial viability to the same extent that the Company enjoys in a surcharge situation. Nationally, according to the

[1] In Order No. 28722 regarding these cases, the Commission questioned the prudency of certain power purchase costs, and therefore deferred the recovery of approximately $59 million pending further investigation.

Small Business Administration (SBA), an estimated 627,200 new employer firms began operations in 2008, and 595,600 firms closed that same year. Although conditions have shown signs of improvement in the second and third quarters of this year, many businesses need relief now in order to keep doing business. For many of these businesses, if rate relief is not received now, they may have paid into a deferral account they will never have returned. According to a report filed by the Idaho Department of Labor, "The rapid escalation of Idaho's unemployment rate has hit every county. Fifteen had double digit rates in August 2009, and every county had a rate higher than a year earlier." Families have had to make decisions between purchases to put food on the table and paying bills to heat their homes. The economic climate remains challenging for businesses and families alike. Given past Commission decisions regarding the amortization of rate adjustment mechanisms, the current economic conditions, and the low risk of gas price increases next year, Staff recommends the Commission amortize the deferred credit balance over one year instead of accepting the Company's proposed two-year amortization. If Staff's recommendation is approved, the per therm amortization rate for Schedule 155 will increase by 2.008 cents per therm for customers on tariff Schedules 101 and 111 and 0.433 cents per therm for customers on tariff Schedule 131. When this is combined with the proposed decrease in Schedule 150 rates, the Company's annual overall revenue will decrease by approximately $18.8 million or about 22.9%, as compared to the Company's proposal of approximately $14.7 million or about 17.8%. The calculation of Staff's proposal can be seen in Attachments 1 through 5.

Hedging Policies

The Company's gas procurement plan generally incorporates a structured approach for the hedging portion of the portfolio, however it also maintains flexibility in its plan so discretionary adjustments can be made when the wholesale gas market changes. Discretion is used in evaluating current volatility, forward curve shapes, and alternatives when considering price triggers. The Company continues to hedge utilizing a series of price targets. In the case of decreasing prices, target purchase volumes are increased. The Company meets with Staff to collaborate on the procurement plan given the wholesale natural gas environment. In meetings this spring, the Company informed Staff of several additions to its long-term hedging strategies. Specifically, the Company has: (1) defined its pricing targets [redacted]

[redacted] (2) decided to keep long-term hedges open for up to two or three years, depending on which strip triggers first; (3) decided price targets will be "open" all year; and (4) dropped the minimum portfolio hedge percentage by 10% with an additional 15% carved out for discretionary action. Throughout the year the Company communicates with Staff when it believes a decision is being made outside the scope of the normal procurement plan. Over the course of the year, the Company has communicated with Staff regarding its storage and procurement activities, [redacted] Given volatility in the natural gas market over the last two years, the Company has done a reasonable job of maintaining a procurement plan that is structured but provides discretionary decision making. The Company continues to purchase gas at favorable prices and provide stability to customers.

CONSUMER ISSUES

Customer Notice and Press Release

The press release was included in Avista's original Application. The Application was received September 15, 2009. Staff obtained a copy of the Customer Notice. Staff reviewed the original customer notice and press release and determined that the Company was in compliance with the requirements of IDAPA 31.21.02.102. The customer notice was mailed with cyclical billings beginning September 20, 2009 and ending October 20, 2009.

Customer Comments

Customers were given until October 16, 2009 to file comments. As of October 16, 2009, no comments had been filed by customers.

RECOMMENDATION

After a complete examination of the Company's Application and gas purchases for the year, Staff has the following recommendations for the Commission:

1) That the Company's proposed changes to the Schedule 150 (Purchased Gas Cost Adjustment) be accepted. In doing so, Staff recommends that the Commission accept the proposed WACOG of 49.093 cents per therm which results in a Schedule 150 credit of

26.922 cents per therm for customers on tariff Schedules 101, 111 and 112 and a credit of 26.891 cents per therm for interruptible customers on Schedules 131 and 132.

2) That the Commission approve a one-year amortization of deferral balances. In doing so, Staff recommends that the Commission accept a proposed decrease in the credit of 2.008 cents per therm for customers on tariff Schedules 101, and 111 and a decrease in the credit of 0.433 cents per therm for customers on tariff Schedule 131. This would result in a decrease to the Company's annual overall revenue by $18,881,959 or 22.90%. This compares to the Company's proposal that results in an annual overall revenue decrease by $14,699,479 or 17.83%.

3) Staff also recommends that the Commission reserve the right to reopen this case and reevaluate any approved tariffs if the WACOG materially changes below that included in this Application.

Respectfully submitted this 16TH day of October 2009.

Kristine A. Sasser

Kristine A. Sasser
Deputy Attorney General

Technical Staff: Matt Elam
Donn English
Daniel Klein

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Idaho Public Utilities Commission
Staff's Proposal
Calculation of Overall Rate Change

	GRC* Annual Therms	Sch 150 Per Therm Inc <Dec>	Sch 150 Annual Inc <Dec>	Sch 155 Per Therm Inc <Dec>	Sch 155 Annual Inc <Dec>	Sch 155 Direct Chg <Refunds>	Total Sch 155 Inc <Dec>	Total Sch 150/155 Inc <Dec>
Schedule 101	56,159,133	($0.26922)	($15,119,162)	$0.02008	$1,127,675		$1,127,675	($13,991,487)
Schedule 111	18,733,321	($0.26922)	($5,043,385)	$0.02008	$376,165		$376,165	($4,667,220)
Schedule 112		($0.26922)						
Schedule 131		($0.26891)		$0.00433				
Schedule 132	422,828	($0.26891)	($113,703)					($113,703)
Schedule 146	3,687,960							
Lignetics						($242)	($242)	($242)
North Idaho Energy Logs						($86,233)	($86,233)	($86,233)
Stimson Lumber (RA)								
St Joseph Hospital						($23,074)	($23,074)	($23,074)
	79,003,242		($20,276,250)		$1,503,840	($109,549)	$1,394,291	($18,881,959)
Total Annual GRC Weather Adjusted Revenue*								$82,448,022
Percent of Increase <Decrease>								-22.90%

*Annual therms and weather adjusted revenue are based on the last general rate case (GRC)

Idaho Public Utilities Commission
Staff's Proposal
Calculation of Idaho Proposed Rates

Sch No.	Description	Present Rate	Proposed Schedule 150	Proposed Schedule 155	Present Schedule 191 (DSM)	Total Proposed Rate
101	General	$0.87815	$0.05117	($0.13797)	$0.03458	$0.82593
111	Large General					
	First 200	$0.86316	$0.05117	($0.13797)	$0.03045	$0.80681
	Next 800	$0.79944	$0.05117	($0.13797)	$0.03045	$0.74309
	1,0001 - 10,000	$0.72485	$0.05117	($0.13797)	$0.03045	$0.66850
	Over 10,000	$0.68401	$0.05117	($0.13797)	$0.03045	$0.62766
112	Large General					
	First 200	$0.86316	$0.05117		$0.03045	$0.94478
	Next 800	$0.79944	$0.05117		$0.03045	$0.88106
	1,0001 - 10,000	$0.72485	$0.05117		$0.03045	$0.80647
	Over 10,000	$0.68401	$0.05117		$0.03045	$0.76563
131	Interruptible	$0.61264	$0.04104	($0.11600)	$0.02552	$0.56320
132	Interruptible	$0.61264	$0.04104		$0.02552	$0.67920
146	Transportation	$0.11385				$0.11385

Idaho Public Utilities Commission
Staff's Proposal
Average Increase Per Customer

Sch No.	Average No. of Customers	Description	Average Mo. Usage Per Cust.	Present Rate	Total Present Cost	Proposed Rate	Total Proposed Cost	Estimated Monthly Decrease	Estimated Decrease Percentage
101	69,515		66	$1.07507	$70.95	$0.82593	$54.51		
		Basic Charge		$4.00	$4.00		$4.00		
					$74.95		$58.51	($16.44)	-21.93%
111	792		1,971						
		First 200		$1.05595	$211.19	$0.80681	$161.36		
		Next 800		$0.99223	$793.78	$0.74309	$594.48		
		1,0001 - 10,000		$0.91764	$891.03	$0.66850	$649.11		
		Over 10,000		$0.87680		$0.62766			
					$1,896.00		$1,404.95	($491.05)	-25.90%
131	None			$0.82778		$0.56320			-31.96%
132	1		35,236	$0.94811	$33,407.60	$0.67920	$23,932.29	($9,475.31)	-28.36%
	70,308								

Idaho Public Utilities Commission
Comparison of Idaho Proposed Rates
Company vs. Staff

Sch No.	Description	Total Present Rate	Company's Total Proposed Rate	Staff's Total Proposed Rate	Company's Proposal vs. Present Rates	Staff's Proposal vs. Present Rates
101	General	$1.07507	$0.88199	$0.82593	-17.96%	-23.17%
111	Large General					
	First 200	$1.05595	$0.86287	$0.80681	-18.28%	-23.59%
	Next 800	$0.99223	$0.79915	$0.74309	-19.46%	-25.11%
	1,0001 - 10,000	$0.91764	$0.72456	$0.66850	-21.04%	-27.15%
	Over 10,000	$0.87680	$0.68372	$0.62766	-22.02%	-28.41%
112	Large General					
	First 200	$1.21400	$0.94478	$0.94478	-22.18%	-22.18%
	Next 800	$1.15028	$0.88106	$0.88106	-23.40%	-23.40%
	1,0001 - 10,000	$1.07569	$0.80647	$0.80647	-25.03%	-25.03%
	Over 10,000	$1.03485	$0.76563	$0.76563	-26.02%	-26.02%
131	Interruptible	$0.82778	$0.59798	$0.56320	-27.76%	-31.96%
132	Interruptible	$0.94811	$0.67920	$0.67920	-28.36%	-28.36%
146	Transportation	$0.11385	$0.11385	$0.11385		

Idaho Public Utilities Commission
Staff's Proposal
Gas Rate Adjustment (Schedule 155)
Calculation of Changes

Schedule	Current Rate Incr <Decr>	Proposed Rate Incr <Decr>	Total Proposed Incr <Decr>
Firm Customers, Schs 101 & 111	($0.15805)	($0.13797)	$0.02008
Firm Customers, Schedules 112			
Interruptible Customers, Schedules 131	($0.12033)	($0.11600)	$0.00433
Interruptible Customers, Schedules 132			
Transportation Customers, Schedules 146			
Special Amortization Rates			

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 16TH DAY OF OCTOBER 2009, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. AVU-G-09-05, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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